

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c))
Emergency Order: Tri-State)
Generation and Transmission)
Association, Platte River Power)
Authority, Salt River Project,)
PacifiCorp, and Xcel Energy)

Order No. 202-25-14

Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
Public Interest Organizations

Filed January 28, 2026

Exhibit 1-106:
EIA Annual 2024



Independent Statistics and Analysis

**U.S. Energy Information
Administration**

Electric Power Annual 2024

October 2025

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Independent Statistics & Analysis

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U.S. Department of Energy

Washington, DC 20585

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Chapter 1

National Summary Data

Table 1.1. Total Electric Power Industry Summary Statistics, 2024 and 2023

Net Generation and Consumption of Fuels for January through December														
		Total (All Sectors)			Electric Power Sector				Commercial		Industrial		Residential	
					Electric Utilities		Independent Power Producers							
Fuel	Facility Type	Year 2024	Year 2023	Percentage Change	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023
Net Generation (Thousand Megawatthours)														
Coal	Utility Scale Facilities	652,156	675,115	-3.4%	508,149	518,330	139,527	152,238	204	220	4,276	4,327	0	0
Petroleum Liquids	Utility Scale Facilities	11,456	11,397	0.5%	8,504	8,254	2,567	2,573	12	76	372	494	0	0
Petroleum Coke	Utility Scale Facilities	3,629	4,836	-25.0%	1,946	3,146	1,377	1,415	4	2	302	273	0	0
Natural Gas	Utility Scale Facilities	1,869,902	1,806,063	3.5%	953,446	895,910	812,528	803,945	7,157	7,744	96,771	98,463	0	0
Other Fossil Gas	Utility Scale Facilities	10,845	11,778	-7.9%	0	0	2,976	3,340	0	0	7,870	8,438	0	0
Nuclear	Utility Scale Facilities	781,865	774,873	0.9%	444,521	441,391	337,345	333,482	0	0	0	0	0	0
Hydroelectric Conventional	Utility Scale Facilities	242,896	245,002	-0.9%	220,163	220,003	21,612	23,862	311	293	810	844	0	0
Renewable Sources Excluding Hydroelectric	Utility Scale Facilities	733,567	650,239	12.8%	123,555	106,543	582,350	516,694	4,441	4,545	23,220	22,456	0	0
... Wind	Utility Scale Facilities	451,904	421,141	7.3%	89,056	80,120	362,616	340,780	133	130	99	112	0	0
... Solar Thermal and Photovoltaic	Utility Scale Facilities	219,834	165,530	32.8%	30,347	22,230	188,376	142,360	566	615	546	326	0	0
... Wood and Wood-Derived Fuels	Utility Scale Facilities	31,564	31,615	-0.2%	2,436	2,549	7,218	7,637	111	107	21,800	21,320	0	0
... Other Biomass	Utility Scale Facilities	14,858	15,585	-4.7%	804	862	9,647	10,332	3,631	3,693	776	698	0	0
... Geothermal	Utility Scale Facilities	15,407	16,367	-5.9%	914	782	14,493	15,586	0	0	0	0	0	0
Hydroelectric Pumped Storage	Utility Scale Facilities	-5,852	-5,990	-2.3%	-4,232	-4,545	-1,619	-1,445	0	0	0	0	0	0
Other Energy Sources	Utility Scale Facilities	8,170	9,957	-17.9%	285	580	1,627	2,823	3,130	3,185	3,127	3,369	0	0
All Energy Sources	Utility Scale Facilities	4,308,634	4,183,270	3.0%	2,256,336	2,189,614	1,900,291	1,838,927	15,258	16,066	136,749	138,664	0	0
Estimated Small Scale Solar Photovoltaic	Small Scale Facilities	83,918	73,406	14.3%	0	0	0	0	21,652	19,751	4,719	4,382	57,547	49,273
Estimated Total Solar Photovoltaic	All Facilities	300,634	236,090	27.3%	30,347	22,230	185,257	139,513	22,218	20,366	5,265	4,708	57,547	49,273
Estimated Total Solar	All Facilities	303,752	238,937	27.1%	30,347	22,230	188,376	142,360	22,218	20,366	5,265	4,708	57,547	49,273
Consumption of Fossil Fuels for Electricity Generation														
Coal (1000 tons)	Utility Scale Facilities	372,931	386,626	-3.5%	284,849	291,034	86,586	94,063	65	69	1,431	1,460	0	0
Petroleum Liquids (1000 barrels)	Utility Scale Facilities	20,787	21,335	-2.6%	16,058	16,366	4,137	4,253	179	200	414	517	0	0
Petroleum Coke (1000 tons)	Utility Scale Facilities	1,662	2,028	-18.0%	960	1,328	596	594	1	1	104	105	0	0
Natural Gas (1000 Mcf)	Utility Scale Facilities	13,754,749	13,245,495	3.8%	7,282,518	6,821,490	5,831,864	5,766,810	47,993	49,069	592,373	608,127	0	0
Consumption of Fossil Fuels for Useful Thermal Output														
Coal (1000 tons)	Utility Scale Facilities	8,883	9,363	-5.1%	1,485	1,580	338	527	356	331	6,703	6,925	0	0
Petroleum Liquids (1000 barrels)	Utility Scale Facilities	2,238	3,133	-28.6%	66	65	612	330	440	363	1,120	2,374	0	0
Petroleum Coke (1000 tons)	Utility Scale Facilities	608	622	-2.2%	0	8	103	115	5	3	499	495	0	0
Natural Gas (1000 Mcf)	Utility Scale Facilities	1,246,683	1,210,187	3.0%	48,851	46,531	313,214	306,058	80,431	69,832	804,187	787,767	0	0
Consumption of Fossil Fuels for Electricity Generation and Useful Thermal Output														
Coal (1000 tons)	Utility Scale Facilities	381,814	395,989	-3.6%	286,334	292,615	86,924	94,591	422	400	8,134	8,384	0	0
Petroleum Liquids (1000 barrels)	Utility Scale Facilities	23,025	24,468	-5.9%	16,124	16,431	4,748	4,583	619	563	1,534	2,891	0	0
Petroleum Coke (1000 tons)	Utility Scale Facilities	2,270	2,649	-14.3%	960	1,336	699	709	6	4	604	600	0	0
Natural Gas (1000 Mcf)	Utility Scale Facilities	15,001,432	14,455,682	3.8%	7,331,369	6,868,021	6,145,078	6,072,868	128,424	118,901	1,396,561	1,395,893	0	0

Sales, Revenue, and Average Price of Electricity to Ultimate Customers for January through December									
Total U.S. Electric Power Industry									
Sales of Electricity to Ultimate Customers (million kWh)				Revenue from Sales of Electricity to Ultimate Customers (million dollars)			Average Price of Electricity to Ultimate Customers (cents/kWh)		
Sector	Year 2024	Year 2023	Percentage Change	Year 2024	Year 2023	Percentage Change	Year 2024	Year 2023	Percentage Change
Residential	1,482,874	1,450,025	2.3%	244,367	231,993	5.3%	16.48	16.00	3.0%
Commercial	1,450,941	1,408,109	3.0%	185,043	177,342	4.3%	12.75	12.59	1.3%
Industrial	1,034,584	1,009,256	2.5%	84,095	81,159	3.6%	8.13	8.04	1.1%
Transportation	6,983	6,864	1.7%	890	877	1.6%	12.75	12.77	-0.2%
All Sectors	3,975,382	3,874,253	2.6%	514,396	491,370	4.7%	12.94	12.68	2.1%

NM = Not meaningful due to large relative standard error.

W = Withheld to avoid disclosure of individual company data.

Displayed values of zero may represent small values that round to zero. The Excel version of this table provides additional precision which may be accessed by selecting individual cells.

Coal generation and consumption includes anthracite, bituminous, subbituminous, lignite, waste coal, refined coal, synthetic coal, and coal-derived synthesis gas.

Petroleum Liquids includes distillate fuel oil, residual fuel oil, jet fuel, kerosene, propane, and waste oil.

Petroleum Coke includes petroleum coke and synthesis gas derived from petroleum coke.

Natural gas includes a small amount of supplemental gaseous fuels that cannot be identified separately.

Other Fossil Gas includes gaseous propane, blast furnace gas, other manufactured and waste gases derived from fossil fuels other than hydrogen.

Wood and Wood-Derived Fuels include wood, black liquor, and other wood waste.

Other Biomass includes biogenic municipal solid waste, landfill gas, sludge waste, agricultural byproducts, and other biomass.

Other Energy Sources includes hydrogen, non-biogenic municipal solid waste, batteries, purchased steam, sulfur, tire-derived fuel, and other miscellaneous energy sources.

Coal stocks include anthracite, bituminous, subbituminous, lignite, refined coal, and synthetic coal; waste coal is excluded.

Sales of electricity to ultimate customers and net generation may not correspond exactly for a particular month for a variety of reasons (e.g., sales data may include imported electricity).

Net generation is presented for the calendar month while sales of electricity to ultimate customers and associated revenue accumulate from bills collected for periods of time that vary depending

Table 1.2. Summary Statistics for the United States, 2014 - 2024

(From Table 2.1.) Number of Ultimate Customers

Year	Residential	Commer-cial	Industrial	Transpor-tation	Other	Total
2014	128,680,416	17,853,995	839,212	79	N/A	147,373,702
2015	129,811,718	17,985,690	835,536	78	N/A	148,633,022
2016	131,068,760	18,148,353	838,059	86	N/A	150,055,258
2017	132,579,747	18,359,427	840,329	86	N/A	151,779,589
2018	133,893,321	18,605,393	840,321	83	N/A	153,339,118
2019	135,249,616	18,694,240	954,222	83	N/A	154,898,161
2020	136,682,001	18,848,813	992,311	83	N/A	156,523,208
2021	138,308,772	19,102,304	1,022,212	82	N/A	158,433,370
2022	139,854,178	19,257,529	1,049,983	86	N/A	160,161,776
2023	141,282,713	19,381,328	1,078,249	85	N/A	161,742,375
2024	143,144,185	19,480,886	1,115,974	81	N/A	163,741,126

(From Table 2.2.) Sales to Ultimate Customers

(Thousand Megawatthours)

Year	Residential	Commer-cial	Industrial	Transpor-tation	Other	Total
2014	1,407,208	1,352,158	997,576	7,758	N/A	3,764,700
2015	1,404,096	1,360,752	986,508	7,637	N/A	3,758,992
2016	1,411,058	1,367,191	976,715	7,497	N/A	3,762,462
2017	1,378,648	1,352,888	984,298	7,523	N/A	3,723,356
2018	1,469,093	1,381,755	1,000,673	7,665	N/A	3,859,185
2019	1,440,289	1,360,877	1,002,353	7,632	N/A	3,811,150
2020	1,464,605	1,287,440	959,082	6,548	N/A	3,717,674
2021	1,470,487	1,328,439	1,000,613	6,334	N/A	3,805,874
2022	1,509,233	1,390,873	1,020,464	6,599	N/A	3,927,169
2023	1,450,025	1,408,109	1,009,256	6,864	N/A	3,874,253
2024	1,482,874	1,450,941	1,034,584	6,983	N/A	3,975,382

(From Table 2.3.) Revenue From Ultimate Customers

(Million Dollars)

Year	Residential	Commer-cial	Industrial	Transpor-tation	Other	Total
2014	176,178	145,253	70,855	810	N/A	393,096
2015	177,624	144,781	68,166	771	N/A	391,341
2016	177,077	142,643	66,068	722	N/A	386,509
2017	177,661	144,242	67,691	728	N/A	390,322
2018	189,033	147,425	69,218	744	N/A	406,420
2019	187,436	145,280	68,285	737	N/A	401,738
2020	192,663	136,372	63,956	648	N/A	393,639
2021	200,834	149,008	71,835	646	N/A	422,323
2022	226,990	172,600	84,895	765	N/A	485,249
2023	231,993	177,342	81,159	877	N/A	491,370

Table 1.2. Summary Statistics for the United States, 2014 - 2024

2024	244,367	185,043	84,095	890	N/A	514,396

(From Table 2.4.) Average Price

(Cents per Kilowatthour)

Year	Residential	Commer-cial	Industrial	Transpor-tation	Other	Total
2014	12.52	10.74	7.10	10.45	N/A	10.44
2015	12.65	10.64	6.91	10.09	N/A	10.41
2016	12.55	10.43	6.76	9.63	N/A	10.27
2017	12.89	10.66	6.88	9.68	N/A	10.48
2018	12.87	10.67	6.92	9.70	N/A	10.53
2019	13.01	10.68	6.81	9.66	N/A	10.54
2020	13.15	10.59	6.67	9.90	N/A	10.59
2021	13.66	11.22	7.18	10.20	N/A	11.10
2022	15.04	12.41	8.32	11.59	N/A	12.36
2023	16.00	12.59	8.04	12.77	N/A	12.68
2024	16.48	12.75	8.13	12.75	N/A	12.94

(From Tables 2.12. - 2.14.) Trade

(Thousand Megawatthours)

Year	Purchases	Sales for Resale	Imports	Exports
2014	4,802,227	4,908,839	66,510	13,298
2015	4,761,523	4,797,395	75,770	9,100
2016	4,723,571	4,746,967	72,716	6,214
2017	4,861,257	4,889,947	65,685	9,371
2018	5,168,874	5,127,276	58,261	13,804
2019	5,371,635	5,172,430	59,052	20,008
2020	5,224,580	5,145,459	61,449	14,135
2021	5,067,170	4,938,756	53,167	13,855
2022	5,130,963	5,105,520	56,970	15,758
2023	4,795,772	4,866,463	38,917	20,013
2024	4,610,886	4,715,342	33,254	19,437

(From Tables 3.1.A. and 3.1.B.) Net Generation (Thousand Megawatthours)

Generation at Utility Scale Facilities									
Year	Coal	Petroleum	Natural Gas	Other Fossil Gas	Nuclear	Hydro Conventional	Hydro Pumped Storage	Geothermal	Wind
2014	1,581,710	30,232	1,126,635	12,022	797,166	259,367	-6,174	15,877	181,655
2015	1,352,398	28,249	1,334,668	13,117	797,178	249,080	-5,091	15,918	190,719
2016	1,239,149	24,205	1,379,271	12,807	805,694	267,812	-6,686	15,826	226,993
2017	1,205,835	21,390	1,297,703	12,469	804,950	300,333	-6,495	15,927	254,303
2018	1,149,487	25,226	1,471,843	13,463	807,084	292,524	-5,905	15,967	272,667
2019	964,957	18,341	1,588,533	12,591	809,409	287,874	-5,261	15,473	295,882
2020	773,393	17,341	1,626,790	11,818	789,879	285,274	-5,321	15,890	337,938
2021	897,999	19,173	1,579,190	11,397	779,645	251,585	-5,112	15,975	378,197
2022	831,512	22,931	1,687,065	11,722	771,537	254,789	-6,028	16,087	434,297
2023	675,115	16,233	1,806,063	11,778	774,873	245,002	-5,990	16,367	421,141

Table 1.2. Summary Statistics for the United States, 2014 - 2024

2024	652,156	15,084	1,869,902	10,845	781,865	242,896	-5,852	15,407	451,904

Generation at Utility Scale Facilities							Small Scale Generation	Utility and Small Scale Generation	
Year	Solar Photo-voltaic	Solar Thermal	Wood and Wood-Derived Fuels	Other Biomass	Other Energy Sources	Total Utility Scale Generation	Estimated Photo-voltaic	Total Photo-voltaic	Total Solar
2014	15,250	2,441	42,340	21,650	13,393	4,093,564	11,233	26,482	28,924
2015	21,666	3,227	41,929	21,703	13,955	4,078,714	14,139	35,805	39,032
2016	32,670	3,384	40,947	21,813	13,689	4,077,574	18,812	51,483	54,866
2017	50,018	3,269	41,124	21,610	13,008	4,035,443	23,990	74,008	77,277
2018	60,234	3,592	40,936	20,896	12,973	4,180,988	29,539	89,773	93,365
2019	68,719	3,218	38,543	18,964	13,331	4,130,574	34,957	103,676	106,894
2020	86,066	3,133	36,219	18,493	12,855	4,009,767	41,522	127,588	130,721
2021	112,335	2,924	36,463	17,790	12,140	4,109,699	49,164	161,499	164,422
2022	140,793	2,999	35,466	16,383	11,114	4,230,668	61,282	202,075	205,074
2023	162,683	2,847	31,615	15,585	9,957	4,183,270	73,406	236,090	238,937
2024	216,715	3,118	31,564	14,858	8,170	4,308,634	83,918	300,634	303,752

(From Tables 4.2.A. and 4.2.B.) Net Summer Generating Capacity (Megawatts)

Utility Scale Capacity									
Year	Coal	Petroleum	Natural Gas	Other Fossil Gas	Nuclear	Hydro Conventional	Hydro Pumped Storage	Geothermal	Wind
2014	299,094.2	41,135.4	432,150.3	1,914.3	98,569.3	79,677.3	22,485.1	2,514.3	64,231.5
2015	279,719.9	36,830.3	439,425.4	2,500.4	98,672.0	79,664.2	22,575.1	2,541.5	72,573.4
2016	266,619.9	34,382.4	446,823.2	2,456.9	99,564.8	79,912.9	22,778.7	2,516.6	81,286.6
2017	256,547.3	33,306.7	456,011.6	2,375.8	99,628.9	79,794.5	22,810.4	2,483.3	87,597.5
2018	242,785.6	32,218.2	470,236.9	2,543.9	99,432.9	79,871.8	22,830.2	2,444.3	94,417.7
2019	228,657.4	31,400.3	476,567.4	2,499.2	98,119.0	79,773.1	22,778.3	2,555.4	103,571.2
2020	215,554.2	27,569.3	485,807.2	2,275.2	96,500.6	79,924.3	23,016.2	2,571.9	118,378.7
2021	209,825.7	28,204.5	491,870.2	1,888.0	95,546.4	79,909.7	23,007.7	2,596.7	132,753.4
2022	189,316.3	30,775.3	502,396.9	1,728.2	94,658.9	80,067.6	23,043.9	2,648.6	141,402.2
2023	178,441.7	29,440.7	507,535.8	1,866.8	95,712.2	79,985.3	23,147.4	2,695.8	147,444.7
2024	174,177.6	28,649.7	506,371.0	1,678.1	98,391.2	79,896.5	23,156.6	2,695.5	152,097.3

Utility Scale Capacity							Small Scale Capacity	Utility and Small Scale Capacity	
Year	Solar Photo-voltaic	Solar Thermal	Wood and Wood-Derived Fuels	Other Biomass	Other Energy Sources	Total Utility Scale Capacity	Estimated Photo-voltaic	Total Photo-voltaic	Total Solar
2014	8,656.6	1,666.7	8,368.1	5,166.5	2,792.6	1,068,422.2	7,326.6	15,983.2	17,649.9
2015	11,905.4	1,757.9	8,968.9	5,124.5	1,795.6	1,064,054.5	9,778.5	21,683.9	23,441.8
2016	20,192.9	1,757.9	8,936.1	5,088.8	2,015.1	1,074,332.8	12,765.1	32,958.0	34,715.9
2017	25,209.0	1,757.9	8,830.9	5,129.5	2,886.3	1,084,369.6	16,147.8	41,356.8	43,114.7
2018	30,120.5	1,757.9	8,694.6	5,038.6	2,346.7	1,094,739.8	19,547.1	49,667.6	51,425.5

Table 1.2. Summary Statistics for the United States, 2014 - 2024

2019	35,710.2	1,758.1	8,374.5	4,738.8	2,606.4	1,099,109.3	23,213.6	58,923.8	60,681.9
2020	46,306.2	1,747.9	8,326.5	4,623.3	3,079.3	1,115,680.8	27,584.8	73,891.0	75,638.9
2021	60,070.1	1,480.0	7,923.2	4,469.2	6,311.3	1,145,856.1	33,081.0	93,151.1	94,631.1
2022	71,381.5	1,480.0	7,804.5	4,322.3	10,405.6	1,161,431.8	39,828.0	111,209.5	112,689.5
2023	90,517.8	1,480.0	7,693.1	4,133.2	17,450.9	1,187,545.4	47,774.7	138,292.5	139,772.5
2024	122,061.8	1,392.0	7,414.8	3,996.9	28,436.4	1,230,415.2	53,228.1	175,289.9	176,681.9

(From Chapter 5.) Consumption of Fossil Fuels

Year	For Electricity Generation				For Useful Thermal Output			
	Coal (Thousand Tons)	Petroleum (Thousand Barrels)	Natural Gas (Millions of Cubic Feet)	Other Fossil Gas (Millions of BTU)	Coal (Thousand Tons)	Petroleum (Thousand Barrels)	Natural Gas (Millions of Cubic Feet)	Other Fossil Gas (Millions of BTU)
2014	853,634	53,593	8,544,387	110,010	18,107	9,513	865,146	194,088
2015	739,594	49,145	10,016,576	105,997	16,632	8,864	935,098	183,596
2016	677,371	43,671	10,170,110	73,785	16,586	7,770	1,151,866	221,835
2017	663,911	39,144	9,508,062	70,721	14,667	6,899	1,168,544	227,981
2018	636,213	46,727	10,842,129	78,757	13,813	7,261	1,205,962	274,612
2019	537,620	34,454	11,612,858	71,854	12,397	6,357	1,196,025	209,000
2020	435,351	33,391	11,928,104	69,609	10,402	5,629	1,292,624	199,076
2021	500,367	36,982	11,502,569	65,137	11,301	5,873	1,221,841	198,379
2022	471,576	43,684	12,384,086	64,285	11,356	7,769	1,206,250	194,981
2023	386,626	31,474	13,245,495	65,145	9,363	6,241	1,210,187	211,645
2024	372,931	29,096	13,754,749	58,777	8,883	5,277	1,246,683	210,613

Year	Total			
	Coal (Thousand Tons)	Petroleum (Thousand Barrels)	Natural Gas (Millions of Cubic Feet)	Other Fossil Gas (Millions of BTU)
2014	871,741	63,106	9,409,532	304,098
2015	756,226	58,009	10,951,674	289,593
2016	693,958	51,441	11,321,975	295,619
2017	678,578	46,043	10,676,606	298,702
2018	650,027	53,988	12,048,091	353,369
2019	550,017	40,811	12,808,883	280,854
2020	445,753	39,020	13,220,728	268,685
2021	511,669	42,855	12,724,410	263,515
2022	482,931	51,452	13,590,336	259,266
2023	395,989	37,714	14,455,682	276,790
2024	381,814	34,373	15,001,432	269,390

(From Tables 6.1. and 7.1)

Year End Stocks, Annual Receipts and Average Costs

Year	Electric Power Sector Year End Stocks		Annual Receipts at All Electricity Generators			Average Cost of Fuel at All Electricity Generators		
	Coal (Thousand Tons)	Petroleum (Thousand Barrels)	Coal (Thousand Tons)	Petroleum (Thousand Barrels)	Natural Gas (Millions of Cubic Feet)	Coal (Dollars per MMBtu)	Petroleum (Dollars per MMBtu)	Natural Gas (Dollars per MMBtu)

Table 1.2. Summary Statistics for the United States, 2014 - 2024

2014	151,548	36,459	854,560	54,488	8,431,423	2.37	11.60	5.00
2015	195,548	38,396	782,929	48,804	9,842,581	2.22	6.74	3.23
2016	162,009	34,818	650,770	37,637	10,271,180	2.11	5.24	2.87
2017	137,687	32,407	642,364	32,672	9,628,733	2.06	7.10	3.37
2018	102,793	28,674	596,215	37,341	10,894,849	2.06	9.68	3.55
2019	128,102	28,317	560,153	24,556	11,704,743	2.02	9.07	2.88
2020	131,431	27,552	439,636	24,846	11,981,552	1.92	5.98	2.40
2021	91,884	27,513	461,477	27,783	11,578,254	1.98	10.08	5.20
2022	88,861	24,404	469,718	30,792	12,436,074	2.36	16.53	7.21
2023	133,028	26,539	431,375	25,590	13,237,380	2.51	15.98	3.36
2024	127,826	25,204	369,134	19,275	13,741,165	2.47	14.70	2.76

**(From Table 9.1.) Emissions
(Thousand Metric Tons)**

Year	Carbon Dioxide (CO ₂)	Sulfur Dioxide (SO ₂)	Nitrogen Oxides (NO _x)
2014	2,168,284	3,454	2,100
2015	2,031,452	2,548	1,824
2016	1,928,401	1,807	1,630
2017	1,849,750	1,599	1,493
2018	1,872,330	1,517	1,474
2019	1,724,873	1,267	1,342
2020	1,553,586	1,023	1,211
2021	1,651,911	1,168	1,253
2022	1,650,367	1,079	1,230
2023	1,531,554	848	1,117
2024	1,537,073	808	1,112

(From Tables 10.1. and 10.2.) Energy Efficiency

Year	Savings		Incremental Costs		Life Cycle Savings		Life Cycle Costs	
	Energy (MWh)	Peak Demand (MW)	Incentives (thousand dollars)	Other (thousand dollars)	Energy (MWh)	Peak Demand (MW)	Incentives (thousand dollars)	Other (thousand dollars)
2014	26,466,020	6,453	3,410,854	2,209,098	301,956,123	8,040	4,007,452	3,120,898
2015	26,129,489	5,952	3,448,286	2,283,300	296,346,403	7,096	4,255,368	3,710,453
2016	27,500,224	5,658	3,570,950	2,522,854	354,347,692	7,050	4,126,758	3,432,717
2017	29,899,028	6,071	3,664,407	2,297,957	374,826,892	5,951	4,849,803	3,162,995
2018	28,415,037	6,309	3,484,767	2,165,981	359,446,175	6,075	4,177,905	4,179,320
2019	28,562,529	7,135	3,657,477	2,288,028	355,216,512	6,931	4,351,926	3,655,607
2020	28,167,459	6,287	3,152,372	2,112,261	367,829,206	6,003	3,561,148	3,349,318
2021	25,760,657	5,801	3,375,805	2,240,600	300,327,216	5,631	3,678,879	2,466,541
2022	24,384,518	5,445	3,374,379	2,216,696	273,589,534	5,216	4,019,332	2,666,853
2023	24,221,289	5,761	3,850,362	2,538,191	270,451,419	5,655	4,413,487	2,919,623
2024	23,838,965	6,264	4,208,481	2,692,606	281,386,727	6,152	4,744,110	3,040,059

(From Tables 10.3. and 10.4.) Demand Response

Yearly Energy and Demand Savings	Program Costs

Table 1.2. Summary Statistics for the United States, 2014 - 2024

Year	Customers	Energy (MWh)	Potential Peak Demand (MW)	Actual Peak Demand (MW)	Incentives (thousand dollars)	Other (thousand dollars)
2014	9,265,629	1,436,449	31,191	12,683	1,217,796	447,659
2015	9,094,138	1,251,006	32,875	13,036	1,120,446	381,918
2016	9,839,355	1,336,136	35,924	11,841	1,039,890	379,707
2017	9,440,938	1,310,862	31,508	12,248	1,003,124	370,700
2018	9,752,238	1,426,211	30,895	12,522	1,189,284	360,718
2019	10,932,845	1,462,735	31,020	11,334	1,118,882	343,214
2020	11,665,663	1,509,124	29,470	10,387	987,653	326,872
2021	10,492,584	1,153,791	29,222	12,211	1,188,390	312,091
2022	10,319,774	1,292,980	30,448	13,827	1,149,280	329,053
2023	10,567,254	407,255	30,542	10,752	1,118,770	311,943
2024	10,950,828	409,404	31,491	12,322	1,224,694	362,073

Coal includes anthracite, bituminous, subbituminous and lignite coal. Starting in 2002 waste coal is included in all coal metrics except for year-end stocks. Starting in 2002 Synthetic coal is included in all coal metrics. Starting in 2011 Coal-derived synthesis gas is included in all coal metrics.

Prior to 2011 coal-derived synthesis gas was included in Other Fossil Gas.

Petroleum includes 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. Prior to 2011 propane was in the Other Fossil Gas category. Beginning in 2004 small quantities of waste oil were excluded from petroleum stocks.

Natural gas includes a small number of generators for which waste heat is the primary energy source. Natural gas also includes a small amount of supplemental gaseous fuels that cannot be identified separately.

Prior to 2011, synthesis gas derived from petroleum coke was in the Other Fossil Gas category. Other Fossil Gas includes blast furnace gas, propane gas, and other manufactured and waste gases derived from fossil fuels.

Conventional hydroelectric power excludes pumped storage facilities.

Wood and wood derived fuels include 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.

Other biomass includes 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). The reported summer capacity for other biomass also includes non-biogenic municipal solid waste.

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.

Other energy sources include hydrogen, non-biogenic municipal solid waste, batteries, purchased steam, sulfur, tire-derived fuel, and other miscellaneous energy sources.

Costs of fuels for 2002 through 2007 include data from the Form EIA-423 for independent power producers, commercial power-producing facilities, and industrial power-producing facilities. Beginning in 2008, data are collected on the Form EIA-923 for utilities, independent power producers, commercial power-producing facilities, and industrial power-producing facilities. Receipts, 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 receipts beginning with 2008 data. Receipts of coal include imported coal.

UNIT CONVERSIONS:

Notes: See Glossary reference for definitions. See Technical Notes Appendix 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. In 2013, EIA revised its approach to estimating imports from Mexico.

Table 1.2. Summary Statistics for the United States, 2014 - 2024

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: National Energy Board of Canada; FERC 714, Annual Electric Balancing Authority Area and Planning Report; California Energy Commission; and EIA estimates

Table 1.3. Supply and Disposition of Electricity, 2014 through 2024

(From Chapter 3.) Supply (Thousand Megawatthours)

	Generation						
Year	Electric Utilities	IPP (Non-CHP)	IPP (CHP)	Commercial Sector	Industrial Sector	Total Imports	Total Supply
2014	2,382,500	1,404,256	150,205	12,520	144,083	66,510	4,160,074
2015	2,316,508	1,448,726	155,173	12,595	145,712	75,770	4,154,484
2016	2,305,887	1,459,558	153,532	12,706	145,890	72,716	4,150,290
2017	2,275,539	1,464,503	138,584	13,060	143,758	65,685	4,101,128
2018	2,339,960	1,538,235	142,682	13,312	146,798	58,261	4,239,248
2019	2,268,723	1,559,801	139,824	13,689	148,537	59,052	4,189,626
2020	2,170,316	1,546,400	136,940	13,046	143,064	61,449	4,071,216
2021	2,211,643	1,612,655	132,883	12,768	139,750	53,167	4,162,866
2022	2,229,605	1,714,779	129,503	16,737	140,043	56,970	4,287,638
2023	2,189,614	1,703,467	135,460	16,066	138,664	38,917	4,222,188
2024	2,256,336	1,763,678	136,613	15,258	136,749	33,254	4,341,889

(From Chapter 2.) Disposition (Thousand Megawatthours)

	Sales to Ultimate Customers						
Year	Full-Service Providers	Energy-Only Providers	Facility Direct	Direct Use	Total Exports	Losses and Unaccounted For	Total Disposition
2014	3,184,841	563,441	16,418	138,574	13,298	243,502	4,160,074
2015	3,191,425	554,944	12,624	141,168	9,100	245,224	4,154,484
2016	3,189,541	560,015	12,905	139,837	6,214	241,778	4,150,290
2017	3,149,973	559,727	13,656	140,959	9,371	227,442	4,101,128
2018	3,260,944	584,077	14,164	143,904	13,804	222,355	4,239,248
2019	3,213,129	583,431	14,591	143,270	20,008	215,198	4,189,626
2020	3,144,898	558,832	13,944	138,703	14,135	200,704	4,071,216
2021	3,215,297	575,567	15,011	138,915	13,855	204,222	4,162,866
2022	3,346,987	565,117	15,064	139,726	15,758	204,985	4,287,638
2023	3,294,907	562,573	16,773	136,918	20,013	191,003	4,222,188
2024	3,364,435	593,516	17,430	135,041	19,437	212,029	4,341,889

N/A = Not Available.

Facility Direct Sales to ultimate customers 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).

Chapter 2

Electricity Sales

Table 2.1. Number of Ultimate Customers Served by Sector, by Provider, 2014 through 2024

Year	Residential	Commercial	Industrial	Transportation	Total
Total Electric Industry					
2014	128,680,416	17,853,995	839,212	79	147,373,702
2015	129,811,718	17,985,690	835,536	78	148,633,022
2016	131,068,760	18,148,353	838,059	86	150,055,258
2017	132,579,747	18,359,427	840,329	86	151,779,589
2018	133,893,321	18,605,393	840,321	83	153,339,118
2019	135,249,616	18,694,240	954,222	83	154,898,161
2020	136,682,001	18,848,813	992,311	83	156,523,208
2021	138,308,772	19,102,304	1,022,212	82	158,433,370
2022	139,854,178	19,257,529	1,049,983	86	160,161,776
2023	141,282,713	19,381,328	1,078,249	85	161,742,375
2024	143,144,185	19,480,886	1,115,974	81	163,741,126
Full-Service Providers					
2014	117,230,661	15,942,158	789,803	50	133,962,672
2015	119,477,949	16,108,931	787,466	48	136,374,394
2016	120,875,548	16,197,174	788,641	53	137,861,416
2017	121,964,414	16,329,808	789,732	52	139,084,006
2018	122,767,933	16,415,207	794,548	49	139,977,737
2019	122,422,722	16,367,082	904,443	50	139,694,297
2020	123,575,349	16,466,429	940,350	52	140,982,180
2021	125,145,266	16,631,306	971,419	51	142,748,042
2022	126,936,159	16,800,418	1,001,592	53	144,738,222
2023	127,697,761	16,885,126	1,027,326	53	145,610,266
2024	128,358,886	16,854,267	1,046,810	50	146,260,013
Energy-Only Providers					
2014	11,449,755	1,911,837	49,409	29	13,411,030
2015	10,333,769	1,876,759	48,070	30	12,258,628
2016	10,193,212	1,951,179	49,418	33	12,193,842
2017	10,615,333	2,029,619	50,597	34	12,695,583
2018	11,125,388	2,190,186	45,773	34	13,361,381
2019	12,826,894	2,327,158	49,779	33	15,203,864
2020	13,106,652	2,382,384	51,961	31	15,541,028
2021	13,163,506	2,470,998	50,793	31	15,685,328
2022	12,918,019	2,457,111	48,391	33	15,423,554
2023	13,584,952	2,496,202	50,923	32	16,132,109
2024	14,785,299	2,626,619	69,164	31	17,481,113

N/A = Not Available.

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

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." and Form EIA-861S, "Annual Electric Power Industry Report (Short Form)."

Table 2.2. Sales and Direct Use of Electricity to Ultimate Customers by Sector, by Provider, 2014 through 2024 (Megawatthours)

Year	Residential	Commercial	Industrial	Transportation	Total	Direct Use	Total End Use
Total Electric Industry							
2014	1,407,208,311	1,352,158,263	997,576,138	7,757,555	3,764,700,267	138,573,884	3,903,274,151
2015	1,404,096,499	1,360,751,527	986,507,732	7,636,632	3,758,992,390	141,167,519	3,900,159,909
2016	1,411,058,153	1,367,191,386	976,715,181	7,496,910	3,762,461,630	139,836,699	3,902,298,329
2017	1,378,647,742	1,352,887,694	984,297,945	7,522,593	3,723,355,974	140,959,389	3,864,315,363
2018	1,469,093,059	1,381,754,845	1,000,672,553	7,664,804	3,859,185,261	143,903,731	4,003,088,992
2019	1,440,288,909	1,360,876,555	1,002,352,849	7,632,150	3,811,150,463	143,270,338	3,954,420,801
2020	1,464,605,046	1,287,439,583	959,082,028	6,547,824	3,717,674,481	138,702,540	3,856,377,021
2021	1,470,486,882	1,328,439,498	1,000,613,490	6,334,383	3,805,874,253	138,915,068	3,944,789,321
2022	1,509,233,162	1,390,872,813	1,020,463,986	6,599,108	3,927,169,069	139,725,701	4,066,894,770
2023	1,450,025,184	1,408,108,755	1,009,255,634	6,863,789	3,874,253,362	136,918,155	4,011,171,517
2024	1,482,873,586	1,450,941,216	1,034,584,190	6,982,840	3,975,381,832	135,040,521	4,110,422,353
Full-Service Providers							
2014	1,301,458,851	1,083,806,639	814,206,541	1,787,408	3,201,259,439	N/A	3,201,259,439
2015	1,307,918,081	1,089,268,864	805,111,979	1,749,450	3,204,048,374	N/A	3,204,048,374
2016	1,316,113,416	1,091,957,177	792,712,354	1,663,475	3,202,446,422	N/A	3,202,446,422
2017	1,285,787,376	1,078,679,288	797,505,332	1,656,960	3,163,628,956	N/A	3,163,628,956
2018	1,368,032,531	1,096,773,561	808,613,290	1,688,442	3,275,107,824	N/A	3,275,107,824
2019	1,335,937,347	1,078,046,650	811,871,096	1,864,134	3,227,719,227	N/A	3,227,719,227
2020	1,355,779,174	1,023,022,155	778,352,070	1,688,885	3,158,842,284	N/A	3,158,842,284
2021	1,364,227,749	1,051,202,406	813,202,989	1,674,150	3,230,307,294	N/A	3,230,307,294
2022	1,410,779,678	1,110,251,412	839,329,783	1,690,901	3,362,051,774	N/A	3,362,051,774
2023	1,354,990,246	1,128,111,069	826,674,586	1,904,230	3,311,680,131	N/A	3,311,680,131
2024	1,375,013,511	1,160,639,617	844,599,508	1,612,799	3,381,865,435	N/A	3,381,865,435
Energy-Only Providers							
2014	105,749,460	268,351,624	183,369,597	5,970,147	563,440,828	N/A	563,440,828
2015	96,178,418	271,482,663	181,395,753	5,887,182	554,944,016	N/A	554,944,016
2016	94,944,737	275,234,209	184,002,827	5,833,435	560,015,208	N/A	560,015,208
2017	92,860,366	274,208,406	186,792,613	5,865,633	559,727,018	N/A	559,727,018
2018	101,060,528	284,981,284	192,059,263	5,976,362	584,077,437	N/A	584,077,437
2019	104,351,562	282,829,905	190,481,753	5,768,016	583,431,236	N/A	583,431,236
2020	108,825,872	264,417,428	180,729,958	4,858,939	558,832,197	N/A	558,832,197
2021	106,259,133	277,237,092	187,410,501	4,660,233	575,566,959	N/A	575,566,959
2022	98,453,484	280,621,401	181,134,203	4,908,207	565,117,295	N/A	565,117,295
2023	95,034,938	279,997,686	182,581,048	4,959,559	562,573,231	N/A	562,573,231
2024	107,860,075	290,301,599	189,984,682	5,370,041	593,516,397	N/A	593,516,397

N/A = Not Available.

Starting in 2023- Many of the changes in the industrial and commercial sector retail sales are the result of improved reporting practices for data center and cryptocurrency mining operations.

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.

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

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.", Form EIA-861S, "Annual Electric Power Industry Report (Short Form)" and Form EIA-923, "Power Plant Operations Report"

**Table 2.3. Revenue from Sales of Electricity to Ultimate Customers
by Sector, by Provider, 2014 through 2024 (Million Dollars)**

Year	Residential	Commercial	Industrial	Transportation	Total
Total Electric Industry					
2014	176,178	145,253	70,855	810	393,096
2015	177,624	144,781	68,166	771	391,341
2016	177,077	142,643	66,068	722	386,509
2017	177,661	144,242	67,691	728	390,322
2018	189,033	147,425	69,218	744	406,420
2019	187,436	145,280	68,285	737	401,738
2020	192,663	136,372	63,956	648	393,639
2021	200,834	149,008	71,835	646	422,323
2022	226,990	172,600	84,895	765	485,249
2023	231,993	177,342	81,159	877	491,370
2024	244,367	185,043	84,095	890	514,396
Full-Service Providers					
2014	160,637	113,880	57,140	187	331,845
2015	162,857	113,225	54,787	170	331,038
2016	162,395	111,218	52,958	164	326,735
2017	162,762	112,576	54,412	171	329,921
2018	172,556	114,007	55,058	176	341,797
2019	169,967	112,036	54,782	190	336,876
2020	173,742	105,065	51,346	178	330,331
2021	181,387	113,630	57,714	183	352,913
2022	206,032	131,400	68,249	220	405,902
2023	208,850	134,213	64,748	262	408,072
2024	217,175	138,072	65,408	205	420,861
Competitive Service Providers					
2014	15,541	31,373	13,715	623	61,251
2015	14,767	31,557	13,379	601	60,303
2016	14,682	31,425	13,110	557	59,774
2017	14,899	31,666	13,279	557	60,402
2018	16,477	33,418	14,161	567	64,623
2019	17,569	33,244	13,502	547	64,863
2020	18,921	31,307	12,610	470	63,309
2021	19,447	35,379	14,121	463	69,410
2022	20,957	41,199	16,645	545	79,347
2023	23,143	43,130	16,411	615	83,298
2024	27,192	46,971	18,687	685	93,535
Energy-Only Providers					
2014	9,079	19,948	10,813	436	40,277
2015	8,428	19,657	10,298	407	38,791
2016	7,947	18,850	9,896	360	37,053
2017	7,666	18,368	9,829	363	36,227
2018	8,438	19,279	10,424	378	38,518
2019	8,718	18,436	9,738	360	37,253
2020	9,017	16,485	8,829	305	34,636
2021	8,750	18,223	10,024	295	37,292
2022	10,100	22,791	12,458	360	45,709
2023	11,640	24,381	11,966	413	48,401
2024	12,769	25,386	12,797	447	51,400
Delivery-Only Providers					
2014	6,462	11,425	2,901	187	20,975
2015	6,339	11,900	3,081	193	21,512
2016	6,735	12,575	3,213	197	22,720
2017	7,232	13,298	3,450	194	24,174
2018	8,039	14,139	3,737	190	26,105
2019	8,850	14,809	3,764	187	27,610
2020	9,904	14,823	3,781	165	28,672
2021	10,697	17,155	4,097	168	32,118
2022	10,857	18,408	4,187	185	33,638
2023	11,503	18,749	4,445	201	34,898
2024	14,423	21,584	5,890	238	42,135

N/A = Not Available.

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

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 Competitive Service Providers represent the sum of Energy-Only and Delivery-Only Services."

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." Form EIA-861S, "Annual Electric Power Industry Report (Short Form)."

Table 2.4. Average Price of Electricity to Ultimate Customers

by End-Use Sectors 2014 through 2024 (Cents per kilowatthour)

Year	Residential	Commercial	Industrial	Transportation	Total
Total Electric Industry					
2014	12.52	10.74	7.10	10.45	10.44
2015	12.65	10.64	6.91	10.09	10.41
2016	12.55	10.43	6.76	9.63	10.27
2017	12.89	10.66	6.88	9.68	10.48
2018	12.87	10.67	6.92	9.70	10.53
2019	13.01	10.68	6.81	9.66	10.54
2020	13.15	10.59	6.67	9.90	10.59
2021	13.66	11.22	7.18	10.20	11.10
2022	15.04	12.41	8.32	11.59	12.36
2023	16.00	12.59	8.04	12.77	12.68
2024	16.48	12.75	8.13	12.75	12.94
Full-Service Providers					
2014	12.34	10.51	7.02	10.49	10.37
2015	12.45	10.39	6.80	9.71	10.33
2016	12.34	10.19	6.68	9.87	10.20
2017	12.66	10.44	6.82	10.32	10.43
2018	12.61	10.39	6.81	10.44	10.44
2019	12.72	10.39	6.75	10.20	10.44
2020	12.81	10.27	6.60	10.53	10.46
2021	13.30	10.81	7.10	10.92	10.93
2022	14.60	11.84	8.13	13.02	12.07
2023	15.41	11.90	7.83	13.75	12.32
2024	15.79	11.90	7.74	12.72	12.44
Competitive Service Providers					
2014	14.70	11.69	7.48	10.44	10.87
2015	15.35	11.62	7.38	10.20	10.87
2016	15.46	11.42	7.12	9.56	10.67
2017	16.04	11.55	7.11	9.50	10.79
2018	16.30	11.73	7.37	9.49	11.06
2019	16.84	11.75	7.09	9.49	11.12
2020	17.39	11.84	6.98	9.68	11.33
2021	18.30	12.76	7.53	9.94	12.06
2022	21.29	14.68	9.19	11.10	14.04
2023	24.35	15.40	8.99	12.39	14.81
2024	25.21	16.18	9.84	12.76	15.76
Energy-Only Providers					
2014	8.59	7.43	5.90	7.31	7.15
2015	8.76	7.24	5.68	6.92	6.99
2016	8.37	6.85	5.38	6.17	6.62
2017	8.26	6.70	5.26	6.19	6.47
2018	8.35	6.77	5.43	6.32	6.59
2019	8.35	6.52	5.11	6.25	6.39
2020	8.29	6.23	4.89	6.29	6.20
2021	8.23	6.57	5.35	6.33	6.48
2022	10.26	8.12	6.88	7.33	8.09
2023	12.25	8.71	6.55	8.33	8.60
2024	11.84	8.74	6.74	8.33	8.66
Delivery-Only Providers					
2014	6.11	4.26	1.58	3.12	3.72
2015	6.59	4.38	1.70	3.28	3.88
2016	7.09	4.57	1.75	3.38	4.06
2017	7.79	4.85	1.85	3.31	4.32
2018	7.95	4.96	1.95	3.17	4.47
2019	8.48	5.24	1.98	3.24	4.73
2020	9.10	5.61	2.09	3.40	5.13
2021	10.07	6.19	2.19	3.61	5.58
2022	11.03	6.56	2.31	3.77	5.95
2023	12.10	6.70	2.43	4.06	6.20
2024	13.37	7.44	3.10	4.43	7.10

N/A = Not Available.

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

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 Competitive Service Providers represent the sum of Energy-Only and Delivery-Only Services."

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." Form EIA-861S, "Annual Electric Power Industry Report (Short Form)."

**Table 2.5. Sales of Electricity to Ultimate Customers:
Total by End-Use Sector, 2014 - December 2024 (Thousand Megawatthours)**

Period	Residential	Commercial	Industrial	Transportation	All Sectors
Annual Totals					
2014	1,407,208	1,352,158	997,576	7,758	3,764,700
2015	1,404,096	1,360,752	986,508	7,637	3,758,992
2016	1,411,058	1,367,191	976,715	7,497	3,762,462
2017	1,378,648	1,352,888	984,298	7,523	3,723,356
2018	1,469,093	1,381,755	1,000,673	7,665	3,859,185
2019	1,440,289	1,360,877	1,002,353	7,632	3,811,150
2020	1,464,605	1,287,440	959,082	6,548	3,717,674
2021	1,470,487	1,328,439	1,000,613	6,334	3,805,874
2022	1,509,233	1,390,873	1,020,464	6,599	3,927,169
2023	1,450,025	1,408,109	1,009,256	6,864	3,874,253
2024	1,482,874	1,450,941	1,034,584	6,983	3,975,382
Year 2022					
January	140,504	113,605	83,982	565	338,656
February	125,342	103,063	76,893	566	305,863
March	111,439	108,603	83,679	579	304,300
April	97,432	104,566	82,422	513	284,933
May	110,071	113,007	86,090	529	309,697
June	136,310	121,567	88,716	513	347,106
July	164,277	133,952	90,420	566	389,214
August	160,271	135,676	93,143	536	389,626
September	129,241	124,195	86,550	558	340,544
October	99,792	111,851	85,017	535	297,196
November	103,152	106,858	81,701	546	292,258
December	131,402	113,929	81,852	593	327,776
Year 2023					
January	131,638	112,790	80,408	579	325,415
February	112,105	103,830	76,449	561	292,946
March	110,417	112,643	82,817	577	306,454
April	96,196	104,091	80,011	513	280,811
May	100,231	113,243	84,704	529	298,706
June	121,320	120,707	86,193	579	328,798
July	159,715	136,394	90,526	621	387,256
August	161,460	138,390	92,009	578	392,436
September	132,807	126,546	86,472	652	346,476
October	103,314	118,208	85,978	565	308,065
November	101,907	109,756	82,036	549	294,248
December	118,917	111,512	81,652	561	312,642
Year 2024					
January	142,354	118,234	82,517	612	343,717
February	115,477	108,967	78,277	538	303,258
March	102,203	111,382	83,100	593	297,278
April	94,674	108,972	82,078	532	286,257
May	107,605	117,864	87,901	592	313,961
June	138,920	127,949	88,446	566	355,882
July	164,833	139,551	92,848	641	397,873
August	159,098	140,632	93,848	621	394,199
September	127,340	127,248	87,920	563	343,071
October	106,083	120,899	88,354	566	315,902
November	98,782	112,091	84,369	554	295,796
December	125,504	117,152	84,927	605	328,188

Starting in 2023- Many of the changes in the industrial and commercial sector retail sales are the result of improved reporting practices for data center and cryptocurrency mining operations.

See Technical notes for additional information on the Commercial, Industrial, and Transportation sectors. NA = Not available. See Glossary for definitions.

Geographic coverage is the 50 States and the District of Columbia. Values include energy service provider (power marketer) data.

Values are final. See Technical Notes for a discussion of the sample design for the Form EIA-826. 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. 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. Sales and net generation may not correspond exactly for a particular month for a variety of reasons (i.e., sales data may include purchases of electricity from nonutilities or imported electricity). Net generation is for the calendar month while sales and associated revenue accumulate from bills collected for periods of time (28 to 35 days) that vary dependent upon customer class and consumption occurring in and outside the calendar month.

Sources: U.S. Energy Information Administration, Form EIA-861M (formerly EIA-826), Monthly Electric Industry Power Report.

Form EIA-826, Monthly Electric Sales and Revenue Report with State Distributions Report;

Form EIA-861, Annual Electric Power Industry Report; and Form EIA-861S, Annual Electric Power Industry Report (Short Form).

**Table 2.6. Revenue from Sales of Electricity to Ultimate Customers:
Total by End-Use Sector, 2014 - December 2024 (Million Dollars)**

Period	Residential	Commercial	Industrial	Transportation	All Sectors
Annual Totals					
2014	176,178	145,253	70,855	810	393,096
2015	177,624	144,781	68,166	771	391,341
2016	177,077	142,643	66,068	722	386,509
2017	177,661	144,242	67,691	728	390,322
2018	189,033	147,425	69,218	744	406,420
2019	187,436	145,280	68,285	737	401,738
2020	192,663	136,372	63,956	648	393,639
2021	200,834	149,008	71,835	646	422,323
2022	226,990	172,600	84,895	765	485,249
2023	231,993	177,342	81,159	877	491,370
2024	244,367	185,043	84,095	890	514,396
Year 2022					
January	19,163	12,794	6,037	60	38,053
February	17,247	12,019	5,601	62	34,929
March	16,062	12,647	6,164	63	34,936
April	14,194	12,355	6,343	58	32,950
May	16,394	13,561	7,099	57	37,112
June	20,850	15,506	7,854	62	44,272
July	25,155	17,435	8,422	70	51,082
August	25,354	18,199	8,739	69	52,361
September	20,930	16,492	7,841	70	45,333
October	15,961	14,418	7,184	63	37,627
November	16,041	13,179	6,654	63	35,937
December	19,637	13,996	6,955	68	40,656
Year 2023					
January	20,371	14,228	6,578	73	41,249
February	17,910	13,013	6,125	74	37,123
March	17,716	13,923	6,460	71	38,171
April	15,492	12,572	6,009	62	34,136
May	16,176	13,769	6,472	66	36,483
June	19,515	15,248	6,987	72	41,821
July	25,336	17,603	7,563	79	50,582
August	25,693	18,102	8,185	77	52,057
September	21,602	16,538	7,291	94	45,525
October	17,022	15,047	6,883	71	39,024
November	16,501	13,646	6,394	69	36,610
December	18,659	13,653	6,210	69	38,591
Year 2024					
January	21,942	14,785	6,663	77	43,467
February	18,595	13,658	6,078	71	38,401
March	17,036	13,888	6,382	71	37,377
April	15,966	13,457	6,397	66	35,886
May	17,649	14,521	6,921	73	39,164
June	22,757	16,498	7,434	72	46,761
July	27,389	18,654	8,110	84	54,237
August	26,417	18,508	8,135	83	53,143
September	21,424	16,832	7,428	74	45,758
October	18,127	15,583	7,162	70	40,943
November	16,644	13,844	6,623	69	37,180
December	20,422	14,813	6,763	81	42,079

See Technical notes for additional information on the Commercial, Industrial, and Transportation sectors. NA = Not available. See Glossary for definitions.

Geographic coverage is the 50 States and the District of Columbia. Values include energy service provider (power marketer) data.

Values are final. See Technical Notes for a discussion of the sample design for the Form EIA-826. 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. 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. Sales and net generation may not correspond exactly for a particular month for a variety of reasons (i.e., sales data may include purchases of electricity from nonutilities or imported electricity). Net generation is for the calendar month while sales and associated revenue accumulate from bills collected for periods of time (28 to 35 days) that vary dependent upon customer class and consumption occurring in and outside the calendar month.

Sources: U.S. Energy Information Administration, Form EIA-861M (formerly EIA-826), Monthly Electric Industry Power Report.

Form EIA-826, Monthly Electric Sales and Revenue Report with State Distributions Report;

Form EIA-861, Annual Electric Power Industry Report; and Form EIA-861S, Annual Electric Power Industry Report (Short Form).

**Table 2.7. Average Price of Electricity to Ultimate Customers:
Total by End-Use Sector, 2014 - December 2024 (Cents per Kilowatthour)**

Period	Residential	Commercial	Industrial	Transportation	All Sectors
Annual Totals					
2014	12.52	10.74	7.10	10.45	10.44
2015	12.65	10.64	6.91	10.09	10.41
2016	12.55	10.43	6.76	9.63	10.27
2017	12.89	10.66	6.88	9.68	10.48
2018	12.87	10.67	6.92	9.70	10.53
2019	13.01	10.68	6.81	9.66	10.54
2020	13.15	10.59	6.67	9.90	10.59
2021	13.66	11.22	7.18	10.20	11.10
2022	15.04	12.41	8.32	11.59	12.36
2023	16.00	12.59	8.04	12.77	12.68
2024	16.48	12.75	8.13	12.75	12.94
Year 2022					
January	13.64	11.26	7.19	10.54	11.24
February	13.76	11.66	7.28	10.95	11.42
March	14.41	11.65	7.37	10.87	11.48
April	14.57	11.82	7.70	11.26	11.56
May	14.89	12.00	8.25	10.79	11.98
June	15.30	12.75	8.85	12.10	12.75
July	15.31	13.02	9.31	12.39	13.12
August	15.82	13.41	9.38	12.90	13.44
September	16.19	13.28	9.06	12.57	13.31
October	15.99	12.89	8.45	11.81	12.66
November	15.55	12.33	8.14	11.56	12.30
December	14.94	12.28	8.50	11.48	12.40
Year 2023					
January	15.47	12.61	8.18	12.54	12.68
February	15.98	12.53	8.01	13.14	12.67
March	16.04	12.36	7.80	12.28	12.46
April	16.10	12.08	7.51	12.05	12.16
May	16.14	12.16	7.64	12.43	12.21
June	16.09	12.63	8.11	12.41	12.72
July	15.86	12.91	8.36	12.77	13.06
August	15.91	13.08	8.90	13.26	13.27
September	16.27	13.07	8.43	14.45	13.14
October	16.48	12.73	8.01	12.65	12.67
November	16.19	12.43	7.79	12.60	12.44
December	15.69	12.24	7.61	12.34	12.34
Year 2024					
January	15.41	12.50	8.07	12.66	12.65
February	16.10	12.53	7.76	13.12	12.66
March	16.67	12.47	7.68	11.95	12.57
April	16.86	12.35	7.79	12.46	12.54
May	16.40	12.32	7.87	12.29	12.47
June	16.38	12.89	8.41	12.68	13.14
July	16.62	13.37	8.73	13.18	13.63
August	16.60	13.16	8.67	13.30	13.48
September	16.82	13.23	8.45	13.09	13.34
October	17.09	12.89	8.11	12.43	12.96
November	16.85	12.35	7.85	12.37	12.57
December	16.27	12.64	7.96	13.38	12.82

See Technical notes for additional information on the Commercial, Industrial, and Transportation sectors. NA = Not available. See Glossary for definitions. Geographic coverage is the 50 States and the District of Columbia. Values include energy service provider (power marketer) data. Values are final. See Technical Notes for a discussion of the sample design for the Form EIA-826. 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. 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. Sales and net generation may not correspond exactly for a particular month for a variety of reasons (i.e., sales data may include purchases of electricity from nonutilities or imported electricity). Net generation is for the calendar month while sales and associated revenue accumulate from bills collected for periods of time (28 to 35 days) that vary dependent upon customer class and consumption occurring in and outside the calendar month. Sources: U.S. Energy Information Administration, Form EIA-861M (formerly EIA-826), Monthly Electric Industry Power Report; Form EIA-826, Monthly Electric Sales and Revenue Report with State Distributions Report; Form EIA-861, Annual Electric Power Industry Report; and Form EIA-861S, Annual Electric Power Industry Report (Short Form).

Table 2.8. Sales of Electricity to Ultimate Customers by End-Use Sector, by State, 2024 and 2023 (Thousand Megawatthours)

Census Division and State	Residential		Commercial		Industrial		Transportation		All Sectors	
	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023
New England	48,025	46,664	48,994	49,271	14,376	14,909	504	484	111,899	111,329
Connecticut	12,942	12,553	11,663	11,374	2,556	2,579	191	179	27,351	26,685
Maine	4,901	4,919	4,118	4,017	2,322	2,400	0	0	11,342	11,336
Massachusetts	19,993	19,366	23,489	24,276	5,645	6,091	291	279	49,419	50,012
New Hampshire	4,847	4,655	4,105	4,051	1,961	1,926	0	0	10,914	10,631
Rhode Island	3,111	2,995	3,666	3,651	615	629	22	26	7,414	7,301
Vermont	2,230	2,176	1,952	1,904	1,277	1,284	0	0	5,459	5,364
Middle Atlantic	134,823	130,856	146,688	143,307	70,987	71,544	3,678	3,523	356,175	349,230
New Jersey	29,693	28,415	37,087	36,083	6,351	6,224	401	375	73,531	71,097
New York	50,857	50,113	71,053	71,422	15,805	15,174	2,782	2,713	140,498	139,422
Pennsylvania	54,273	52,328	38,548	35,802	48,831	50,147	495	434	142,147	138,711
East North Central	185,595	179,525	180,205	174,691	187,138	184,688	498	463	553,436	539,367
Illinois	44,851	43,320	45,240	45,576	42,694	41,267	442	415	133,227	130,578
Indiana	33,049	31,739	23,664	23,016	42,489	41,229	18	11	99,220	95,995
Michigan	33,505	32,534	37,191	36,534	28,290	28,515	5	5	98,991	97,589
Ohio	52,174	49,714	50,814	46,351	50,688	50,546	32	30	153,707	146,641
Wisconsin	22,017	22,219	23,296	23,213	22,977	23,131	1	1	68,291	68,564
West North Central	106,070	107,369	109,950	107,264	101,064	99,248	41	42	317,125	313,923
Iowa	14,469	14,582	12,815	12,601	27,647	27,217	0	0	54,930	54,400
Kansas	13,840	13,815	15,791	15,727	11,628	11,509	0	0	41,258	41,052
Minnesota	22,063	23,023	22,468	22,614	20,016	20,561	15	18	64,562	66,216
Missouri	35,227	34,965	29,570	29,174	12,954	12,813	25	24	77,776	76,976
Nebraska	10,391	10,671	12,885	11,261	11,915	11,640	0	0	35,191	33,571
North Dakota	4,911	5,067	11,309	10,855	13,550	12,280	0	0	29,770	28,202
South Dakota	5,170	5,246	5,111	5,033	3,356	3,227	0	0	13,637	13,506
South Atlantic	385,618	370,594	355,825	341,272	134,841	136,603	1,252	1,177	877,536	849,646
Delaware	5,175	4,932	4,282	4,149	1,917	2,001	0	0	11,374	11,082
District of Columbia	2,446	2,372	7,193	7,030	187	176	316	301	10,143	9,880
Florida	138,371	135,805	99,197	97,255	17,457	17,809	70	71	255,095	250,940
Georgia	62,063	58,412	55,173	51,405	32,617	32,068	152	144	150,004	142,029
Maryland	27,327	26,108	27,773	27,062	3,502	3,456	416	408	59,019	57,033
North Carolina	61,745	58,738	49,524	48,197	25,623	26,144	12	13	136,905	133,091
South Carolina	32,545	30,898	26,306	25,194	25,110	25,110	0	0	83,961	81,202
Virginia	45,273	43,096	78,711	73,807	13,776	15,176	286	240	138,045	132,319
West Virginia	10,675	10,234	7,665	7,174	14,651	14,663	0	0	32,991	32,071
East South Central	121,405	115,857	93,344	90,842	98,826	96,872	0	0	313,576	303,571
Alabama	32,899	31,410	22,862	22,213	31,762	31,257	0	0	87,523	84,880
Kentucky	26,086	24,553	20,314	19,303	28,006	27,367	0	0	74,406	71,223
Mississippi	18,593	18,544	14,172	14,231	15,919	15,647	0	0	48,685	48,422
Tennessee	43,828	41,351	35,996	35,094	23,139	22,601	0	0	102,962	99,046
West South Central	238,936	242,549	225,086	224,347	258,724	238,748	22	179	722,768	705,823
Arkansas	18,581	18,374	11,789	11,694	19,526	18,581	0	0	49,896	48,649
Louisiana	30,975	31,747	23,652	23,743	40,720	39,874	10	10	95,357	95,374
Oklahoma	24,328	23,818	25,412	23,117	22,343	22,044	0	0	72,084	68,979
Texas	165,052	168,611	164,233	165,792	176,135	158,249	12	169	505,431	492,820
Mountain	113,434	109,662	112,525	105,323	86,373	84,248	157	162	312,489	299,394
Arizona	40,435	38,992	36,100	32,620	14,298	14,297	10	10	90,843	85,919
Colorado	20,694	19,999	21,172	20,698	14,892	14,779	86	90	56,843	55,566
Idaho	9,832	9,793	6,964	6,842	9,574	9,039	0	0	26,370	25,674
Montana	5,700	5,756	5,034	5,063	4,832	4,686	0	0	15,567	15,505
Nevada	14,631	13,509	14,259	12,367	11,766	12,367	8	7	40,665	38,249
New Mexico	7,348	7,336	9,593	9,349	13,356	11,662	0	0	30,296	28,347
Utah	11,825	11,328	14,129	13,338	8,681	8,623	53	54	34,688	33,344
Wyoming	2,968	2,948	5,275	5,046	8,974	8,796	0	0	17,217	16,790
Pacific Contiguous	144,245	142,206	172,890	166,389	77,414	77,589	831	834	395,379	387,018
California	85,851	82,821	115,126	112,936	44,026	42,999	715	725	245,717	239,480
Oregon	19,768	20,445	24,662	23,084	15,228	14,434	22	23	59,681	57,985
Washington	38,627	38,940	33,102	30,370	18,159	20,156	94	86	89,982	89,553
Pacific Noncontiguous	4,722	4,744	5,434	5,402	4,843	4,806	0	0	14,999	14,952
Alaska	2,071	2,051	2,604	2,603	1,372	1,371	0	0	6,047	6,025
Hawaii	2,652	2,693	2,830	2,799	3,470	3,435	0	0	8,952	8,927
U.S. Total	1,482,874	1,450,025	1,450,941	1,408,109	1,034,584	1,009,256	6,983	6,864	3,975,382	3,874,253

Starting in 2023- Many of the changes in the industrial and commercial sector retail sales are the result of improved reporting practices for data center and cryptocurrency mining operations.

See Technical notes for additional information on the Commercial, Industrial, and Transportation sectors.

Displayed values of zero may represent small values that round to zero. The Excel version of this table provides additional precision which may be accessed by selecting individual cells.

Notes: - See Glossary for definitions. - Values are final.

See Technical Notes for a discussion of the sample design for the Form EIA-826.

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.

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.

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 2.9. Revenue from Sales of Electricity to Ultimate Customers by End-Use Sector, by State, 2024 and 2023 (Million Dollars)

Census Division and State	Residential		Commercial		Industrial		Transportation		All Sectors	
	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023
New England	13,293	13,407	10,070	9,570	2,341	2,357	66	63	25,769	25,396
Connecticut	3,720	3,751	2,474	2,273	438	405	34	39	6,665	6,468
Maine	1,190	1,349	750	718	289	295	0	0	2,230	2,362
Massachusetts	5,868	5,734	4,908	4,763	1,027	1,089	27	20	11,830	11,607
New Hampshire	1,135	1,310	796	827	318	304	0	0	2,249	2,441
Rhode Island	891	809	773	645	121	119	5	5	1,790	1,579
Vermont	488	453	369	343	148	145	0	0	1,005	940
Middle Atlantic	27,810	25,650	23,020	21,951	6,049	5,656	503	516	57,381	53,774
New Jersey	5,744	5,031	5,431	5,052	758	727	45	46	11,977	10,856
New York	12,424	11,148	13,337	12,866	1,450	1,042	409	426	27,621	25,482
Pennsylvania	9,642	9,472	4,252	4,033	3,841	3,886	49	44	17,784	17,436
East North Central	30,587	29,072	21,860	20,855	15,124	14,670	40	33	67,612	64,630
Illinois	7,118	6,804	5,345	5,124	3,768	3,385	34	29	16,265	15,342
Indiana	4,880	4,741	2,944	2,889	3,461	3,399	2	1	11,287	11,031
Michigan	6,466	6,130	5,210	4,895	2,336	2,326	1	1	14,013	13,351
Ohio	8,340	7,647	5,418	4,984	3,597	3,554	2	2	17,358	16,187
Wisconsin	3,783	3,750	2,943	2,963	1,962	2,007	0	0	8,689	8,719
West North Central	14,283	13,979	11,274	11,065	7,804	7,715	4	5	33,365	32,764
Iowa	1,939	1,940	1,310	1,302	1,881	1,880	0	0	5,130	5,122
Kansas	1,958	1,849	1,767	1,707	899	879	0	0	4,624	4,435
Minnesota	3,409	3,392	2,729	2,801	1,831	1,893	2	2	7,971	8,088
Missouri	4,548	4,398	3,034	2,958	1,020	1,012	3	2	8,605	8,370
Nebraska	1,198	1,195	1,081	986	913	888	0	0	3,193	3,070
North Dakota	565	558	813	801	982	905	0	0	2,360	2,263
South Dakota	665	647	539	511	278	259	0	0	1,482	1,416
South Atlantic	55,964	53,552	38,032	36,933	10,461	10,358	125	120	104,582	100,963
Delaware	857	776	522	491	163	157	0	0	1,542	1,424
District of Columbia	433	390	1,228	1,191	20	19	31	30	1,712	1,630
Florida	19,561	20,652	10,903	11,621	1,484	1,673	8	8	31,955	33,953
Georgia	8,740	7,997	5,995	5,498	2,352	2,206	12	11	17,099	15,711
Maryland	4,880	4,333	3,601	3,456	350	344	48	46	8,879	8,179
North Carolina	8,727	7,593	5,230	4,662	1,990	1,868	1	1	15,948	14,125
South Carolina	4,632	4,228	2,798	2,618	1,718	1,677	0	0	9,148	8,523
Virginia	6,524	6,146	6,865	6,604	1,239	1,353	26	25	14,655	14,128
West Virginia	1,609	1,438	891	791	1,144	1,061	0	0	3,644	3,291
East South Central	16,264	15,194	11,538	11,020	6,645	6,511	0	0	34,447	32,725
Alabama	4,993	4,594	3,118	2,924	2,304	2,221	0	0	10,415	9,739
Kentucky	3,335	3,106	2,335	2,196	1,820	1,793	0	0	7,490	7,096
Mississippi	2,490	2,453	1,746	1,760	1,085	1,089	0	0	5,321	5,302
Tennessee	5,445	5,041	4,338	4,140	1,437	1,408	0	0	11,220	10,589
West South Central	33,551	33,184	19,994	20,478	15,664	15,441	2	14	69,211	69,116
Arkansas	2,289	2,251	1,207	1,209	1,291	1,276	0	0	4,786	4,736
Louisiana	3,633	3,666	2,473	2,481	2,286	2,345	1	1	8,394	8,494
Oklahoma	2,977	2,877	2,268	2,158	1,305	1,380	0	0	6,550	6,415
Texas	24,652	24,389	14,046	14,629	10,782	10,441	1	12	49,481	49,471
Mountain	16,021	15,003	12,411	11,525	6,654	6,604	17	20	35,102	33,152
Arizona	6,028	5,466	4,415	3,845	1,130	1,159	1	1	11,573	10,471
Colorado	3,087	2,859	2,480	2,409	1,284	1,256	8	12	6,859	6,537
Idaho	1,133	1,083	639	601	737	648	0	0	2,508	2,331
Montana	722	722	597	613	367	366	0	0	1,686	1,700
Nevada	2,194	2,252	1,453	1,473	1,016	1,281	1	1	4,664	5,006
New Mexico	1,043	1,016	1,011	999	725	671	0	0	2,780	2,685
Utah	1,444	1,269	1,326	1,135	682	603	6	7	3,459	3,012
Wyoming	370	338	489	451	714	621	0	0	1,573	1,409
Pacific Contiguous	34,945	31,320	35,201	32,310	11,904	10,379	134	106	82,184	74,114
California	27,444	24,440	29,400	27,007	9,478	8,014	120	94	66,442	59,555
Oregon	2,906	2,603	2,494	2,291	1,226	1,085	3	3	6,629	5,982
Washington	4,596	4,277	3,307	3,012	1,200	1,279	11	9	9,114	8,577
Pacific Noncontiguous	1,651	1,632	1,642	1,635	1,449	1,468	0	0	4,742	4,735
Alaska	514	490	562	543	265	256	0	0	1,341	1,290
Hawaii	1,137	1,142	1,081	1,092	1,184	1,212	0	0	3,402	3,446
U.S. Total	244,367	231,993	185,043	177,342	84,095	81,159	890	877	514,396	491,370

See Technical notes for additional information on the Commercial, Industrial, and Transportation sectors.

Displayed values of zero may represent small values that round to zero. The Excel version of this table provides additional precision which may be accessed by selecting individual cells.

Notes: - See Glossary for definitions. - Values are final.

See Technical Notes for a discussion of the sample design for the Form EIA-826.

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.

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.

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 2.10. Average Price of Electricity to Ultimate Customers by End-Use Sector, by State, 2024 and 2023 (Cents per Kilowatthour)

Census Division and State	Residential		Commercial		Industrial		Transportation		All Sectors	
	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023
New England	27.68	28.73	20.55	19.42	16.28	15.81	12.99	13.01	23.03	22.81
Connecticut	28.75	29.88	21.21	19.99	17.12	15.69	17.77	21.55	24.37	24.24
Maine	24.29	27.42	18.22	17.88	12.46	12.30	--	--	19.66	20.84
Massachusetts	29.35	29.61	20.90	19.62	18.19	17.88	9.22	7.15	23.94	23.21
New Hampshire	23.40	28.15	19.40	20.40	16.21	15.76	--	--	20.60	22.96
Rhode Island	28.65	27.02	21.09	17.68	19.70	18.98	21.53	17.29	24.15	21.62
Vermont	21.90	20.82	18.89	18.00	11.58	11.27	--	--	18.41	17.53
Middle Atlantic	20.63	19.60	15.69	15.32	8.52	7.91	13.67	14.65	16.11	15.40
New Jersey	19.34	17.70	14.64	14.00	11.93	11.68	11.11	12.22	16.29	15.27
New York	24.43	22.24	18.77	18.01	9.17	6.87	14.70	15.70	19.66	18.28
Pennsylvania	17.77	18.10	11.03	11.26	7.87	7.75	9.96	10.21	12.51	12.57
East North Central	16.48	16.19	12.13	11.94	8.08	7.94	7.99	7.08	12.22	11.98
Illinois	15.87	15.71	11.81	11.24	8.83	8.20	7.76	6.90	12.21	11.75
Indiana	14.77	14.94	12.44	12.55	8.15	8.24	12.31	12.73	11.38	11.49
Michigan	19.30	18.84	14.01	13.40	8.26	8.16	14.09	13.67	14.16	13.68
Ohio	15.99	15.38	10.66	10.75	7.10	7.03	7.32	5.91	11.29	11.04
Wisconsin	17.18	16.88	12.63	12.76	8.54	8.68	18.36	17.21	12.72	12.72
West North Central	13.47	13.02	10.25	10.32	7.72	7.77	10.98	10.89	10.52	10.44
Iowa	13.40	13.31	10.22	10.33	6.80	6.91	--	--	9.34	9.42
Kansas	14.15	13.38	11.19	10.85	7.73	7.64	--	--	11.21	10.80
Minnesota	15.45	14.73	12.15	12.39	9.15	9.20	12.71	12.35	12.35	12.21
Missouri	12.91	12.58	10.26	10.14	7.87	7.90	9.94	9.77	11.06	10.87
Nebraska	11.53	11.20	8.39	8.76	7.66	7.63	--	--	9.07	9.14
North Dakota	11.51	11.01	7.19	7.38	7.25	7.37	--	--	7.93	8.03
South Dakota	12.86	12.32	10.55	10.16	8.28	8.01	--	--	10.87	10.49
South Atlantic	14.51	14.45	10.69	10.82	7.76	7.58	10.02	10.23	11.92	11.88
Delaware	16.57	15.73	12.20	11.83	8.49	7.85	--	--	13.56	12.85
District of Columbia	17.71	16.45	17.07	16.94	10.85	9.66	9.94	9.94	16.88	16.50
Florida	14.14	15.21	10.99	11.95	8.50	9.39	10.87	11.33	12.53	13.53
Georgia	14.08	13.69	10.87	10.70	7.21	6.88	7.64	7.29	11.40	11.06
Maryland	17.86	16.60	12.96	12.77	10.01	9.94	11.55	11.23	15.04	14.34
North Carolina	14.13	12.93	10.56	9.67	7.77	7.15	10.28	8.86	11.65	10.61
South Carolina	14.23	13.68	10.64	10.39	6.84	6.68	--	--	10.90	10.50
Virginia	14.41	14.26	8.72	8.95	8.99	8.92	9.25	10.42	10.62	10.68
West Virginia	15.07	14.05	11.62	11.03	7.81	7.24	--	--	11.05	10.26
East South Central	13.40	13.11	12.36	12.13	6.72	6.72	--	--	10.99	10.78
Alabama	15.18	14.63	13.64	13.16	7.25	7.10	--	--	11.90	11.47
Kentucky	12.79	12.65	11.50	11.38	6.50	6.55	--	--	10.07	9.96
Mississippi	13.39	13.23	12.32	12.37	6.81	6.96	--	--	10.93	10.95
Tennessee	12.42	12.19	12.05	11.80	6.21	6.23	--	--	10.90	10.69
West South Central	14.04	13.68	8.88	9.13	6.05	6.47	7.76	7.53	9.58	9.79
Arkansas	12.32	12.25	10.24	10.34	6.61	6.87	13.23	14.93	9.59	9.73
Louisiana	11.73	11.55	10.46	10.45	5.61	5.88	11.54	11.00	8.80	8.91
Oklahoma	12.24	12.08	8.92	9.34	5.84	6.26	--	--	9.09	9.30
Texas	14.94	14.46	8.55	8.82	6.12	6.60	4.35	7.30	9.79	10.04
Mountain	14.12	13.68	11.03	10.94	7.70	7.84	10.61	12.69	11.23	11.07
Arizona	14.91	14.02	12.23	11.79	7.90	8.11	10.95	10.01	12.74	12.19
Colorado	14.92	14.30	11.71	11.64	8.62	8.50	9.66	13.23	12.07	11.76
Idaho	11.52	11.05	9.17	8.78	7.69	7.17	--	--	9.51	9.08
Montana	12.66	12.54	11.87	12.11	7.59	7.80	--	--	10.83	10.97
Nevada	15.00	16.67	10.19	11.91	8.64	10.36	10.66	12.75	11.47	13.09
New Mexico	14.20	13.85	10.54	10.68	5.43	5.75	--	--	9.18	9.47
Utah	12.22	11.20	9.39	8.51	7.86	6.99	12.07	12.28	9.97	9.03
Wyoming	12.47	11.46	9.27	8.94	7.96	7.06	--	--	9.14	8.39
Pacific Contiguous	24.23	22.02	20.36	19.42	15.38	13.38	16.10	12.67	20.79	19.15
California	31.97	29.51	25.54	23.91	21.53	18.64	16.79	13.01	27.04	24.87
Oregon	14.70	12.73	10.11	9.92	8.05	7.52	12.54	11.41	11.11	10.32
Washington	11.90	10.98	9.99	9.92	6.61	6.35	11.64	10.17	10.13	9.58
Pacific Noncontiguous	34.95	34.40	30.22	30.28	29.93	30.55	--	--	31.62	31.67
Alaska	24.82	23.90	21.57	20.87	19.31	18.70	--	--	22.17	21.41
Hawaii	42.86	42.39	38.18	39.03	34.13	35.28	--	--	38.00	38.60
U.S. Total	16.48	16.00	12.75	12.59	8.13	8.04	12.75	12.77	12.94	12.68

See Technical notes for additional information on the Commercial, Industrial, and Transportation sectors.

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Notes: - See Glossary for definitions. - Values are final.

See Technical Notes for a discussion of the sample design for the Form EIA-826.

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.

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.

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 2.11. Number of Ultimate Customers by Sector
by State, 2023 and 2024

Census Division and State	Residential		Commercial		Industrial		Transportation		All Sectors	
	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023
New England	6,653,781	6,579,669	945,130	943,130	21,150	21,474	6	6	7,620,067	7,544,279
Connecticut	1,552,746	1,541,895	156,818	156,310	3,864	3,936	3	3	1,713,431	1,702,144
Maine	742,549	731,969	111,084	108,745	1,925	2,040	--	--	855,558	842,754
Massachusetts	2,924,535	2,886,203	438,014	443,991	10,353	10,510	2	2	3,372,904	3,340,706
New Hampshire	652,608	647,007	112,277	111,302	3,116	3,125	--	--	768,001	761,434
Rhode Island	457,383	450,190	62,629	60,297	1,649	1,606	1	1	521,662	512,094
Vermont	323,960	322,405	64,308	62,485	243	257	--	--	388,511	385,147
Middle Atlantic	16,690,432	16,603,564	2,444,687	2,455,311	40,817	33,989	18	21	19,175,954	19,092,885
New Jersey	3,735,638	3,702,963	540,221	539,427	11,251	11,246	7	8	4,287,117	4,253,644
New York	7,420,214	7,384,444	1,163,769	1,180,841	16,605	7,178	6	8	8,600,594	8,572,471
Pennsylvania	5,534,580	5,516,157	740,697	735,043	12,961	15,565	5	5	6,288,243	6,266,770
East North Central	20,951,042	20,833,849	2,574,768	2,547,590	54,769	55,099	10	11	23,580,589	23,436,549
Illinois	5,392,477	5,394,659	638,510	626,171	5,686	5,541	3	4	6,036,676	6,026,375
Indiana	3,056,216	3,018,496	374,858	371,773	19,345	19,291	1	1	3,450,420	3,409,561
Michigan	4,516,367	4,496,300	564,574	559,552	5,762	5,589	2	2	5,086,705	5,061,443
Ohio	5,142,108	5,110,814	627,393	624,926	18,237	19,087	2	2	5,787,740	5,754,829
Wisconsin	2,843,874	2,813,580	369,433	365,168	5,739	5,591	2	2	3,219,048	3,184,341
West North Central	10,017,809	9,915,499	1,526,285	1,517,734	132,146	131,428	3	3	11,676,243	11,564,664
Iowa	1,448,818	1,436,037	251,716	250,532	9,477	9,451	--	--	1,710,011	1,696,020
Kansas	1,317,095	1,306,777	245,169	245,544	23,963	24,106	--	--	1,586,227	1,576,427
Minnesota	2,581,180	2,551,574	308,460	308,285	9,410	9,351	1	1	2,899,051	2,869,211
Missouri	2,933,314	2,906,438	403,957	399,085	9,443	9,831	2	2	3,347,316	3,315,356
Nebraska	905,415	893,123	161,501	160,540	64,672	63,824	--	--	1,131,588	1,117,487
North Dakota	397,839	395,002	77,191	76,700	10,864	10,628	--	--	485,894	482,330
South Dakota	433,548	426,548	78,291	77,048	4,317	4,237	--	--	516,156	507,833
South Atlantic	30,673,496	30,090,394	4,040,023	4,000,173	88,735	88,038	13	13	34,802,267	34,178,618
Delaware	473,508	468,358	60,653	59,839	1,169	876	--	--	535,330	529,073
District of Columbia	318,780	312,982	27,521	27,387	1	1	3	3	346,305	340,373
Florida	10,443,373	10,222,476	1,309,027	1,292,988	26,610	26,085	2	2	11,779,012	11,541,551
Georgia	4,815,501	4,703,796	619,171	609,978	24,336	24,366	1	1	5,459,009	5,338,141
Maryland	2,451,753	2,432,423	261,469	260,822	9,286	9,226	5	5	2,722,513	2,702,476
North Carolina	5,067,762	4,951,380	751,027	746,025	8,930	9,082	1	1	5,827,720	5,706,488
South Carolina	2,581,882	2,518,272	413,387	410,802	3,604	3,634	--	--	2,998,873	2,932,708
Virginia	3,654,481	3,615,939	445,756	441,468	3,794	3,673	1	1	4,104,032	4,061,081
West Virginia	866,456	864,768	152,012	150,864	11,005	11,095	--	--	1,029,473	1,026,727
East South Central	8,981,949	8,853,035	1,507,151	1,484,981	25,513	24,411	--	--	10,514,613	10,362,427
Alabama	2,398,172	2,353,274	389,925	384,122	7,246	7,239	--	--	2,795,343	2,744,635
Kentucky	2,077,215	2,057,705	327,448	323,183	4,846	5,136	--	--	2,409,509	2,386,024
Mississippi	1,340,459	1,335,278	246,813	246,032	12,415	11,023	--	--	1,599,687	1,592,333
Tennessee	3,166,103	3,106,778	542,965	531,644	1,006	1,013	--	--	3,710,074	3,639,435
West South Central	18,051,370	17,711,160	2,363,886	2,400,621	451,075	419,810	6	6	20,866,337	20,531,597
Arkansas	1,476,944	1,459,802	207,035	205,526	36,772	36,612	2	2	1,720,753	1,701,942
Louisiana	2,147,745	2,137,199	301,288	300,640	18,203	18,790	1	1	2,467,237	2,456,630
Oklahoma	1,878,818	1,857,151	298,476	304,896	20,002	19,874	--	--	2,197,296	2,181,921
Texas	12,547,863	12,257,008	1,557,087	1,589,559	376,098	344,534	3	3	14,481,051	14,191,104
Mountain	10,925,227	10,725,657	1,532,262	1,502,127	100,429	100,935	5	6	12,557,923	12,328,725
Arizona	3,134,733	3,068,552	348,423	344,059	7,555	7,614	2	2	3,490,713	3,420,227
Colorado	2,557,732	2,517,452	405,693	397,348	14,750	15,358	1	2	2,978,176	2,930,160
Idaho	868,141	845,896	123,982	121,675	29,658	29,322	--	--	1,021,781	996,893
Montana	557,432	549,248	123,483	116,235	11,624	12,019	--	--	692,539	677,502
Nevada	1,311,755	1,288,498	177,740	174,042	4,786	4,784	1	1	1,494,282	1,467,325
New Mexico	936,098	928,216	148,104	147,632	9,256	9,339	--	--	1,093,458	1,085,187
Utah	1,272,861	1,244,066	145,854	142,545	10,805	10,719	1	1	1,429,521	1,397,331
Wyoming	286,475	283,729	58,983	58,591	11,995	11,780	--	--	357,453	354,100
Pacific Contiguous	19,454,170	19,227,491	2,430,030	2,412,748	199,328	201,091	20	19	22,083,548	21,841,349
California	14,217,180	14,063,972	1,777,305	1,766,915	146,327	148,000	13	12	16,140,825	15,978,899
Oregon	1,868,012	1,843,683	247,412	244,410	26,616	26,545	2	2	2,142,042	2,114,640
Washington	3,368,978	3,319,836	405,313	401,423	26,385	26,546	5	5	3,800,681	3,747,810
Pacific Noncontiguous	744,909	742,395	116,664	116,913	2,012	1,974	--	--	863,585	861,282
Alaska	298,397	296,192	57,009	56,796	1,191	1,161	--	--	356,597	354,149
Hawaii	446,512	446,203	59,655	60,117	821	813	--	--	506,988	507,133
U.S. Total	143,144,185	141,282,713	19,480,886	19,381,328	1,115,974	1,078,249	81	85	163,741,126	161,742,375

**Table 2.12. Electric Power Industry - Electricity Purchases,
2014 through 2024 (Thousand Megawatthours)**

Year	Electric Utilities	Energy-Only Providers	Independent Power Producers	Combined Heat and Power	U.S. Total
2014	2,145,378	2,559,875	17,000	79,975	4,802,227
2015	2,101,788	2,506,185	54,046	99,505	4,761,523
2016	2,089,540	2,438,204	8,520	187,307	4,723,571
2017	2,102,971	2,552,146	9,372	196,768	4,861,257
2018	2,187,615	2,713,174	8,730	259,354	5,168,874
2019	2,231,042	2,778,349	9,391	352,854	5,371,635
2020	2,146,608	2,792,233	9,458	276,281	5,224,580
2021	2,258,989	2,541,686	5,950	260,545	5,067,170
2022	2,407,972	2,436,300	11,634	275,057	5,130,963
2023	2,247,163	2,329,456	19,670	199,483	4,795,772
2024	2,302,830	2,118,199	21,095	168,762	4,610,886

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" and Form EIA-923, "Power Plant Operations Report"

**Table 2.13. Electric Power Industry - Electricity Sales for Resale,
2014 through 2024 (Thousand Megawatthours)**

Year	Electric Utilities	Energy-Only Providers	Independent Power Producers	Combined Heat and Power	U.S. Total
2014	1,485,964	2,081,235	1,301,724	39,916	4,908,839
2015	1,393,396	2,033,705	1,331,181	39,113	4,797,395
2016	1,391,873	1,947,036	1,372,928	35,131	4,746,967
2017	1,396,838	2,066,455	1,389,083	37,571	4,889,947
2018	1,431,952	2,193,414	1,463,236	38,674	5,127,276
2019	1,402,200	2,259,028	1,466,561	44,641	5,172,430
2020	1,364,031	2,284,266	1,457,591	39,572	5,145,459
2021	1,481,890	2,020,031	1,402,064	34,772	4,938,756
2022	1,526,810	1,909,697	1,626,033	42,980	5,105,520
2023	1,394,671	1,785,875	1,638,113	47,804	4,866,463
2024	1,433,061	1,534,145	1,708,929	39,207	4,715,342

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" and Form EIA-923, "Power Plant Operations Report"

Table 2.14. Electric Power Industry - U.S. Electricity Imports from and Electricity Exports to Canada and Mexico, 2014-2024 (Megawatthours)

Year	Canada		Mexico		U.S. Total	
	Imports from	Exports to	Imports from	Exports to	Imports	Exports
2014	59,369,660	12,860,889	7,140,624	437,364	66,510,284	13,298,253
2015	68,462,277	8,707,873	7,308,192	392,016	75,770,469	9,099,889
2016	65,173,818	2,682,381	7,542,445	3,531,636	72,716,263	6,214,017
2017	59,909,320	3,312,798	5,775,597	6,058,005	65,684,917	9,370,803
2018	51,494,627	7,290,070	6,765,975	6,514,422	58,260,602	13,804,492
2019	52,309,254	13,532,067	6,743,207	6,475,965	59,052,461	20,008,032
2020	57,001,240	9,855,106	4,447,623	4,279,573	61,448,863	14,134,679
2021	48,140,438	10,067,396	5,026,570	3,788,022	53,167,008	13,855,418
2022	52,187,403	10,651,209	4,782,900	5,107,113	56,970,303	15,758,322
2023	33,225,087	18,384,320	5,692,121	1,628,726	38,917,208	20,013,046
2024	27,201,095	17,343,144	6,053,393	2,093,903	33,254,488	19,437,047

Notes: As of November 2017, the data for 2016 and going forward will be published using data from the Form EIA-111, "Quarterly Electricity Imports and Exports Report." During 2013-2015, EIA revised its approach to estimating imports from Mexico.

Sources: 2016-2024, U.S. Energy Information Administration, Form EIA-111, "Quarterly Electricity Imports and Exports Report"; 2006-2015 data, National Energy Board of Canada; FERC 714, Annual Electric Balancing Authority Area and Planning Report; California Energy Commission; and EIA estimates.

Chapter 3

Net Generation

Table 3.1.A. Net Generation by Energy Source: Total (All Sectors), 2014 - 2024
(Thousand Megawatthours)

Period	Generation at Utility Scale Facilities											Small Scale Generation	Net Generation From Utility and Small Scale Facilities	
	Coal	Petroleum Liquids	Petroleum Coke	Natural Gas	Other Fossil Gas	Nuclear	Hydroelectric Conventional	Solar	Renewable Sources Excluding Hydroelectric and Solar	Hydroelectric Pumped Storage	Other	Total Generation at Utility Scale Facilities	Estimated Solar Photovoltaic	Estimated Total Solar Photovoltaic
Annual Totals														
2014	1,581,710	18,276	11,955	1,126,636	12,022	797,166	259,367	17,691	261,522	-6,174	13,393	4,093,564	11,233	26,482
2015	1,352,398	17,372	10,877	1,334,668	13,117	797,178	249,080	24,893	270,268	-5,091	13,955	4,078,714	14,139	35,805
2016	1,239,149	13,008	11,197	1,379,271	12,807	805,694	267,812	36,054	305,579	-6,686	13,689	4,077,574	18,812	51,483
2017	1,205,835	12,414	8,976	1,297,703	12,469	804,950	300,333	53,287	332,963	-6,495	13,008	4,035,443	23,990	74,008
2018	1,149,487	16,245	8,981	1,471,843	13,463	807,084	292,524	63,825	350,467	-5,905	12,973	4,180,988	29,539	89,773
2019	964,957	11,522	6,819	1,588,533	12,591	809,409	287,874	71,937	368,862	-5,261	13,331	4,130,574	34,957	103,676
2020	773,393	9,662	7,679	1,626,790	11,818	789,879	285,274	89,199	408,539	-5,321	12,855	4,009,767	41,522	127,588
2021	897,999	11,663	7,511	1,579,190	11,397	779,645	251,585	115,258	448,424	-5,112	12,140	4,109,699	49,164	161,499
2022	831,512	15,805	7,126	1,687,065	11,722	771,537	254,789	143,792	502,234	-6,028	11,114	4,230,668	61,282	202,075
2023	675,115	11,397	4,836	1,806,063	11,778	774,873	245,002	165,530	484,708	-5,990	9,957	4,183,270	73,406	236,090
2024	652,156	11,456	3,629	1,869,902	10,845	781,865	242,896	219,834	513,733	-5,852	8,170	4,308,634	83,918	300,634
Year 2022														
January	87,588	3,105	564	134,948	1,005	70,577	24,198	7,822	43,424	-493	1,029	373,766	3,376	11,065
February	70,966	1,114	621	114,945	886	61,852	21,321	9,027	43,090	-412	900	324,311	3,717	12,585
March	61,019	959	500	112,477	963	63,154	24,436	11,694	48,677	-318	979	324,530	5,121	16,560
April	55,329	749	528	105,506	921	55,290	20,066	13,402	51,528	-265	941	303,994	5,671	18,751
May	62,532	834	596	127,091	1,036	63,382	23,359	15,120	47,729	-467	971	342,184	6,236	20,985
June	73,463	897	683	155,517	987	65,715	25,988	16,052	39,461	-589	959	379,134	6,229	21,910
July	86,415	1,045	488	189,042	1,083	68,857	24,567	15,765	35,499	-768	982	422,975	6,438	21,915
August	85,215	1,001	576	188,860	1,008	68,897	21,133	14,502	30,657	-640	924	412,133	6,194	20,418
September	64,998	942	648	156,948	987	63,733	17,026	13,286	32,840	-598	845	351,655	5,544	18,545
October	54,228	952	610	133,492	968	58,945	14,367	11,942	38,036	-434	844	313,949	5,022	16,674
November	56,377	911	568	127,523	911	62,041	17,898	8,403	46,779	-495	864	321,780	4,035	12,289
December	73,381	3,296	744	140,716	978	69,094	20,430	6,777	44,514	-548	876	360,257	3,698	10,377
Year 2023														
January	61,357	983	421	138,503	945	70,870	22,754	7,806	44,043	-620	889	347,950	3,989	11,711
February	46,374	1,233	395	125,036	891	60,807	19,961	9,435	46,467	-456	778	310,922	4,387	13,713
March	50,096	924	314	133,699	1,028	62,820	21,331	12,213	49,007	-519	790	331,704	6,005	18,064
April	40,233	868	301	120,012	866	56,662	19,820	15,062	47,626	-290	744	301,903	6,742	21,509
May	43,804	880	330	137,394	1,011	61,155	27,651	17,281	37,570	-459	857	327,474	7,543	24,525
June	57,772	878	389	161,981	974	64,819	21,572	17,834	32,728	-551	838	359,234	7,405	24,874
July	78,903	964	651	199,522	1,046	69,888	21,978	18,894	33,394	-656	872	425,455	7,720	26,234
August	78,112	958	651	199,221	1,088	69,744	21,293	17,744	33,882	-653	865	422,905	7,504	24,938
September	59,959	894	592	166,311	983	65,560	16,916	15,583	33,470	-553	775	360,490	6,604	21,894
October	50,933	990	293	140,825	924	61,436	15,673	14,121	41,060	-372	837	326,718	6,076	19,910
November	51,209	906	179	135,531	959	62,258	17,026	10,446	41,774	-347	844	320,785	4,938	15,218
December	56,385	920	318	148,029	1,062	68,854	19,028	9,113	43,688	-514	869	347,732	4,494	13,500
Year 2024														
January	75,618	1,469	360	161,667	1,074	69,080	21,554	9,583	40,334	-414	799	381,122	4,726	14,230
February	44,137	740	217	131,845	931	64,584	20,795	12,540	46,108	-404	720	322,214	5,342	17,763
March	38,505	784	207	131,137	882	63,346	23,363	16,019	50,354	-349	689	324,938	7,113	22,911
April	37,246	866	278	121,532	913	57,542	20,916	19,241	51,940	-338	644	310,780	7,832	26,741
May	45,812	850	304	143,993	889	64,973	24,477	22,371	44,360	-284	738	348,485	8,539	30,496
June	61,339	890	389	169,156	941	68,192	22,397	24,459	43,755	-579	694	391,632	8,553	32,598
July	71,565	997	451	205,959	949	69,851	21,384	24,484	33,593	-639	723	429,317	8,778	32,901
August	68,760	993	432	202,915	911	69,760	20,491	24,328	34,653	-798	682	423,127	8,412	32,387
September	54,559	839	236	169,671	836	62,660	15,911	20,538	34,165	-637	619	359,397	7,511	27,714
October	46,890	929	232	146,711	801	58,773	15,352	19,828	44,334	-439	570	333,980	6,736	26,331
November	44,924	875	220	137,687	800	61,904	16,723	13,841	45,214	-490	652	322,351	5,393	19,098
December	62,800	1,224	304	147,630	919	71,200	19,533	12,601	44,923	-481	639	361,292	4,984	17,465

Coal includes anthracite, bituminous, subbituminous, lignite, and waste coal; synthetic coal and refined coal; and beginning in 2011, coal-derived synthesis gas. Prior to 2011 coal-derived synthesis gas was included in Other Fossil Gas.

Petroleum Liquids includes distillate and residual fuel oils, jet fuel, kerosene, waste oil, and beginning in 2011, propane. Prior to 2011 propane was included in Other Fossil Gas.

Petroleum Coke includes petroleum coke-derived synthesis gas. Prior to 2011, petroleum coke-derived synthesis gas was included in Other Fossil Gas.

Other Fossil Gas includes gaseous propane, blast furnace gas, other manufactured and waste gases derived from fossil fuels other than hydrogen.

See the Technical Notes for fuel conversion factors.

Renewable Sources include wood, black liquor, other wood waste, biogenic municipal solid waste, landfill gas, sludge waste, agriculture byproducts, other biomass, geothermal, solar thermal, photovoltaic energy, and wind.

Other includes hydrogen, non-biogenic municipal solid waste, batteries, purchased steam, sulfur, tire-derived fuel, and other miscellaneous energy sources.

Notes: Beginning with 2001 data, non-biogenic municipal solid waste and tire-derived fuels are reclassified as non-renewable energy sources and included in Other. Biogenic municipal solid waste is included in Other Renewable Sources.

See Glossary for definitions. Values are final. See Technical Notes for a discussion of the sample design for the Form EIA-923 and predecessor forms.

Totals may not equal sum of components because of independent rounding. NM=Not meaningful due to large standard error. W=Withheld to avoid disclosure of individual company data.

Displayed values of zero may represent small values that round to zero. The Excel version of this table provides additional precision which may be accessed by selecting individual cells.

Sources: U.S. Energy Information Administration, Form EIA-923, Power Plant Operations Report; U.S. Energy Information Administration, Form EIA-906, Power Plant Report; U.S. Energy Information Administration, Form EIA-920 Combined Heat and Power Plant Report; and predecessor forms.

Beginning with 2008 data, the Form EIA-923, Power Plant Operations Report, replaced the following: Form EIA-906, Power Plant Report; Form EIA-920, Combined Heat and Power Plant Report; and predecessor forms.

Form EIA-423, Monthly Cost and Quality of Fuels for Electric Plants Report, and Federal Energy Regulatory Commission, FERC Form 423, Monthly Report of Cost and Quality of Fuels for Electric Plants.

Estimated small scale solar photovoltaic generation and small scale solar photovoltaic capacity are based on data from Form EIA-861M, Form EIA-861 and from estimation methods described in the technical notes.

Table 3.1.B. Net Generation from Renewable Sources: Total (All Sectors), 2014 - 2024
(Thousand Megawatthours)

Period	Generation at Utility Scale Facilities										Small Scale Generation	Generation From Utility and Small Scale Facilities	
	Wind	Solar Photovoltaic	Solar Thermal	Wood and Wood-Derived Fuels	Landfill Gas	Biogenic Municipal Solid Waste	Other Waste Biomass	Geothermal	Conventional Hydroelectric	Total Renewable Generation at Utility Scale Facilities	Estimated Solar Photovoltaic	Estimated Total Solar Photovoltaic	Estimated Total Solar
Annual Totals													
2014	181,655	15,250	2,441	42,340	11,220	7,228	3,202	15,877	259,367	538,579	11,233	26,482	28,924
2015	190,719	21,666	3,227	41,929	11,291	7,211	3,201	15,918	249,080	544,241	14,139	35,805	39,032
2016	226,993	32,670	3,384	40,947	11,218	7,265	3,331	15,826	267,812	609,445	18,812	51,483	54,866
2017	254,303	50,018	3,269	41,124	11,543	6,951	3,115	15,927	300,333	686,583	23,990	74,008	77,277
2018	272,667	60,234	3,592	40,936	11,036	7,136	2,724	15,967	292,524	706,816	29,539	89,773	93,965
2019	295,882	68,719	3,218	38,543	10,468	6,093	2,402	15,473	287,874	728,673	34,957	103,676	106,894
2020	337,938	86,066	3,133	36,219	10,212	6,080	2,201	15,890	285,274	783,012	41,522	127,588	130,721
2021	378,197	112,335	2,924	36,463	9,421	6,101	2,267	15,975	251,585	815,267	49,164	161,499	164,422
2022	434,297	140,793	2,999	35,466	8,535	5,776	2,073	16,087	254,789	900,814	61,282	202,075	205,074
2023	421,141	162,683	2,847	31,615	7,935	5,568	2,082	16,367	245,002	895,241	73,406	236,090	238,937
2024	451,904	216,715	3,118	31,564	7,341	5,402	2,115	15,407	242,896	976,463	83,918	300,634	303,752
Year 2022													
January	37,416	7,689	133	3,106	748	492	192	1,470	24,198	75,443	3,376	11,065	11,198
February	37,645	8,868	159	2,897	701	432	173	1,243	21,321	73,438	3,717	12,585	12,744
March	43,031	11,439	255	2,934	773	465	188	1,296	24,436	84,808	5,121	16,560	16,815
April	46,167	13,080	321	2,736	699	482	161	1,282	20,066	84,995	5,671	18,751	19,073
May	42,124	14,749	371	2,907	722	492	157	1,327	23,359	86,208	6,236	20,985	21,356
June	33,768	15,681	372	3,045	710	498	166	1,276	25,988	81,501	6,229	21,910	22,281
July	29,475	15,477	288	3,276	723	510	173	1,341	24,567	75,831	6,438	21,915	22,203
August	24,718	14,223	279	3,206	707	498	174	1,354	21,133	66,293	6,194	20,418	20,697
September	27,331	13,001	285	2,864	686	470	159	1,329	17,026	63,152	5,544	18,545	18,830
October	32,745	11,652	289	2,624	714	473	182	1,298	14,367	64,345	5,022	16,674	16,964
November	41,199	8,254	149	2,865	678	473	167	1,397	17,898	73,079	4,035	12,289	12,438
December	38,680	6,679	99	3,005	674	493	181	1,482	20,430	71,721	3,698	10,377	10,475
Year 2023													
January	38,358	7,722	84	2,920	694	483	168	1,420	22,754	74,603	3,989	11,711	11,795
February	41,424	9,326	109	2,533	614	420	174	1,302	19,961	75,863	4,387	13,713	13,822
March	43,584	12,059	154	2,704	670	446	162	1,442	21,331	82,552	6,005	18,064	18,218
April	42,746	14,767	295	2,336	623	409	157	1,356	19,820	82,507	6,742	21,509	21,803
May	32,227	16,981	300	2,654	692	475	176	1,345	27,651	82,502	7,543	24,525	24,824
June	27,547	17,469	365	2,579	666	483	159	1,293	21,572	72,134	7,405	24,874	25,239
July	28,005	18,514	380	2,758	674	497	165	1,296	21,978	74,266	7,720	26,234	26,614
August	28,394	17,435	309	2,884	680	482	174	1,267	21,293	72,919	7,504	24,938	25,248
September	28,353	15,290	293	2,573	629	441	160	1,315	16,916	65,968	6,604	21,894	22,187
October	36,020	13,834	287	2,317	649	463	191	1,420	15,673	70,853	6,076	19,910	20,196
November	36,445	10,280	166	2,584	651	471	183	1,440	17,026	69,246	4,938	15,218	15,384
December	38,038	9,006	106	2,774	693	498	213	1,473	19,028	71,829	4,494	13,500	13,606
Year 2024													
January	34,791	9,504	79	2,849	642	467	186	1,399	21,554	71,471	4,726	14,230	14,309
February	40,982	12,421	119	2,621	605	421	176	1,303	20,795	79,444	5,342	17,763	17,882
March	45,102	15,798	221	2,651	638	422	181	1,359	23,363	89,736	7,113	22,911	23,132
April	47,088	18,909	332	2,423	583	408	158	1,280	20,916	92,097	7,832	26,741	27,073
May	39,256	21,957	414	2,575	638	469	176	1,246	24,477	91,209	8,539	30,496	30,910
June	38,661	24,045	414	2,681	593	450	168	1,202	22,397	90,610	8,553	32,598	33,012
July	28,304	24,122	361	2,806	624	475	166	1,218	21,384	79,460	8,778	32,901	33,262
August	29,290	23,974	354	2,839	641	480	175	1,227	20,491	79,472	8,412	32,387	32,741
September	29,178	20,203	335	2,563	604	447	170	1,201	15,911	70,614	7,511	27,714	28,049
October	39,592	19,595	233	2,240	608	448	187	1,261	15,352	79,514	6,736	26,331	26,564
November	40,133	13,705	136	2,550	577	456	180	1,317	16,723	75,779	5,393	19,098	19,234
December	39,527	12,481	120	2,765	588	457	192	1,393	19,533	77,057	4,984	17,465	17,585

Wood and Wood-derived fuels include 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.

Other Waste Biomass includes sludge waste, agricultural byproducts, other biomass solids, other biomass liquids, and other biomass gases (including digester gases, methane, and other biomass gases).

Notes: Beginning with 2001 data, non-biogenic municipal solid waste and tire-derived fuels are reclassified as non-renewable energy sources and included in Other. Biogenic municipal solid waste is included in Other Renewable Sources.

See Glossary for definitions. Values are final. See Technical Notes for a discussion of the sample design for the Form EIA-923 and predecessor forms.

Totals may not equal sum of components because of independent rounding. N/A=Not meaningful due to large standard error. W=Withheld to avoid disclosure of individual company data.

Displayed values of zero may represent small values that round to zero. The Excel version of this table provides additional precision which may be accessed by selecting individual cells.

Sources: U.S. Energy Information Administration, Form EIA-923, Power Plant Operations Report; U.S. Energy Information Administration, Form EIA-906, Power Plant Report; U.S. Energy Information Administration, Form EIA-920 Combined Heat and Power Plant Report; and predecessor forms.

Beginning with 2008 data, the Form EIA-923, Power Plant Operations Report, replaced the following: 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 Federal Energy Regulatory Commission, FERC Form 423, Monthly Report of Cost and Quality of Fuels for Electric Plants.

Estimated small scale solar photovoltaic generation and small scale solar photovoltaic capacity are based on data from Form EIA-861M, Form EIA-861 and from estimation methods described in the technical notes.

Table 3.2.A. Net Generation by Energy Source: Electric Utilities, 2014 - 2024
(Thousand Megawatthours)

Period	Generation at Utility Scale Facilities											Total
	Coal	Petroleum Liquids	Petroleum Coke	Natural Gas	Other Fossil Gas	Nuclear	Hydroelectric Conventional	Solar	Renewable Sources Excluding Hydroelectric and Solar	Hydroelectric Pumped Storage	Other	
Annual Totals												
2014	1,173,073	10,696	9,147	501,440	112	419,871	238,185	1,218	33,278	-5,144	622	2,382,500
2015	996,385	10,386	8,278	619,003	199	416,680	229,640	1,494	35,992	-4,105	558	2,316,508
2016	922,399	9,969	8,861	655,744	154	424,400	247,787	1,995	40,666	-5,629	421	2,305,887
2017	893,039	8,567	6,711	625,094	149	424,485	275,677	3,348	42,763	-5,448	553	2,275,539
2018	863,505	10,108	6,617	722,916	151	424,251	267,336	4,916	44,184	-4,785	561	2,339,960
2019	722,885	8,313	5,112	787,745	154	430,672	262,364	6,785	48,403	-4,261	551	2,268,723
2020	582,374	7,182	5,663	815,414	45	428,953	264,650	9,945	59,797	-4,326	618	2,170,316
2021	674,804	8,791	5,728	777,057	12	430,683	228,689	13,911	75,338	-3,876	508	2,211,643
2022	621,853	9,356	5,383	832,421	0	427,933	232,953	17,692	86,233	-4,752	534	2,229,605
2023	518,330	8,254	3,146	895,910	0	441,391	220,003	22,230	84,313	-4,545	580	2,189,614
2024	508,149	8,504	1,946	953,446	0	444,521	220,163	30,347	93,209	-4,232	285	2,256,336
Year 2022												
January	63,823	1,254	388	66,875	0	39,295	22,395	1,066	8,258	-420	58	202,990
February	50,911	629	453	55,560	0	34,300	19,408	1,188	7,998	-301	51	170,198
March	43,015	691	324	54,831	0	34,385	21,943	1,533	8,561	-214	55	165,124
April	40,123	548	361	51,428	0	30,252	17,583	1,714	8,652	-164	43	150,540
May	47,965	639	503	62,462	0	35,037	21,195	1,850	7,488	-375	53	176,816
June	56,910	652	545	79,183	0	36,908	24,296	1,836	6,114	-460	40	206,024
July	66,531	678	388	95,206	0	38,888	23,132	1,811	5,104	-623	40	231,355
August	64,386	661	423	93,582	0	38,921	19,776	1,717	4,993	-495	36	223,900
September	49,704	680	460	59,375	0	35,914	15,593	1,499	5,846	-493	33	185,222
October	41,060	676	440	64,375	0	32,085	12,963	1,460	6,736	-370	46	159,472
November	41,209	673	446	63,004	0	33,612	16,315	1,046	8,593	-398	40	164,537
December	56,116	1,575	636	69,839	0	38,335	18,352	982	7,992	-437	39	193,428
Year 2023												
January	47,822	749	265	69,060	0	40,507	19,961	1,198	7,368	-496	50	186,483
February	34,662	721	257	61,273	0	34,281	17,914	1,480	8,665	-359	44	158,939
March	37,670	678	166	66,443	0	36,091	18,841	1,928	8,423	-389	47	169,897
April	29,082	634	176	59,851	0	33,574	17,367	1,992	9,198	-191	41	151,724
May	32,611	657	166	70,281	0	34,559	25,345	2,322	6,601	-336	44	172,249
June	46,228	687	257	81,588	0	37,005	19,980	2,288	4,812	-420	52	192,477
July	62,726	678	484	99,498	0	39,977	19,811	2,325	4,726	-519	51	229,758
August	61,744	733	491	100,846	0	40,065	19,175	2,301	5,570	-499	59	230,484
September	46,714	653	441	81,426	0	37,575	15,262	1,965	5,788	-415	47	189,456
October	38,830	695	176	68,791	0	34,541	14,167	1,873	7,410	-294	47	166,235
November	37,358	669	100	63,741	0	34,719	15,453	1,403	8,015	-245	47	161,261
December	42,884	699	167	73,111	0	38,497	16,728	1,154	7,737	-379	53	180,651
Year 2024												
January	58,491	1,028	200	80,561	0	39,090	19,005	1,291	7,117	-287	32	206,527
February	34,812	590	91	66,015	0	36,601	18,487	1,993	8,381	-268	27	166,728
March	31,039	609	40	66,011	0	35,957	20,610	2,413	9,619	-213	20	166,104
April	28,360	643	137	61,043	0	32,153	18,197	3,022	10,124	-231	15	153,463
May	35,539	649	153	74,969	0	36,822	22,074	3,303	7,979	-144	27	181,372
June	48,750	652	252	87,902	0	38,907	20,702	3,216	7,676	-439	25	207,643
July	56,197	699	285	107,213	0	40,388	19,685	3,164	5,187	-472	24	232,380
August	53,679	770	277	105,880	0	39,992	18,685	3,084	5,824	-638	24	227,576
September	42,774	665	142	87,049	0	35,308	14,867	2,536	6,359	-501	22	189,221
October	35,531	728	137	74,370	0	33,821	14,374	2,554	8,548	-328	25	169,761
November	34,323	675	85	69,701	0	35,228	15,766	1,901	8,027	-351	24	165,377
December	48,654	796	147	72,734	0	40,244	17,712	1,870	8,368	-359	21	190,186

Coal includes anthracite, bituminous, subbituminous, lignite, and waste coal; synthetic coal and refined coal; and beginning in 2011, coal-derived synthesis gas. Prior to 2011 coal-derived synthesis gas was included in Other Fossil Gas.

Petroleum Liquids includes distillate and residual fuel oils, jet fuel, kerosene, waste oil, and beginning in 2011, propane. Prior to 2011 propane was included in Other Fossil Gas.

Petroleum Coke includes petroleum coke-derived synthesis gas. Prior to 2011, petroleum coke-derived synthesis gas was included in Other Fossil Gas.

Other Fossil Gas includes gaseous propane, blast furnace gas, other manufactured and waste gases derived from fossil fuels other than hydrogen.

See the Technical Notes for fuel conversion factors.

Renewable Sources include wood, black liquor, other wood waste, biogenic municipal solid waste, landfill gas, sludge waste, agriculture byproducts, other biomass, geothermal, solar thermal, photovoltaic energy, and wind.

Other includes hydrogen, non-biogenic municipal solid waste, batteries, purchased steam, sulfur, tire-derived fuel, and other miscellaneous energy sources.

Notes: Beginning with 2001 data, non-biogenic municipal solid waste and tire-derived fuels are reclassified as non-renewable energy sources and included in Other. Biogenic municipal solid waste is included in Other Renewable Sources.

See Glossary for definitions. Values are final. See Technical Notes for a discussion of the sample design for the Form EIA-923 and predecessor forms.

Totals may not equal sum of components because of independent rounding. NM=Not meaningful due to large standard error. W=Withheld to avoid disclosure of individual company data.

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Sources: U.S. Energy Information Administration, Form EIA-923, Power Plant Operations Report; U.S. Energy Information Administration, Form EIA-906, Power Plant Report; U.S. Energy Information Administration, Form EIA-920 Combined Heat and Power Plant Report; and predecessor forms.

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

Table 3.2.B. Net Generation from Renewable Sources: Electric Utilities, 2014 - 2024
(Thousand Megawatthours)

Period	Generation at Utility Scale Facilities										Small Scale Generation	Generation From Utility and Small Scale Facilities	
	Wind	Solar Photovoltaic	Solar Thermal	Wood and Wood-Derived Fuels	Landfill Gas	Biogenic Municipal Solid Waste	Other Waste Biomass	Geothermal	Conventional Hydroelectric	Total Renewable Generation at Utility Scale Facilities	Estimated Solar Photovoltaic	Estimated Total Solar Photovoltaic	Estimated Total Solar
Annual Totals													
2014	27,671	1,094	124	3,050	1,068	191	182	1,116	238,185	272,681	0	1,094	1,218
2015	30,412	1,388	106	3,018	1,061	195	218	1,089	229,640	267,125	0	1,388	1,494
2016	35,070	1,920	75	3,038	1,040	201	237	1,080	247,787	290,448	0	1,920	1,995
2017	37,068	3,326	22	3,226	1,103	184	161	1,022	275,677	321,788	0	3,326	3,348
2018	38,466	4,865	51	3,364	1,004	203	138	1,009	267,336	316,436	0	4,865	4,916
2019	43,636	6,757	28	2,784	964	122	126	771	262,364	317,552	0	6,757	6,785
2020	55,554	9,915	30	2,077	1,006	126	120	915	264,650	334,392	0	9,915	9,945
2021	70,338	13,883	29	2,796	973	108	116	1,007	228,689	317,938	0	13,883	13,911
2022	80,962	17,664	28	3,263	813	111	58	1,026	232,953	336,878	0	17,664	17,692
2023	80,120	22,230	0	2,549	653	115	94	782	220,003	326,546	0	22,230	22,230
2024	89,056	30,347	0	2,436	597	113	93	914	220,163	343,718	0	30,347	30,347
Year 2022													
January	7,790	1,057	9	281	76	9	6	96	22,395	31,718	0	1,057	1,066
February	7,537	1,187	1	292	71	9	3	96	19,408	28,594	0	1,187	1,188
March	8,171	1,531	2	224	77	6	4	79	21,943	32,037	0	1,531	1,533
April	8,302	1,711	3	182	69	9	3	87	17,583	27,948	0	1,711	1,714
May	7,057	1,845	4	254	70	12	6	89	21,195	30,532	0	1,845	1,850
June	5,665	1,834	2	281	67	10	5	84	24,296	32,247	0	1,834	1,836
July	4,587	1,809	2	347	68	11	6	87	23,132	30,046	0	1,809	1,811
August	4,364	1,715	2	360	65	11	4	88	19,778	26,388	0	1,715	1,717
September	5,420	1,488	2	263	64	8	6	86	15,593	22,929	0	1,488	1,489
October	6,352	1,459	1	222	65	10	5	82	12,963	21,159	0	1,459	1,460
November	8,206	1,046	0	231	62	9	6	79	16,315	25,953	0	1,046	1,046
December	7,511	982	0	326	59	8	5	83	18,352	27,326	0	982	982
Year 2023													
January	6,934	1,198	0	279	58	9	9	79	19,961	28,527	0	1,198	1,198
February	8,273	1,480	0	245	50	6	8	82	17,914	28,060	0	1,480	1,480
March	8,122	1,928	0	169	58	8	6	60	18,841	29,193	0	1,928	1,928
April	8,930	1,992	0	121	53	8	9	76	17,367	28,557	0	1,992	1,992
May	6,291	2,322	0	180	58	9	7	56	25,345	34,267	0	2,322	2,322
June	4,459	2,288	0	245	56	11	5	36	19,980	27,079	0	2,288	2,288
July	4,279	2,325	0	293	55	10	7	82	19,811	26,862	0	2,325	2,325
August	5,121	2,301	0	293	54	11	6	83	19,175	27,046	0	2,301	2,301
September	5,447	1,965	0	215	49	10	8	59	15,262	23,016	0	1,965	1,965
October	7,143	1,873	0	133	52	11	12	59	14,167	23,450	0	1,873	1,873
November	7,721	1,403	0	166	53	10	7	58	15,453	24,871	0	1,403	1,403
December	7,399	1,154	0	211	56	11	10	50	16,728	25,619	0	1,154	1,154
Year 2024													
January	6,694	1,291	0	298	49	8	5	62	19,005	27,413	0	1,291	1,291
February	8,036	1,993	0	224	50	7	5	59	18,487	28,861	0	1,993	1,993
March	9,356	2,413	0	134	51	5	8	65	20,610	32,642	0	2,413	2,413
April	9,793	3,022	0	199	46	4	6	76	18,197	31,343	0	3,022	3,022
May	7,648	3,303	0	176	50	12	8	83	22,074	33,356	0	3,303	3,303
June	7,271	3,216	0	257	48	12	10	78	20,702	31,594	0	3,216	3,216
July	4,785	3,164	0	253	51	11	11	77	19,685	28,036	0	3,164	3,164
August	5,401	3,084	0	270	54	11	12	77	18,685	27,592	0	3,084	3,084
September	6,072	2,536	0	145	51	11	7	73	14,867	23,763	0	2,536	2,536
October	8,304	2,554	0	93	50	11	8	83	14,374	25,476	0	2,554	2,554
November	7,739	1,901	0	131	49	11	6	90	15,766	25,693	0	1,901	1,901
December	7,957	1,870	0	255	48	10	7	91	17,712	27,950	0	1,870	1,870

Wood and Wood-derived fuels include 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.

Other Waste Biomass includes sludge waste, agricultural byproducts, other biomass solids, other biomass liquids, and other biomass gases (including digester gases, methane, and other biomass gases).

Notes: Beginning with 2001 data, non-biogenic municipal solid waste and tire-derived fuels are reclassified as non-renewable energy sources and included in Other. Biogenic municipal solid waste is included in Other Renewable Sources.

See Glossary for definitions. Values are final. See Technical Notes for a discussion of the sample design for the Form EIA-923 and predecessor forms.

Totals may not equal sum of components because of independent rounding. N/A=Not meaningful due to large standard error. W=Withheld to avoid disclosure of individual company data.

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Estimated small scale solar photovoltaic generation and small scale solar photovoltaic capacity are based on data from Form EIA-861M, Form EIA-861 and from estimation methods described in the technical notes.

Table 3.3.A. Net Generation by Energy Source: Independent Power Producers, 2014 - 2024
(Thousand Megawatthours)

Period	Generation at Utility Scale Facilities								Renewable Sources Excluding Hydroelectric and Solar	Hydroelectric Pumped Storage	Other	Total
	Coal	Petroleum Liquids	Petroleum Coke	Natural Gas	Other Fossil Gas	Nuclear	Hydroelectric Conventional	Solar				
Annual Totals												
2014	395,701	6,789	1,410	531,758	3,246	377,295	19,861	16,086	196,723	-1,030	6,622	1,554,462
2015	342,608	6,240	1,601	619,839	3,517	380,498	17,996	22,962	202,858	-987	6,765	1,603,898
2016	307,263	3,360	1,401	624,600	3,758	381,294	18,539	33,502	233,553	-1,057	6,876	1,613,090
2017	304,198	3,281	1,480	572,919	3,978	380,465	23,034	49,376	258,962	-1,047	6,439	1,603,086
2018	278,688	5,487	1,516	645,616	3,925	382,823	23,812	58,237	275,154	-1,119	6,677	1,680,917
2019	235,847	2,669	1,125	692,113	3,883	378,738	24,288	64,480	290,343	-1,000	7,138	1,699,625
2020	185,328	1,984	1,504	706,885	3,129	360,925	19,409	78,567	319,633	-995	6,971	1,683,340
2021	217,636	2,378	1,413	699,547	3,292	348,961	21,702	100,612	344,784	-1,235	6,449	1,745,538
2022	204,243	5,734	1,354	750,266	3,451	343,604	20,673	125,155	387,590	-1,276	3,487	1,844,282
2023	152,238	2,573	1,415	803,945	3,340	333,482	23,862	142,360	374,335	-1,445	2,823	1,838,927
2024	139,527	2,567	1,377	812,528	2,976	337,345	21,612	188,376	393,974	-1,619	1,627	1,900,291
Year 2022												
January	23,291	1,778	144	58,734	292	31,282	1,702	6,707	32,672	-73	337	156,865
February	19,627	438	131	51,382	251	27,552	1,808	7,781	32,824	-111	276	141,960
March	17,526	222	145	49,110	270	28,768	2,358	10,085	37,718	-103	307	146,406
April	14,792	154	137	46,169	291	25,037	2,380	11,598	40,541	-101	296	141,274
May	14,096	149	58	56,228	365	28,345	2,054	13,172	37,838	-92	289	152,501
June	16,076	192	108	67,698	281	28,807	1,601	14,109	30,941	-129	309	159,993
July	19,305	311	71	84,262	342	29,969	1,357	13,851	27,894	-146	312	177,519
August	20,347	295	124	85,897	277	29,976	1,272	12,685	23,314	-145	298	174,141
September	14,860	210	140	72,425	306	27,819	1,354	11,709	24,739	-105	275	153,744
October	12,745	228	136	60,642	276	26,860	1,338	10,406	29,126	-64	255	141,947
November	14,768	190	84	55,774	236	28,430	1,504	7,299	35,838	-97	252	144,278
December	16,810	1,566	76	62,134	264	30,759	1,966	5,753	34,153	-111	284	153,654
Year 2023												
January	13,093	166	123	60,766	285	30,363	2,679	6,565	34,358	-122	280	148,554
February	11,333	444	112	55,594	238	26,526	1,935	7,898	35,759	-97	223	139,965
March	12,063	191	117	58,519	280	26,730	2,356	10,209	38,364	-130	227	148,927
April	10,796	191	107	52,576	202	23,088	2,336	12,968	36,407	-99	217	138,789
May	10,816	186	143	58,727	308	26,596	2,196	14,853	28,754	-123	270	142,728
June	11,172	149	114	71,301	273	27,814	1,505	15,445	25,822	-132	252	153,716
July	15,778	243	140	90,386	305	29,910	2,075	16,463	26,509	-137	240	181,912
August	15,990	183	138	88,699	333	29,679	2,037	15,347	26,048	-154	239	178,539
September	12,872	200	132	75,669	289	27,985	1,589	13,534	25,576	-137	195	157,903
October	11,746	255	98	63,236	249	26,895	1,443	12,176	31,570	-78	214	147,803
November	13,493	193	59	62,888	262	27,538	1,507	8,985	31,544	-102	228	146,593
December	13,087	173	130	65,586	316	30,357	2,205	7,916	33,623	-135	238	153,496
Year 2024												
January	16,710	399	133	71,562	292	29,990	2,431	8,246	30,935	-127	217	160,788
February	9,956	112	98	57,404	244	27,983	2,191	10,482	35,573	-135	197	143,102
March	7,068	144	138	56,708	227	27,389	2,633	13,514	38,488	-135	177	146,350
April	8,579	187	117	52,269	256	25,389	2,599	16,111	39,662	-107	143	145,205
May	9,925	174	128	60,666	210	28,151	2,286	18,942	34,139	-140	165	154,645
June	12,231	203	112	72,845	291	29,285	1,613	21,114	33,890	-140	115	171,560
July	14,966	267	135	89,542	265	29,453	1,627	21,195	26,131	-167	127	183,541
August	14,696	194	131	87,422	224	29,768	1,731	21,125	26,541	-160	114	181,787
September	11,422	148	75	73,993	264	27,353	988	17,902	25,655	-136	102	157,765
October	11,001	173	72	64,449	246	24,952	896	17,185	33,735	-111	69	152,666
November	10,232	170	112	59,828	217	26,676	885	11,879	34,944	-138	107	144,913
December	13,742	396	127	65,840	238	30,956	1,733	10,681	34,281	-123	96	157,968

Coal includes anthracite, bituminous, subbituminous, lignite, and waste coal; synthetic coal and refined coal; and beginning in 2011, coal-derived synthesis gas. Prior to 2011 coal-derived synthesis gas was included in Other Fossil Gas.

Petroleum Liquids includes distillate and residual fuel oils, jet fuel, kerosene, waste oil, and beginning in 2011, propane. Prior to 2011 propane was included in Other Fossil Gas.

Petroleum Coke includes petroleum coke-derived synthesis gas. Prior to 2011, petroleum coke-derived synthesis gas was included in Other Fossil Gas.

Other Fossil Gas includes gaseous propane, blast furnace gas, other manufactured and waste gases derived from fossil fuels other than hydrogen.

See the Technical Notes for fuel conversion factors.

Renewable Sources include wood, black liquor, other wood waste, biogenic municipal solid waste, landfill gas, sludge waste, agriculture byproducts, other biomass, geothermal, solar thermal, photovoltaic energy, and wind.

Other includes hydrogen, non-biogenic municipal solid waste, batteries, purchased steam, sulfur, tire-derived fuel, and other miscellaneous energy sources.

Notes: Beginning with 2001 data, non-biogenic municipal solid waste and tire-derived fuels are reclassified as non-renewable energy sources and included in Other. Biogenic municipal solid waste is included in Other Renewable Sources.

See Glossary for definitions. Values are final. See Technical Notes for a discussion of the sample design for the Form EIA-923 and predecessor forms.

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Table 3.3.B. Net Generation from Renewable Sources: Independent Power Producers, 2014 - 2024
(Thousand Megawatthours)

Period	Generation at Utility Scale Facilities										Small Scale Generation	Generation From Utility and Small Scale Facilities	
	Wind	Solar Photovoltaic	Solar Thermal	Wood and Wood-Derived Fuels	Landfill Gas	Biogenic Municipal Solid Waste	Other Waste Biomass	Geothermal	Conventional Hydroelectric	Total Renewable Generation at Utility Scale Facilities	Estimated Solar Photovoltaic	Estimated Total Solar Photovoltaic	Estimated Total Solar
Annual Totals													
2014	153,825	13,769	2,317	11,977	9,062	5,838	1,261	14,761	19,861	232,670	0	13,769	16,086
2015	160,135	19,841	3,121	11,545	9,202	5,806	1,342	14,829	17,996	243,816	0	19,841	22,962
2016	191,720	30,194	3,308	10,382	9,255	5,965	1,486	14,746	18,539	285,594	0	30,194	33,502
2017	217,006	46,128	3,248	10,416	9,505	5,652	1,479	14,905	23,034	331,372	0	46,128	49,376
2018	233,931	54,796	3,540	10,021	9,162	5,891	1,226	14,924	23,812	357,303	0	54,796	58,337
2019	251,968	61,290	3,190	9,237	8,739	5,096	1,043	14,260	24,288	379,111	0	61,290	64,480
2020	281,599	75,464	3,103	9,135	8,417	5,117	839	14,526	19,409	417,609	0	75,464	78,567
2021	307,579	97,717	2,895	9,101	7,717	5,019	900	14,466	21,702	467,098	0	97,717	100,612
2022	353,032	122,184	2,971	8,739	7,077	2,904	776	15,061	20,673	533,418	0	122,184	125,155
2023	340,790	139,513	2,847	7,637	6,646	2,858	828	15,596	23,862	540,557	0	139,513	142,360
2024	362,616	185,257	3,118	7,218	6,161	2,734	752	14,493	21,612	603,962	0	185,257	188,376
Year 2022													
January	29,596	6,583	124	760	613	259	70	1,374	1,702	41,080	0	6,583	6,707
February	30,076	7,624	157	727	578	217	69	1,157	1,808	42,413	0	7,624	7,781
March	34,827	9,832	253	740	639	237	67	1,208	2,358	50,161	0	9,832	10,085
April	37,831	11,279	319	643	586	232	53	1,195	2,360	54,499	0	11,279	11,598
May	35,040	12,805	367	675	601	237	47	1,238	2,054	53,064	0	12,805	13,172
June	28,081	13,740	369	755	590	251	71	1,192	1,601	46,650	0	13,740	14,109
July	24,872	13,565	286	823	600	260	74	1,255	1,357	43,092	0	13,565	13,851
August	20,341	12,409	277	797	585	254	71	1,266	1,272	37,271	0	12,409	12,685
September	21,896	11,426	283	730	567	241	63	1,243	1,354	37,803	0	11,426	11,709
October	26,369	10,117	289	648	593	232	69	1,216	1,338	40,870	0	10,117	10,406
November	32,961	7,150	149	709	565	231	54	1,318	1,504	44,641	0	7,150	7,299
December	31,142	5,654	99	732	560	254	66	1,399	1,966	41,872	0	5,654	5,753
Year 2023													
January	31,400	6,481	84	715	581	254	66	1,341	2,679	43,601	0	6,481	6,565
February	33,123	7,790	109	600	513	227	76	1,219	1,935	45,592	0	7,790	7,898
March	35,432	10,056	154	691	557	242	59	1,382	2,356	50,929	0	10,056	10,209
April	33,788	12,673	295	554	517	210	59	1,279	2,336	51,712	0	12,673	12,968
May	25,915	14,554	300	660	582	246	62	1,289	2,196	45,803	0	14,554	14,853
June	23,074	15,080	365	630	557	243	61	1,257	1,505	42,772	0	15,080	15,445
July	23,717	16,083	380	696	565	252	66	1,214	2,075	45,047	0	16,083	16,463
August	23,260	15,038	309	715	570	246	73	1,184	2,037	43,433	0	15,038	15,347
September	22,895	13,241	293	604	528	221	72	1,255	1,589	40,699	0	13,241	13,534
October	28,858	11,889	287	501	549	231	71	1,361	1,443	45,189	0	11,889	12,176
November	28,701	8,818	166	613	546	235	67	1,382	1,507	42,036	0	8,818	8,985
December	30,617	7,810	106	657	580	251	96	1,422	2,205	43,744	0	7,810	7,916
Year 2024													
January	28,077	8,167	79	681	541	233	67	1,337	2,431	41,613	0	8,167	8,246
February	32,931	10,362	119	616	506	213	63	1,244	2,191	48,245	0	10,362	10,482
March	35,727	13,293	221	662	535	218	52	1,295	2,633	54,635	0	13,293	13,514
April	37,272	15,779	332	448	491	203	43	1,204	2,599	58,372	0	15,779	16,111
May	31,588	18,528	414	566	540	230	52	1,163	2,286	55,367	0	18,528	18,942
June	31,372	20,700	414	604	502	223	64	1,124	1,613	56,617	0	20,700	21,114
July	23,506	20,834	361	658	525	244	58	1,141	1,627	48,953	0	20,834	21,195
August	23,875	20,771	354	666	538	242	70	1,151	1,731	49,397	0	20,771	21,125
September	23,091	17,567	335	632	506	228	69	1,128	988	44,545	0	17,567	17,902
October	31,270	16,952	233	479	508	225	75	1,178	896	51,816	0	16,952	17,185
November	32,367	11,743	136	569	479	238	63	1,227	895	47,708	0	11,743	11,879
December	31,540	10,561	120	636	491	236	75	1,302	1,733	46,695	0	10,561	10,681

Wood and Wood-derived fuels include 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.

Other Waste Biomass includes sludge waste, agricultural byproducts, other biomass solids, other biomass liquids, and other biomass gases (including digester gases, methane, and other biomass gases).

Notes: Beginning with 2001 data, non-biogenic municipal solid waste and tire-derived fuels are reclassified as non-renewable energy sources and included in Other. Biogenic municipal solid waste is included in Other Renewable Sources.

See Glossary for definitions. Values are final. See Technical Notes for a discussion of the sample design for the Form EIA-923 and predecessor forms.

Totals may not equal sum of components because of independent rounding. NM=Not meaningful due to large standard error. W=Withheld to avoid disclosure of individual company data.

Displayed values of zero may represent small values that round to zero. The Excel version of this table provides additional precision which may be accessed by selecting individual cells.

Sources: U.S. Energy Information Administration, Form EIA-923, Power Plant Operations Report; U.S. Energy Information Administration, Form EIA-906, Power Plant Report; U.S. Energy Information Administration, Form EIA-920 Combined Heat and Power Plant Report; and predecessor forms.

Beginning with 2008 data, the Form EIA-923, Power Plant Operations Report, replaced the following: 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 Federal Energy Regulatory Commission, FERC Form 423, Monthly Report of Cost and Quality of Fuels for Electric Plants.

Estimated small scale solar photovoltaic generation and small scale solar photovoltaic capacity are based on data from Form EIA-861M, Form EIA-861 and from estimation methods described in the technical notes.

Table 3.4.A. Net Generation by Energy Source: Commercial Sector, 2014 - 2024
(Thousand Megawatthours)

Period	Generation at Utility Scale Facilities											Small Scale Generation	Net Generation From Utility and Small Scale Facilities	
	Coal	Petroleum Liquids	Petroleum Coke	Natural Gas	Other Fossil Gas	Nuclear	Hydroelectric Conventional	Solar	Renewable Sources Excluding Hydroelectric and Solar	Hydroelectric Pumped Storage	Other	Total Generation at Utility Scale Facilities	Estimated Solar Photovoltaic	Estimated Total Solar Photovoltaic
Annual Totals														
2014	595	247	9	7,227	0	0	38	371	2,862	0	1,171	12,520	5,146	5,516
2015	509	183	8	7,471	0	0	35	416	2,803	0	1,170	12,595	5,689	6,106
2016	383	77	6	7,730	0	0	217	529	2,697	0	1,068	12,706	6,158	6,687
2017	329	103	8	8,042	0	0	240	521	2,729	0	1,088	13,060	7,685	8,206
2018	303	132	7	8,419	0	0	227	525	2,688	0	1,010	13,312	9,798	10,324
2019	268	116	5	8,610	0	0	188	587	2,840	0	1,076	13,689	11,002	11,588
2020	240	97	2	8,110	0	0	214	586	2,761	0	1,035	13,046	12,859	13,445
2021	280	94	4	7,346	0	0	258	598	2,978	0	1,209	12,768	15,124	15,722
2022	287	101	10	7,830	0	0	263	669	4,185	0	3,391	16,737	17,724	18,393
2023	220	76	2	7,744	0	0	293	615	3,930	0	3,185	16,066	19,751	20,366
2024	204	12	4	7,157	0	0	311	566	3,875	0	3,130	15,258	21,652	22,218
Year 2022														
January	29	23	1	655	0	0	24	36	358	0	276	1,403	1,012	1,048
February	19	6	1	563	0	0	21	42	324	0	254	1,232	1,116	1,158
March	18	5	1	606	0	0	24	56	346	0	271	1,328	1,521	1,576
April	13	6	1	559	0	0	21	66	349	0	295	1,308	1,662	1,728
May	10	6	1	611	0	0	26	71	358	0	298	1,381	1,816	1,887
June	27	8	1	672	0	0	27	74	354	0	291	1,455	1,819	1,893
July	26	7	1	807	0	0	26	72	359	0	294	1,592	1,894	1,966
August	29	8	0	822	0	0	22	69	360	0	286	1,595	1,801	1,871
September	30	5	0	696	0	0	18	61	335	0	272	1,417	1,608	1,668
October	28	5	0	571	0	0	15	52	345	0	284	1,300	1,383	1,435
November	28	6	1	601	0	0	18	40	350	0	286	1,330	1,086	1,126
December	30	18	1	668	0	0	20	29	347	0	284	1,397	1,007	1,037
Year 2023														
January	28	9	1	624	0	0	29	28	327	0	270	1,316	1,119	1,147
February	26	19	0	587	0	0	26	38	290	0	230	1,215	1,234	1,272
March	20	7	0	611	0	0	30	51	305	0	240	1,264	1,680	1,731
April	21	4	0	564	0	0	30	67	295	0	234	1,214	1,855	1,923
May	17	5	0	594	0	0	26	71	333	0	271	1,317	2,023	2,095
June	9	4	0	660	0	0	19	66	343	0	281	1,381	2,011	2,077
July	12	5	0	784	0	0	24	70	346	0	289	1,529	2,087	2,156
August	12	4	0	746	0	0	24	62	346	0	277	1,471	2,010	2,072
September	15	4	0	706	0	0	18	53	317	0	257	1,370	1,796	1,849
October	18	5	0	627	0	0	23	46	332	0	271	1,323	1,558	1,604
November	18	5	0	609	0	0	22	37	340	0	277	1,308	1,225	1,262
December	23	6	1	633	0	0	23	25	358	0	288	1,358	1,153	1,178
Year 2024														
January	34	0	1	620	0	0	30	23	346	0	278	1,330	1,218	1,241
February	23	-1	0	567	0	0	28	34	305	0	247	1,204	1,386	1,420
March	19	2	0	565	0	0	31	48	313	0	243	1,221	1,821	1,869
April	15	3	0	533	0	0	30	56	305	0	245	1,187	2,007	2,063
May	7	0	1	525	0	0	32	64	338	0	278	1,245	2,216	2,280
June	10	6	1	613	0	0	23	67	323	0	264	1,308	2,213	2,280
July	14	1	0	728	0	0	24	63	335	0	270	1,435	2,297	2,360
August	15	0	0	699	0	0	23	61	330	0	280	1,409	2,204	2,265
September	16	-1	0	602	0	0	20	48	316	0	255	1,257	1,969	2,018
October	14	-2	0	563	0	0	21	46	315	0	258	1,215	1,709	1,755
November	17	2	0	563	0	0	23	31	321	0	254	1,210	1,336	1,367
December	19	1	1	580	0	0	25	25	328	0	259	1,238	1,276	1,300

Coal includes anthracite, bituminous, subbituminous, lignite, and waste coal; synthetic coal and refined coal; and beginning in 2011, coal-derived synthesis gas. Prior to 2011 coal-derived synthesis gas was included in Other Fossil Gas.

Petroleum Liquids includes distillate and residual fuel oils, jet fuel, kerosene, waste oil, and beginning in 2011, propane. Prior to 2011 propane was included in Other Fossil Gas.

Petroleum Coke includes petroleum coke-derived synthesis gas. Prior to 2011, petroleum coke-derived synthesis gas was included in Other Fossil Gas.

Other Fossil Gas includes gaseous propane, blast furnace gas, other manufactured and waste gases derived from fossil fuels other than hydrogen.

See the Technical Notes for fuel conversion factors.

Renewable Sources include wood, black liquor, other wood waste, biogenic municipal solid waste, landfill gas, sludge waste, agriculture byproducts, other biomass, geothermal, solar thermal, photovoltaic energy, and wind.

Other includes hydrogen, non-biogenic municipal solid waste, batteries, purchased steam, sulfur, tire-derived fuel, and other miscellaneous energy sources.

Notes: Beginning with 2001 data, non-biogenic municipal solid waste and tire-derived fuels are reclassified as non-renewable energy sources and included in Other. Biogenic municipal solid waste is included in Other Renewable Sources.

See Glossary for definitions. Values are final. See Technical Notes for a discussion of the sample design for the Form EIA-923 and predecessor forms.

Totals may not equal sum of components because of independent rounding. NM=Not meaningful due to large standard error. W=Withheld to avoid disclosure of individual company data.

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Sources: U.S. Energy Information Administration, Form EIA-923, Power Plant Operations Report; U.S. Energy Information Administration, Form EIA-906, Power Plant Report; U.S. Energy Information Administration, Form EIA-920 Combined Heat and Power Plant Report; and predecessor forms.

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

Estimated small scale solar photovoltaic generation and small scale solar photovoltaic capacity are based on data from Form EIA-861M, Form EIA-861 and from estimation methods described in the technical notes.

Table 3.4.B. Net Generation from Renewable Sources: Commercial Sector, 2014 - 2024
(Thousand Megawatthours)

Period	Generation at Utility Scale Facilities										Small Scale Generation	Generation From Utility and Small Scale Facilities	
	Wind	Solar Photovoltaic	Solar Thermal	Wood and Wood-Derived Fuels	Landfill Gas	Biogenic Municipal Solid Waste	Other Waste Biomass	Geothermal	Conventional Hydroelectric	Total Renewable Generation at Utility Scale Facilities	Estimated Solar Photovoltaic	Estimated Total Solar Photovoltaic	Estimated Total Solar
Annual Totals													
2014	107	371	0	74	905	1,202	575	0	38	3,271	5,146	5,516	5,516
2015	118	416	0	48	847	1,199	592	0	35	3,255	5,689	6,106	6,106
2016	131	529	0	69	753	1,093	649	0	217	3,443	6,158	6,687	6,687
2017	144	521	0	70	753	1,114	648	0	240	3,490	7,685	8,206	8,206
2018	174	525	0	77	703	1,038	664	33	227	3,441	9,798	10,324	10,324
2019	179	587	0	90	626	869	634	442	188	3,615	11,002	11,588	11,588
2020	166	586	0	91	657	832	565	449	214	3,561	12,859	13,445	13,445
2021	166	598	0	153	612	973	571	502	258	3,834	15,124	15,722	15,722
2022	173	669	0	175	517	2,761	560	0	263	5,118	17,724	18,393	18,393
2023	130	615	0	107	509	2,595	589	0	293	4,838	19,751	20,366	20,366
2024	133	566	0	111	459	2,554	617	0	311	4,752	21,652	22,218	22,218
Year 2022													
January	18	36	0	15	48	225	52	0	24	418	1,012	1,048	1,048
February	17	42	0	14	42	206	43	0	21	388	1,116	1,158	1,158
March	19	56	0	10	46	221	50	0	24	426	1,521	1,576	1,576
April	19	66	0	11	35	240	44	0	21	435	1,662	1,728	1,728
May	16	71	0	17	40	243	43	0	26	455	1,816	1,887	1,887
June	13	74	0	20	42	237	43	0	27	456	1,819	1,893	1,893
July	9	72	0	18	45	240	47	0	26	457	1,894	1,966	1,966
August	7	69	0	27	46	233	47	0	22	451	1,801	1,871	1,871
September	10	61	0	12	45	221	47	0	18	414	1,608	1,668	1,668
October	13	52	0	6	45	231	50	0	15	412	1,383	1,435	1,435
November	18	40	0	11	41	233	47	0	18	408	1,086	1,126	1,126
December	15	29	0	12	43	231	46	0	20	396	1,007	1,037	1,037
Year 2023													
January	13	28	0	11	44	220	39	0	29	384	1,119	1,147	1,147
February	15	38	0	7	40	187	41	0	26	353	1,234	1,272	1,272
March	16	51	0	7	42	196	44	0	30	386	1,680	1,731	1,731
April	16	67	0	5	42	191	41	0	30	392	1,855	1,923	1,923
May	13	71	0	3	41	221	55	0	26	430	2,023	2,095	2,095
June	7	66	0	11	42	229	54	0	19	428	2,011	2,077	2,077
July	4	70	0	10	44	236	52	0	24	439	2,087	2,156	2,156
August	6	62	0	14	46	225	54	0	24	432	2,010	2,072	2,072
September	7	53	0	12	43	209	45	0	18	388	1,796	1,849	1,849
October	9	46	0	8	39	221	55	0	23	402	1,558	1,604	1,604
November	11	37	0	9	42	226	52	0	22	398	1,225	1,262	1,262
December	12	25	0	11	44	235	55	0	23	406	1,153	1,178	1,178
Year 2024													
January	10	23	0	16	41	226	53	0	30	398	1,218	1,241	1,241
February	10	34	0	6	38	201	50	0	28	367	1,386	1,420	1,420
March	14	48	0	4	40	199	56	0	31	392	1,821	1,869	1,869
April	16	56	0	0	36	200	52	0	30	392	2,007	2,063	2,063
May	13	64	0	5	39	227	55	0	32	434	2,216	2,280	2,280
June	12	67	0	10	35	215	52	0	23	413	2,213	2,280	2,280
July	8	63	0	18	38	220	51	0	24	423	2,297	2,360	2,360
August	8	61	0	10	39	228	45	0	23	415	2,204	2,265	2,265
September	9	48	0	14	37	208	47	0	20	384	1,969	2,018	2,018
October	9	46	0	6	38	211	51	0	21	382	1,709	1,755	1,755
November	11	31	0	12	39	207	52	0	23	374	1,336	1,367	1,367
December	13	25	0	10	40	212	54	0	25	378	1,276	1,300	1,300

Wood and Wood-derived fuels include 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.

Other Waste Biomass includes sludge waste, agricultural byproducts, other biomass solids, other biomass liquids, and other biomass gases (including digester gases, methane, and other biomass gases).

Notes: Beginning with 2001 data, non-biogenic municipal solid waste and tire-derived fuels are reclassified as non-renewable energy sources and included in Other. Biogenic municipal solid waste is included in Other Renewable Sources.

See Glossary for definitions. Values are final. See Technical Notes for a discussion of the sample design for the Form EIA-923 and predecessor forms.

Totals may not equal sum of components because of independent rounding. NM=Not meaningful due to large standard error. W=Withheld to avoid disclosure of individual company data.

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Sources: U.S. Energy Information Administration, Form EIA-923, Power Plant Operations Report; U.S. Energy Information Administration, Form EIA-906, Power Plant Report; U.S. Energy Information Administration, Form EIA-920 Combined Heat and Power Plant Report; and predecessor forms.

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Estimated small scale solar photovoltaic generation and small scale solar photovoltaic capacity are based on data from Form EIA-861M, Form EIA-861 and from estimation methods described in the technical notes.

Table 3.5.A. Net Generation by Energy Source: Industrial Sector, 2014 - 2024
(Thousand Megawatthours)

Period	Generation at Utility Scale Facilities											Small Scale Generation	Net Generation From Utility and Small Scale Facilities	
	Coal	Petroleum Liquids	Petroleum Coke	Natural Gas	Other Fossil Gas	Nuclear	Hydroelectric Conventional	Solar	Renewable Sources Excluding Hydroelectric and Solar	Hydroelectric Pumped Storage	Other	Total Generation at Utility Scale Facilities	Estimated Solar Photovoltaic	Estimated Total Solar Photovoltaic
Annual Totals														
2014	12,341	544	1,389	86,209	8,664	0	1,282	16	28,659	0	4,978	144,083	1,139	1,156
2015	10,896	563	990	88,355	9,401	0	1,410	21	28,614	0	5,462	145,712	1,451	1,472
2016	9,103	503	909	91,197	8,895	0	1,269	27	28,663	0	5,324	145,890	2,060	2,087
2017	7,669	463	776	91,647	8,343	0	1,382	42	28,508	0	4,928	143,758	2,364	2,406
2018	7,011	517	640	94,892	9,377	0	1,149	47	28,440	0	4,725	146,798	2,636	2,683
2019	5,957	424	576	100,065	8,554	0	1,033	85	27,276	0	4,567	148,537	3,041	3,127
2020	5,451	398	510	96,381	8,644	0	1,001	101	26,348	0	4,231	143,064	3,484	3,586
2021	5,278	400	367	95,240	8,093	0	936	137	25,324	0	3,975	139,750	3,858	3,994
2022	5,128	614	379	96,548	8,271	0	899	276	24,226	0	3,702	140,043	4,048	4,324
2023	4,327	494	273	98,463	8,438	0	844	326	22,130	0	3,369	138,664	4,382	4,708
2024	4,276	372	302	96,771	7,870	0	810	546	22,675	0	3,127	136,749	4,719	5,265
Year 2022														
January	445	51	31	8,683	713	0	77	13	2,137	0	359	12,508	230	243
February	409	NM	36	7,440	635	0	83	15	1,944	0	319	10,921	244	259
March	459	41	30	7,931	683	0	111	21	2,051	0	347	11,673	348	369
April	402	42	28	7,350	630	0	102	24	1,986	0	308	10,871	377	401
May	461	40	35	7,790	671	0	84	28	2,045	0	332	11,485	413	441
June	450	45	29	7,964	706	0	63	32	2,053	0	319	11,661	413	446
July	453	48	28	8,667	741	0	53	31	2,152	0	336	12,510	426	458
August	453	38	31	8,759	731	0	61	30	2,091	0	303	12,498	411	441
September	404	47	29	7,842	680	0	60	26	1,919	0	265	11,272	368	395
October	396	43	33	7,903	692	0	51	24	1,828	0	260	11,230	333	357
November	372	43	38	8,144	675	0	62	18	1,998	0	287	11,635	256	273
December	425	137	31	8,075	714	0	92	13	2,023	0	270	11,779	229	242
Year 2023														
January	414	59	32	8,052	660	0	85	16	1,989	0	290	11,597	244	260
February	354	50	25	7,582	654	0	86	18	1,753	0	281	10,803	259	277
March	343	48	31	8,127	748	0	104	24	1,916	0	276	11,616	370	395
April	334	39	17	7,021	665	0	87	34	1,725	0	252	10,176	408	442
May	359	32	20	7,791	703	0	84	35	1,882	0	273	11,180	447	481
June	362	38	18	8,433	701	0	69	35	1,751	0	253	11,660	446	481
July	387	38	27	8,854	741	0	69	37	1,813	0	292	12,255	461	497
August	366	38	23	8,930	755	0	57	34	1,918	0	290	12,410	444	478
September	358	36	19	8,511	694	0	46	30	1,789	0	276	11,760	400	429
October	340	36	20	8,171	675	0	40	26	1,747	0	304	11,358	363	389
November	340	38	21	8,293	697	0	45	21	1,875	0	293	11,622	286	307
December	370	41	20	8,699	746	0	72	17	1,971	0	290	12,226	254	271
Year 2024														
January	383	42	27	8,925	782	0	88	23	1,936	0	273	12,477	268	290
February	346	39	28	7,860	687	0	89	32	1,849	0	250	11,181	296	329
March	380	29	30	7,853	655	0	89	43	1,935	0	249	11,263	406	449
April	293	32	24	7,687	657	0	89	52	1,849	0	242	10,925	440	492
May	341	27	22	7,834	680	0	85	62	1,904	0	268	11,224	478	540
June	348	29	23	7,795	649	0	58	62	1,866	0	291	11,122	476	539
July	388	30	32	8,475	684	0	48	61	1,939	0	302	11,960	490	551
August	371	28	23	8,914	687	0	51	59	1,958	0	264	12,354	473	532
September	346	27	19	8,027	572	0	36	52	1,835	0	240	11,154	433	485
October	344	30	22	7,330	555	0	62	44	1,736	0	217	10,338	390	433
November	352	28	23	7,595	583	0	51	31	1,922	0	267	10,852	303	334
December	385	32	29	8,476	681	0	63	25	1,946	0	263	11,900	267	292

Coal includes anthracite, bituminous, subbituminous, lignite, and waste coal; synthetic coal and refined coal; and beginning in 2011, coal-derived synthesis gas. Prior to 2011 coal-derived synthesis gas was included in Other Fossil Gas.

Petroleum Liquids includes distillate and residual fuel oils, jet fuel, kerosene, waste oil, and beginning in 2011, propane. Prior to 2011 propane was included in Other Fossil Gas.

Petroleum Coke includes petroleum coke-derived synthesis gas. Prior to 2011, petroleum coke-derived synthesis gas was included in Other Fossil Gas.

Other Fossil Gas includes gaseous propane, blast furnace gas, other manufactured and waste gases derived from fossil fuels other than hydrogen.

See the Technical Notes for fuel conversion factors.

Renewable Sources include wood, black liquor, other wood waste, biogenic municipal solid waste, landfill gas, sludge waste, agriculture byproducts, other biomass, geothermal, solar thermal, photovoltaic energy, and wind.

Other includes hydrogen, non-biogenic municipal solid waste, batteries, purchased steam, sulfur, tire-derived fuel, and other miscellaneous energy sources.

Notes: Beginning with 2001 data, non-biogenic municipal solid waste and tire-derived fuels are reclassified as non-renewable energy sources and included in Other. Biogenic municipal solid waste is included in Other Renewable Sources.

See Glossary for definitions. Values are final. See Technical Notes for a discussion of the sample design for the Form EIA-923 and predecessor forms.

Totals may not equal sum of components because of independent rounding. NM=Not meaningful due to large standard error. W=Withheld to avoid disclosure of individual company data.

Displayed values of zero may represent small values that round to zero. The Excel version of this table provides additional precision which may be accessed by selecting individual cells.

Sources: U.S. Energy Information Administration, Form EIA-923, Power Plant Operations Report; U.S. Energy Information Administration, Form EIA-906, Power Plant Report; U.S. Energy Information Administration, Form EIA-920 Combined Heat and Power Plant Report; and predecessor forms.

Beginning with 2008 data, the Form EIA-923, Power Plant Operations Report, replaced the following: 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 Federal Energy Regulatory Commission, FERC Form 423, Monthly Report of Cost and Quality of Fuels for Electric Plants.

Estimated small scale solar photovoltaic generation and small scale solar photovoltaic capacity are based on data from Form EIA-861M, Form EIA-861 and from estimation methods described in the technical notes.

Table 3.5.B. Net Generation from Renewable Sources: Industrial Sector, 2014 - 2024
(Thousand Megawatthours)

		Generation at Utility Scale Facilities										Small Scale Generation	Generation From Utility and Small Scale Facilities	
		Wind	Solar Photovoltaic	Solar Thermal	Wood and Wood-Derived Fuels	Landfill Gas	Biogenic Municipal Solid Waste	Other Waste Biomass	Geothermal	Conventional Hydroelectric	Total Renewable Generation at Utility Scale Facilities	Estimated Solar Photovoltaic	Estimated Total Solar Photovoltaic	Estimated Total Solar
Annual Totals														
	2014	53	16	0	27,239	185	-2	1,185	0	1,282	29,957	1,139	1,156	1,156
	2015	53	21	0	27,318	182	12	1,049	0	1,410	30,045	1,451	1,472	1,472
	2016	71	27	0	27,458	170	6	959	0	1,269	29,960	2,060	2,087	2,087
	2017	84	42	0	27,412	183	1	827	0	1,382	29,932	2,364	2,406	2,406
	2018	97	47	0	27,475	168	4	697	0	1,149	29,636	2,636	2,683	2,683
	2019	100	85	0	26,433	139	5	598	0	1,033	28,395	3,041	3,127	3,127
	2020	617	101	0	24,916	133	5	676	0	1,001	27,450	3,484	3,586	3,586
	2021	112	137	0	24,413	119	1	680	0	936	26,397	3,858	3,994	3,994
	2022	130	276	0	23,289	128	0	678	0	899	25,401	4,048	4,324	4,324
	2023	112	326	0	21,320	127	0	571	0	844	23,300	4,382	4,708	4,708
	2024	99	546	0	21,800	123	0	652	0	810	24,031	4,719	5,265	5,265
Year 2022														
	January	12	13	0	2,049	10	0	65	0	77	2,226	230	243	243
	February	14	15	0	1,864	10	0	57	0	83	2,042	244	259	259
	March	15	21	0	1,960	11	0	66	0	111	2,183	348	369	369
	April	14	24	0	1,901	10	0	62	0	102	2,112	377	401	401
	May	12	28	0	1,961	10	0	62	0	84	2,157	413	441	441
	June	8	32	0	1,988	11	0	46	0	63	2,148	413	446	446
	July	7	31	0	2,088	11	0	46	0	53	2,236	426	458	458
	August	5	30	0	2,022	11	0	52	0	61	2,182	411	441	441
	September	6	26	0	1,860	11	0	42	0	60	2,006	368	395	395
	October	11	24	0	1,748	11	0	58	0	51	1,904	333	357	357
	November	14	18	0	1,914	10	0	59	0	62	2,077	256	273	273
	December	12	13	0	1,936	12	0	64	0	92	2,127	229	242	242
Year 2023														
	January	11	16	0	1,914	10	0	54	0	85	2,091	244	260	260
	February	13	18	0	1,680	11	0	48	0	86	1,858	259	277	277
	March	13	24	0	1,838	13	0	52	0	104	2,044	370	395	395
	April	11	34	0	1,655	11	0	48	0	87	1,846	408	442	442
	May	9	35	0	1,811	10	0	52	0	84	2,001	447	481	481
	June	7	35	0	1,693	11	0	40	0	69	1,855	446	481	481
	July	5	37	0	1,758	10	0	40	0	69	1,918	461	497	497
	August	6	34	0	1,862	10	0	40	0	57	2,009	444	478	478
	September	5	30	0	1,741	9	0	34	0	46	1,865	400	429	429
	October	10	26	0	1,675	9	0	53	0	40	1,813	363	389	389
	November	12	21	0	1,796	10	0	57	0	45	1,941	286	307	307
	December	10	17	0	1,896	12	0	52	0	72	2,060	254	271	271
Year 2024														
	January	9	23	0	1,854	11	0	61	0	88	2,047	268	290	290
	February	5	32	0	1,774	12	0	59	0	89	1,971	296	329	329
	March	6	43	0	1,852	12	0	65	0	89	2,067	406	449	449
	April	7	52	0	1,775	10	0	57	0	89	1,990	440	492	492
	May	7	62	0	1,828	8	0	61	0	85	2,052	478	540	540
	June	7	62	0	1,809	9	0	41	0	58	1,986	476	539	539
	July	5	61	0	1,878	11	0	45	0	48	2,048	490	551	551
	August	5	59	0	1,894	11	0	48	0	51	2,068	473	532	532
	September	6	52	0	1,772	10	0	47	0	36	1,923	433	485	485
	October	8	44	0	1,662	12	0	54	0	62	1,841	390	433	433
	November	17	31	0	1,837	9	0	59	0	51	2,004	303	334	334
	December	17	25	0	1,863	9	0	56	0	63	2,034	267	292	292

Wood and Wood-derived fuels include 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.

Other Waste Biomass includes sludge waste, agricultural byproducts, other biomass solids, other biomass liquids, and other biomass gases (including digester gases, methane, and other biomass gases).

Notes: Beginning with 2001 data, non-biogenic municipal solid waste and tire-derived fuels are reclassified as non-renewable energy sources and included in Other. Biogenic municipal solid waste is included in Other Renewable Sources.

See Glossary for definitions. Values are final. See Technical Notes for a discussion of the Form EIA-923 and predecessor forms.

Totals may not equal sum of components because of independent rounding. NM=Not meaningful due to large standard error. W=Withheld to avoid disclosure of individual company data.

Displayed values of zero may represent small values that round to zero. The Excel version of this table provides additional precision which may be accessed by selecting individual cells.

Sources: U.S. Energy Information Administration, Form EIA-923, Power Plant Operations Report; U.S. Energy Information Administration, Form EIA-906, Power Plant Report; U.S. Energy Information Administration, Form EIA-920 Combined Heat and Power Plant Report; and predecessor forms.

Beginning with 2008 data, the Form EIA-923, Power Plant Operations Report, replaced the following: 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 Federal Energy Regulatory Commission, FERC Form 423, Monthly Report of Cost and Quality of Fuels for Electric Plants.

Estimated small scale solar photovoltaic generation and small scale solar photovoltaic capacity are based on data from Form EIA-861M, Form EIA-861 and from estimation methods described in the technical notes.

Table 3.6. Net Generation by Energy Source: Residential Sector, 2014 - 2024
(Thousand Megawatthours)

Period	Small Scale Generation
	Estimated Small Scale Solar Photovoltaic Generation
Annual Totals	
2014	4,947
2015	6,999
2016	10,595
2017	13,942
2018	17,105
2019	20,914
2020	25,179
2021	30,182
2022	39,510
2023	49,273
2024	57,547
Year 2022	
January	2,135
February	2,357
March	3,252
April	3,632
May	4,007
June	3,997
July	4,118
August	3,982
September	3,569
October	3,306
November	2,693
December	2,462
Year 2023	
January	2,625
February	2,894
March	3,954
April	4,478
May	5,073
June	4,948
July	5,173
August	5,049
September	4,409
October	4,155
November	3,428
December	3,087
Year 2024	
January	3,240
February	3,659
March	4,885
April	5,385
May	5,845
June	5,863
July	5,991
August	5,735
September	5,108
October	4,638
November	3,754
December	3,442

See Glossary for definitions. Values are final.

Totals may not equal sum of components because of independent rounding. NM=Not meaningful due to large standard error. W=Withheld to avoid disclosure of individual company data.

Displayed values of zero may represent small values that round to zero. The Excel version of this table provides additional precision which may be accessed by selecting individual cells.

Sources:

Estimated small scale solar photovoltaic generation and small scale solar photovoltaic capacity are based on data from Form EIA-861M, Form EIA-861 and from estimation methods described in the technical notes.

Table 3.7. Utility Scale Facility Net Generation
by State, by Sector, 2024 and 2023 (Thousand Megawatthours)

Census Division and State	All Sectors			Electric Power Sector				Commercial Sector		Industrial Sector	
				Electric Utilities		Independent Power Producers					
				Generation at Utility Scale Facilities		Generation at Utility Scale Facilities		Generation at Utility Scale Facilities		Generation at Utility Scale Facilities	
	Year 2024	Year 2023	Percentage Change	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023
New England	109,310	102,611	6.5%	1,591	1,658	103,672	96,713	2,060	2,129	1,987	2,110
Connecticut	44,761	40,666	10.1%	134	135	43,782	39,582	189	294	656	655
Maine	14,655	12,512	17.1%	3	5	13,599	11,361	41	47	1,013	1,099
Massachusetts	20,915	19,696	6.2%	547	529	18,493	17,323	1,727	1,673	148	172
New Hampshire	16,942	16,825	0.7%	7	17	16,852	16,719	60	62	23	27
Rhode Island	9,777	10,431	-6.3%	0	0	9,589	10,223	41	50	147	157
Vermont	2,259	2,480	-8.9%	900	973	1,356	1,504	2	2	0	0
Middle Atlantic	430,689	424,194	1.5%	36,583	35,522	385,352	379,475	3,521	3,834	5,233	5,362
New Jersey	60,175	64,229	-6.3%	264	282	58,144	62,260	1,138	1,107	630	580
New York	129,015	124,040	4.0%	36,207	35,157	90,153	85,934	1,798	2,145	857	804
Pennsylvania	241,499	235,925	2.4%	112	84	237,055	231,282	585	581	3,746	3,978
East North Central	614,249	584,213	5.1%	222,905	210,067	379,644	361,790	1,752	1,794	9,948	10,562
Illinois	185,013	177,738	4.1%	4,245	4,104	178,405	170,954	401	435	1,963	2,244
Indiana	97,013	90,047	7.7%	59,952	54,096	32,195	30,705	230	238	4,636	5,007
Michigan	124,200	120,657	2.9%	90,700	88,209	31,495	30,476	721	717	1,284	1,255
Ohio	142,747	133,223	7.1%	15,750	13,608	125,959	118,678	293	273	744	664
Wisconsin	65,276	62,549	4.4%	52,258	50,050	11,589	10,976	108	130	1,321	1,392
West North Central	354,289	351,225	0.9%	254,885	258,247	94,121	88,242	613	590	4,670	4,145
Iowa	70,464	69,837	0.9%	55,445	55,970	12,638	11,744	133	128	2,248	1,994
Kansas	57,696	58,457	-1.3%	30,081	33,224	27,227	24,863	13	13	375	357
Minnesota	58,595	57,277	2.3%	40,859	40,376	16,037	15,431	256	247	1,443	1,222
Missouri	66,876	66,703	0.3%	60,065	59,453	6,578	7,025	192	182	40	43
Nebraska	37,229	39,446	-5.6%	24,876	27,292	12,006	11,830	20	19	327	304
North Dakota	42,557	42,069	1.2%	32,738	32,582	9,648	9,321	0	0	171	166
South Dakota	20,872	17,436	19.7%	10,821	9,350	9,987	8,028	NM	NM	65	58
South Atlantic	835,080	800,717	4.3%	689,706	659,687	126,929	122,815	2,572	2,774	15,873	15,441
Delaware	4,799	4,772	0.6%	73	25	3,561	3,479	5	7	1,161	1,262
District of Columbia	187	172	8.9%	1	3	30	21	156	147	0	0
Florida	266,119	259,798	2.4%	249,531	243,421	12,096	11,636	994	1,097	3,499	3,644
Georgia	139,805	129,222	8.2%	115,578	105,782	19,369	19,110	3	2	4,856	4,327
Maryland	35,425	36,001	-1.6%	2,974	4,431	32,074	31,164	322	346	56	59
North Carolina	134,965	126,553	6.6%	112,771	104,306	20,621	20,481	263	263	1,311	1,504
South Carolina	100,485	100,853	-0.4%	94,347	95,650	4,515	3,717	3	2	1,621	1,485
Virginia	102,699	97,059	12.8%	76,211	68,967	23,450	19,136	828	910	2,210	2,047
West Virginia	50,595	52,287	-3.2%	38,220	37,103	11,214	14,070	0	0	1,161	1,114
East South Central	363,376	353,377	2.8%	314,219	301,637	39,474	42,486	206	201	9,476	9,053
Alabama	142,921	139,435	2.5%	104,915	97,501	32,981	37,210	0	0	5,025	4,725
Kentucky	66,951	63,217	5.9%	65,646	62,094	793	587	2	1	510	535
Mississippi	77,337	72,933	6.0%	71,679	68,027	3,806	3,004	0	0	1,852	1,902
Tennessee	76,167	77,791	-2.1%	71,980	74,015	1,893	1,685	205	200	2,089	1,892
West South Central	821,737	797,511	3.0%	260,797	246,870	488,572	475,533	703	833	71,666	74,274
Arkansas	61,542	63,196	-2.6%	54,386	57,015	6,096	5,219	50	55	1,010	906
Louisiana	99,623	97,785	1.9%	64,884	60,863	6,997	7,028	58	92	27,683	29,802
Oklahoma	94,069	89,236	5.4%	46,638	43,593	46,589	44,864	-6	-18	849	796
Texas	566,503	547,295	3.5%	94,889	85,398	428,890	418,422	601	704	42,123	42,771
Mountain	382,802	372,230	2.8%	258,581	258,965	120,408	109,550	620	614	3,193	3,101
Arizona	116,027	111,839	3.7%	86,749	86,637	29,091	25,017	153	151	34	34
Colorado	58,798	57,542	2.2%	37,598	39,336	20,931	17,962	22	24	248	220
Idaho	20,035	17,842	12.3%	13,475	11,701	5,954	5,527	77	70	529	544
Montana	26,873	26,896	-0.1%	11,663	10,516	15,183	16,354	0	0	26	26
Nevada	45,528	42,164	8.0%	26,478	25,302	18,460	16,249	110	111	481	502
New Mexico	39,697	39,269	1.1%	20,683	20,503	18,836	18,592	110	107	69	67
Utah	35,134	33,497	4.9%	27,900	27,811	6,735	5,332	150	150	349	203
Wyoming	40,709	43,181	-5.7%	34,035	37,159	5,217	4,517	0	0	1,457	1,505
Pacific Contiguous	381,250	381,281	0.0%	205,473	205,332	158,927	159,101	2,469	2,579	14,382	14,269
California	214,191	216,629	-1.1%	75,922	77,633	124,107	124,804	2,372	2,504	11,791	11,688
Oregon	64,661	61,692	4.8%	41,616	40,869	22,209	20,119	80	67	756	637
Washington	102,398	102,961	-0.5%	87,935	86,831	12,611	14,177	17	9	1,835	1,944
Pacific Noncontiguous	15,851	15,912	-0.4%	11,598	11,628	3,193	3,220	740	718	320	346
Alaska	6,691	6,718	-0.4%	6,020	6,023	182	194	395	384	93	117
Hawaii	9,161	9,194	-0.4%	5,577	5,606	3,011	3,027	345	334	228	228
U.S. Total	4,308,634	4,183,270	3.0%	2,256,336	2,189,614	1,900,291	1,838,927	15,258	16,066	136,749	138,664

Displayed values of zero may represent small values that round to zero. The Excel version of this table provides additional precision which may be accessed by selecting individual cells.

NM = Not meaningful due to large relative standard error or excessive percentage change.

Notes: See Glossary for definitions. Values are final. See Technical Notes for a discussion of the sample design for the Form EIA-923.

Negative generation denotes that electric power consumed for plant use exceeds gross generation.

Totals may not equal sum of components because of independent rounding. Percentage change is calculated before rounding.

Source: U.S. Energy Information Administration, Form EIA-923, Power Plant Operations Report.

Table 3.8. Utility Scale Facility Net Generation from Coal
by State, by Sector, 2024 and 2023 (Thousand Megawatthours)

Census Division and State	All Sectors			Electric Power Sector				Commercial Sector		Industrial Sector	
				Electric Utilities		Independent Power Producers					
	Generation at Utility Scale Facilities			Generation at Utility Scale Facilities		Generation at Utility Scale Facilities		Generation at Utility Scale Facilities		Generation at Utility Scale Facilities	
	Year 2024	Year 2023	Percentage Change	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023
New England	254	203	24.8%	0	0	254	203	0	0	0	0
Connecticut	0	0	--	0	0	0	0	0	0	0	0
Maine	29	43	-32.0%	0	0	29	43	0	0	0	0
Massachusetts	0	0	--	0	0	0	0	0	0	0	0
New Hampshire	224	160	40.2%	0	0	224	160	0	0	0	0
Rhode Island	0	0	--	0	0	0	0	0	0	0	0
Vermont	0	0	--	0	0	0	0	0	0	0	0
Middle Atlantic	13,042	12,835	1.6%	0	0	12,954	12,745	0	0	88	90
New Jersey	0	0	--	0	0	0	0	0	0	0	0
New York	0	0	--	0	0	0	0	0	0	0	0
Pennsylvania	13,042	12,835	1.6%	0	0	12,954	12,745	0	0	88	90
East North Central	144,073	144,159	-0.1%	89,438	87,049	53,890	56,070	21	41	723	999
Illinois	26,965	27,150	-0.7%	1,174	1,273	25,124	24,977	10	16	657	884
Indiana	40,526	40,932	-1.0%	37,156	36,822	3,359	4,085	11	25	0	0
Michigan	25,738	23,555	9.3%	25,569	23,349	166	205	0	0	3	0
Ohio	30,080	31,436	-4.3%	4,839	4,632	25,241	26,804	0	0	0	0
Wisconsin	20,763	21,087	-1.5%	20,700	20,972	0	0	0	0	64	114
West North Central	118,904	127,850	-7.0%	116,882	125,969	0	0	13	14	2,009	1,866
Iowa	14,464	16,414	-11.9%	13,030	15,121	0	0	2	7	1,432	1,286
Kansas	13,079	16,291	-19.7%	13,079	16,291	0	0	0	0	0	0
Minnesota	11,430	12,794	-10.7%	11,279	12,641	0	0	6	5	145	148
Missouri	38,832	40,347	-3.8%	38,826	40,345	0	0	6	2	0	0
Nebraska	16,352	17,916	-8.7%	16,050	17,618	0	0	0	0	302	298
North Dakota	23,183	22,525	2.9%	23,054	22,390	0	0	0	0	129	135
South Dakota	1,563	1,563	0.0%	1,563	1,563	0	0	0	0	0	0
South Atlantic	107,283	105,731	1.5%	98,187	94,578	8,778	10,830	21	11	297	312
Delaware	144	-6	NM	0	0	144	-6	0	0	0	0
District of Columbia	0	0	--	0	0	0	0	0	0	0	0
Florida	7,846	11,691	-32.9%	7,827	11,665	0	0	0	0	19	27
Georgia	17,837	16,769	6.4%	17,716	16,664	0	0	0	0	121	105
Maryland	2,466	1,709	44.3%	0	0	2,466	1,709	0	0	0	0
North Carolina	17,079	14,205	20.2%	17,025	14,126	0	0	21	11	33	68
South Carolina	16,842	15,150	11.2%	16,829	15,066	0	62	0	0	13	22
Virginia	1,972	1,415	39.4%	1,860	1,325	0	0	0	0	113	90
West Virginia	43,098	44,798	-3.8%	36,929	35,732	6,169	9,065	0	0	0	0
East South Central	86,534	82,459	4.9%	84,194	79,522	1,868	2,538	0	0	473	399
Alabama	20,936	19,182	9.1%	20,936	19,182	0	0	0	0	0	0
Kentucky	44,829	43,447	3.2%	44,829	43,447	0	0	0	0	0	0
Mississippi	3,334	4,037	-17.4%	1,466	1,499	1,868	2,538	0	0	0	0
Tennessee	17,435	15,793	10.4%	16,962	15,394	0	0	0	0	473	399
West South Central	91,041	98,491	-7.6%	43,970	46,458	46,989	51,981	0	0	83	52
Arkansas	15,660	16,844	-7.0%	12,515	13,440	3,113	3,371	0	0	32	33
Louisiana	3,700	4,834	-23.5%	2,920	3,483	780	1,350	0	0	0	0
Oklahoma	6,135	5,199	18.0%	6,085	5,180	0	0	0	0	50	19
Texas	65,545	71,615	-8.5%	22,450	24,355	43,095	47,260	0	0	0	0
Mountain	87,181	98,285	-11.3%	74,997	84,321	11,849	13,588	0	0	335	376
Arizona	9,815	12,069	-18.7%	9,815	12,069	0	0	0	0	0	0
Colorado	16,478	18,788	-12.3%	16,478	18,788	0	0	0	0	0	0
Idaho	0	0	--	0	0	0	0	0	0	0	0
Montana	9,785	11,553	-15.3%	0	0	9,781	11,548	0	0	5	5
Nevada	2,323	2,060	12.8%	1,160	975	1,163	1,084	0	0	0	0
New Mexico	8,432	7,372	14.4%	8,432	7,372	0	0	0	0	0	0
Utah	15,967	15,600	2.3%	15,617	15,286	349	314	0	0	0	0
Wyoming	24,382	30,844	-21.0%	23,495	29,831	556	642	0	0	331	371
Pacific Contiguous	3,092	4,371	-29.3%	0	0	2,825	4,138	0	0	268	233
California	246	209	17.6%	0	0	0	0	0	0	246	209
Oregon	0	0	--	0	0	0	0	0	0	0	0
Washington	2,847	4,163	-31.6%	0	0	2,825	4,138	0	0	22	24
Pacific Noncontiguous	752	731	3.0%	483	434	121	143	148	154	0	0
Alaska	752	731	3.0%	483	434	121	143	148	154	0	0
Hawaii	0	0	--	0	0	0	0	0	0	0	0
U.S. Total	652,156	675,115	-3.4%	508,149	518,330	139,527	152,238	204	220	4,276	4,327

Displayed values of zero may represent small values that round to zero. The Excel version of this table provides additional precision which may be accessed by selecting individual cells.
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Notes: See Glossary for definitions. Values are final. See Technical Notes for a discussion of the sample design for the Form EIA-923.

Negative generation denotes that electric power consumed for plant use exceeds gross generation.

Totals may not equal sum of components because of independent rounding. Percentage change is calculated before rounding.

Source: U.S. Energy Information Administration, Form EIA-923, Power Plant Operations Report.

Table 3.9. Utility Scale Facility Net Generation from Petroleum Liquids
by State, by Sector, 2024 and 2023 (Thousand Megawatthours)

Census Division and State	All Sectors			Electric Power Sector				Commercial Sector		Industrial Sector	
				Electric Utilities		Independent Power Producers					
	Generation at Utility Scale Facilities			Generation at Utility Scale Facilities		Generation at Utility Scale Facilities		Generation at Utility Scale Facilities		Generation at Utility Scale Facilities	
	Year 2024	Year 2023	Percentage Change	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023
New England	314	390	-19.5%	43	34	292	316	-35	22	14	18
Connecticut	20	124	-84.3%	4	5	75	115	-62	1	2	3
Maine	60	67	-11.0%	0	0	47	53	0	0	12	14
Massachusetts	177	97	81.3%	36	27	127	63	15	7	-1	1
New Hampshire	47	68	-31.4%	0	0	36	56	11	12	0	0
Rhode Island	8	31	-72.7%	0	0	7	29	NM	NM	0	0
Vermont	3	3	18.1%	3	3	0	0	0	0	0	0
Middle Atlantic	430	504	-14.6%	155	126	249	339	13	22	14	18
New Jersey	31	42	-26.7%	0	0	30	40	1	1	0	0
New York	313	413	-24.3%	152	125	145	259	9	15	7	13
Pennsylvania	87	49	77.6%	3	1	74	39	3	5	7	4
East North Central	433	383	13.3%	294	248	127	122	2	1	11	11
Illinois	21	26	-21.1%	6	6	15	20	0	0	0	0
Indiana	120	97	24.1%	119	90	0	6	1	0	0	1
Michigan	87	97	-10.0%	84	92	0	0	NM	0	3	5
Ohio	141	114	23.1%	25	14	112	96	0	1	NM	4
Wisconsin	64	48	33.8%	60	47	0	0	0	0	5	2
West North Central	417	418	-0.3%	409	411	2	2	3	2	3	3
Iowa	43	62	-30.4%	41	60	2	2	1	NM	0	0
Kansas	97	59	65.0%	97	59	0	0	0	0	0	0
Minnesota	21	54	-60.7%	16	50	0	1	2	1	3	3
Missouri	148	132	12.0%	147	132	0	0	0	0	0	0
Nebraska	48	35	36.2%	48	35	0	0	0	0	0	0
North Dakota	44	53	-17.9%	43	53	0	0	0	0	0	0
South Dakota	16	23	-30.8%	16	23	0	0	NM	NM	0	0
South Atlantic	1,135	942	20.5%	688	607	345	137	14	17	88	181
Delaware	18	-2	NM	0	1	18	-3	0	0	0	0
District of Columbia	0	0	-35.1%	0	0	0	0	0	0	0	0
Florida	168	220	-23.8%	158	204	5	10	0	0	5	6
Georgia	145	182	-20.5%	49	29	32	5	1	1	63	147
Maryland	212	64	229.3%	-2	-2	213	66	NM	0	0	NM
North Carolina	157	84	87.1%	127	62	21	6	3	1	6	15
South Carolina	106	96	9.8%	95	86	2	3	0	0	8	7
Virginia	205	135	52.1%	136	66	54	49	9	14	5	6
West Virginia	125	163	-23.4%	125	161	0	2	0	0	0	0
East South Central	200	195	2.8%	187	181	NM	0	0	0	13	14
Alabama	12	25	-49.3%	3	13	NM	0	0	0	9	11
Kentucky	58	61	-5.1%	58	61	0	0	0	0	0	0
Mississippi	9	7	21.3%	5	5	0	0	0	0	4	2
Tennessee	121	102	18.7%	121	102	0	0	0	0	0	1
West South Central	263	250	5.2%	147	105	109	141	0	0	6	4
Arkansas	55	45	22.5%	48	34	7	10	0	0	0	0
Louisiana	10	9	4.7%	10	9	0	0	0	0	0	0
Oklahoma	27	20	36.6%	24	18	0	0	0	0	3	2
Texas	171	176	-2.7%	66	43	102	131	0	0	4	3
Mountain	177	172	3.0%	158	157	19	14	0	0	0	0
Arizona	30	32	-5.2%	30	32	0	0	0	0	0	0
Colorado	42	48	-12.2%	39	47	3	0	0	0	0	0
Idaho	0	0	-63.5%	0	0	0	0	0	0	0	0
Montana	19	10	96.5%	6	0	13	10	0	0	0	0
Nevada	6	8	-27.9%	4	6	1	2	0	0	0	0
New Mexico	1	1	-46.7%	1	1	0	0	0	0	0	0
Utah	33	29	14.1%	32	27	1	2	0	0	0	0
Wyoming	46	44	4.8%	46	44	0	0	0	0	0	0
Pacific Contiguous	113	99	14.2%	80	47	13	11	9	5	11	35
California	57	75	-24.6%	33	32	6	6	8	5	10	32
Oregon	13	0	NM	13	0	0	0	0	0	0	0
Washington	43	24	82.6%	34	15	7	5	0	0	2	3
Pacific Noncontiguous	7,973	8,045	-0.9%	6,344	6,338	1,412	1,491	6	6	212	209
Alaska	919	885	3.8%	866	835	0	0	2	2	51	48
Hawaii	7,054	7,159	-1.5%	5,477	5,503	1,412	1,491	4	5	161	161
U.S. Total	11,456	11,397	0.5%	8,504	8,254	2,567	2,573	12	76	372	494

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Negative generation denotes that electric power consumed for plant use exceeds gross generation.

Totals may not equal sum of components because of independent rounding. Percentage change is calculated before rounding.

Source: U.S. Energy Information Administration, Form EIA-923, Power Plant Operations Report.

Table 3.10. Utility Scale Facility Net Generation from Petroleum Coke
by State, by Sector, 2024 and 2023 (Thousand Megawatthours)

Census Division and State	All Sectors			Electric Power Sector				Commercial Sector		Industrial Sector	
				Electric Utilities		Independent Power Producers					
	Generation at Utility Scale Facilities			Generation at Utility Scale Facilities		Generation at Utility Scale Facilities		Generation at Utility Scale Facilities		Generation at Utility Scale Facilities	
	Year 2024	Year 2023	Percentage Change	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023
New England	0	0	--	0	0	0	0	0	0	0	0
Connecticut	0	0	--	0	0	0	0	0	0	0	0
Maine	0	0	--	0	0	0	0	0	0	0	0
Massachusetts	0	0	--	0	0	0	0	0	0	0	0
New Hampshire	0	0	--	0	0	0	0	0	0	0	0
Rhode Island	0	0	--	0	0	0	0	0	0	0	0
Vermont	0	0	--	0	0	0	0	0	0	0	0
Middle Atlantic	0	0	--	0	0	0	0	0	0	0	0
New Jersey	0	0	--	0	0	0	0	0	0	0	0
New York	0	0	--	0	0	0	0	0	0	0	0
Pennsylvania	0	0	--	0	0	0	0	0	0	0	0
East North Central	2,411	2,235	7.9%	1,263	1,141	1,001	934	0	0	147	160
Illinois	0	0	--	0	0	0	0	0	0	0	0
Indiana	0	0	--	0	0	0	0	0	0	0	0
Michigan	1,406	1,257	11.9%	1,260	1,098	0	0	0	0	146	159
Ohio	1,002	935	7.1%	0	0	1,001	934	0	0	1	1
Wisconsin	3	43	-92.8%	3	43	0	0	0	0	0	0
West North Central	5	2	129.7%	0	0	0	0	4	2	1	0
Iowa	5	2	129.7%	0	0	0	0	4	2	1	0
Kansas	0	0	--	0	0	0	0	0	0	0	0
Minnesota	0	0	--	0	0	0	0	0	0	0	0
Missouri	0	0	--	0	0	0	0	0	0	0	0
Nebraska	0	0	--	0	0	0	0	0	0	0	0
North Dakota	0	0	--	0	0	0	0	0	0	0	0
South Dakota	0	0	--	0	0	0	0	0	0	0	0
South Atlantic	743	1,036	-28.3%	646	982	0	0	0	0	96	54
Delaware	0	0	--	0	0	0	0	0	0	0	0
District of Columbia	0	0	--	0	0	0	0	0	0	0	0
Florida	646	982	-34.2%	646	982	0	0	0	0	0	0
Georgia	96	54	78.2%	0	0	0	0	0	0	96	54
Maryland	0	0	--	0	0	0	0	0	0	0	0
North Carolina	0	0	--	0	0	0	0	0	0	0	0
South Carolina	0	0	--	0	0	0	0	0	0	0	0
Virginia	0	0	--	0	0	0	0	0	0	0	0
West Virginia	0	0	--	0	0	0	0	0	0	0	0
East South Central	0	0	-100.0%	0	0	0	0	0	0	0	0
Alabama	0	0	--	0	0	0	0	0	0	0	0
Kentucky	0	0	-100.0%	0	0	0	0	0	0	0	0
Mississippi	0	0	--	0	0	0	0	0	0	0	0
Tennessee	0	0	--	0	0	0	0	0	0	0	0
West South Central	95	1,082	-91.2%	37	1,023	0	0	0	0	58	59
Arkansas	0	0	--	0	0	0	0	0	0	0	0
Louisiana	37	1,023	-96.4%	37	1,023	0	0	0	0	0	0
Oklahoma	0	0	--	0	0	0	0	0	0	0	0
Texas	58	59	-1.3%	0	0	0	0	0	0	58	59
Mountain	375	481	-22.0%	0	0	375	481	0	0	0	0
Arizona	0	0	--	0	0	0	0	0	0	0	0
Colorado	0	0	--	0	0	0	0	0	0	0	0
Idaho	0	0	--	0	0	0	0	0	0	0	0
Montana	375	481	-22.0%	0	0	375	481	0	0	0	0
Nevada	0	0	--	0	0	0	0	0	0	0	0
New Mexico	0	0	--	0	0	0	0	0	0	0	0
Utah	0	0	--	0	0	0	0	0	0	0	0
Wyoming	0	0	--	0	0	0	0	0	0	0	0
Pacific Contiguous	0	0	--	0	0	0	0	0	0	0	0
California	0	0	--	0	0	0	0	0	0	0	0
Oregon	0	0	--	0	0	0	0	0	0	0	0
Washington	0	0	--	0	0	0	0	0	0	0	0
Pacific Noncontiguous	0	0	--	0	0	0	0	0	0	0	0
Alaska	0	0	--	0	0	0	0	0	0	0	0
Hawaii	0	0	--	0	0	0	0	0	0	0	0
U.S. Total	3,629	4,836	-25.0%	1,946	3,146	1,377	1,415	4	2	302	273

Displayed values of zero may represent small values that round to zero. The Excel version of this table provides additional precision which may be accessed by selecting individual cells.

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Negative generation denotes that electric power consumed for plant use exceeds gross generation.

Totals may not equal sum of components because of independent rounding. Percentage change is calculated before rounding.

Source: U.S. Energy Information Administration, Form EIA-923, Power Plant Operations Report.

Table 3.11. Utility Scale Facility Net Generation from Natural Gas
by State, by Sector, 2024 and 2023 (Thousand Megawatthours)

Census Division and State	All Sectors			Electric Power Sector				Commercial Sector		Industrial Sector	
				Electric Utilities		Independent Power Producers					
				Generation at Utility Scale Facilities		Generation at Utility Scale Facilities		Generation at Utility Scale Facilities		Generation at Utility Scale Facilities	
	Year 2024	Year 2023	Percentage Change	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023
New England	61,851	57,482	7.6%	273	176	59,384	55,017	1,079	1,056	1,115	1,233
Connecticut	26,036	24,952	4.3%	96	91	25,041	23,925	245	289	654	648
Maine	6,399	3,975	61.0%	0	0	6,222	3,710	31	31	146	234
Massachusetts	16,203	14,774	9.7%	176	84	15,126	13,843	757	680	145	167
New Hampshire	4,421	4,226	4.6%	0	0	4,385	4,186	13	13	23	27
Rhode Island	8,791	9,554	-8.0%	0	0	8,611	9,354	33	43	147	157
Vermont	1	1	-15.5%	1	0	0	0	1	1	0	0
Middle Atlantic	235,907	230,740	2.2%	13,124	11,855	218,219	213,752	715	1,159	3,848	3,973
New Jersey	29,649	33,056	-10.3%	137	156	28,852	32,244	252	236	408	420
New York	62,346	58,428	6.7%	12,962	11,682	48,442	45,417	316	757	626	573
Pennsylvania	143,913	139,256	3.3%	26	18	140,925	136,092	148	167	2,814	2,980
East North Central	237,114	221,688	7.0%	90,219	81,915	140,722	133,424	1,539	1,563	4,633	4,785
Illinois	30,137	28,445	6.0%	2,934	2,667	25,932	24,515	384	417	888	846
Indiana	39,860	34,849	14.4%	20,021	15,593	17,588	16,841	209	205	2,042	2,210
Michigan	55,734	54,068	3.1%	31,349	30,333	23,227	22,550	623	623	535	562
Ohio	85,137	78,705	8.2%	10,584	8,659	73,975	69,518	274	258	304	269
Wisconsin	26,246	25,621	2.4%	25,331	24,664	0	0	50	60	865	898
West North Central	46,155	44,054	4.8%	36,833	34,798	7,276	7,448	362	356	1,683	1,451
Iowa	9,765	10,241	-4.7%	8,911	9,494	0	0	118	111	736	637
Kansas	5,318	4,369	21.7%	4,960	4,027	0	0	0	0	358	342
Minnesota	15,889	13,824	14.9%	10,338	8,770	4,983	4,574	99	103	468	376
Missouri	9,100	9,260	-1.7%	6,631	6,205	2,293	2,874	139	140	37	40
Nebraska	1,381	1,411	-2.1%	1,349	1,403	0	0	7	2	25	6
North Dakota	2,442	2,833	-13.8%	2,428	2,826	0	0	0	0	14	8
South Dakota	2,261	2,116	6.9%	2,216	2,074	0	0	0	0	45	42
South Atlantic	422,751	406,806	3.9%	355,485	341,918	61,581	59,136	682	666	5,004	5,086
Delaware	4,206	4,383	-4.0%	66	17	3,221	3,289	0	0	919	1,077
District of Columbia	100	89	11.6%	0	0	0	0	100	89	0	0
Florida	204,507	197,191	3.7%	193,943	186,966	9,087	8,709	119	105	1,358	1,411
Georgia	56,937	60,044	-5.2%	47,168	48,880	8,870	10,397	0	0	899	768
Maryland	13,910	15,336	-9.3%	2,968	4,425	10,577	10,530	309	322	56	59
North Carolina	55,503	51,788	7.2%	47,078	43,156	8,170	8,336	128	135	127	160
South Carolina	22,809	23,691	-3.7%	21,485	23,115	1,192	429	0	0	131	148
Virginia	60,998	50,605	20.5%	42,271	34,878	17,861	14,884	25	15	840	827
West Virginia	3,782	3,680	2.8%	506	483	2,604	2,562	0	0	673	635
East South Central	158,375	147,135	7.6%	122,093	107,051	32,309	36,456	201	196	3,772	3,432
Alabama	64,599	61,848	4.4%	31,054	24,273	31,766	35,992	0	0	1,779	1,584
Kentucky	17,267	15,090	14.4%	16,518	14,426	535	457	0	0	214	206
Mississippi	60,026	55,168	8.8%	59,444	54,592	NM	7	0	0	574	568
Tennessee	16,483	15,030	9.7%	15,077	13,760	0	0	201	196	1,206	1,074
West South Central	440,925	428,273	3.0%	171,601	158,955	203,800	201,551	656	797	64,868	66,970
Arkansas	24,725	26,487	-6.7%	23,409	25,055	1,081	1,220	33	37	201	175
Louisiana	75,263	74,414	1.1%	47,037	43,877	4,084	4,635	58	92	24,085	25,811
Oklahoma	47,742	45,213	5.6%	32,057	30,195	15,206	14,500	0	-1	479	520
Texas	293,193	282,159	3.9%	69,097	59,829	183,428	181,197	565	669	40,103	40,464
Mountain	134,011	129,519	3.5%	106,822	101,455	24,934	25,928	443	430	1,813	1,707
Arizona	55,090	52,818	4.3%	38,128	36,354	16,825	16,332	137	131	0	0
Colorado	17,927	17,220	4.1%	15,170	14,844	2,582	2,207	5	2	170	167
Idaho	6,285	5,686	10.5%	4,709	3,700	1,373	1,810	40	39	164	137
Montana	995	1,002	-0.6%	808	885	187	116	0	0	1	1
Nevada	24,999	24,599	1.6%	23,380	22,869	1,087	1,176	62	65	471	489
New Mexico	11,648	14,231	-18.2%	8,705	9,881	2,764	4,177	110	105	69	67
Utah	11,640	11,834	-1.6%	11,209	11,490	116	111	89	86	227	148
Wyoming	5,426	2,129	154.8%	4,713	1,431	1	1	0	0	712	698
Pacific Contiguous	129,679	137,183	-5.5%	53,905	54,673	64,303	71,232	1,479	1,521	9,992	9,757
California	86,656	94,390	-8.2%	27,900	28,299	48,343	55,779	1,425	1,484	8,987	8,829
Oregon	24,926	23,385	6.6%	13,284	13,228	11,462	10,011	47	36	133	111
Washington	18,097	19,408	-6.8%	12,721	13,147	4,497	5,442	7	1	872	817
Pacific Noncontiguous	3,134	3,182	-1.5%	3,092	3,113	0	0	0	0	42	69
Alaska	3,134	3,182	-1.5%	3,092	3,113	0	0	0	0	42	69
Hawaii	0	0	--	0	0	0	0	0	0	0	0
U.S. Total	1,869,902	1,806,063	3.5%	953,446	895,910	812,528	803,945	7,157	7,744	96,771	98,463

Displayed values of zero may represent small values that round to zero. The Excel version of this table provides additional precision which may be accessed by selecting individual cells.

NM = Not meaningful due to large relative standard error or excessive percentage change.

Notes: See Glossary for definitions. Values are final. See Technical Notes for a discussion of the sample design for the Form EIA-923.

Negative generation denotes that electric power consumed for plant use exceeds gross generation.

Totals may not equal sum of components because of independent rounding. Percentage change is calculated before rounding.

Source: U.S. Energy Information Administration, Form EIA-923, Power Plant Operations Report.

Table 3.12. Utility Scale Facility Net Generation from Other Fossil Gas
by State, by Sector, 2024 and 2023 (Thousand Megawatthours)

Census Division and State	All Sectors			Electric Power Sector				Commercial Sector		Industrial Sector	
				Electric Utilities		Independent Power Producers					
	Generation at Utility Scale Facilities			Generation at Utility Scale Facilities		Generation at Utility Scale Facilities		Generation at Utility Scale Facilities		Generation at Utility Scale Facilities	
	Year 2024	Year 2023	Percentage Change	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023
New England	0	0	--	0	0	0	0	0	0	0	0
Connecticut	0	0	--	0	0	0	0	0	0	0	0
Maine	0	0	--	0	0	0	0	0	0	0	0
Massachusetts	0	0	--	0	0	0	0	0	0	0	0
New Hampshire	0	0	--	0	0	0	0	0	0	0	0
Rhode Island	0	0	--	0	0	0	0	0	0	0	0
Vermont	0	0	--	0	0	0	0	0	0	0	0
Middle Atlantic	710	739	-3.9%	0	0	24	30	0	0	686	709
New Jersey	168	161	4.0%	0	0	24	29	0	0	144	132
New York	0	0	--	0	0	0	0	0	0	0	0
Pennsylvania	542	578	-6.1%	0	0	0	0	0	0	542	577
East North Central	4,093	4,684	-12.6%	0	0	1,581	2,032	0	0	2,512	2,652
Illinois	177	248	-28.6%	0	0	0	0	0	0	177	248
Indiana	2,114	2,272	-7.0%	0	0	0	0	0	0	2,114	2,272
Michigan	946	1,377	-31.3%	0	0	946	1,377	0	0	0	0
Ohio	856	787	8.7%	0	0	635	655	0	0	221	132
Wisconsin	0	0	--	0	0	0	0	0	0	0	0
West North Central	28	23	17.9%	0	0	0	0	0	0	28	23
Iowa	0	0	--	0	0	0	0	0	0	0	0
Kansas	0	0	--	0	0	0	0	0	0	0	0
Minnesota	0	0	--	0	0	0	0	0	0	0	0
Missouri	0	0	--	0	0	0	0	0	0	0	0
Nebraska	0	0	--	0	0	0	0	0	0	0	0
North Dakota	28	23	17.9%	0	0	0	0	0	0	28	23
South Dakota	0	0	--	0	0	0	0	0	0	0	0
South Atlantic	261	204	27.9%	0	0	0	0	0	0	261	204
Delaware	221	172	28.5%	0	0	0	0	0	0	221	172
District of Columbia	0	0	--	0	0	0	0	0	0	0	0
Florida	0	0	34.6%	0	0	0	0	0	0	0	0
Georgia	0	0	--	0	0	0	0	0	0	0	0
Maryland	0	0	--	0	0	0	0	0	0	0	0
North Carolina	0	0	--	0	0	0	0	0	0	0	0
South Carolina	0	0	--	0	0	0	0	0	0	0	0
Virginia	0	0	--	0	0	0	0	0	0	0	0
West Virginia	40	32	24.9%	0	0	0	0	0	0	40	32
East South Central	12	11	6.0%	0	0	0	0	0	0	12	11
Alabama	0	0	-84.2%	0	0	0	0	0	0	0	0
Kentucky	0	0	--	0	0	0	0	0	0	0	0
Mississippi	0	0	--	0	0	0	0	0	0	0	0
Tennessee	12	11	6.3%	0	0	0	0	0	0	12	11
West South Central	3,980	4,132	-3.7%	0	0	1,365	1,269	0	0	2,614	2,863
Arkansas	0	0	--	0	0	0	0	0	0	0	0
Louisiana	1,448	1,804	-19.8%	0	0	0	0	0	0	1,448	1,804
Oklahoma	0	0	--	0	0	0	0	0	0	0	0
Texas	2,532	2,327	8.8%	0	0	1,365	1,269	0	0	1,166	1,059
Mountain	331	365	-9.3%	0	0	5	10	0	0	325	355
Arizona	0	0	--	0	0	0	0	0	0	0	0
Colorado	0	0	--	0	0	0	0	0	0	0	0
Idaho	0	0	--	0	0	0	0	0	0	0	0
Montana	5	10	-42.9%	0	0	5	10	0	0	0	0
Nevada	0	0	--	0	0	0	0	0	0	0	0
New Mexico	0	0	--	0	0	0	0	0	0	0	0
Utah	1	3	-51.5%	0	0	0	0	0	0	1	3
Wyoming	324	352	-8.0%	0	0	0	0	0	0	324	352
Pacific Contiguous	1,431	1,620	-11.7%	0	0	0	0	0	0	1,431	1,620
California	1,209	1,382	-12.5%	0	0	0	0	0	0	1,209	1,382
Oregon	0	0	--	0	0	0	0	0	0	0	0
Washington	223	238	-6.6%	0	0	0	0	0	0	223	238
Pacific Noncontiguous	0	0	--	0	0	0	0	0	0	0	0
Alaska	0	0	--	0	0	0	0	0	0	0	0
Hawaii	0	0	--	0	0	0	0	0	0	0	0
U.S. Total	10,845	11,778	-7.9%	0	0	2,976	3,340	0	0	7,870	8,438

Displayed values of zero may represent small values that round to zero. The Excel version of this table provides additional precision which may be accessed by selecting individual cells.

NM = Not meaningful due to large relative standard error or excessive percentage change.

Notes: See Glossary for definitions. Values are final. See Technical Notes for a discussion of the sample design for the Form EIA-923.

Negative generation denotes that electric power consumed for plant use exceeds gross generation.

Totals may not equal sum of components because of independent rounding. Percentage change is calculated before rounding.

Source: U.S. Energy Information Administration, Form EIA-923, Power Plant Operations Report.

Table 3.13. Utility Scale Facility Net Generation from Nuclear Energy
by State, by Sector, 2024 and 2023 (Thousand Megawatthours)

Census Division and State	All Sectors			Electric Power Sector				Commercial Sector		Industrial Sector	
				Electric Utilities		Independent Power Producers					
	Generation at Utility Scale Facilities			Generation at Utility Scale Facilities		Generation at Utility Scale Facilities		Generation at Utility Scale Facilities		Generation at Utility Scale Facilities	
	Year 2024	Year 2023	Percentage Change	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023
New England	26,547	23,204	14.4%	0	0	26,547	23,204	0	0	0	0
Connecticut	16,870	13,669	23.4%	0	0	16,870	13,669	0	0	0	0
Maine	0	0	--	0	0	0	0	0	0	0	0
Massachusetts	0	0	--	0	0	0	0	0	0	0	0
New Hampshire	9,677	9,535	1.5%	0	0	9,677	9,535	0	0	0	0
Rhode Island	0	0	--	0	0	0	0	0	0	0	0
Vermont	0	0	--	0	0	0	0	0	0	0	0
Middle Atlantic	130,155	131,165	-0.8%	0	0	130,155	131,165	0	0	0	0
New Jersey	27,677	28,335	-2.3%	0	0	27,677	28,335	0	0	0	0
New York	27,073	27,525	-1.6%	0	0	27,073	27,525	0	0	0	0
Pennsylvania	75,404	75,305	0.1%	0	0	75,404	75,305	0	0	0	0
East North Central	153,586	151,445	1.4%	26,281	27,996	127,306	123,449	0	0	0	0
Illinois	99,212	97,559	1.7%	0	0	99,212	97,559	0	0	0	0
Indiana	0	0	--	0	0	0	0	0	0	0	0
Michigan	26,281	27,996	-6.1%	26,281	27,996	0	0	0	0	0	0
Ohio	17,947	16,207	10.7%	0	0	17,947	16,207	0	0	0	0
Wisconsin	10,147	9,683	4.8%	0	0	10,147	9,683	0	0	0	0
West North Central	37,670	38,331	-1.7%	37,670	38,331	0	0	0	0	0	0
Iowa	0	0	--	0	0	0	0	0	0	0	0
Kansas	9,204	10,302	-10.7%	9,204	10,302	0	0	0	0	0	0
Minnesota	11,845	11,924	-0.7%	11,845	11,924	0	0	0	0	0	0
Missouri	10,526	9,180	14.7%	10,526	9,180	0	0	0	0	0	0
Nebraska	6,096	6,926	-12.0%	6,096	6,926	0	0	0	0	0	0
North Dakota	0	0	--	0	0	0	0	0	0	0	0
South Dakota	0	0	--	0	0	0	0	0	0	0	0
South Atlantic	217,819	209,922	3.8%	203,095	194,938	14,724	14,984	0	0	0	0
Delaware	0	0	--	0	0	0	0	0	0	0	0
District of Columbia	0	0	--	0	0	0	0	0	0	0	0
Florida	29,054	29,940	-3.0%	29,054	29,940	0	0	0	0	0	0
Georgia	47,976	37,377	28.4%	47,976	37,377	0	0	0	0	0	0
Maryland	14,724	14,984	-1.7%	0	0	14,724	14,984	0	0	0	0
North Carolina	43,349	42,336	2.4%	43,349	42,336	0	0	0	0	0	0
South Carolina	53,770	55,622	-3.3%	53,770	55,622	0	0	0	0	0	0
Virginia	28,945	29,663	-2.4%	28,945	29,663	0	0	0	0	0	0
West Virginia	0	0	--	0	0	0	0	0	0	0	0
East South Central	87,327	95,266	-8.3%	87,327	95,266	0	0	0	0	0	0
Alabama	44,487	45,579	-2.4%	44,487	45,579	0	0	0	0	0	0
Kentucky	0	0	--	0	0	0	0	0	0	0	0
Mississippi	10,653	11,750	-9.3%	10,653	11,750	0	0	0	0	0	0
Tennessee	32,186	37,937	-15.2%	32,186	37,937	0	0	0	0	0	0
West South Central	68,027	67,864	0.2%	29,414	27,184	38,613	40,680	0	0	0	0
Arkansas	14,763	14,972	-1.4%	14,763	14,972	0	0	0	0	0	0
Louisiana	14,652	12,211	20.0%	14,652	12,211	0	0	0	0	0	0
Oklahoma	0	0	--	0	0	0	0	0	0	0	0
Texas	38,613	40,680	-5.1%	0	0	38,613	40,680	0	0	0	0
Mountain	32,388	31,523	2.7%	32,388	31,523	0	0	0	0	0	0
Arizona	32,388	31,523	2.7%	32,388	31,523	0	0	0	0	0	0
Colorado	0	0	--	0	0	0	0	0	0	0	0
Idaho	0	0	--	0	0	0	0	0	0	0	0
Montana	0	0	--	0	0	0	0	0	0	0	0
Nevada	0	0	--	0	0	0	0	0	0	0	0
New Mexico	0	0	--	0	0	0	0	0	0	0	0
Utah	0	0	--	0	0	0	0	0	0	0	0
Wyoming	0	0	--	0	0	0	0	0	0	0	0
Pacific Contiguous	28,346	26,153	8.4%	28,346	26,153	0	0	0	0	0	0
California	18,379	17,718	3.7%	18,379	17,718	0	0	0	0	0	0
Oregon	0	0	--	0	0	0	0	0	0	0	0
Washington	9,967	8,435	18.2%	9,967	8,435	0	0	0	0	0	0
Pacific Noncontiguous	0	0	--	0	0	0	0	0	0	0	0
Alaska	0	0	--	0	0	0	0	0	0	0	0
Hawaii	0	0	--	0	0	0	0	0	0	0	0
U.S. Total	781,865	774,873	0.9%	444,521	441,391	337,345	333,482	0	0	0	0

Displayed values of zero may represent small values that round to zero. The Excel version of this table provides additional precision which may be accessed by selecting individual cells.

NM = Not meaningful due to large relative standard error or excessive percentage change.

Notes: See Glossary for definitions. Values are final. See Technical Notes for a discussion of the sample design for the Form EIA-923.

Negative generation denotes that electric power consumed for plant use exceeds gross generation.

Totals may not equal sum of components because of independent rounding. Percentage change is calculated before rounding.

Source: U.S. Energy Information Administration, Form EIA-923, Power Plant Operations Report.

Table 3.14. Utility Scale Facility Net Generation from Hydroelectric (Conventional) Power by State, by Sector, 2024 and 2023 (Thousand Megawatthours)

Census Division and State	All Sectors			Electric Power Sector				Commercial Sector		Industrial Sector	
				Electric Utilities		Independent Power Producers					
	Generation at Utility Scale Facilities			Generation at Utility Scale Facilities		Generation at Utility Scale Facilities		Generation at Utility Scale Facilities		Generation at Utility Scale Facilities	
	Year 2024	Year 2023	Percentage Change	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023
New England	6,799	8,601	-20.9%	685	874	6,064	7,625	3	5	47	97
Connecticut	369	465	-20.7%	31	39	337	426	0	0	0	0
Maine	2,952	3,832	-25.6%	3	5	2,802	3,730	0	0	47	97
Massachusetts	881	1,165	-24.4%	226	304	652	857	3	5	0	0
New Hampshire	1,411	1,592	-11.3%	7	17	1,405	1,575	0	0	0	0
Rhode Island	3	8	-63.8%	0	0	3	8	0	0	0	0
Vermont	1,284	1,539	-16.6%	418	510	866	1,029	0	0	0	0
Middle Atlantic	30,670	31,229	-1.8%	23,589	23,566	7,011	7,607	3	5	66	61
New Jersey	4	12	-69.5%	0	0	4	12	0	0	0	0
New York	27,945	28,434	-1.7%	23,505	23,490	4,371	4,878	3	5	66	61
Pennsylvania	2,721	2,783	-2.2%	84	66	2,637	2,718	0	0	0	0
East North Central	4,244	4,384	-3.2%	3,744	3,868	380	405	7	6	113	105
Illinois	75	92	-18.6%	42	64	33	29	0	0	0	0
Indiana	375	464	-19.1%	368	458	0	0	7	6	0	0
Michigan	1,255	1,395	-10.0%	1,180	1,328	67	57	0	0	8	10
Ohio	468	507	-7.8%	293	292	175	215	0	0	0	0
Wisconsin	2,072	1,926	7.6%	1,860	1,726	106	104	0	0	106	96
West North Central	10,783	10,055	7.2%	10,483	9,799	236	198	0	0	63	58
Iowa	1,030	948	8.7%	1,025	944	5	4	0	0	0	0
Kansas	20	13	49.1%	0	0	20	13	0	0	0	0
Minnesota	868	750	15.6%	594	513	211	180	0	0	63	58
Missouri	1,020	785	30.0%	1,020	785	0	0	0	0	0	0
Nebraska	1,183	1,143	3.5%	1,183	1,143	0	0	0	0	0	0
North Dakota	2,061	2,119	-2.8%	2,061	2,119	0	0	0	0	0	0
South Dakota	4,601	4,296	7.1%	4,601	4,296	0	0	0	0	0	0
South Atlantic	14,822	14,291	3.7%	11,376	10,784	2,978	3,040	13	11	455	456
Delaware	0	0	-	0	0	0	0	0	0	0	0
District of Columbia	0	0	-	0	0	0	0	0	0	0	0
Florida	177	224	-20.9%	177	224	0	0	0	0	0	0
Georgia	2,941	2,872	2.4%	2,929	2,857	5	6	0	0	7	9
Maryland	1,848	1,849	0.0%	0	0	1,848	1,849	0	0	0	0
North Carolina	4,829	4,225	14.3%	4,138	3,552	681	664	10	9	0	0
South Carolina	2,412	2,199	9.7%	2,358	2,140	51	57	2	2	0	0
Virginia	1,253	1,391	-9.9%	1,143	1,284	110	107	0	0	0	0
West Virginia	1,361	1,530	-11.0%	631	727	283	357	0	0	448	446
East South Central	21,382	20,426	4.7%	20,660	19,746	723	680	0	0	0	0
Alabama	8,357	8,430	-0.9%	8,357	8,430	0	0	0	0	0	0
Kentucky	4,114	3,955	4.0%	4,099	3,943	14	11	0	0	0	0
Mississippi	0	0	-	0	0	0	0	0	0	0	0
Tennessee	8,911	8,042	10.8%	8,203	7,373	708	669	0	0	0	0
West South Central	6,378	6,178	3.2%	5,396	5,371	982	807	0	0	0	0
Arkansas	3,134	3,229	-2.9%	3,074	3,172	60	56	0	0	0	0
Louisiana	885	708	25.1%	0	0	885	708	0	0	0	0
Oklahoma	1,582	1,483	6.6%	1,582	1,483	0	0	0	0	0	0
Texas	777	758	2.5%	741	715	36	43	0	0	0	0
Mountain	28,879	27,817	3.8%	27,551	26,520	1,263	1,234	65	64	0	0
Arizona	5,314	5,937	-10.5%	5,314	5,937	0	0	0	0	0	0
Colorado	1,660	1,597	4.0%	1,423	1,376	223	207	14	14	0	0
Idaho	9,150	8,378	9.2%	8,322	7,566	828	812	0	0	0	0
Montana	9,220	8,792	4.9%	9,103	8,672	118	120	0	0	0	0
Nevada	1,606	1,319	21.8%	1,532	1,246	74	73	0	0	0	0
New Mexico	153	108	42.1%	153	108	0	0	0	0	0	0
Utah	759	769	-1.3%	697	707	11	12	51	50	0	0
Wyoming	1,017	917	10.8%	1,007	908	10	9	0	0	0	0
Pacific Contiguous	117,123	120,156	-2.5%	115,161	117,897	1,944	2,246	18	13	0	0
California	29,454	32,381	-9.0%	27,966	30,525	1,470	1,843	18	13	0	0
Oregon	26,933	26,329	2.3%	26,673	26,110	259	219	0	0	0	0
Washington	60,736	61,446	-1.2%	60,521	61,262	215	184	0	0	0	0
Pacific Noncontiguous	1,816	1,867	-2.7%	1,518	1,589	30	20	201	190	66	67
Alaska	1,715	1,773	-3.3%	1,514	1,584	0	0	201	190	0	0
Hawaii	100	93	7.7%	4	5	30	20	0	0	66	67
U.S. Total	242,896	245,002	-0.9%	220,163	220,003	21,612	23,862	311	293	810	844

Displayed values of zero may represent small values that round to zero. The Excel version of this table provides additional precision which may be accessed by selecting individual cells.

NM = Not meaningful due to large relative standard error or excessive percentage change.

Notes: See Glossary for definitions. Values are final. See Technical Notes for a discussion of the sample design for the Form EIA-923.

Negative generation denotes that electric power consumed for plant use exceeds gross generation.

Totals may not equal sum of components because of independent rounding. Percentage change is calculated before rounding.

Source: U.S. Energy Information Administration, Form EIA-923, Power Plant Operations Report.

Table 3.15. Utility Scale Facility Net Generation from Renewable Sources Excluding Hydroelectric by State, by Sector, 2024 and 2023 (Thousand Megawatthours)

Census Division and State	All Sectors			Electric Power Sector				Commercial Sector		Industrial Sector	
				Electric Utilities		Independent Power Producers					
	Generation at Utility Scale Facilities			Generation at Utility Scale Facilities		Generation at Utility Scale Facilities		Generation at Utility Scale Facilities		Generation at Utility Scale Facilities	
	Year 2024	Year 2023	Percentage Change	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023
New England	12,351	11,419	8.2%	588	572	10,577	9,692	513	528	673	627
Connecticut	1,038	1,022	1.6%	2	0	1,030	1,012	6	5	0	5
Maine	5,035	4,320	16.6%	0	0	4,361	3,694	4	7	669	618
Massachusetts	3,221	3,111	3.5%	110	115	2,648	2,520	459	472	4	4
New Hampshire	1,113	1,194	-6.8%	0	0	1,076	1,157	36	37	0	0
Rhode Island	975	839	16.2%	0	0	969	834	6	6	0	0
Vermont	970	934	3.8%	476	457	492	476	2	1	0	0
Middle Atlantic	18,865	16,047	17.6%	127	358	16,919	13,903	1,360	1,298	459	489
New Jersey	2,272	2,233	1.7%	127	126	1,670	1,637	471	465	5	6
New York	10,752	8,663	24.1%	0	232	9,922	7,649	671	625	159	157
Pennsylvania	5,841	5,151	13.4%	0	0	5,327	4,616	219	208	295	326
East North Central	68,488	55,069	24.4%	12,624	8,565	54,606	45,278	129	131	1,129	1,095
Illinois	28,192	23,961	17.7%	88	95	28,095	23,863	6	3	2	NM
Indiana	13,587	10,953	24.0%	2,290	1,134	11,248	9,774	2	2	47	43
Michigan	13,635	11,584	17.7%	5,953	4,822	7,049	6,201	44	42	589	519
Ohio	7,115	4,526	57.2%	11	12	6,877	4,250	19	14	208	249
Wisconsin	5,958	4,046	47.3%	4,282	2,503	1,336	1,190	58	70	283	283
West North Central	139,829	130,196	7.4%	52,301	48,823	86,458	80,452	191	180	879	741
Iowa	45,158	42,170	7.1%	32,439	30,352	12,631	11,738	9	8	80	71
Kansas	29,972	27,420	9.3%	2,741	2,546	27,207	24,850	13	13	12	11
Minnesota	18,232	17,628	3.4%	6,665	6,354	10,695	10,534	109	102	764	638
Missouri	7,103	7,049	0.8%	2,767	2,855	4,284	4,150	48	40	3	3
Nebraska	12,169	12,015	1.3%	150	167	12,006	11,830	13	18	0	0
North Dakota	14,763	14,477	2.0%	5,114	5,155	9,648	9,321	0	0	0	0
South Dakota	12,432	9,439	31.7%	2,426	1,395	9,987	8,028	0	0	20	17
South Atlantic	69,604	60,851	14.4%	22,811	18,491	37,373	33,468	944	1,056	8,475	7,835
Delaware	210	226	-6.9%	7	7	178	199	5	7	21	13
District of Columbia	88	83	6.0%	1	3	30	21	56	58	0	0
Florida	21,615	17,183	25.8%	17,752	13,478	2,185	1,994	403	457	1,274	1,254
Georgia	14,551	12,501	16.4%	503	640	10,465	8,707	2	2	3,581	3,153
Maryland	1,927	1,746	10.4%	7	8	1,907	1,715	13	24	0	0
North Carolina	13,828	13,680	1.1%	1,058	1,075	11,750	11,475	100	106	920	1,024
South Carolina	4,753	4,504	5.5%	59	74	3,264	3,161	0	0	1,429	1,268
Virginia	10,436	8,830	18.2%	3,393	3,206	5,427	4,098	365	402	1,251	1,123
West Virginia	2,196	2,099	4.7%	30	0	2,166	2,099	0	0	0	0
East South Central	10,100	8,347	21.0%	319	334	4,578	2,811	5	5	5,196	5,197
Alabama	4,522	4,371	3.5%	77	25	1,215	1,217	0	0	3,230	3,129
Kentucky	671	573	17.0%	129	124	244	119	2	1	296	329
Mississippi	3,319	1,972	68.3%	111	182	1,934	459	0	0	1,274	1,332
Tennessee	1,589	1,430	11.1%	2	3	1,185	1,016	4	3	398	407
West South Central	210,660	190,432	10.6%	9,977	7,481	197,057	179,194	50	46	3,576	3,711
Arkansas	3,121	1,511	106.6%	501	241	1,834	561	17	19	769	690
Louisiana	3,176	2,280	39.3%	28	40	1,248	335	0	0	1,900	1,904
Oklahoma	38,610	37,356	3.4%	6,911	6,743	31,384	30,365	-3	-7	317	256
Texas	165,753	149,285	11.0%	2,536	457	162,591	147,932	35	35	590	861
Mountain	99,112	83,476	18.7%	16,555	14,764	82,045	68,184	116	121	397	408
Arizona	13,546	9,365	44.6%	1,038	593	12,458	8,718	16	20	34	34
Colorado	22,629	19,840	14.1%	4,433	4,256	18,159	15,568	6	8	30	8
Idaho	4,531	3,706	22.3%	445	435	3,753	2,906	37	31	295	335
Montana	6,216	4,825	28.8%	1,747	959	4,449	3,846	0	0	21	20
Nevada	16,712	14,192	17.8%	418	177	16,236	13,955	47	47	10	12
New Mexico	19,474	17,576	10.8%	3,393	3,142	16,080	14,433	0	1	0	0
Utah	6,581	5,163	27.5%	306	255	6,259	4,894	9	14	7	0
Wyoming	9,425	8,810	7.0%	4,774	4,945	4,651	3,865	0	0	0	0
Pacific Contiguous	102,537	92,484	10.9%	8,087	6,996	91,081	82,145	934	991	2,434	2,352
California	79,350	71,348	11.2%	1,751	1,490	75,614	67,939	891	953	1,095	966
Oregon	12,776	11,955	6.9%	1,646	1,532	10,474	9,866	33	31	623	526
Washington	10,410	9,181	13.4%	4,691	3,974	4,993	4,340	10	7	716	860
Pacific Noncontiguous	2,020	1,918	5.3%	166	158	1,655	1,569	199	190	0	0
Alaska	174	150	15.8%	70	61	61	50	43	39	0	0
Hawaii	1,846	1,767	4.4%	96	97	1,594	1,519	156	151	0	0
U.S. Total	733,567	650,239	12.8%	123,555	106,543	582,350	516,694	4,441	4,545	23,220	22,456

Displayed values of zero may represent small values that round to zero. The Excel version of this table provides additional precision which may be accessed by selecting individual cells.

NM = Not meaningful due to large relative standard error or excessive percentage change.

Notes: See Glossary for definitions. Values are final. See Technical Notes for a discussion of the sample design for the Form EIA-923.

Negative generation denotes that electric power consumed for plant use exceeds gross generation.

Totals may not equal sum of components because of independent rounding. Percentage change is calculated before rounding.

Source: U.S. Energy Information Administration, Form EIA-923, Power Plant Operations Report.

Table 3.16. Utility Scale Facility Net Generation from Hydroelectric (Pumped Storage) Power
by State, by Sector, 2024 and 2023 (Thousand Megawatthours)

Census Division and State	All Sectors			Electric Power Sector				Commercial Sector		Industrial Sector	
				Electric Utilities		Independent Power Producers					
	Generation at Utility Scale Facilities			Generation at Utility Scale Facilities		Generation at Utility Scale Facilities		Generation at Utility Scale Facilities		Generation at Utility Scale Facilities	
	Year 2024	Year 2023	Percentage Change	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023
New England	-479	-375	27.7%	0	0	-479	-375	0	0	0	0
Connecticut	5	5	-0.2%	0	0	5	5	0	0	0	0
Maine	0	0	--	0	0	0	0	0	0	0	0
Massachusetts	-483	-379	27.4%	0	0	-483	-379	0	0	0	0
New Hampshire	0	0	--	0	0	0	0	0	0	0	0
Rhode Island	0	0	--	0	0	0	0	0	0	0	0
Vermont	0	0	--	0	0	0	0	0	0	0	0
Middle Atlantic	-1,550	-1,442	7.5%	-410	-372	-1,141	-1,070	0	0	0	0
New Jersey	-232	-165	40.3%	0	0	-232	-165	0	0	0	0
New York	-410	-372	10.1%	-410	-372	0	0	0	0	0	0
Pennsylvania	-909	-905	0.4%	0	0	-909	-905	0	0	0	0
East North Central	-976	-810	20.5%	-976	-810	0	0	0	0	0	0
Illinois	0	0	--	0	0	0	0	0	0	0	0
Indiana	0	0	--	0	0	0	0	0	0	0	0
Michigan	-976	-810	20.5%	-976	-810	0	0	0	0	0	0
Ohio	0	0	--	0	0	0	0	0	0	0	0
Wisconsin	0	0	--	0	0	0	0	0	0	0	0
West North Central	147	-49	-400.6%	147	-49	0	0	0	0	0	0
Iowa	0	0	--	0	0	0	0	0	0	0	0
Kansas	0	0	--	0	0	0	0	0	0	0	0
Minnesota	0	0	--	0	0	0	0	0	0	0	0
Missouri	147	-49	-400.6%	147	-49	0	0	0	0	0	0
Nebraska	0	0	--	0	0	0	0	0	0	0	0
North Dakota	0	0	--	0	0	0	0	0	0	0	0
South Dakota	0	0	--	0	0	0	0	0	0	0	0
South Atlantic	-2,544	-2,573	-1.1%	-2,544	-2,573	0	0	0	0	0	0
Delaware	0	0	--	0	0	0	0	0	0	0	0
District of Columbia	0	0	--	0	0	0	0	0	0	0	0
Florida	0	0	--	0	0	0	0	0	0	0	0
Georgia	-760	-664	14.5%	-760	-664	0	0	0	0	0	0
Maryland	0	0	--	0	0	0	0	0	0	0	0
North Carolina	0	0	--	0	0	0	0	0	0	0	0
South Carolina	-251	-454	-44.8%	-251	-454	0	0	0	0	0	0
Virginia	-1,533	-1,455	5.3%	-1,533	-1,455	0	0	0	0	0	0
West Virginia	0	0	--	0	0	0	0	0	0	0	0
East South Central	-571	-554	3.1%	-571	-554	0	0	0	0	0	0
Alabama	0	0	--	0	0	0	0	0	0	0	0
Kentucky	0	0	--	0	0	0	0	0	0	0	0
Mississippi	0	0	--	0	0	0	0	0	0	0	0
Tennessee	-571	-554	3.1%	-571	-554	0	0	0	0	0	0
West South Central	29	47	-38.9%	29	47	0	0	0	0	0	0
Arkansas	77	101	-23.9%	77	101	0	0	0	0	0	0
Louisiana	0	0	--	0	0	0	0	0	0	0	0
Oklahoma	-48	-53	-10.4%	-48	-53	0	0	0	0	0	0
Texas	0	0	--	0	0	0	0	0	0	0	0
Mountain	136	161	-15.9%	136	161	0	0	0	0	0	0
Arizona	69	136	-49.6%	69	136	0	0	0	0	0	0
Colorado	67	25	167.6%	67	25	0	0	0	0	0	0
Idaho	0	0	--	0	0	0	0	0	0	0	0
Montana	0	0	--	0	0	0	0	0	0	0	0
Nevada	0	0	--	0	0	0	0	0	0	0	0
New Mexico	0	0	--	0	0	0	0	0	0	0	0
Utah	0	0	--	0	0	0	0	0	0	0	0
Wyoming	0	0	--	0	0	0	0	0	0	0	0
Pacific Contiguous	-44	-396	-88.9%	-44	-396	0	0	0	0	0	0
California	-46	-393	-88.4%	-46	-393	0	0	0	0	0	0
Oregon	0	0	--	0	0	0	0	0	0	0	0
Washington	2	-3	-156.3%	2	-3	0	0	0	0	0	0
Pacific Noncontiguous	0	0	--	0	0	0	0	0	0	0	0
Alaska	0	0	--	0	0	0	0	0	0	0	0
Hawaii	0	0	--	0	0	0	0	0	0	0	0
U.S. Total	-5,852	-5,990	-2.3%	-4,232	-4,545	-1,619	-1,445	0	0	0	0

Displayed values of zero may represent small values that round to zero. The Excel version of this table provides additional precision which may be accessed by selecting individual cells.

NM = Not meaningful due to large relative standard error or excessive percentage change.

Notes: See Glossary for definitions. Values are final. See Technical Notes for a discussion of the sample design for the Form EIA-923.

Negative generation denotes that electric power consumed for plant use exceeds gross generation.

Totals may not equal sum of components because of independent rounding. Percentage change is calculated before rounding.

Source: U.S. Energy Information Administration, Form EIA-923, Power Plant Operations Report.

Table 3.17. Utility Scale Facility Net Generation from Other Energy Sources
by State, by Sector, and 2024 and 2023 (Thousand Megawatthours)

Census Division and State	All Sectors			Electric Power Sector				Commercial Sector		Industrial Sector	
				Electric Utilities		Independent Power Producers					
	Generation at Utility Scale Facilities			Generation at Utility Scale Facilities		Generation at Utility Scale Facilities		Generation at Utility Scale Facilities		Generation at Utility Scale Facilities	
	Year 2024	Year 2023	Percentage Change	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023
New England	1,671	1,686	-0.9%	2	2	1,031	1,031	500	518	139	136
Connecticut	424	429	-1.2%	0	0	424	429	0	0	0	0
Maine	280	276	1.7%	0	0	136	131	5	9	139	136
Massachusetts	917	928	-1.2%	-1	-1	423	420	494	509	0	0
New Hampshire	50	51	-2.9%	0	0	50	51	0	0	0	0
Rhode Island	0	0	8.0%	0	0	0	0	0	0	0	0
Vermont	1	3	-63.7%	2	3	-1	0	0	0	0	0
Middle Atlantic	2,462	2,377	3.6%	-2	0	962	1,005	1,429	1,350	73	22
New Jersey	607	554	9.5%	0	0	120	127	414	405	73	22
New York	997	949	5.0%	-2	0	200	206	799	743	0	0
Pennsylvania	858	874	-1.8%	0	0	643	672	216	202	0	0
East North Central	782	977	-20.0%	19	95	30	76	54	51	679	755
Illinois	233	256	-8.8%	0	0	-5	-9	0	0	239	265
Indiana	432	482	-10.4%	-2	0	0	0	0	0	434	482
Michigan	94	138	-32.3%	0	0	40	87	54	51	0	0
Ohio	1	6	-77.8%	-1	0	-5	-2	0	0	6	8
Wisconsin	22	95	-76.9%	22	95	0	0	0	0	0	0
West North Central	353	344	2.4%	159	163	148	143	40	36	5	3
Iowa	-1	0	NM	-1	0	0	0	0	0	0	0
Kansas	5	3	60.0%	0	0	0	0	0	0	5	3
Minnesota	311	303	2.4%	122	125	148	143	40	36	0	0
Missouri	0	0	-	0	0	0	0	0	0	0	0
Nebraska	0	0	92.6%	0	0	0	0	0	0	0	0
North Dakota	38	38	-1.1%	38	38	0	0	0	0	0	0
South Dakota	0	0	-	0	0	0	0	0	0	0	0
South Atlantic	3,206	3,508	-8.6%	-38	-39	1,149	1,221	900	1,014	1,196	1,313
Delaware	0	0	-	0	0	0	0	0	0	0	0
District of Columbia	0	0	-	0	0	0	0	0	0	0	0
Florida	2,106	2,366	-11.0%	-26	-38	818	923	471	535	843	946
Georgia	83	86	-3.8%	-2	0	-4	-5	0	0	89	91
Maryland	338	312	8.2%	0	0	338	312	0	0	0	0
North Carolina	220	235	-6.7%	-5	-1	0	0	0	0	225	237
South Carolina	45	44	2.2%	0	0	7	5	0	0	39	40
Virginia	422	477	-11.6%	-4	0	-2	-2	428	478	0	0
West Virginia	-8	-14	-45.3%	0	0	-8	-14	0	0	0	0
East South Central	16	92	-82.8%	12	91	-4	0	0	0	8	0
Alabama	7	0	NM	0	0	0	0	0	0	7	0
Kentucky	12	91	-87.1%	12	91	0	0	0	0	0	0
Mississippi	-4	0	-	0	0	-4	0	0	0	0	0
Tennessee	0	0	-1.0%	0	0	0	0	0	0	0	0
West South Central	340	762	-55.4%	226	245	-343	-89	-4	-10	461	615
Arkansas	7	6	11.3%	0	0	0	0	-1	-1	8	7
Louisiana	452	501	-9.8%	201	219	0	0	0	0	251	282
Oklahoma	21	18	11.6%	26	28	-2	0	-3	-9	0	0
Texas	-140	236	-159.5%	-1	-1	-341	-89	0	0	202	326
Mountain	211	432	-51.1%	-26	66	-82	112	-3	0	322	254
Arizona	-224	-40	466.6%	-33	-6	-191	-33	0	0	0	0
Colorado	-4	25	-116.5%	-12	0	-37	-20	-3	0	48	45
Idaho	69	72	-4.8%	-1	0	0	0	0	0	70	72
Montana	256	224	14.4%	0	0	256	224	0	0	0	0
Nevada	-118	-13	805.1%	-17	28	-101	-41	0	0	0	0
New Mexico	-10	-19	-48.6%	-2	-1	-8	-18	0	0	0	0
Utah	153	98	55.2%	39	46	0	0	0	0	114	53
Wyoming	90	84	6.8%	0	0	0	0	0	0	90	84
Pacific Contiguous	-1,027	-390	163.5%	-62	-38	-1,240	-671	29	49	245	271
California	-1,113	-482	130.7%	-61	-39	-1,326	-763	29	49	245	271
Oregon	13	23	-42.6%	0	0	14	24	0	0	0	0
Washington	72	69	4.4%	0	1	73	69	0	0	0	0
Pacific Noncontiguous	156	170	-8.1%	-5	-4	-25	-4	186	178	0	0
Alaska	-5	-4	6.0%	-5	-4	0	0	0	0	0	0
Hawaii	161	174	-7.7%	0	0	-25	-4	186	178	0	0
U.S. Total	8,170	9,957	-17.9%	285	580	1,627	2,823	3,130	3,185	3,127	3,369

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Negative generation denotes that electric power consumed for plant use exceeds gross generation.

Totals may not equal sum of components because of independent rounding. Percentage change is calculated before rounding.

Source: U.S. Energy Information Administration, Form EIA-923, Power Plant Operations Report.

Table 3.18. Utility Scale Facility Net Generation from Wind
by State, by Sector, 2024 and 2023 (Thousand Megawatthours)

Census Division and State	All Sectors			Electric Power Sector				Commercial Sector		Industrial Sector	
				Electric Utilities		Independent Power Producers					
				Generation at Utility Scale Facilities		Generation at Utility Scale Facilities		Generation at Utility Scale Facilities		Generation at Utility Scale Facilities	
	Year 2024	Year 2023	Percentage Change	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023
New England	3,604	3,450	4.5%	204	202	3,377	3,223	23	25	0	0
Connecticut	10	10	5.7%	0	0	10	10	0	0	0	0
Maine	2,446	2,339	4.6%	0	0	2,446	2,339	0	0	0	0
Massachusetts	169	182	-6.9%	32	37	119	125	17	19	0	0
New Hampshire	445	411	8.1%	0	0	445	411	0	0	0	0
Rhode Island	178	169	5.5%	0	0	172	163	6	6	0	0
Vermont	355	340	4.6%	171	165	184	175	0	0	0	0
Middle Atlantic	9,307	8,076	15.2%	0	232	9,303	7,840	3	3	2	1
New Jersey	19	18	5.2%	0	0	19	18	0	0	0	0
New York	6,031	4,800	25.7%	0	232	6,027	4,563	3	3	2	1
Pennsylvania	3,257	3,258	-0.1%	0	0	3,257	3,258	0	0	0	0
East North Central	49,877	43,502	14.7%	7,474	5,903	42,310	37,483	28	24	66	92
Illinois	24,910	21,808	14.2%	6	10	24,900	21,797	4	1	0	0
Indiana	10,312	8,844	16.6%	228	0	10,084	8,844	0	0	0	0
Michigan	9,839	8,292	18.6%	5,873	4,742	3,966	3,551	0	0	0	0
Ohio	2,822	169	0.1%	4	5	2,755	2,726	2	3	61	86
Wisconsin	1,994	1,738	14.7%	1,362	1,147	605	564	22	20	5	7
West North Central	134,372	125,583	7.0%	51,351	48,134	82,970	77,404	39	34	12	11
Iowa	44,277	41,439	6.8%	31,993	30,030	12,282	11,407	2	2	0	0
Kansas	29,795	27,273	9.2%	2,682	2,530	27,088	24,718	13	13	12	11
Minnesota	14,781	14,398	2.7%	6,397	6,160	8,360	8,220	24	19	0	0
Missouri	6,790	6,775	0.2%	2,676	2,777	4,114	3,998	0	0	0	0
Nebraska	11,891	11,845	0.4%	62	87	11,829	11,758	0	0	0	0
North Dakota	14,763	14,477	2.0%	5,114	5,155	9,648	9,321	0	0	0	0
South Dakota	12,074	9,376	28.8%	2,426	1,395	9,648	7,981	0	0	0	0
South Atlantic	3,144	3,151	-0.2%	50	47	3,091	3,100	3	4	0	0
Delaware	3	4	-36.8%	0	0	0	0	3	4	0	0
District of Columbia	0	0	--	0	0	0	0	0	0	0	0
Florida	0	0	--	0	0	0	0	0	0	0	0
Georgia	0	0	--	0	0	0	0	0	0	0	0
Maryland	558	482	15.9%	0	0	558	482	0	0	0	0
North Carolina	530	529	0.2%	0	0	530	529	0	0	0	0
South Carolina	0	0	--	0	0	0	0	0	0	0	0
Virginia	50	47	7.0%	50	47	0	0	0	0	0	0
West Virginia	2,003	2,089	-4.1%	0	0	2,003	2,089	0	0	0	0
East South Central	360	16	NM	0	0	360	16	0	0	0	0
Alabama	0	0	--	0	0	0	0	0	0	0	0
Kentucky	0	0	--	0	0	0	0	0	0	0	0
Mississippi	347	0	--	0	0	347	0	0	0	0	0
Tennessee	13	16	-18.7%	0	0	13	16	0	0	0	0
West South Central	162,244	156,867	3.4%	9,151	6,861	153,061	149,975	33	32	0	0
Arkansas	0	0	--	0	0	0	0	0	0	0	0
Louisiana	0	0	--	0	0	0	0	0	0	0	0
Oklahoma	37,967	37,012	2.6%	6,820	6,669	31,147	30,344	0	0	0	0
Texas	124,278	119,855	3.7%	2,331	193	121,914	119,631	33	32	0	0
Mountain	54,179	49,227	10.1%	14,029	12,980	40,147	36,243	0	1	3	2
Arizona	2,540	1,733	46.6%	0	0	2,540	1,733	0	0	0	0
Colorado	17,602	16,091	9.4%	4,415	4,243	13,184	11,846	0	0	3	2
Idaho	3,016	2,320	30.0%	167	149	2,849	2,170	0	0	0	0
Montana	5,815	4,557	27.6%	1,729	951	4,086	3,606	0	0	0	0
Nevada	319	291	9.6%	0	0	319	291	0	0	0	0
New Mexico	15,136	14,914	1.5%	2,943	2,691	12,193	12,222	0	1	0	0
Utah	748	683	9.5%	0	0	748	683	0	0	0	0
Wyoming	9,002	8,637	4.2%	4,774	4,945	4,227	3,691	0	0	0	0
Pacific Contiguous	34,031	30,522	11.5%	6,727	5,699	27,281	24,812	6	7	16	5
California	15,648	14,019	11.6%	755	579	14,871	13,428	6	7	16	5
Oregon	9,519	8,954	6.3%	1,580	1,462	7,939	7,491	0	0	0	0
Washington	8,863	7,550	17.4%	4,392	3,657	4,472	3,892	0	0	0	0
Pacific Noncontiguous	787	746	5.5%	70	61	717	684	0	0	0	0
Alaska	123	111	10.8%	70	61	53	50	0	0	0	0
Hawaii	663	634	4.6%	0	0	663	634	0	0	0	0
U.S. Total	451,904	421,141	7.3%	89,056	80,120	362,616	340,780	133	130	99	112

Displayed values of zero may represent small values that round to zero. The Excel version of this table provides additional precision which may be accessed by selecting individual cells.
NM = Not meaningful due to large relative standard error or excessive percentage change.

Notes: See Glossary for definitions. Values are final. See Technical Notes for a discussion of the sample design for the Form EIA-923.

Negative generation denotes that electric power consumed for plant use exceeds gross generation.

Totals may not equal sum of components because of independent rounding. Percentage change is calculated before rounding.

Source: U.S. Energy Information Administration, Form EIA-923, Power Plant Operations Report.

Table 3.19. Utility Scale Facility Net Generation from Biomass
by State, by Sector, 2024 and 2023 (Thousand Megawatthours)

Census Division and State	All Sectors			Electric Power Sector				Commercial Sector		Industrial Sector	
				Electric Utilities		Independent Power Producers					
				Generation at Utility Scale Facilities		Generation at Utility Scale Facilities		Generation at Utility Scale Facilities		Generation at Utility Scale Facilities	
	Year 2024	Year 2023	Percentage Change	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023
New England	4,379	4,392	-0.3%	246	236	2,989	3,049	475	489	669	618
Connecticut	551	591	-6.7%	0	0	551	591	0	0	0	0
Maine	1,644	1,458	12.7%	0	0	970	833	4	7	669	618
Massachusetts	925	914	1.2%	0	0	493	471	432	443	0	0
New Hampshire	664	779	-14.7%	0	0	628	742	36	37	0	0
Rhode Island	197	247	-20.4%	0	0	197	247	0	0	0	0
Vermont	398	403	-1.4%	246	236	150	166	2	1	0	0
Middle Atlantic	3,739	3,830	-2.4%	0	0	2,088	2,215	1,214	1,149	436	465
New Jersey	657	671	-2.1%	0	0	312	335	345	335	0	0
New York	1,593	1,627	-2.1%	0	0	786	869	658	612	149	146
Pennsylvania	1,489	1,532	-2.8%	0	0	990	1,011	212	201	288	319
East North Central	3,721	3,873	-3.9%	631	640	1,949	2,137	84	96	1,057	1,000
Illinois	224	242	-7.4%	75	83	149	159	0	0	0	0
Indiana	183	254	-28.0%	94	154	42	57	0	0	47	43
Michigan	1,937	2,023	-4.2%	0	0	1,304	1,462	44	42	589	519
Ohio	292	324	-9.9%	0	0	137	154	8	8	147	162
Wisconsin	1,085	1,030	5.3%	461	403	317	305	32	46	275	276
West North Central	1,645	1,616	1.8%	239	249	479	490	152	147	775	729
Iowa	217	209	3.8%	28	31	103	101	7	6	80	71
Kansas	56	66	-15.3%	0	0	56	66	0	0	0	0
Minnesota	1,165	1,135	2.6%	118	129	289	285	85	83	673	638
Missouri	106	99	6.7%	23	17	31	39	48	40	3	3
Nebraska	82	90	-9.1%	69	72	0	0	13	18	0	0
North Dakota	0	0	--	0	0	0	0	0	0	0	0
South Dakota	20	17	19.2%	0	0	0	0	0	0	20	17
South Atlantic	15,438	15,325	0.7%	1,390	1,491	4,771	5,095	815	912	8,462	7,827
Delaware	42	66	-37.1%	0	0	27	53	0	0	15	13
District of Columbia	56	58	-3.6%	0	0	0	0	56	58	0	0
Florida	2,965	3,124	-5.1%	330	366	969	1,056	396	450	1,271	1,251
Georgia	5,366	4,951	8.4%	0	0	1,785	1,798	0	0	3,581	3,153
Maryland	333	322	3.3%	0	0	333	319	0	3	0	0
North Carolina	1,454	1,692	-14.1%	0	0	534	668	0	0	920	1,024
South Carolina	1,827	1,741	4.9%	52	67	351	412	0	0	1,424	1,263
Virginia	3,388	3,361	0.8%	1,009	1,058	764	779	364	401	1,251	1,123
West Virginia	8	9	-16.2%	0	0	8	9	0	0	0	0
East South Central	5,414	5,380	0.6%	86	81	135	107	0	0	5,193	5,192
Alabama	3,267	3,171	3.0%	0	0	37	41	0	0	3,230	3,129
Kentucky	394	418	-5.7%	86	81	12	8	0	0	296	329
Mississippi	1,281	1,339	-4.4%	0	0	7	8	0	0	1,274	1,332
Tennessee	471	452	4.3%	0	0	79	50	0	0	393	402
West South Central	4,018	4,247	-5.4%	190	250	258	305	-3	-7	3,572	3,700
Arkansas	792	713	11.0%	0	0	27	27	0	0	765	687
Louisiana	1,978	1,988	-0.5%	0	0	78	84	0	0	1,900	1,904
Oklahoma	332	265	25.2%	0	0	17	17	-3	-7	317	256
Texas	916	1,280	-28.4%	190	250	136	177	0	0	590	853
Mountain	860	957	-10.1%	38	25	466	536	46	44	310	352
Arizona	184	193	-4.5%	0	0	184	193	0	0	0	0
Colorado	88	134	-34.1%	0	0	88	134	0	0	0	0
Idaho	405	444	-8.7%	20	17	56	64	37	31	292	332
Montana	35	27	27.5%	18	8	0	0	0	0	17	20
Nevada	52	54	-2.8%	0	0	52	54	0	0	0	0
New Mexico	25	13	92.8%	0	0	25	13	0	0	0	0
Utah	70	92	-23.9%	0	0	61	79	9	14	0	0
Wyoming	0	0	--	0	0	0	0	0	0	0	0
Pacific Contiguous	6,947	7,253	-4.2%	401	420	3,682	3,911	763	787	2,101	2,135
California	4,750	5,062	-6.2%	48	47	3,220	3,518	720	749	761	749
Oregon	1,087	924	17.6%	60	65	370	303	33	31	623	526
Washington	1,110	1,267	-12.4%	292	309	92	90	10	7	716	860
Pacific Noncontiguous	262	327	-19.9%	19	19	48	124	195	184	0	0
Alaska	43	39	10.5%	0	0	0	0	43	39	0	0
Hawaii	219	288	-24.0%	19	19	48	124	152	145	0	0
U.S. Total	46,422	47,199	-1.6%	3,239	3,411	16,865	17,970	3,742	3,800	22,575	22,018

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NM = Not meaningful due to large relative standard error or excessive percentage change.

Notes: See Glossary for definitions. Values are final. See Technical Notes for a discussion of the sample design for the Form EIA-923.

Negative generation denotes that electric power consumed for plant use exceeds gross generation.

Totals may not equal sum of components because of independent rounding. Percentage change is calculated before rounding.

Source: U.S. Energy Information Administration, Form EIA-923, Power Plant Operations Report.

Table 3.20. Utility Scale Facility Net Generation from Geothermal
by State, by Sector, 2024 and 2023 (Thousand Megawatthours)

Census Division and State	All Sectors			Electric Power Sector				Commercial Sector		Industrial Sector	
				Electric Utilities		Independent Power Producers					
	Generation at Utility Scale Facilities			Generation at Utility Scale Facilities		Generation at Utility Scale Facilities		Generation at Utility Scale Facilities		Generation at Utility Scale Facilities	
	Year 2024	Year 2023	Percentage Change	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023
New England	0	0	--	0	0	0	0	0	0	0	0
Connecticut	0	0	--	0	0	0	0	0	0	0	0
Maine	0	0	--	0	0	0	0	0	0	0	0
Massachusetts	0	0	--	0	0	0	0	0	0	0	0
New Hampshire	0	0	--	0	0	0	0	0	0	0	0
Rhode Island	0	0	--	0	0	0	0	0	0	0	0
Vermont	0	0	--	0	0	0	0	0	0	0	0
Middle Atlantic	0	0	--	0	0	0	0	0	0	0	0
New Jersey	0	0	--	0	0	0	0	0	0	0	0
New York	0	0	--	0	0	0	0	0	0	0	0
Pennsylvania	0	0	--	0	0	0	0	0	0	0	0
East North Central	0	0	--	0	0	0	0	0	0	0	0
Illinois	0	0	--	0	0	0	0	0	0	0	0
Indiana	0	0	--	0	0	0	0	0	0	0	0
Michigan	0	0	--	0	0	0	0	0	0	0	0
Ohio	0	0	--	0	0	0	0	0	0	0	0
Wisconsin	0	0	--	0	0	0	0	0	0	0	0
West North Central	0	0	--	0	0	0	0	0	0	0	0
Iowa	0	0	--	0	0	0	0	0	0	0	0
Kansas	0	0	--	0	0	0	0	0	0	0	0
Minnesota	0	0	--	0	0	0	0	0	0	0	0
Missouri	0	0	--	0	0	0	0	0	0	0	0
Nebraska	0	0	--	0	0	0	0	0	0	0	0
North Dakota	0	0	--	0	0	0	0	0	0	0	0
South Dakota	0	0	--	0	0	0	0	0	0	0	0
South Atlantic	0	0	--	0	0	0	0	0	0	0	0
Delaware	0	0	--	0	0	0	0	0	0	0	0
District of Columbia	0	0	--	0	0	0	0	0	0	0	0
Florida	0	0	--	0	0	0	0	0	0	0	0
Georgia	0	0	--	0	0	0	0	0	0	0	0
Maryland	0	0	--	0	0	0	0	0	0	0	0
North Carolina	0	0	--	0	0	0	0	0	0	0	0
South Carolina	0	0	--	0	0	0	0	0	0	0	0
Virginia	0	0	--	0	0	0	0	0	0	0	0
West Virginia	0	0	--	0	0	0	0	0	0	0	0
East South Central	0	0	--	0	0	0	0	0	0	0	0
Alabama	0	0	--	0	0	0	0	0	0	0	0
Kentucky	0	0	--	0	0	0	0	0	0	0	0
Mississippi	0	0	--	0	0	0	0	0	0	0	0
Tennessee	0	0	--	0	0	0	0	0	0	0	0
West South Central	0	0	--	0	0	0	0	0	0	0	0
Arkansas	0	0	--	0	0	0	0	0	0	0	0
Louisiana	0	0	--	0	0	0	0	0	0	0	0
Oklahoma	0	0	--	0	0	0	0	0	0	0	0
Texas	0	0	--	0	0	0	0	0	0	0	0
Mountain	4,455	4,733	-5.9%	272	248	4,182	4,485	0	0	0	0
Arizona	0	0	--	0	0	0	0	0	0	0	0
Colorado	0	0	--	0	0	0	0	0	0	0	0
Idaho	92	89	3.9%	0	0	92	89	0	0	0	0
Montana	0	0	--	0	0	0	0	0	0	0	0
Nevada	3,886	4,150	-6.4%	0	0	3,886	4,150	0	0	0	0
New Mexico	26	36	-27.2%	0	0	26	36	0	0	0	0
Utah	451	458	-1.5%	272	248	179	210	0	0	0	0
Wyoming	0	0	--	0	0	0	0	0	0	0	0
Pacific Contiguous	10,693	11,442	-6.5%	642	534	10,052	10,908	0	0	0	0
California	10,524	11,266	-6.6%	642	534	9,883	10,732	0	0	0	0
Oregon	169	176	-4.0%	0	0	169	176	0	0	0	0
Washington	0	0	--	0	0	0	0	0	0	0	0
Pacific Noncontiguous	259	193	34.5%	0	0	259	193	0	0	0	0
Alaska	0	0	--	0	0	0	0	0	0	0	0
Hawaii	259	193	34.5%	0	0	259	193	0	0	0	0
U.S. Total	15,407	16,367	-5.9%	914	782	14,493	15,586	0	0	0	0

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Notes: See Glossary for definitions. Values are final. See Technical Notes for a discussion of the sample design for the Form EIA-923.

Negative generation denotes that electric power consumed for plant use exceeds gross generation.

Totals may not equal sum of components because of independent rounding. Percentage change is calculated before rounding.

Source: U.S. Energy Information Administration, Form EIA-923, Power Plant Operations Report.

Table 3.21. Net Generation from Solar Photovoltaic
by State, by Sector, 2024 and 2023 (Thousand Megawatthours)

Census Division and State	All Sectors										Electric Power Sector										Commercial Sector										Industrial Sector										Residential Sector																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																	
	Estimated Generation From Utility and Small Scale Facilities					Generation at Utility Scale Facilities					Estimated Small Scale Generation					Electric Utilities					Independent Power Producers					Estimated Generation From Utility and Small Scale Facilities					Generation at Utility Scale Facilities					Estimated Small Scale Generation					Estimated Generation From Utility and Small Scale Facilities					Generation at Utility Scale Facilities					Estimated Small Scale Generation					Estimated Small Scale Generation																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																		
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	Year 2024	Year 2023	Percentage Change	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024

Table 3.22. Utility Scale Facility Net Generation from Solar Thermal
by State, by Sector, 2024 and 2023 (Thousand Megawatthours)

Census Division and State	All Sectors			Electric Power Sector				Commercial Sector		Industrial Sector	
				Electric Utilities		Independent Power Producers					
	Generation at Utility Scale Facilities			Generation at Utility Scale Facilities		Generation at Utility Scale Facilities		Generation at Utility Scale Facilities		Generation at Utility Scale Facilities	
	Year 2024	Year 2023	Percentage Change	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023
New England	0	0	--	0	0	0	0	0	0	0	0
Connecticut	0	0	--	0	0	0	0	0	0	0	0
Maine	0	0	--	0	0	0	0	0	0	0	0
Massachusetts	0	0	--	0	0	0	0	0	0	0	0
New Hampshire	0	0	--	0	0	0	0	0	0	0	0
Rhode Island	0	0	--	0	0	0	0	0	0	0	0
Vermont	0	0	--	0	0	0	0	0	0	0	0
Middle Atlantic	0	0	--	0	0	0	0	0	0	0	0
New Jersey	0	0	--	0	0	0	0	0	0	0	0
New York	0	0	--	0	0	0	0	0	0	0	0
Pennsylvania	0	0	--	0	0	0	0	0	0	0	0
East North Central	0	0	--	0	0	0	0	0	0	0	0
Illinois	0	0	--	0	0	0	0	0	0	0	0
Indiana	0	0	--	0	0	0	0	0	0	0	0
Michigan	0	0	--	0	0	0	0	0	0	0	0
Ohio	0	0	--	0	0	0	0	0	0	0	0
Wisconsin	0	0	--	0	0	0	0	0	0	0	0
West North Central	0	0	--	0	0	0	0	0	0	0	0
Iowa	0	0	--	0	0	0	0	0	0	0	0
Kansas	0	0	--	0	0	0	0	0	0	0	0
Minnesota	0	0	--	0	0	0	0	0	0	0	0
Missouri	0	0	--	0	0	0	0	0	0	0	0
Nebraska	0	0	--	0	0	0	0	0	0	0	0
North Dakota	0	0	--	0	0	0	0	0	0	0	0
South Dakota	0	0	--	0	0	0	0	0	0	0	0
South Atlantic	0	0	--	0	0	0	0	0	0	0	0
Delaware	0	0	--	0	0	0	0	0	0	0	0
District of Columbia	0	0	--	0	0	0	0	0	0	0	0
Florida	0	0	--	0	0	0	0	0	0	0	0
Georgia	0	0	--	0	0	0	0	0	0	0	0
Maryland	0	0	--	0	0	0	0	0	0	0	0
North Carolina	0	0	--	0	0	0	0	0	0	0	0
South Carolina	0	0	--	0	0	0	0	0	0	0	0
Virginia	0	0	--	0	0	0	0	0	0	0	0
West Virginia	0	0	--	0	0	0	0	0	0	0	0
East South Central	0	0	--	0	0	0	0	0	0	0	0
Alabama	0	0	--	0	0	0	0	0	0	0	0
Kentucky	0	0	--	0	0	0	0	0	0	0	0
Mississippi	0	0	--	0	0	0	0	0	0	0	0
Tennessee	0	0	--	0	0	0	0	0	0	0	0
West South Central	0	0	--	0	0	0	0	0	0	0	0
Arkansas	0	0	--	0	0	0	0	0	0	0	0
Louisiana	0	0	--	0	0	0	0	0	0	0	0
Oklahoma	0	0	--	0	0	0	0	0	0	0	0
Texas	0	0	--	0	0	0	0	0	0	0	0
Mountain	1,073	946	13.4%	0	0	1,073	946	0	0	0	0
Arizona	828	775	6.9%	0	0	828	775	0	0	0	0
Colorado	0	0	--	0	0	0	0	0	0	0	0
Idaho	0	0	--	0	0	0	0	0	0	0	0
Montana	0	0	--	0	0	0	0	0	0	0	0
Nevada	245	172	42.8%	0	0	245	172	0	0	0	0
New Mexico	0	0	--	0	0	0	0	0	0	0	0
Utah	0	0	--	0	0	0	0	0	0	0	0
Wyoming	0	0	--	0	0	0	0	0	0	0	0
Pacific Contiguous	2,045	1,901	7.6%	0	0	2,045	1,901	0	0	0	0
California	2,045	1,901	7.6%	0	0	2,045	1,901	0	0	0	0
Oregon	0	0	--	0	0	0	0	0	0	0	0
Washington	0	0	--	0	0	0	0	0	0	0	0
Pacific Noncontiguous	0	0	--	0	0	0	0	0	0	0	0
Alaska	0	0	--	0	0	0	0	0	0	0	0
Hawaii	0	0	--	0	0	0	0	0	0	0	0
U.S. Total	3,118	2,847	9.5%	0	0	3,118	2,847	0	0	0	0

Displayed values of zero may represent small values that round to zero. The Excel version of this table provides additional precision which may be accessed by selecting individual cells.

NM = Not meaningful due to large relative standard error or excessive percentage change.

Notes: See Glossary for definitions. Values are final. See Technical Notes for a discussion of the sample design for the Form EIA-923.

Negative generation denotes that electric power consumed for plant use exceeds gross generation.

Totals may not equal sum of components because of independent rounding. Percentage change is calculated before rounding.

Source: U.S. Energy Information Administration, Form EIA-923, Power Plant Operations Report.

Table 3.23. Useful Thermal Output by Energy Source: Total Combined Heat and Power (All Sectors), 2014 - 2024
(Billion Btus)

Period	Coal	Petroleum Liquids	Petroleum Coke	Natural Gas	Other Fossil Gas	Renewable Sources	Other	Total
Annual Totals								
2014	232,509	11,990	23,457	545,624	104,869	624,086	21,390	1,563,923
2015	211,030	11,796	21,748	591,749	98,910	626,887	19,729	1,581,849
2016	220,162	8,607	20,122	785,413	148,881	698,858	25,342	1,907,384
2017	193,164	7,922	17,322	789,485	151,579	674,248	23,685	1,857,405
2018	182,373	9,878	16,581	813,127	172,677	663,644	23,169	1,881,448
2019	162,108	7,992	14,278	802,153	142,229	643,548	22,429	1,794,736
2020	139,423	6,463	12,359	835,666	135,048	602,034	20,901	1,751,893
2021	149,948	7,603	12,390	818,647	135,509	609,495	19,596	1,753,188
2022	146,782	16,516	11,793	805,556	133,148	587,576	18,475	1,719,846
2023	121,382	12,155	9,979	810,007	143,075	541,688	19,090	1,657,377
2024	114,656	8,211	10,262	835,189	146,260	532,926	18,733	1,666,236
Year 2022								
January	13,842	1,523	941	74,850	11,832	52,132	1,668	156,788
February	12,010	951	988	65,806	10,693	47,280	1,470	139,200
March	12,937	1,371	1,029	68,372	11,541	49,787	1,401	146,438
April	11,623	1,387	928	62,340	10,702	49,043	1,450	137,473
May	11,936	1,243	1,100	63,862	11,755	50,125	1,389	141,411
June	11,579	1,442	921	65,044	10,959	48,845	1,617	140,406
July	12,492	1,439	864	70,619	11,501	50,440	1,734	149,089
August	12,458	934	1,056	70,833	11,502	49,912	1,586	148,279
September	11,532	1,270	883	64,472	10,485	45,872	1,562	136,075
October	11,966	1,319	1,026	63,798	10,902	46,754	1,504	137,270
November	11,637	1,323	1,085	65,580	10,519	48,226	1,605	139,975
December	12,768	2,314	974	69,981	10,757	49,159	1,489	147,443
Year 2023								
January	12,058	1,558	685	70,919	11,903	50,312	1,575	149,009
February	10,343	1,551	465	64,348	10,823	44,130	1,477	133,137
March	10,805	1,196	1,037	69,034	12,139	48,554	1,525	144,290
April	9,472	1,383	913	62,551	11,606	42,243	1,403	129,571
May	9,975	625	975	63,680	11,946	45,258	1,448	133,906
June	9,422	611	839	66,229	11,959	41,360	1,535	131,955
July	10,386	659	817	70,460	12,273	43,700	1,556	139,852
August	9,582	802	884	69,535	12,304	44,606	1,572	139,284
September	9,534	779	871	66,880	12,504	43,397	1,381	135,347
October	9,351	739	848	65,086	12,537	43,637	1,383	133,581
November	9,933	981	809	68,719	11,043	46,833	2,065	140,383
December	10,522	1,271	837	72,566	12,038	47,659	2,169	147,062
Year 2024								
January	11,761	1,164	997	77,746	12,817	46,520	1,718	152,722
February	9,653	584	795	68,086	11,908	44,034	1,577	136,636
March	10,546	566	775	69,222	12,500	45,611	1,614	140,834
April	8,659	814	779	63,287	11,798	44,450	1,695	131,481
May	8,677	604	867	65,800	12,713	43,372	1,279	133,312
June	8,626	626	879	67,413	12,338	42,263	1,435	133,580
July	9,595	757	954	72,773	12,724	43,392	2,045	142,240
August	9,225	523	899	73,417	12,805	43,863	1,560	142,293
September	8,914	412	822	68,490	11,558	44,213	1,270	135,679
October	9,053	564	777	66,940	11,698	41,692	1,367	132,092
November	9,620	550	788	68,215	11,196	45,580	1,458	137,406
December	10,326	1,048	932	73,801	12,205	47,935	1,713	147,960

Coal includes anthracite, bituminous, subbituminous, lignite, and waste coal; synthetic coal and refined coal; and beginning in 2011, coal-derived synthesis gas. Prior to 2011 coal-derived synthesis gas was included in Other Fossil Gas.

Petroleum Liquids includes distillate and residual fuel oils, jet fuel, kerosene, waste oil, and beginning in 2011, propane. Prior to 2011 propane was included in Other Fossil Gas.

Petroleum Coke includes petroleum coke-derived synthesis gas. Prior to 2011, petroleum coke-derived synthesis gas was included in Other Fossil Gas.

Other Fossil Gas includes gaseous propane, blast furnace gas, other manufactured and waste gases derived from fossil fuels other than hydrogen. Prior to 2011, Other Fossil Gas included propane and synthesis gases.

See the Technical Notes for fuel conversion factors.

Renewable Sources include wood, black liquor, other wood waste, biogenic municipal solid waste, landfill gas, sludge waste, agriculture byproducts, other biomass, geothermal, and solar thermal.

Other includes hydrogen, non-biogenic municipal solid waste, batteries, purchased steam, sulfur, tire-derived fuel, and other miscellaneous energy sources.

Notes: Beginning with 2001 data, non-biogenic municipal solid waste and tire-derived fuels are reclassified as non-renewable energy sources and included in Other. Biogenic municipal solid waste is included in Other Renewable Sources.

Beginning with the collection of Form EIA-923 in January 2008, the methodology for separating the fuel used for electricity generation and useful thermal output from combined heat and power plants changed. The new methodology was retroactively applied to 2004-2007, as well as 2008-2015. Beginning with the 2016 Form EIA-923 data, the methodology for separating the fuel used for electricity generation and useful thermal output from CHP plants was updated. This update will apply to the 2016 data and future data years. See the Technical Notes (Appendix C) for further information.

See Glossary for definitions. Values are final. See Technical Notes for a discussion of the sample design for the Form EIA-923 and predecessor forms.

Totals may not equal sum of components because of independent rounding. NM=Not meaningful due to large standard error. W=Withheld to avoid disclosure of individual company data.

Sources: U.S. Energy Information Administration, Form EIA-923, Power Plant Operations Report; U.S. Energy Information Administration, Form EIA-906, Power Plant Report; U.S. Energy Information Administration, Form EIA-920 Combined Heat and Power Plant Report; and predecessor forms.

Beginning with 2008 data, the Form EIA-923, Power Plant Operations Report, replaced the following: 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 Federal Energy Regulatory Commission, FERC Form 423, Monthly Report of Cost and Quality of Fuels for Electric Plants.

Table 3.24. Useful Thermal Output by Energy Source: Electric Power Sector Combined Heat and Power, 2014 - 2024
(Billion Btus)

Period	Coal	Petroleum Liquids	Petroleum Coke	Natural Gas	Other Fossil Gas	Renewable Sources	Other	Total
Annual Totals								
2014	15,513	4,931	936	182,148	7,732	17,736	5,666	234,662
2015	16,036	4,894	1,143	178,167	7,161	16,999	5,180	229,580
2016	13,922	695	1,237	227,427	17,400	24,993	8,046	293,719
2017	11,269	627	1,267	192,299	17,798	24,279	7,422	254,961
2018	13,573	1,023	1,023	207,459	18,692	23,375	7,119	272,265
2019	12,759	655	1,019	197,106	19,684	26,057	7,544	264,823
2020	7,412	530	1,300	203,104	17,318	24,815	7,322	261,801
2021	6,793	891	1,180	191,119	16,931	22,963	5,547	245,424
2022	6,936	1,201	996	187,898	17,384	20,406	2,882	237,704
2023	4,653	982	1,208	188,431	17,627	19,046	3,244	235,191
2024	2,488	2,407	1,085	193,640	17,106	16,305	3,150	236,180
Year 2022								
January	674	213	89	17,433	1,426	2,155	278	22,268
February	637	55	109	15,602	1,380	1,874	224	19,881
March	742	104	99	16,051	1,420	1,863	210	20,489
April	611	77	87	13,952	1,648	1,563	235	18,171
May	533	78	85	14,840	1,825	1,323	229	18,913
June	475	83	68	15,765	1,497	1,492	248	19,628
July	488	69	14	17,425	1,467	1,601	285	21,350
August	568	71	85	16,961	1,407	1,603	264	20,959
September	541	81	85	15,310	1,403	1,546	215	19,182
October	539	92	88	14,489	1,350	1,529	229	18,317
November	582	99	89	14,166	1,161	1,865	200	18,162
December	546	179	98	15,903	1,399	1,993	265	20,384
Year 2023								
January	442	109	98	15,783	1,327	1,854	263	19,876
February	480	95	104	15,205	1,157	1,872	241	19,153
March	652	78	110	15,908	1,411	2,499	242	20,901
April	435	84	89	14,339	1,415	1,791	292	18,445
May	374	75	107	14,012	1,588	1,639	290	18,085
June	476	77	98	15,307	1,534	1,428	284	19,204
July	304	70	101	17,143	1,495	1,229	285	20,627
August	266	63	106	17,205	1,715	1,042	278	20,674
September	244	73	109	15,559	1,502	786	214	18,486
October	379	100	90	15,440	1,395	1,670	187	19,261
November	290	71	87	16,148	1,409	1,595	328	19,927
December	313	88	108	16,381	1,679	1,641	340	20,551
Year 2024								
January	290	239	100	17,376	1,477	1,786	349	21,616
February	258	77	87	15,881	1,167	1,532	287	19,289
March	317	79	99	16,072	1,576	1,470	296	19,910
April	193	319	72	13,883	1,435	1,330	260	17,492
May	231	196	79	15,182	1,189	1,144	242	18,264
June	189	138	108	16,097	1,516	1,000	235	19,283
July	166	401	107	17,927	1,386	1,183	249	21,420
August	144	211	125	18,422	1,495	1,194	272	21,863
September	146	77	84	16,736	1,375	1,172	206	19,795
October	162	111	8	15,860	1,596	1,201	213	19,151
November	144	126	85	14,604	1,356	1,568	183	18,067
December	247	432	130	15,601	1,538	1,725	358	20,030

Coal includes anthracite, bituminous, subbituminous, lignite, and waste coal; synthetic coal and refined coal; and beginning in 2011, coal-derived synthesis gas. Prior to 2011 coal-derived synthesis gas was included in Other Fossil Gas.

Petroleum Liquids includes distillate and residual fuel oils, jet fuel, kerosene, waste oil, and beginning in 2011, propane. Prior to 2011 propane was included in Other Fossil Gas.

Petroleum Coke includes petroleum coke-derived synthesis gas. Prior to 2011, petroleum coke-derived synthesis gas was included in Other Fossil Gas.

Other Fossil Gas includes gaseous propane, blast furnace gas, other manufactured and waste gases derived from fossil fuels other than hydrogen. Prior to 2011, Other Fossil Gas included propane and synthesis gases.

See the Technical Notes for fuel conversion factors.

Renewable Sources include wood, black liquor, other wood waste, biogenic municipal solid waste, landfill gas, sludge waste, agriculture byproducts, other biomass, geothermal, and solar thermal.

Other includes hydrogen, non-biogenic municipal solid waste, batteries, purchased steam, sulfur, tire-derived fuel, and other miscellaneous energy sources.

Notes: Beginning with 2001 data, non-biogenic municipal solid waste and tire-derived fuels are reclassified as non-renewable energy sources and included in Other. Biogenic municipal solid waste is included in Other Renewable Sources.

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

Table 3.25. Useful Thermal Output by Energy Source: Commercial Sector Combined Heat and Power, 2014 - 2024
(Billion Btus)

Period	Coal	Petroleum Liquids	Petroleum Coke	Natural Gas	Other Fossil Gas	Renewable Sources	Other	Total
Annual Totals								
2014	11,081	820	327	26,876	0	7,610	5,123	51,837
2015	7,966	823	325	26,498	0	8,228	5,641	49,482
2016	8,313	924	140	57,356	0	11,017	5,381	83,131
2017	7,360	806	234	71,149	0	10,762	5,140	95,450
2018	6,943	1,020	165	58,312	0	10,902	4,918	82,260
2019	6,211	1,346	95	56,356	0	8,307	3,335	75,650
2020	5,446	692	50	55,508	0	6,929	2,863	71,489
2021	5,975	820	88	50,047	0	6,377	2,825	66,132
2022	5,996	1,165	212	52,264	0	9,263	6,333	75,235
2023	4,334	908	50	49,140	0	8,717	6,303	69,453
2024	4,668	1,022	81	57,762	0	8,711	6,342	78,586
Year 2022								
January	682	303	27	5,178	0	834	561	7,584
February	652	81	25	4,604	0	761	485	6,606
March	438	97	27	4,509	0	745	487	6,303
April	298	75	23	4,035	0	663	483	5,576
May	304	75	29	3,921	0	779	542	5,651
June	428	38	26	4,061	0	865	557	5,975
July	487	68	19	4,727	0	848	591	6,738
August	496	60	0	4,787	0	878	591	6,812
September	503	29	5	4,021	0	743	537	5,838
October	499	37	0	3,770	0	665	475	5,447
November	571	48	11	3,980	0	781	560	5,951
December	639	255	21	4,671	0	702	465	6,752
Year 2023								
January	557	133	22	4,468	0	755	493	6,429
February	483	99	5	4,079	0	661	492	5,819
March	439	65	3	4,170	0	748	526	5,952
April	382	26	0	3,616	0	672	502	5,197
May	287	29	0	3,656	0	668	570	5,209
June	263	43	0	3,848	0	739	498	5,390
July	280	40	0	4,419	0	691	543	5,973
August	295	36	0	4,203	0	787	579	5,900
September	296	42	0	4,063	0	770	520	5,691
October	268	40	0	3,941	0	660	430	5,338
November	359	74	0	4,276	0	731	547	5,987
December	425	282	20	4,400	0	836	604	6,567
Year 2024								
January	721	214	21	5,683	0	841	571	8,051
February	531	102	9	4,993	0	724	550	6,909
March	397	115	0	4,790	0	685	540	6,527
April	346	80	0	4,098	0	546	404	5,474
May	225	98	16	3,809	0	710	540	5,398
June	299	188	18	4,525	0	741	541	6,311
July	307	26	0	5,295	0	825	573	7,026
August	327	18	0	5,176	0	671	477	6,669
September	327	18	0	4,627	0	740	507	6,219
October	334	26	0	4,547	0	706	539	6,152
November	406	46	0	4,815	0	734	545	6,545
December	448	91	18	5,405	0	788	556	7,305

Coal includes anthracite, bituminous, subbituminous, lignite, and waste coal; synthetic coal and refined coal; and beginning in 2011, coal-derived synthesis gas. Prior to 2011 coal-derived synthesis gas was included in Other Fossil Gas.

Petroleum Liquids includes distillate and residual fuel oils, jet fuel, kerosene, waste oil, and beginning in 2011, propane. Prior to 2011 propane was included in Other Fossil Gas.

Petroleum Coke includes petroleum coke-derived synthesis gas. Prior to 2011, petroleum coke-derived synthesis gas was included in Other Fossil Gas.

Other Fossil Gas includes gaseous propane, blast furnace gas, other manufactured and waste gases derived from fossil fuels other than hydrogen. Prior to 2011, Other Fossil Gas included propane and synthesis gases.

See the Technical Notes for fuel conversion factors.

Renewable Sources include wood, black liquor, other wood waste, biogenic municipal solid waste, landfill gas, sludge waste, agriculture byproducts, other biomass, geothermal, and solar thermal.

Other includes hydrogen, non-biogenic municipal solid waste, batteries, purchased steam, sulfur, tire-derived fuel, and other miscellaneous energy sources.

Notes: Beginning with 2001 data, non-biogenic municipal solid waste and tire-derived fuels are reclassified as non-renewable energy sources and included in Other. Biogenic municipal solid waste is included in Other Renewable Sources.

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Table 3.26. Useful Thermal Output by Energy Source: Industrial Sector Combined Heat and Power, 2014 - 2024
(Billion Btus)

Period	Coal	Petroleum Liquids	Petroleum Coke	Natural Gas	Other Fossil Gas	Renewable Sources	Other	Total
Annual Totals								
2014	199,512	6,120	22,167	334,901	97,137	596,087	10,600	1,266,524
2015	180,501	5,965	20,203	384,369	91,749	598,890	8,899	1,290,576
2016	173,589	6,792	18,692	478,068	131,481	655,831	11,904	1,476,358
2017	151,780	6,289	15,721	503,614	133,781	631,768	11,112	1,454,066
2018	142,671	7,535	15,281	521,936	153,985	622,699	11,118	1,475,224
2019	127,411	5,787	13,012	523,919	122,544	607,138	11,535	1,411,347
2020	114,031	5,078	10,863	548,938	117,730	568,537	10,702	1,375,879
2021	120,335	5,658	10,933	547,717	118,578	578,150	11,208	1,392,579
2022	116,212	13,837	10,375	537,793	115,764	555,335	9,245	1,358,561
2023	100,884	10,076	8,645	545,036	125,448	511,656	9,521	1,311,266
2024	97,987	4,589	9,094	554,896	129,154	505,459	9,238	1,310,416
Year 2022								
January	10,800	927	810	49,490	10,406	48,935	827	122,194
February	9,296	774	779	43,261	9,313	44,432	760	108,616
March	10,346	1,153	891	45,486	10,121	46,936	702	115,636
April	9,433	1,223	816	42,760	9,054	46,595	732	110,614
May	9,975	1,076	975	43,143	9,930	47,876	618	113,592
June	9,260	1,307	817	42,871	9,462	46,320	811	110,848
July	9,778	1,285	822	45,738	10,033	47,805	857	116,319
August	9,761	792	963	46,573	10,095	47,228	730	116,142
September	8,923	1,146	786	42,961	9,082	43,356	807	107,061
October	9,632	1,176	931	43,722	9,552	44,432	798	110,243
November	9,130	1,162	932	45,012	9,359	45,296	844	111,734
December	9,877	1,815	853	46,774	9,358	46,125	758	115,561
Year 2023								
January	9,826	1,296	559	48,140	10,576	47,447	816	118,660
February	8,491	1,334	345	42,775	9,666	41,382	742	104,735
March	8,685	1,041	905	46,609	10,728	45,062	756	113,786
April	7,998	1,260	802	42,614	10,191	39,561	609	103,034
May	8,452	500	868	44,063	10,358	42,904	585	107,730
June	7,826	478	740	44,839	10,425	39,045	752	104,105
July	8,597	534	709	46,224	10,778	41,615	726	109,184
August	7,843	691	771	45,820	10,589	42,588	712	109,013
September	7,959	655	760	45,007	11,002	41,743	646	107,772
October	7,928	581	757	43,791	11,142	41,115	765	106,078
November	8,436	821	721	45,921	9,634	44,267	1,189	110,989
December	8,845	886	708	49,233	10,359	44,926	1,223	116,179
Year 2024								
January	9,548	654	874	52,132	11,340	43,634	797	118,979
February	8,025	394	698	44,847	10,741	41,537	739	106,983
March	9,058	360	676	45,816	10,924	43,193	778	110,804
April	7,395	398	707	43,312	10,363	42,335	1,031	105,541
May	7,549	299	771	44,624	11,524	41,384	497	106,649
June	7,446	285	754	44,418	10,821	40,325	659	104,709
July	8,284	318	847	46,753	11,338	41,162	1,224	109,926
August	7,819	281	774	47,087	11,310	41,808	811	109,891
September	7,705	308	737	44,588	10,184	42,102	557	106,181
October	7,943	412	770	44,427	10,102	39,689	616	103,959
November	8,433	365	702	46,684	9,840	43,082	730	109,836
December	8,783	513	784	50,207	10,666	45,208	800	116,960

Coal includes anthracite, bituminous, subbituminous, lignite, and waste coal; synthetic coal and refined coal; and beginning in 2011, coal-derived synthesis gas. Prior to 2011 coal-derived synthesis gas was included in Other Fossil Gas.

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Petroleum Coke includes petroleum coke-derived synthesis gas. Prior to 2011, petroleum coke-derived synthesis gas was included in Other Fossil Gas.

Other Fossil Gas includes gaseous propane, blast furnace gas, other manufactured and waste gases derived from fossil fuels other than hydrogen. Prior to 2011, Other Fossil Gas included propane and synthesis gases.

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Renewable Sources include wood, black liquor, other wood waste, biogenic municipal solid waste, landfill gas, sludge waste, agriculture byproducts, other biomass, geothermal, and solar thermal.

Other includes hydrogen, non-biogenic municipal solid waste, batteries, purchased steam, sulfur, tire-derived fuel, and other miscellaneous energy sources.

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Table 3.27 Gross/Net Generation by Energy Storage Technology: Total (All Sectors), 2014 - 2024
(Thousand Megawatthours)

Period	Generation at Utility Scale Facilities									
	Gross Generation					Net Generation				
	Battery	Compressed Air	Flywheels	Hydroelectric Pumped Storage	Total	Battery	Compressed Air	Flywheels	Hydroelectric Pumped Storage	Total
Annual Totals										
2014	24	9	47	20,054	20,133	-14	-2	-21	-6,174	-6,210
2015	76	8	49	20,111	20,244	-20	-7	-24	-5,091	-5,142
2016	142	17	43	22,443	22,645	-170	-8	-22	-6,686	-6,886
2017	383	12	62	22,752	23,209	-69	-8	-26	-6,495	-6,597
2018	358	6	67	21,503	21,934	-88	-6	-28	-5,905	-6,026
2019	456	6	59	20,772	21,293	-97	-7	-26	-5,261	-5,391
2020	557	6	53	21,073	21,689	-131	-5	-24	-5,321	-5,482
2021	1,507	23	46	20,618	22,194	-264	-6	-23	-5,112	-5,404
2022	3,808	26	49	22,466	26,349	-689	-6	-23	-6,028	-6,746
2023	6,696	2	42	22,132	28,872	-1,281	-4	-20	-5,990	-7,294
2024	14,936	1	22	23,151	38,109	-2,399	-2	-16	-5,852	-8,269
Year 2022										
January	201	1	4	1,626	1,832	-33	0	-2	-493	-528
February	224	0	3	1,375	1,602	-40	0	-2	-412	-453
March	225	0	4	1,566	1,795	-39	0	-2	-318	-359
April	248	1	4	1,216	1,468	-40	0	-2	-265	-307
May	287	2	4	1,874	2,167	-53	-1	-2	-467	-522
June	322	4	4	2,461	2,791	-57	-1	-2	-589	-649
July	345	4	4	2,726	3,081	-66	-1	-2	-768	-838
August	348	5	4	2,812	3,169	-67	-1	-2	-640	-710
September	349	3	4	2,191	2,546	-68	-1	-2	-598	-668
October	423	3	4	1,442	1,872	-78	-1	-2	-434	-515
November	416	1	4	1,524	1,946	-75	0	-2	-495	-572
December	421	2	4	1,653	2,081	-72	-1	-2	-548	-623
Year 2023										
January	474	0	4	1,574	2,051	-76	0	-2	-620	-698
February	403	0	4	1,482	1,889	-98	0	-2	-456	-556
March	484	0	4	1,579	2,067	-118	0	-2	-519	-639
April	497	0	4	1,465	1,965	-85	0	-2	-290	-377
May	477	0	4	1,880	2,360	-82	0	-2	-459	-543
June	510	0	4	2,299	2,813	-94	-1	-2	-551	-647
July	576	0	3	2,707	3,287	-121	-1	-2	-656	-779
August	606	0	3	2,678	3,287	-116	-1	-2	-653	-771
September	599	0	3	2,213	2,815	-123	0	-2	-553	-677
October	703	0	3	1,496	2,202	-123	0	-2	-372	-497
November	687	0	3	1,378	2,068	-118	0	-1	-347	-466
December	680	0	3	1,383	2,066	-128	0	-2	-514	-643
Year 2024										
January	744	0	2	1,642	2,388	-129	0	-1	-414	-545
February	827	0	2	1,557	2,386	-126	0	-1	-404	-532
March	969	0	2	1,276	2,247	-148	0	-1	-349	-498
April	1,078	0	2	1,526	2,606	-158	0	-1	-338	-498
May	1,114	0	2	2,166	3,282	-177	0	-1	-284	-462
June	1,186	0	2	2,605	3,793	-209	0	-2	-579	-789
July	1,370	0	2	2,902	4,275	-224	0	-1	-639	-865
August	1,448	0	2	2,822	4,272	-239	0	-2	-798	-1,039
September	1,371	0	1	2,169	3,541	-228	0	-1	-637	-867
October	1,565	0	2	1,429	2,997	-261	0	-2	-439	-702
November	1,553	0	2	1,443	2,999	-237	0	-1	-490	-728
December	1,710	0	2	1,614	3,325	-261	0	-1	-481	-744

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Displayed values of zero may represent small values that round to zero. The Excel version of this table provides additional precision which may be accessed by selecting individual cells.

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Chapter 4

Generation Capacity

Table 4.1. Count of Electric Power Industry Power Plants, by Sector, by Predominant Energy Sources within Plant, 2014 through 2024

Year	Coal	Petroleum	Natural Gas	Other Fossil Gas	Nuclear	Hydroelectric Conventional	Other Renewables	Hydroelectric Pumped Storage	Other Energy Sources
Total (All Sectors)									
2014	491	1,082	1,749	43	62	1,441	2,674	41	94
2015	427	1,082	1,779	45	62	1,440	3,043	41	83
2016	381	1,076	1,801	45	61	1,451	3,624	40	117
2017	359	1,080	1,820	44	61	1,458	4,174	40	148
2018	336	1,087	1,854	46	60	1,458	4,667	40	171
2019	308	1,090	1,899	43	58	1,452	5,244	40	212
2020	284	1,091	1,926	42	56	1,446	5,918	40	267
2021	269	1,104	2,020	37	55	1,449	6,579	40	372
2022	242	1,084	2,073	33	54	1,445	7,084	40	483
2023	227	1,075	2,084	35	54	1,441	7,684	40	617
2024	219	1,065	2,078	34	56	1,433	8,503	39	791
Electric Utilities									
2014	286	780	803	1	32	889	272	35	20
2015	256	782	816	1	32	890	318	35	15
2016	230	771	819	1	31	893	375	35	36
2017	219	765	820	1	31	894	417	35	53
2018	206	751	819	1	31	896	462	35	60
2019	194	743	818	1	31	898	512	35	71
2020	181	743	820	1	31	892	586	35	78
2021	169	739	813	1	31	879	649	34	86
2022	157	726	835	1	31	875	709	34	104
2023	148	721	837	1	31	873	782	34	132
2024	145	717	844	1	31	867	899	33	175
Independent Power Producers, Non-Combined Heat and Power Plants									
2014	87	148	395	1	30	499	2,006	5	18
2015	80	143	397	--	30	497	2,309	5	21
2016	75	142	406	--	30	500	2,826	5	34
2017	71	145	415	--	30	505	3,320	5	43
2018	65	140	450	--	29	514	3,749	5	59
2019	59	141	476	--	27	506	4,251	5	74
2020	56	135	491	--	25	506	4,847	5	119
2021	56	150	521	--	24	521	5,429	6	214
2022	46	139	548	--	23	521	5,833	6	306
2023	43	135	562	--	23	520	6,359	6	409
2024	42	131	551	--	25	519	7,060	6	539
Independent Power Producers, Combined Heat and Power Plants									
2014	30	9	145	2	--	--	54	--	7
2015	27	8	143	3	--	--	58	--	3
2016	24	7	143	3	--	--	57	--	2
2017	22	7	138	3	--	--	56	--	3
2018	19	8	133	3	--	--	56	--	3
2019	14	6	128	3	--	--	56	--	3
2020	12	7	121	3	--	--	56	--	4
2021	11	8	122	3	--	--	52	--	4
2022	8	7	119	3	--	--	54	--	3
2023	8	7	118	3	--	--	52	--	3
2024	7	7	117	3	--	1	49	--	3
Commercial Sector									
2014	17	93	169	--	--	10	178	1	6
2015	12	94	176	--	--	10	186	1	3
2016	9	101	181	--	--	14	195	--	3
2017	9	112	189	--	--	15	203	--	4
2018	7	139	192	--	--	15	220	--	5
2019	6	152	203	--	--	15	242	--	20
2020	4	156	220	--	--	15	240	--	21
2021	4	160	281	--	--	16	255	--	24
2022	3	161	287	--	--	17	277	--	26
2023	3	163	285	--	--	17	278	--	28
2024	3	162	285	--	--	16	270	--	29
Industrial Sector									
2014	71	52	237	39	--	43	164	--	43
2015	52	55	247	41	--	43	172	--	41
2016	43	55	252	41	--	44	171	--	42
2017	38	51	258	40	--	44	178	--	45
2018	39	49	260	42	--	33	180	--	44
2019	35	48	274	39	--	33	183	--	44
2020	31	50	274	38	--	33	189	--	45
2021	29	47	283	33	--	33	194	--	44
2022	28	51	284	29	--	32	211	--	44
2023	25	49	282	31	--	31	213	--	45
2024	22	48	281	30	--	30	225	--	45

Notes: 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 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 sites. In addition, changes to predominant energy sources and status codes from year to year may result in changes to previously-posted data.

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. In 2011, EIA corrected the NAICS codes of several plants which resulted in a net capacity shift from the electric utility sector to the commercial sector.

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

Table 4.2.A. Existing Net Summer Capacity by Energy Source and Producer Type, 2014 through 2024 (Megawatts)

	Utility Scale Capacity										Small Scale Capacity
Year	Coal	Petroleum	Natural Gas	Other Fossil Gas	Nuclear	Hydroelectric Conventional	Other Renewable Sources	Hydroelectric Pumped Storage	Other Energy Sources	Utility Total	Estimated Photovoltaic
Total (All Sectors)											
2014	299,094.2	41,135.4	432,150.3	1,914.3	98,569.3	79,677.3	90,603.7	22,485.1	2,792.6	1,068,422.2	7,326.6
2015	279,719.9	36,830.3	439,425.4	2,500.4	98,672.0	79,664.2	102,871.6	22,575.1	1,795.6	1,064,054.5	9,778.5
2016	266,619.9	34,382.4	446,823.2	2,456.9	99,564.8	79,912.9	119,778.9	22,778.7	2,015.1	1,074,332.8	12,765.1
2017	256,547.3	33,306.7	456,011.6	2,375.8	99,628.9	79,794.5	131,008.1	22,810.4	2,886.3	1,084,369.6	16,147.8
2018	242,785.6	32,218.2	470,236.9	2,543.9	99,432.9	79,871.8	142,473.6	22,830.2	2,346.7	1,094,739.8	19,547.1
2019	228,657.4	31,400.3	476,567.4	2,499.2	98,119.0	79,773.1	156,708.2	22,778.3	2,606.4	1,099,109.3	23,213.6
2020	215,554.2	27,569.3	485,807.2	2,275.2	96,500.6	79,924.3	181,954.5	23,016.2	3,079.3	1,115,680.8	27,584.8
2021	209,825.7	28,204.5	491,870.2	1,888.0	95,546.4	79,909.7	209,292.6	23,007.7	6,311.3	1,145,856.1	33,081.0
2022	189,316.3	30,775.3	502,396.9	1,728.2	94,658.9	80,067.6	229,039.1	23,043.9	10,405.6	1,161,431.8	39,828.0
2023	178,441.7	29,440.7	507,535.8	1,866.8	95,712.2	79,985.3	253,964.6	23,147.4	17,450.9	1,187,545.4	47,774.7
2024	174,177.6	28,649.7	506,371.0	1,678.1	98,391.2	79,896.5	289,658.2	23,156.6	28,436.4	1,230,415.2	53,228.1
Electric Utilities											
2014	219,837.9	24,045.0	215,690.8	12.0	52,390.9	73,725.4	10,893.7	19,121.3	914.5	616,631.5	--
2015	202,922.4	22,269.7	223,215.6	12.0	52,457.2	73,713.0	12,654.3	19,211.3	87.5	606,543.0	--
2016	193,122.6	20,285.5	229,677.1	12.0	53,274.1	73,879.3	14,236.4	19,398.3	236.1	604,121.4	--
2017	186,623.1	19,999.9	236,557.8	12.0	53,343.6	73,739.5	15,281.3	19,430.0	519.3	605,506.5	--
2018	179,047.8	18,642.6	241,477.0	12.0	53,725.6	73,818.2	18,155.9	19,449.8	341.8	604,670.7	--
2019	171,088.7	18,219.8	247,018.9	12.0	53,880.6	73,719.7	20,745.8	19,428.9	418.3	604,532.7	--
2020	163,886.7	14,723.5	252,902.3	12.0	54,002.7	73,855.3	27,910.6	19,666.8	438.3	607,398.2	--
2021	157,681.0	15,660.6	257,969.4	12.0	53,917.1	73,316.9	33,028.9	19,235.3	958.5	611,779.7	--
2022	146,127.6	16,411.3	266,709.4	12.0	53,862.9	73,482.6	35,629.0	19,279.1	1,298.5	612,812.4	--
2023	139,158.0	15,291.5	270,951.7	12.0	54,917.4	73,467.1	41,569.6	19,377.1	1,917.6	616,662.0	--
2024	135,786.0	14,931.4	273,739.3	12.0	55,949.3	73,378.7	48,099.6	19,385.6	2,861.5	624,143.3	--
Independent Power Producers, Non-Combined Heat and Power Plants											
2014	71,994.6	15,724.4	172,224.5	47.0	46,178.4	5,651.2	72,144.4	3,358.4	238.7	387,561.6	--
2015	70,217.8	13,102.9	172,519.2	--	46,214.8	5,650.5	82,014.6	3,358.4	354.3	393,432.5	--
2016	67,667.7	12,587.4	173,455.8	--	46,290.7	5,676.9	97,408.4	3,380.4	487.5	406,954.8	--
2017	64,419.3	11,777.0	176,029.0	--	46,285.3	5,697.9	107,618.0	3,380.4	989.3	416,196.2	--
2018	58,716.2	11,732.2	186,542.1	--	45,707.3	5,770.0	116,197.3	3,380.4	670.1	428,716.6	--
2019	53,646.5	11,514.8	187,715.6	--	44,238.4	5,764.3	127,964.3	3,349.4	760.7	434,954.0	--
2020	48,069.4	11,007.6	190,621.4	--	42,497.9	5,780.6	145,809.5	3,349.4	1,204.4	448,340.2	--
2021	48,742.4	10,672.5	190,877.6	--	41,629.3	6,293.8	168,330.4	3,772.4	3,891.7	474,210.1	--
2022	40,460.6	12,386.6	192,400.0	--	40,796.0	6,288.7	185,017.6	3,764.8	7,811.0	488,925.3	--
2023	36,615.5	12,249.2	193,777.0	--	40,794.8	6,224.0	204,050.1	3,770.3	14,192.5	511,673.4	--
2024	36,051.2	11,795.8	190,783.5	--	42,441.9	6,228.4	233,407.1	3,771.0	24,234.5	548,713.3	--
Independent Power Producers, Combined Heat and Power Plants											
2014	4,073.0	308.2	27,676.7	83.0	--	--	885.9	--	335.8	33,362.6	--
2015	3,843.6	307.2	27,284.1	350.0	--	--	970.5	--	126.0	32,881.4	--
2016	3,552.4	301.2	27,222.4	350.0	--	--	1,068.3	--	19.0	32,513.3	--
2017	3,338.0	301.2	26,922.1	350.0	--	--	969.8	--	21.0	31,902.1	--
2018	2,922.0	458.0	25,658.1	350.0	--	--	884.2	--	21.0	30,293.3	--
2019	2,074.1	298.8	24,782.0	350.0	--	--	944.9	--	112.0	28,561.8	--
2020	1,994.2	450.8	24,635.8	350.0	--	--	952.0	--	113.0	28,495.8	--
2021	1,902.6	452.2	24,611.8	350.0	--	--	888.1	--	113.0	28,317.7	--
2022	1,283.9	449.9	24,506.3	350.0	--	--	856.8	--	17.0	27,462.9	--
2023	1,245.0	451.1	24,172.2	350.0	--	--	770.0	--	31.0	27,019.3	--
2024	939.2	451.1	23,371.7	322.0	--	7.2	750.6	--	31.0	25,872.8	--
Commercial Sector											
2014	290.1	463.5	1,832.6	--	--	21.4	1,066.8	5.4	15.6	3,695.4	3,279.7
2015	226.6	466.1	1,932.5	--	--	21.4	1,126.5	5.4	6.7	3,785.2	3,706.7
2016	202.4	511.0	1,982.6	--	--	74.5	1,132.0	--	6.7	3,909.2	4,022.8
2017	202.4	596.5	2,018.7	--	--	74.9	1,162.0	--	11.6	4,066.1	5,155.8
2018	144.2	823.6	2,157.6	--	--	74.7	1,241.5	--	13.0	4,454.6	6,271.4
2019	123.2	856.7	2,247.5	--	--	74.9	1,218.6	--	49.1	4,570.0	7,167.9
2020	77.6	875.1	2,345.0	--	--	74.2	1,217.9	--	51.8	4,641.6	8,376.1
2021	77.6	912.5	2,272.7	--	--	84.8	1,373.0	--	51.1	4,771.7	9,752.0
2022	47.9	958.1	2,378.2	--	--	87.5	1,925.2	--	53.1	5,450.0	11,212.3
2023	47.9	960.5	2,347.4	--	--	87.5	1,927.1	--	55.1	5,425.5	12,605.1
2024	47.9	985.8	2,408.3	--	--	81.3	1,848.0	--	55.6	5,427.0	14,014.0
Industrial Sector											
2014	2,898.6	594.3	14,725.7	1,772.3	--	279.3	5,612.9	--	1,288.0	27,171.1	700.6
2015	2,509.5	684.4	14,474.0	2,138.4	--	279.3	6,105.7	--	1,221.1	27,412.4	880.3
2016	2,074.8	697.3	14,485.3	2,094.9	--	282.2	5,933.8	--	1,265.8	26,834.1	1,215.3
2017	1,964.5	632.1	14,484.0	2,013.8	--	282.2	5,977.0	--	1,345.1	26,698.7	1,365.1
2018	1,955.4	560.8	14,402.1	2,181.9	--	208.9	5,994.7	--	1,300.8	26,604.6	1,555.4
2019	1,724.9	510.2	14,803.4	2,137.2	--	214.2	5,834.6	--	1,266.3	26,490.8	1,796.6
2020	1,526.3	512.3	15,302.7	1,913.2	--	214.2	6,064.5	--	1,271.8	26,805.0	2,045.3
2021	1,422.1	506.7	16,138.7	1,526.0	--	214.2	5,672.2	--	1,297.0	26,776.9	2,212.7
2022	1,396.3	569.4	16,404.0	1,366.2	--	208.8	5,610.5	--	1,226.0	26,781.2	2,321.7
2023	1,375.3	488.4	16,287.5	1,504.8	--	206.7	5,647.8	--	1,254.7	26,765.2	2,558.3
2024	1,353.3	485.6	16,068.4	1,344.1	--	200.9	5,552.9	--	1,253.8	26,258.9	2,712.2
Residential Sector											
2014	--	--	--	--	--	--	--	--	--	--	3,346.3
2015	--	--	--	--	--	--	--	--	--	--	5,191.5
2016	--	--	--	--	--	--	--	--	--	--	7,527.0
2017	--	--	--	--	--	--	--	--	--	--	9,626.8
2018	--	--	--	--	--	--	--	--	--	--	11,720.4
2019	--	--	--	--	--	--	--	--	--	--	14,249.0
2020	--	--	--	--	--	--	--	--	--	--	17,163.3
2021	--	--	--	--	--	--	--	--	--	--	21,116.2
2022	--	--	--	--	--	--	--	--	--	--	26,294.0
2023	--	--	--	--	--	--	--	--	--	--	32,611.3
2024	--	--	--	--	--	--	--	--	--	--	36,501.8

Notes: Coal includes anthracite, bituminous, subbituminous, lignite, and waste coal; coal syrefuel and refined coal; and beginning in 2011, coal-derived synthesis gas. Prior to 2011, coal-derived synthesis gas was included in Other Fossil Gas.

Petroleum includes 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), waste oil, and beginning in 2011, synthetic gas and propane. Prior to 2011, synthetic gas and propane were included in Other Fossil Gas.

Other Fossil Gas includes gaseous propane, blast furnace gas, other manufactured and waste gases derived from fossil fuels other than hydrogen.

Hydroelectric Conventional capacity includes conventional hydroelectric power excluding pumped storage facilities.

Other Renewable Sources include wood, black liquor, other wood waste, municipal solid waste, landfill gas, sludge waste, agriculture byproducts, other biomass, geothermal, solar thermal, photovoltaic energy, and wind.

Other Energy Sources include hydrogen, non-biogenic municipal solid waste, batteries, purchased steam, sulfur, tire-derived fuel, and other miscellaneous energy sources.

In 2011, EIA corrected the NAICS codes of several plants which resulted in a net capacity shift from the electric utility sector to the commercial sector.

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

Estimated small scale solar photovoltaic generation and capacity are based on data from Form EIA-826, Form EIA-861M, Form EIA-861 and from estimation methods described in the technical notes.

Table 4.2.B. Existing Net Summer Capacity of Other Renewable Sources by Producer Type,
2014 through 2024 (Megawatts) (Page 1)

Utility Scale Capacity								Utility and Small Scale Capacity		
Year	Wind	Solar Photovoltaic	Solar Thermal	Wood and Wood-Derived Fuels	Geothermal	Other Biomass	Total Utility (Other Renewable Sources)	Estimated Small Scale Photovoltaic	Total Solar Photovoltaic	Total Solar
Total (All Sectors)										
2014	64,231.5	8,656.6	1,666.7	8,368.1	2,514.3	5,166.5	90,603.7	7,326.6	15,983.2	17,649.9
2015	72,573.4	11,905.4	1,757.9	8,968.9	2,541.5	5,124.5	102,871.6	9,778.5	21,683.9	23,441.8
2016	81,286.6	20,192.9	1,757.9	8,936.1	2,516.6	5,088.8	119,778.9	12,765.1	32,958.0	34,715.9
2017	87,597.5	25,209.0	1,757.9	8,830.9	2,483.3	5,129.5	131,008.1	16,147.8	41,356.8	43,114.7
2018	94,417.7	30,120.5	1,757.9	8,694.6	2,444.3	5,038.6	142,473.6	19,547.1	49,667.6	51,425.5
2019	103,571.2	35,710.2	1,758.1	8,374.5	2,555.4	4,738.8	156,708.2	23,213.6	58,923.8	60,681.9
2020	118,378.7	46,306.2	1,747.9	8,326.5	2,571.9	4,623.3	181,954.5	27,584.8	73,891.0	75,638.9
2021	132,753.4	60,070.1	1,480.0	7,923.2	2,596.7	4,469.2	209,292.6	33,081.0	93,151.1	94,631.1
2022	141,402.2	71,381.5	1,480.0	7,804.5	2,648.6	4,322.3	229,039.1	39,828.0	111,209.5	112,689.5
2023	147,444.7	90,517.8	1,480.0	7,693.1	2,695.8	4,133.2	253,964.6	47,774.7	138,292.5	139,772.5
2024	152,097.3	122,061.8	1,392.0	7,414.8	2,695.5	3,996.9	289,658.2	53,228.1	175,289.9	176,681.9
Electric Utilities										
2014	9,022.6	568.5	--	654.8	164.1	483.7	10,893.7	--	568.5	568.5
2015	10,580.9	842.9	--	623.8	165.9	440.8	12,654.3	--	842.9	842.9
2016	11,552.6	1,388.4	--	708.8	167.9	418.7	14,236.4	--	1,388.4	1,388.4
2017	12,150.8	1,724.5	--	811.3	161.9	432.8	15,281.3	--	1,724.5	1,724.5
2018	14,031.7	2,683.5	--	807.0	148.8	484.9	18,155.9	--	2,683.5	2,683.5
2019	15,715.0	3,851.4	--	696.2	146.5	336.7	20,745.8	--	3,851.4	3,851.4
2020	20,788.5	5,965.4	--	670.8	149.5	336.4	27,910.6	--	5,965.4	5,965.4
2021	23,991.7	7,979.1	--	627.7	149.5	280.9	33,028.9	--	7,979.1	7,979.1
2022	24,445.7	10,141.2	--	628.6	149.5	264.0	35,629.0	--	10,141.2	10,141.2
2023	26,855.3	13,691.6	--	628.6	158.5	235.6	41,569.6	--	13,691.6	13,691.6
2024	27,574.3	19,502.8	--	612.6	158.5	251.5	48,099.6	--	19,502.8	19,502.8
Independent Power Producers, Non-Combined Heat and Power Plants										
2014	55,133.0	7,857.0	1,666.7	1,816.6	2,308.8	3,362.3	72,144.4	--	7,857.0	9,523.7
2015	61,905.4	10,768.2	1,757.9	1,873.3	2,375.6	3,334.2	82,014.6	--	10,768.2	12,526.1
2016	69,645.4	18,483.3	1,757.9	1,789.6	2,348.7	3,383.5	97,408.4	--	18,483.3	20,241.2
2017	75,346.6	23,127.0	1,757.9	1,649.1	2,321.4	3,416.0	107,618.0	--	23,127.0	24,884.9
2018	80,267.6	27,055.8	1,757.9	1,576.2	2,246.1	3,293.7	116,197.3	--	27,055.8	28,813.7
2019	87,737.8	31,416.4	1,758.1	1,475.7	2,359.5	3,216.8	127,964.3	--	31,416.4	33,174.5
2020	97,242.6	39,868.8	1,747.9	1,463.3	2,373.0	3,113.9	145,809.5	--	39,868.8	41,616.7
2021	108,637.2	51,546.2	1,480.0	1,339.8	2,373.0	2,954.2	168,330.4	--	51,546.2	53,026.2
2022	116,829.6	60,617.7	1,480.0	1,318.3	2,499.1	2,272.9	185,017.6	--	60,617.7	62,097.7
2023	120,466.5	76,128.3	1,480.0	1,320.0	2,537.3	2,118.0	204,050.1	--	76,128.3	77,608.3
2024	124,376.6	101,819.0	1,392.0	1,198.8	2,537.0	2,083.6	233,407.1	--	101,819.0	103,211.0

Notes: Wood and wood-derived fuels include 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.

Other Biomass includes 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).

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

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

Estimated small scale solar photovoltaic generation capacity are based on data from Form EIA-826, Form EIA-861M, Form EIA-861 and from estimation methods described in the technical notes.

Table 4.2.B. Existing Net Summer Capacity of Other Renewable Sources by Producer Type,
2014 through 2024 (Megawatts) (Page 2)

Utility Scale Capacity	Utility and Small Scale Capacity

Year	Wind	Solar Photovoltaic	Solar Thermal	Wood and Wood-Derived Fuels	Geothermal	Other Biomass	Total Utility (Other Renewable Sources)	Estimated Small Scale Photovoltaic	Total Solar Photovoltaic	Total Solar
Independent Power Producers, Combined Heat and Power Plants										
2014	--	--	--	465.5	41.4	379.0	885.9	--	--	--
2015	--	--	--	568.2	--	402.3	970.5	--	--	--
2016	--	1.0	--	667.2	--	400.1	1,068.3	--	1.0	1.0
2017	--	2.5	--	582.0	--	385.3	969.8	--	2.5	2.5
2018	--	3.3	--	492.7	--	388.2	884.2	--	3.3	3.3
2019	--	3.3	--	554.7	--	386.9	944.9	--	3.3	3.3
2020	--	3.9	--	563.2	--	384.9	952.0	--	3.9	3.9
2021	--	3.9	--	467.2	--	417.0	888.1	--	3.9	3.9
2022	--	4.1	--	467.2	--	385.5	856.8	--	4.1	4.1
2023	--	3.9	--	382.2	--	383.9	770.0	--	3.9	3.9
2024	--	3.9	--	396.1	--	350.6	750.6	--	3.9	3.9
Commercial Sector										
2014	51.6	223.4	--	65.4	--	726.4	1,066.8	3,279.7	3,503.1	3,503.1
2015	55.3	282.1	--	65.3	--	723.8	1,126.5	3,706.7	3,988.8	3,988.8
2016	56.8	300.8	--	67.1	--	707.3	1,132.0	4,022.8	4,323.6	4,323.6
2017	60.8	311.6	--	63.1	--	726.5	1,162.0	5,155.8	5,467.4	5,467.4
2018	73.4	330.6	--	63.1	49.4	725.0	1,241.5	6,271.4	6,602.0	6,602.0
2019	73.4	381.1	--	63.1	49.4	651.6	1,218.6	7,167.9	7,549.0	7,549.0
2020	67.6	385.1	--	63.3	49.4	652.5	1,217.9	8,376.1	8,761.2	8,761.2
2021	67.8	412.9	--	137.3	74.2	680.8	1,373.0	9,752.0	10,164.9	10,164.9
2022	70.2	444.3	--	137.3	--	1,273.4	1,925.2	11,212.3	11,656.6	11,656.6
2023	69.2	448.6	--	137.3	--	1,272.0	1,927.1	12,605.1	13,053.7	13,053.7
2024	69.2	435.8	--	136.0	--	1,207.0	1,848.0	14,014.0	14,449.9	14,449.9
Industrial Sector										
2014	24.3	7.7	--	5,365.8	--	215.1	5,612.9	700.6	708.3	708.3
2015	31.8	12.2	--	5,838.3	--	223.4	6,105.7	880.3	892.5	892.5
2016	31.8	19.4	--	5,703.4	--	179.2	5,933.8	1,215.3	1,234.7	1,234.7
2017	39.3	43.4	--	5,725.4	--	168.9	5,977.0	1,365.1	1,408.5	1,408.5
2018	45.0	47.3	--	5,755.6	--	146.8	5,994.7	1,555.4	1,602.7	1,602.7
2019	45.0	58.0	--	5,584.8	--	146.8	5,834.6	1,796.6	1,854.6	1,854.6
2020	280.0	83.0	--	5,565.9	--	135.6	6,064.5	2,045.3	2,128.3	2,128.3
2021	56.7	128.0	--	5,351.2	--	136.3	5,672.2	2,212.7	2,340.7	2,340.7
2022	56.7	174.2	--	5,253.1	--	126.5	5,610.5	2,321.7	2,495.9	2,495.9
2023	53.7	245.4	--	5,225.0	--	123.7	5,647.8	2,558.3	2,803.7	2,803.7
2024	77.2	300.2	--	5,071.3	--	104.2	5,552.9	2,712.2	3,012.4	3,012.4
Residential Sector										
2014	--	--	--	--	--	--	--	3,346.3	3,346.3	3,346.3
2015	--	--	--	--	--	--	--	5,191.5	5,191.5	5,191.5
2016	--	--	--	--	--	--	--	7,527.0	7,527.0	7,527.0
2017	--	--	--	--	--	--	--	9,626.8	9,626.8	9,626.8
2018	--	--	--	--	--	--	--	11,720.4	11,720.4	11,720.4
2019	--	--	--	--	--	--	--	14,249.0	14,249.0	14,249.0
2020	--	--	--	--	--	--	--	17,163.3	17,163.3	17,163.3
2021	--	--	--	--	--	--	--	21,116.2	21,116.2	21,116.2
2022	--	--	--	--	--	--	--	26,294.0	26,294.0	26,294.0
2023	--	--	--	--	--	--	--	32,611.3	32,611.3	32,611.3
2024	--	--	--	--	--	--	--	36,501.8	36,501.8	36,501.8

Notes: Wood and wood-derived fuels include 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.

Other Biomass includes 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).

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

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

Estimated small scale solar photovoltaic generation capacity are based on data from Form EIA-826, Form EIA-861M, Form EIA-861 and from estimation methods described in the technical notes.

Table 4.3. Existing Capacity by Energy Source, 2024 (Megawatts)

Energy Source	Facility Type	Number of Generators	Generator Nameplate Capacity	Net Summer Capacity	Net Winter Capacity
Coal	Utility Scale	462	188,951.9	174,177.6	175,340.0
Petroleum	Utility Scale	3,884	33,324.0	28,649.7	31,934.5
Natural Gas	Utility Scale	6,693	571,226.5	506,371.0	542,188.3
Other Fossil Gas	Utility Scale	70	1,871.1	1,678.1	1,692.4
Nuclear	Utility Scale	96	103,581.2	98,391.2	100,774.4
Hydroelectric Conventional	Utility Scale	3,978	79,982.5	79,896.5	79,346.3
Wind	Utility Scale	1,563	153,489.1	152,097.3	152,188.0
Solar Photovoltaic	Utility Scale	7,141	122,907.1	122,061.8	121,433.9
Solar Thermal	Utility Scale	12	1,405.0	1,392.0	1,288.5
Wood and Wood-Derived Fuels	Utility Scale	288	8,369.9	7,414.8	7,529.9
Geothermal	Utility Scale	163	4,002.1	2,695.5	3,162.2
Other Biomass	Utility Scale	1,493	4,549.8	3,996.9	4,050.5
Hydroelectric Pumped Storage	Utility Scale	150	22,224.1	23,156.6	23,180.5
Other Energy Sources	Utility Scale	861	28,856.2	28,436.4	28,474.6
Total	Utility Scale	26,854	1,324,740.5	1,230,415.2	1,272,583.9
Small Scale Photovoltaic	Small Scale	--	--	53,228.1	--
Estimated Total Photovoltaic	Utility and Small Scale	--	--	175,289.9	--
Estimated Total Solar	Utility and Small Scale	--	--	176,681.9	--

Notes: Coal includes anthracite, bituminous, subbituminous, lignite, and waste coal; coal synfuel and refined coal; and beginning in 2011, coal-derived synthesis gas. Prior to 2011, coal-derived synthesis gas was included in Other Fossil Gas.

Petroleum includes 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), waste oil, and beginning in 2011, synthetic gas and propane. Prior to 2011, synthetic gas and propane were included in Other Fossil Gas.

Other Fossil Gas includes gaseous propane, blast furnace gas, other manufactured and waste gases derived from fossil fuels other than hydrogen. Prior to 2011, waste heat was included in Natural Gas.

Hydroelectric Conventional capacity includes conventional hydroelectric power excluding pumped storage facilities.

Wood and wood-derived fuels include 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.

Other Biomass include 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).

Hydroelectric Conventional capacity includes conventional hydroelectric power excluding pumped storage facilities.

Other Energy Sources include hydrogen, non-biogenic municipal solid waste, batteries, purchased steam, sulfur, tire-derived fuel, and other miscellaneous energy sources.

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.

In 2011, EIA corrected the NAICS codes of several plants which resulted in a net capacity shift from the electric utility sector to the commercial sector.

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

Estimated small scale solar photovoltaic capacity is based on data from Form EIA-826, Form EIA-861M, Form EIA-861 and from estimation methods described in the technical notes.

Table 4.4. Existing Capacity by Producer Type, 2024 (Megawatts)

Producer Type	Facility Type	Number of Generators	Generator Nameplate Capacity	Net Summer Capacity	Net Winter Capacity
Electric Power Sector					
Electric Utilities	Utility Scale	9,814	678,231.8	624,143.3	647,698.3
Independent Power Producers, Non-Combined Heat and Power Plants	Utility Scale	13,224	581,128.7	548,713.3	563,474.0
Independent Power Producers, Combined Heat and Power Plants	Utility Scale	438	29,222.8	25,872.8	27,868.1
Total	Utility Scale	23,476	1,288,583.3	1,198,729.3	1,239,040.4
Commercial and Industrial Sectors					
Commercial Sector	Utility Scale	1,888	5,911.4	5,427.0	5,524.1
Industrial Sector	Utility Scale	1,490	30,245.8	26,258.9	28,019.3
Total	Utility Scale	3,378	36,157.2	31,685.9	33,543.4
All Sectors					
Total	Utility Scale	26,854	1,324,740.5	1,230,415.2	1,272,583.9
Small Scale					
Estimated Solar Photovoltaic	Small Scale	--	--	53,228.1	--

Notes:

See Glossary reference for definitions.

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

In the case of some 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 generator count. 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.'

Estimated small scale solar photovoltaic capacity is based on data from Form EIA-826, Form EIA-861M, Form EIA-861 and from estimation methods described in the technical notes.

Table 4.5. Planned Utility-Scale Generating Capacity Changes, by Energy Source, 2025-2029 (Page 1)

Energy Source	Generator Additions		Generator Retirements		Net Capacity Additions	
	Number of Generators	Net Summer Capacity	Number of Generators	Net Summer Capacity	Number of Generators	Net Summer Capacity
Year 2025						
U.S. Total	953	64,330.8	107	8,745.8	846	55,585.0
Coal	--	--	15	6,163.1	-15	-6,163.1
Petroleum	9	29.1	37	763.2	-28	-734.1
Natural Gas	94	4,725.8	26	1,635.7	68	3,090.1
Other Fossil Gas	--	--	3	62.2	-3	-62.2
Nuclear	--	--	--	--	--	--
Hydroelectric Conventional	10	14.4	1	0.5	9	13.9
Wind	39	7,445.1	2	6.6	37	7,438.5
Solar Thermal and Photovoltaic	580	32,689.2	3	1.8	577	32,687.4
Wood and Wood-Derived Fuels	1	3.0	2	90.0	-1	-87.0
Geothermal	--	--	--	--	--	--
Other Biomass	7	10.4	15	14.7	-8	-4.3
Hydroelectric Pumped Storage	--	--	--	--	--	--
Other Energy Sources	213	19,413.8	3	8.0	210	19,405.8
Year 2026						
U.S. Total	623	72,360.7	81	7,884.4	542	64,476.4
Coal	--	--	8	3,449.9	-8	-3,449.9
Petroleum	3	22.8	3	19.7	--	3.1
Natural Gas	55	5,960.3	41	4,386.9	14	1,573.4
Other Fossil Gas	--	--	1	0.8	-1	-0.8
Nuclear	--	--	--	--	--	--
Hydroelectric Conventional	5	11.8	--	--	5	11.8
Wind	35	10,369.1	9	1.5	26	10,367.6
Solar Thermal and Photovoltaic	345	36,389.3	6	9.6	339	36,379.7
Wood and Wood-Derived Fuels	--	--	--	--	--	--
Geothermal	6	47.5	--	--	6	47.5
Other Biomass	7	59.2	12	11.0	-5	48.2
Hydroelectric Pumped Storage	--	--	--	--	--	--
Other Energy Sources	167	19,500.7	1	5.0	166	19,495.7
Year 2027						
U.S. Total	460	73,389.7	69	11,321.9	391	62,067.8
Coal	--	--	19	6,751.0	-19	-6,751.0
Petroleum	5	17.0	4	8.0	1	9.0
Natural Gas	45	5,676.6	20	4,418.8	25	1,257.8
Other Fossil Gas	--	--	--	--	--	--
Nuclear	--	--	--	--	--	--
Hydroelectric Conventional	21	63.2	11	18.6	10	44.6
Wind	25	7,552.5	1	80.0	24	7,472.5
Solar Thermal and Photovoltaic	240	40,110.7	4	3.8	236	40,106.9
Wood and Wood-Derived Fuels	--	--	--	--	--	--
Geothermal	3	56.7	--	--	3	56.7
Other Biomass	12	106.4	9	40.7	3	65.7
Hydroelectric Pumped Storage	3	600.0	--	--	3	600.0
Other Energy Sources	106	19,206.6	1	1.0	105	19,205.6

Notes: These data reflect plans as of December 31, 2024

Coal includes anthracite, bituminous, subbituminous, lignite, waste coal, coal synfuel, refined coal, and coal-derived synthesis gas.

Petroleum includes 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), waste oil, synthetic gas, and propane.

Other Fossil Gas includes gaseous propane, blast furnace gas, other manufactured and waste gases derived from fossil fuels other than hydrogen.

Hydroelectric Conventional capacity includes conventional hydroelectric power excluding pumped storage facilities.

Wood and wood-derived fuels include 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.

Other Biomass include 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).

Hydroelectric Conventional capacity includes conventional hydroelectric power excluding pumped storage facilities.

Other Energy Sources include hydrogen, non-biogenic municipal solid waste, batteries, purchased steam, sulfur, tire-derived fuel, and other miscellaneous energy sources.

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.

In the case of 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 generator count.

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

Table 4.5. Planned Generating Capacity Changes, by Energy Source, 2025-2029 (Page 2)

Energy Source	Generator Additions		Generator Retirements		Net Capacity Additions	
	Number of Generators	Net Summer Capacity	Number of Generators	Net Summer Capacity	Number of Generators	Net Summer Capacity
Year 2028						
U.S. Total	270	48,509.1	50	12,789.5	220	35,719.6
Coal	--	--	17	11,420.0	-17	-11,420.0
Petroleum	3	10.9	7	38.4	-4	-27.5
Natural Gas	66	12,259.2	15	1,232.9	51	11,026.3
Other Fossil Gas	--	--	--	--	--	--
Nuclear	--	--	--	--	--	--
Hydroelectric Conventional	33	134.8	2	3.4	31	131.4
Wind	8	2,380.1	2	87.0	6	2,293.1
Solar Thermal and Photovoltaic	92	18,958.6	7	7.8	85	18,950.8
Wood and Wood-Derived Fuels	--	--	--	--	--	--
Geothermal	1	1.8	--	--	1	1.8
Other Biomass	--	--	--	--	--	--
Hydroelectric Pumped Storage	8	2,000.0	--	--	8	2,000.0
Other Energy Sources	59	12,763.7	--	--	59	12,763.7
Year 2029						
U.S. Total	68	17,029.5	18	5,752.9	50	11,276.6
Coal	--	--	7	3,327.9	-7	-3,327.9
Petroleum	--	--	3	704.0	-3	-704.0
Natural Gas	17	5,590.8	7	1,682.0	10	3,908.8
Other Fossil Gas	--	--	--	--	--	--
Nuclear	--	--	--	--	--	--
Hydroelectric Conventional	7	6.3	--	--	7	6.3
Wind	10	3,170.2	--	--	10	3,170.2
Solar Thermal and Photovoltaic	22	5,514.2	--	--	22	5,514.2
Wood and Wood-Derived Fuels	--	--	--	--	--	--
Geothermal	--	--	--	--	--	--
Other Biomass	--	--	1	39.0	-1	-39.0
Hydroelectric Pumped Storage	--	--	--	--	--	--
Other Energy Sources	12	2,748.0	--	--	12	2,748.0
Years 2025-2029						
U.S. Total	2,374	275,619.8	325	46,494.5	2,049	229,125.3
Coal	--	--	66	31,111.9	-66	-31,111.9
Petroleum	20	79.8	54	1,533.3	-34	-1,453.5
Natural Gas	277	34,212.8	109	13,356.3	168	20,856.5
Other Fossil Gas	--	--	4	63.0	-4	-63.0
Nuclear	--	--	--	--	--	--
Hydroelectric Conventional	76	230.5	14	22.5	62	208.0
Wind	117	30,917.0	14	175.1	103	30,741.9
Solar Thermal and Photovoltaic	1,279	133,662.0	20	23.0	1,259	133,639.0
Wood and Wood-Derived Fuels	1	3.0	2	90.0	-1	-87.0
Geothermal	10	106.0	--	--	10	106.0

Other Biomass	26	176.0	37	105.4	-11	70.6
Hydroelectric Pumped Storage	11	2,600.0	--	--	11	2,600.0
Other Energy Sources	557	73,632.8	5	14.0	552	73,618.8

Notes: These data reflect plans as of December 31, 2024

Coal includes anthracite, bituminous, subbituminous, lignite, waste coal, coal synfuel, refined coal, and coal-derived synthesis gas.

Petroleum includes 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), waste oil, synthetic gas, and propane.

Other Fossil Gas includes gaseous propane, blast furnace gas, other manufactured and waste gases derived from fossil fuels other than hydrogen.

Hydroelectric Conventional capacity includes conventional hydroelectric power excluding pumped storage facilities.

Wood and wood-derived fuels include 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.

Other Biomass include 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).

Hydroelectric Conventional capacity includes conventional hydroelectric power excluding pumped storage facilities.

Other Energy Sources include hydrogen, non-biogenic municipal solid waste, batteries, purchased steam, sulfur, tire-derived fuel, and other miscellaneous energy sources.

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.

In the case of 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 generator count.

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

Table 4.6. Utility-Scale Capacity Additions, Retirements and Changes by Energy Source, 2024 (Count, Megawatts)

Energy Source	Generator Additions				Generator Retirements			
	Number of Generators	Generator Nameplate Capacity	Net Summer Capacity	Net Winter Capacity	Number of Generators	Generator Nameplate Capacity	Net Summer Capacity	Net Winter Capacity
Coal	--	--	--	--	12	4,460.0	3,958.6	4,021.7
Petroleum	22	33.1	32.3	32.3	64	299.6	233.8	264.5
Natural Gas	99	2,535.5	2,113.1	2,256.4	73	5,246.3	4,269.2	4,682.1
Other Fossil Gas	--	--	--	--	--	--	--	--
Nuclear	1	1,114.0	1,114.0	1,114.0	--	--	--	--
Hydroelectric Conventional	1	1.0	1.0	1.0	20	148.6	156.2	156.2
Wind	31	5,155.9	5,154.3	5,154.3	5	34.4	34.6	34.6
Solar Thermal and Photovoltaic	693	31,102.3	30,915.9	30,867.0	3	4.5	4.5	4.5
Wood and Wood-Derived Fuels	1	40.0	40.0	40.0	5	201.3	165.6	173.2
Geothermal	2	29.2	20.0	29.2	2	20.6	14.1	15.1
Other Biomass	5	8.0	7.9	7.9	97	180.0	117.6	115.6
Hydroelectric Pumped Storage	--	--	--	--	2	42.0	42.0	42.0
Other Energy Sources	188	11,157.3	11,055.4	11,055.2	8	39.5	31.2	32.7
Total	1,043	51,176.3	50,454.0	50,557.4	291	10,676.8	9,027.4	9,542.2

Energy Source	Other Changes to Existing Capacity			
		Generator Nameplate Capacity	Net Summer Capacity	Net Winter Capacity
Coal		-512.7	-759.9	-722.8
Petroleum		-4,542.8	-4,431.6	-4,237.0
Natural Gas		59.7	-509.8	40.7
Other Fossil Gas		-160.2	-188.7	-179.1
Nuclear		1,792.6	1,565.0	1,597.2
Hydroelectric Conventional		63.9	-24.5	24.9
Wind		226.0	-542.7	-474.7
Solar Thermal and Photovoltaic		338.4	390.5	996.8
Wood and Wood-Derived Fuels		-146.8	-152.7	-148.6
Geothermal		-16.0	-6.2	-6.9
Other Biomass		19.0	-31.5	-30.9
Hydroelectric Pumped Storage		96.0	51.2	35.8
Other Energy Sources		-34.0	-71.2	-71.2
Total		-2,816.9	-4,712.1	-3,175.8

Notes: Coal includes anthracite, bituminous, subbituminous, lignite, and waste coal, coal synfuel, refined coal, and coal-derived synthesis gas.

Petroleum includes 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), waste oil, synthetic gas, and propane.

Other Fossil Gas includes gaseous propane, blast furnace gas, other manufactured and waste gases derived from fossil fuels other than hydrogen.

Hydroelectric Conventional capacity includes conventional hydroelectric power excluding pumped storage facilities.

Wood and wood-derived fuels include 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.

Other Biomass include 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).

Other Energy Sources include hydrogen, non-biogenic municipal solid waste, batteries, purchased steam, sulfur, tire-derived fuel, and other miscellaneous energy sources.

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.

In the case of some 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 generator count.

Other Changes to Existing Capacity reflect updates, derates, repowerings, and changes to previously reported generator capacity.

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

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

Table 4.7.A. Net Summer Capacity of Utility Scale Units by Technology and by State, 2024 and 2023 (Megawatts)

Census Division and State	Renewable Sources		Fossil Fuels		Hydroelectric Pumped Storage		Other Energy Storage		Nuclear		All Other Sources		All Sources	
	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023
New England	7,932.9	7,418.1	21,161.1	22,647.6	1,863.4	1,863.4	407.7	369.9	3,354.2	3,326.9	22.0	22.0	34,741.3	35,647.9
Connecticut	586.1	551.2	7,272.8	7,272.5	29.4	29.4	1.6	1.6	2,104.2	2,081.2	0.0	0.0	9,994.1	9,935.9
Maine	3,073.1	2,724.9	2,428.9	2,442.4	0.0	0.0	62.3	62.3	0.0	0.0	22.0	22.0	5,586.3	5,251.6
Massachusetts	2,072.6	1,981.2	7,292.9	8,766.2	1,834.0	1,834.0	305.9	268.1	0.0	0.0	0.0	0.0	11,505.4	12,849.5
New Hampshire	945.9	946.6	2,260.4	2,260.4	0.0	0.0	14.0	14.0	1,250.0	1,245.7	0.0	0.0	4,470.3	4,466.7
Rhode Island	538.6	505.4	1,780.1	1,780.1	0.0	0.0	3.0	3.0	0.0	0.0	0.0	0.0	2,321.7	2,288.5
Vermont	716.6	708.8	126.0	126.0	0.0	0.0	20.9	20.9	0.0	0.0	0.0	0.0	863.5	855.7
Middle Atlantic	15,678.1	14,452.9	70,655.0	71,613.0	3,317.4	3,312.0	402.4	350.5	16,683.1	15,854.5	11.2	11.2	106,747.2	105,594.1
New Jersey	1,388.3	1,376.1	11,223.8	11,509.1	416.1	415.4	109.7	69.7	3,456.7	3,456.7	11.2	11.2	16,605.8	16,838.2
New York	10,502.0	9,482.0	25,805.4	25,811.9	1,409.8	1,405.1	238.1	226.2	3,330.4	3,304.6	0.0	0.0	41,285.7	40,229.8
Pennsylvania	3,787.8	3,594.8	33,625.8	34,292.0	1,491.5	1,491.5	54.6	54.6	9,896.0	9,093.2	0.0	0.0	48,855.7	48,526.1
East North Central	30,970.7	25,670.1	101,639.1	103,395.4	2,179.8	2,185.6	223.1	173.9	18,997.4	18,206.2	166.0	169.8	154,176.1	149,801.0
Illinois	10,920.5	9,210.5	23,588.8	24,467.0	0.0	0.0	100.3	96.1	11,591.6	11,567.6	78.0	78.0	46,279.2	45,419.2
Indiana	6,249.3	4,849.3	21,418.3	21,605.0	0.0	0.0	81.0	36.0	0.0	0.0	88.0	88.0	27,836.6	26,578.3
Michigan	5,674.1	5,304.5	20,197.7	20,306.7	2,179.8	2,185.6	1.3	1.3	4,086.5	3,318.0	0.0	3.8	32,139.4	31,119.9
Ohio	4,504.5	3,089.8	23,817.4	23,845.1	0.0	0.0	34.8	34.8	2,134.0	2,134.0	0.0	0.0	30,490.7	29,103.7
Wisconsin	3,622.3	3,216.0	12,616.9	13,171.6	0.0	0.0	5.7	5.7	1,185.3	1,186.6	0.0	0.0	17,430.2	17,579.9
West North Central	47,635.7	45,724.5	55,856.5	56,682.2	657.0	657.0	38.0	31.6	4,792.2	4,792.2	12.2	12.2	108,991.6	107,899.7
Iowa	13,771.6	13,295.8	9,444.4	9,401.7	0.0	0.0	10.3	8.9	0.0	0.0	0.0	0.0	23,226.3	22,706.4
Kansas	9,124.5	9,098.8	9,053.9	8,921.1	0.0	0.0	0.0	0.0	1,176.7	1,176.7	0.8	0.8	19,355.9	19,197.4
Minnesota	7,071.7	6,748.7	9,456.8	9,413.8	0.0	0.0	21.0	16.0	1,657.0	1,657.0	6.1	6.1	18,212.6	17,841.6
Missouri	3,425.2	3,038.2	15,145.8	16,286.1	657.0	657.0	1.0	1.0	1,190.0	1,190.0	0.0	0.0	20,419.0	21,172.3
Nebraska	3,946.2	3,854.1	6,148.6	6,153.4	0.0	0.0	4.9	4.9	768.5	768.5	0.0	0.0	10,868.2	10,780.9
North Dakota	5,033.8	4,839.9	4,644.5	4,556.9	0.0	0.0	0.0	0.0	0.0	0.0	5.3	5.3	9,683.6	9,402.1
South Dakota	5,262.7	4,849.0	1,962.5	1,949.2	0.0	0.0	0.8	0.8	0.0	0.0	0.0	0.0	7,226.0	6,799.0
South Atlantic	42,310.5	36,635.5	153,112.6	153,342.1	8,272.5	8,192.5	1,077.1	847.9	27,018.1	25,904.1	366.9	366.9	232,157.7	225,289.0
Delaware	113.1	105.6	3,189.9	3,189.9	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	3,303.0	3,295.5
District of Columbia	41.2	31.6	20.6	20.6	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	61.8	52.2
Florida	11,986.3	8,847.4	55,471.0	55,335.9	0.0	0.0	575.7	560.7	3,666.0	3,666.0	312.9	312.9	72,011.9	68,722.9
Georgia	8,054.8	7,175.1	23,358.5	23,457.0	1,897.4	1,897.4	146.2	81.2	6,289.0	5,175.0	0.0	0.0	39,746.0	37,785.7
Maryland	1,514.9	1,429.2	8,448.4	8,742.0	0.0	0.0	9.4	7.7	1,745.2	1,745.2	0.0	0.0	11,717.9	11,924.1
North Carolina	9,603.0	9,197.4	21,304.2	21,318.2	86.0	86.0	139.8	58.3	5,149.6	5,149.6	54.0	54.0	36,336.6	35,863.5
South Carolina	3,403.2	3,317.2	11,578.1	11,526.3	3,036.0	2,956.0	88.0	22.0	6,600.3	6,600.3	0.0	0.0	24,705.6	24,421.8
Virginia	6,270.3	5,332.8	15,984.6	15,993.8	3,253.1	3,253.1	70.5	70.5	3,568.0	3,568.0	0.0	0.0	29,146.5	28,218.2
West Virginia	1,323.6	1,199.2	13,757.3	13,758.4	0.0	0.0	47.5	47.5	0.0	0.0	0.0	0.0	15,128.4	15,005.1
East South Central	11,207.0	9,893.9	61,699.5	62,317.4	1,616.3	1,616.3	52.5	2.5	11,365.7	11,358.4	1.4	1.4	85,942.4	85,189.9
Alabama	4,568.0	4,509.6	20,974.0	21,134.0	0.0	0.0	1.0	1.0	5,452.7	5,452.7	0.0	0.0	30,995.7	31,097.3
Kentucky	1,634.0	1,290.2	16,746.4	17,045.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	18,380.4	18,335.7
Mississippi	1,706.6	728.0	12,811.3	12,719.1	0.0	0.0	51.5	1.5	1,390.3	1,383.0	1.4	1.4	15,961.1	14,833.0
Tennessee	3,298.4	3,366.1	11,167.8	11,418.8	1,616.3	1,616.3	0.0	0.0	4,522.7	4,522.7	0.0	0.0	20,605.2	20,923.9
West South Central	84,169.8	72,879.6	139,018.8	140,206.5	271.5	288.0	7,948.2	3,830.6	8,852.5	8,941.9	575.8	578.1	240,836.6	226,724.7
Arkansas	3,274.7	2,309.9	10,752.9	10,875.0	30.0	30.0	28.2	22.0	1,821.0	1,825.0	0.0	0.0	15,906.8	15,061.9
Louisiana	1,664.7	958.6	20,633.7	21,508.7	0.0	0.0	0.0	0.0	2,051.5	2,136.9	356.8	359.1	24,706.7	24,963.3
Oklahoma	13,830.3	13,209.5	17,824.8	18,212.3	241.5	258.0	10.0	10.0	0.0	0.0	0.0	0.0	31,906.6	31,689.8
Texas	65,400.1	56,401.6	89,807.4	89,610.5	0.0	0.0	7,910.0	3,798.6	4,980.0	4,980.0	219.0	219.0	168,316.5	155,009.7
Mountain	47,329.9	41,576.5	58,669.1	58,237.6	794.8	806.7	4,306.1	1,955.8	3,937.0	3,937.0	121.6	124.6	115,158.5	106,638.2
Arizona	9,033.8	7,251.8	17,568.4	17,548.5	216.3	216.3	2,121.0	931.0	3,937.0	3,937.0	0.0	0.0	32,876.5	29,884.6
Colorado	8,425.3	8,228.5	10,460.4	10,472.4	578.5	590.4	346.3	241.0	0.0	0.0	6.1	9.1	19,816.6	19,541.4
Idaho	4,381.3	4,095.5	1,111.5	1,242.3	0.0	0.0	40.0	0.0	0.0	0.0	14.8	14.8	5,547.6	5,352.6
Montana	4,908.9	4,589.9	2,233.6	2,068.0	0.0	0.0	0.0	0.0	0.0	0.0	40.0	40.0	7,182.5	6,697.9
Nevada	7,080.9	5,903.3	8,529.0	8,082.3	0.0	0.0	1,108.8	543.8	0.0	0.0	6.5	6.5	16,725.2	14,535.9
New Mexico	6,416.6	5,635.4	4,781.1	4,849.1	0.0	0.0	689.0	239.0	0.0	0.0	0.7	0.7	11,887.4	10,724.2
Utah	2,930.1	2,367.0	7,305.9	7,301.6	0.0	0.0	1.0	1.0	0.0	0.0	40.2	40.2	10,277.2	9,709.8
Wyoming	4,153.0	3,505.1	6,679.2	6,673.4	0.0	0.0	0.0	0.0	0.0	0.0	13.3	13.3	10,845.5	10,191.8
Pacific Contiguous	80,841.0	78,304.1	44,887.8	44,686.6	4,183.9	4,225.9	12,045.3	8,025.6	3,391.0	3,391.0	91.2	94.4	145,440.2	138,727.6
California	41,814.0	39,289.0	37,040.8	36,855.0	3,869.9	3,911.9	11,717.3	7,984.6	2,240.0	2,240.0	91.2	94.4	96,773.2	90,374.9
Oregon	13,600.7	13,664.8	3,769.0	3,769.0	0.0	0.0	322.0	35.0	0.0	0.0	0.0	0.0	17,691.7	17,468.8
Washington	25,426.3	25,350.3	4,078.0	4,062.6	314.0	314.0	6.0	6.0	1,151.0	1,151.0	0.0	0.0	30,975.3	30,883.9
Pacific Noncontiguous	1,478.0	1,404.6	4,177.0	4,156.4	0.0	0.0	566.6	453.6	0.0	0.0	1.1	28.4	6,222.7	6,043.0
Alaska	550.0	549.9	2,168.6	2,176.5	0.0	0.0	133.7	93.7	0.0	0.0	1.1	0.9	2,853.4	2,821.0
Hawaii	928.0	854.7	2,008.4	1,979.9	0.0	0.0	432.9	359.9	0.0	0.0	0.0	27.5	3,369.3	3,222.0
U.S. Total	369,553.6	333,959.8	710,876.5	717,284.8	23,156.6	23,147.4	27,067.0	16,041.9	98,391.2	95,712.2	1,369.4	1,409.0	1,230,414.3	1,187,555.1

NM = Not meaningful due to large relative standard error.

Values are final.

NOTES:

Capacity from facilities with a total generator nameplate capacity less than 1 MW are excluded from this report. This exclusion may represent a significant portion of capacity for some technologies such as solar photovoltaic generation. Concentrated Solar Power Energy Storage is included in 'Renewable sources'; it is not included in 'Other Energy Storage'

Sources: U.S. Energy Information Administration, Form EIA-860, 'Annual Electric Generator Report' and Form EIA-860M, 'Monthly Update to the Annual Electric Generator Report.'

Table 4.7.B. Net Summer Capacity Using Primarily Renewable Energy Sources and by State, 2024 and 2023 (Megawatts)

Census Division and State	Summer Capacity at Utility Scale Facilities														Small Scale Capacity				Capacity From Utility and Small Scale Facilities			
	Wind		Solar Photovoltaic		Solar Thermal		Conventional Hydroelectric		Biomass Sources		Geothermal		Total Renewable Sources		Estimated Solar Photovoltaic		Estimated Total Solar Photovoltaic		Estimated Total Solar			
	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023		
	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023		
New England	1,575.7	1,575.7	3,158.1	2,641.4	0.0	0.0	1,951.7	1,953.6	1,247.4	1,247.4	0.0	0.0	7,932.9	7,418.1	5,628.8	5,033.3	8,786.9	7,674.7	8,786.9	7,674.7		
Connecticut	5.0	5.0	322.3	287.4	0.0	0.0	119.2	119.2	139.6	139.6	0.0	0.0	586.1	551.2	1,132.3	978.6	1,454.6	1,266.0	1,454.6	1,266.0		
Maine	1,029.5	1,029.5	829.2	481.0	0.0	0.0	725.8	725.8	488.6	488.6	0.0	0.0	3,073.1	2,724.9	849.4	532.9	1,678.6	1,013.9	1,678.6	1,013.9		
Massachusetts	101.8	101.8	1,430.5	1,339.1	0.0	0.0	267.2	267.2	273.1	273.1	0.0	0.0	2,072.6	1,981.2	2,966.5	2,661.3	4,397.0	4,000.4	4,397.0	4,000.4		
New Hampshire	211.9	211.9	2.4	2.4	0.0	0.0	505.8	506.5	225.8	225.8	0.0	0.0	945.9	946.6	270.4	232.8	272.8	235.2	272.8	235.2		
Rhode Island	77.3	77.3	418.5	385.3	0.0	0.0	2.7	2.7	40.1	40.1	0.0	0.0	538.6	505.4	224.4	453.2	642.9	838.5	642.9	838.5		
Vermont	150.2	150.2	155.2	146.2	0.0	0.0	331.0	332.2	80.2	80.2	0.0	0.0	716.6	708.8	185.7	174.4	340.9	320.6	340.9	320.6		
Middle Atlantic	4,429.9	4,306.5	4,722.2	3,576.6	0.0	0.0	5,505.2	5,502.6	1,020.8	1,067.2	0.0	0.0	15,678.1	14,452.9	6,867.6	6,104.4	11,589.8	9,681.0	11,589.8	9,681.0		
New Jersey	7.6	7.6	1,179.7	1,167.5	0.0	0.0	12.3	12.3	188.7	188.7	0.0	0.0	1,388.3	1,376.1	2,489.6	2,297.4	3,669.3	3,464.9	3,669.3	3,464.9		
New York	2,869.7	2,746.3	2,688.6	1,719.6	0.0	0.0	4,563.4	4,560.8	400.3	455.3	0.0	0.0	10,502.0	9,482.0	3,394.0	2,995.2	6,062.6	4,714.8	6,062.6	4,714.8		
Pennsylvania	1,552.6	1,552.6	873.9	689.5	0.0	0.0	929.5	929.5	431.8	423.2	0.0	0.0	3,787.8	3,594.8	984.0	811.8	1,857.9	1,501.3	1,857.9	1,501.3		
East North Central	17,215.1	16,816.1	11,949.2	6,969.1	0.0	0.0	880.5	880.2	925.9	1,004.7	0.0	0.0	30,970.7	25,670.1	2,596.2	2,185.1	14,545.4	9,154.2	14,545.4	9,154.2		
Illinois	7,873.7	7,873.7	2,958.7	1,248.7	0.0	0.0	32.9	32.9	55.2	55.2	0.0	0.0	10,920.5	9,210.5	1,372.4	1,164.1	4,331.1	2,412.8	4,331.1	2,412.8		
Indiana	3,639.1	3,439.1	2,490.0	1,288.9	0.0	0.0	71.6	71.6	48.6	49.7	0.0	0.0	6,249.3	4,849.3	270.3	238.1	2,760.3	1,527.0	2,760.3	1,527.0		
Michigan	3,774.3	3,575.3	1,158.0	975.0	0.0	0.0	263.5	263.8	478.3	490.4	0.0	0.0	5,674.1	5,304.5	270.0	226.4	1,428.0	1,201.4	1,428.0	1,201.4		
Ohio	1,101.8	1,101.8	3,236.5	1,808.3	0.0	0.0	101.9	101.9	64.3	77.8	0.0	0.0	4,504.5	3,089.8	411.9	341.2	3,648.4	2,149.5	3,648.4	2,149.5		
Wisconsin	826.2	826.2	2,106.0	1,648.2	0.0	0.0	410.6	410.0	279.5	331.6	0.0	0.0	3,622.3	3,216.0	271.7	215.2	2,377.7	1,863.4	2,377.7	1,863.4		
West North Central	40,683.7	40,153.1	3,198.9	1,815.9	0.0	0.0	3,363.7	3,364.6	389.4	390.9	0.0	0.0	47,635.7	45,724.5	1,220.9	1,059.7	4,419.8	2,875.6	4,419.8	2,875.6		
Iowa	12,865.5	12,803.8	676.1	262.0	0.0	0.0	209.4	209.4	20.6	20.6	0.0	0.0	13,771.6	13,295.8	332.8	286.4	1,008.9	548.4	1,008.9	548.4		
Kansas	9,042.7	9,042.7	65.8	40.1	0.0	0.0	7.0	7.0	9.0	9.0	0.0	0.0	9,124.5	9,098.8	108.6	87.8	174.4	127.9	174.4	127.9		
Minnesota	4,901.4	4,928.7	1,641.7	1,291.4	0.0	0.0	212.0	212.0	316.6	316.6	0.0	0.0	7,071.7	6,748.7	296.1	243.2	1,937.8	1,534.6	1,937.8	1,534.6		
Missouri	2,392.9	2,374.9	469.8	100.8	0.0	0.0	548.5	548.5	14.0	14.0	0.0	0.0	3,425.2	3,038.2	439.8	403.2	909.6	504.0	909.6	504.0		
Nebraska	3,516.9	3,518.3	136.5	40.6	0.0	0.0	278.8	279.7	14.0	15.5	0.0	0.0	3,946.2	3,854.1	36.0	33.0	172.5	73.6	172.5	73.6		
North Dakota	4,514.0	4,320.1	0.0	0.0	0.0	0.0	510.0	510.0	9.8	9.8	0.0	0.0	5,033.8	4,839.9	2.2	2.2	8.9	2.2	8.9	2.2		
South Dakota	3,450.3	3,164.6	209.0	81.0	0.0	0.0	1,598.0	1,598.0	5.4	5.4	0.0	0.0	5,262.7	4,849.0	5.4	3.8	214.4	84.8	214.4	84.8		
South Atlantic	1,456.2	1,287.2	29,987.3	24,432.6	0.0	0.0	7,054.2	7,055.3	3,812.8	3,880.4	0.0	0.0	42,310.5	36,635.5	6,328.6	5,717.6	36,315.9	30,150.2	36,315.9	30,150.2		
Delaware	2.0	2.0	96.9	89.4	0.0	0.0	0.0	0.0	14.2	14.2	0.0	0.0	113.1	105.6	143.5	130.1	240.4	219.5	240.4	219.5		
District of Columbia	0.0	0.0	29.2	19.6	0.0	0.0	0.0	0.0	12.0	12.0	0.0	0.0	41.2	31.6	176.1	142.2	205.3	161.8	205.3	161.8		
Florida	0.0	0.0	10,950.8	7,802.3	0.0	0.0	43.5	43.5	992.0	1,001.6	0.0	0.0	11,986.3	8,847.4	2,819.9	2,582.3	13,770.7	10,384.6	13,770.7	10,384.6		
Georgia	0.0	0.0	5,002.8	4,123.0	0.0	0.0	1,985.0	1,985.0	1,067.1	1,067.1	0.0	0.0	8,054.9	7,175.1	342.4	320.2	5,345.2	4,432.5	5,345.2	4,432.5		
Maryland	190.0	190.0	671.4	584.4	0.0	0.0	514.9	514.9	138.6	139.9	0.0	0.0	1,514.9	1,429.2	1,132.4	1,038.0	1,803.8	1,622.4	1,803.8	1,622.4		
North Carolina	397.0	208.0	6,786.7	6,597.8	0.0	0.0	2,009.4	2,010.5	409.9	381.1	0.0	0.0	9,603.0	9,197.4	579.2	498.1	7,365.9	7,095.9	7,365.9	7,095.9		
South Carolina	0.0	0.0	1,646.7	1,557.5	0.0	0.0	1,294.0	1,294.0	462.5	465.7	0.0	0.0	3,403.2	3,317.2	400.2	378.1	2,046.9	1,935.6	2,046.9	1,935.6		
Virginia	12.0	12.0	4,678.4	3,658.6	0.0	0.0	866.6	866.6	713.3	795.6	0.0	0.0	6,270.3	5,332.8	690.1	592.8	5,368.5	4,251.4	5,368.5	4,251.4		
West Virginia	855.2	855.2	124.4	0.0	0.0	0.0	340.8	340.8	3.2	3.2	0.0	0.0	1,323.6	1,199.2	44.8	35.7	169.2	35.7	169.2	35.7		
East South Central	186.6	29.1	2,910.3	1,692.5	0.0	0.0	7,036.6	7,037.8	1,073.5	1,134.5	0.0	0.0	11,207.0	9,893.9	204.4	177.2	3,114.7	1,869.7	3,114.7	1,869.7		
Alabama	0.0	0.0	663.5	601.1	0.0	0.0	3,290.6	3,291.8	613.9	616.7	0.0	0.0	4,568.0	4,509.6	17.0	15.8	680.5	616.9	680.5	616.9		
Kentucky	0.0	0.0	426.1	82.3	0.0	0.0	1,137.4	1,137.4	70.5	70.5	0.0	0.0	1,634.0	1,290.2	110.4	93.5	536.5	175.8	536.5	175.8		
Mississippi	184.5	0.0	1,219.7	425.6	0.0	0.0	0.0	0.0	302.4	302.4	0.0	0.0	1,706.6	728.0	18.4	14.4	1,238.1	440.0	1,238.1	440.0		
Tennessee	2.1	29.1	601.0	583.5	0.0	0.0	2,608.6	2,608.6	86.7	144.9	0.0	0.0	3,298.4	3,366.1	58.6	53.5	659.6	637.0	659.6	637.0		
West South Central	54,726.1	52,572.3	25,383.8	16,219.1	0.0	0.0	3,002.3	3,013.0	1,057.6	1,075.2	0.0	0.0	84,169.8	72,879.6	3,753.6	3,349.5	29,137.4	19,568.6	29,137.4	19,568.6		
Arkansas	0.0	0.0	1,784.5	820.9	0.0	0.0	1,264.5	1,265.2	225.7	223.8	0.0	0.0	3,274.7	2,309.9	333.9	250.5	2,118.4	1,071.4	2,118.4	1,071.4		
Louisiana	0.0	0.0	1,052.6	344.5	0.0	0.0	192.0	192.0	420.1	422.1	0.0	0.0	1,664.7	958.6	202.6	185.1	1,255.2	529.6	1,255.2	529.6		
Oklahoma	12,748.2	12,245.2	173.5	47.5	0.0	0.0	832.4	840.6	76.2	76.2	0.0	0.0	13,830.3	13,209.5	145.1	110.9	318.6	158.4	318.6	158.4		
Texas	41,977.9	40,327.1	22,373.2	15,006.2	0.0	0.0	713.4	715.2	335.6	353.1	0.0	0.0	65,400.1	56,401.6	3,072.0	2,803.0	25,445.2	17,809.2	25,445.2	17,809.2		
Mountain	17,729.7	16,796.9	17,591.9	12,812.3	474.2	474.2	10,602.9	10,568.6	179.4	176.2	751.8	748.3	47,329.9	41,576.5	6,500.9	5,850.9	24,092.8	18,663.2	24,092.8	18,663.2		
Arizona	1,234.5	855.5	4,755.2	3,350.9	295.6	295.6	2,720.6	2,721.9	27.9	27.9	0.0	0.0	9,033.8	7,251.8	2,896.3	2,679.6	7,651.5	6,030.5	7,651.5	6,030.5		
Colorado	5,336.7	5,336.7	2,366.7	2,173.4	0.0	0.0	693.2	689.7	28.7	28.7	0.0	0.0	8,425.3	8,228.5	1,201.2	1,089.0	3,567.9	3,262.4	3,567.9	3,262.4		
Idaho	1,128.3	968.3	501.6	402.0	0.0	0.0	2,653.8	2,630.8	87.6	84.4												

Table 4.7.C. Net Summer Capacity of Utility Scale Units Using Primarily Fossil Fuels and by State, 2024 and 2023 (Megawatts)

Census Division and State	Natural Gas Fired Combined Cycle		Natural Gas Fired Combustion Turbine		Other Natural Gas		Coal		Petroleum Coke		Petroleum Liquids		Other Fossil Gas		Total Fossil Fuels	
	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023
New England	12,524.2	14,115.3	1,456.3	1,368.4	1,089.5	672.5	533.9	533.9	0.0	0.0	5,557.2	5,957.5	0.0	0.0	21,161.1	22,647.6
Connecticut	3,901.0	3,923.0	591.8	584.0	570.5	556.8	0.0	0.0	0.0	0.0	2,209.5	2,208.7	0.0	0.0	7,272.8	7,272.5
Maine	1,272.2	1,285.7	312.0	312.0	0.0	0.0	0.0	0.0	0.0	0.0	844.7	844.7	0.0	0.0	2,428.9	2,442.4
Massachusetts	4,387.3	5,942.9	536.3	456.2	93.4	90.3	0.0	0.0	0.0	0.0	2,275.9	2,276.8	0.0	0.0	7,292.9	8,766.2
New Hampshire	1,228.5	1,228.5	3.8	3.8	400.2	0.0	533.9	533.9	0.0	0.0	94.0	494.2	0.0	0.0	2,260.4	2,260.4
Rhode Island	1,735.2	1,735.2	12.4	12.4	25.4	25.4	0.0	0.0	0.0	0.0	7.1	7.1	0.0	0.0	1,780.1	1,780.1
Vermont	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	126.0	126.0	0.0	0.0	126.0	126.0
Middle Atlantic	37,150.1	37,337.0	6,914.8	7,092.0	15,931.5	15,936.8	5,362.6	6,008.7	11.6	11.6	5,149.5	5,112.0	114.9	114.9	70,655.0	71,613.0
New Jersey	8,222.0	8,374.0	2,604.2	2,734.5	66.9	69.9	0.0	0.0	11.6	11.6	290.1	290.1	29.0	29.0	11,222.8	11,509.1
New York	9,927.1	9,908.2	2,998.1	2,459.2	9,954.9	9,962.7	0.0	0.0	0.0	0.0	3,525.3	3,481.8	0.0	0.0	25,805.4	25,911.9
Pennsylvania	19,001.0	19,054.8	1,912.5	1,898.3	5,909.7	5,904.2	5,382.6	6,008.7	0.0	0.0	1,334.1	1,340.1	85.9	85.9	33,625.8	34,292.0
East North Central	31,065.4	31,442.5	26,165.6	26,550.4	4,643.6	4,503.0	36,512.1	37,336.3	25.1	25.1	2,147.3	2,269.1	854.0	1,043.0	101,639.1	103,395.4
Illinois	5,452.9	5,823.1	10,367.0	10,721.0	373.0	373.0	6,694.5	6,853.5	0.0	0.0	664.9	659.9	36.5	36.5	23,588.8	24,467.0
Indiana	3,892.3	3,899.6	3,343.0	3,365.9	992.2	851.4	12,721.4	12,847.2	0.0	0.0	85.3	95.8	384.1	545.1	21,418.3	21,605.0
Michigan	7,688.9	7,691.6	3,555.0	3,570.0	2,536.5	2,513.5	5,732.3	5,801.9	47.2	47.2	387.8	432.5	250.0	250.0	20,197.7	20,306.7
Ohio	10,552.6	10,554.2	5,721.0	5,721.3	91.4	102.2	6,620.5	6,607.5	145.5	145.5	503.0	503.0	183.4	211.4	23,817.4	23,845.1
Wisconsin	3,478.7	3,474.0	3,179.6	3,172.2	650.5	662.9	4,743.4	5,226.2	58.4	58.4	506.3	577.9	0.0	0.0	12,616.9	13,171.6
West North Central	7,051.7	7,047.3	11,873.7	11,620.1	3,729.5	3,755.9	29,329.7	30,374.7	32.0	32.0	3,831.5	3,843.8	8.4	8.4	55,856.5	56,682.2
Iowa	1,748.7	1,741.9	1,248.9	1,210.6	781.7	751.2	4,832.9	4,860.8	32.0	32.0	800.2	805.2	0.0	0.0	9,444.4	9,401.7
Kansas	247.0	247.0	2,173.6	2,208.4	1,398.2	1,396.3	4,695.0	4,524.7	0.0	0.0	540.1	544.7	0.0	0.0	9,053.9	8,921.1
Minnesota	2,532.9	2,532.9	2,570.4	2,545.0	428.1	421.9	3,135.5	3,141.7	0.0	0.0	789.9	772.3	0.0	0.0	9,456.8	9,413.8
Missouri	1,869.2	1,892.5	3,323.9	3,200.0	333.1	392.8	8,539.2	9,714.2	0.0	0.0	1,060.4	1,085.8	0.0	0.0	15,145.8	16,286.1
Nebraska	338.9	338.0	1,104.8	1,107.6	513.3	518.4	3,817.9	3,825.8	0.0	0.0	373.7	383.6	0.0	0.0	6,148.6	6,153.4
North Dakota	0.0	0.0	542.4	454.0	203.7	203.9	3,831.9	3,832.5	0.0	0.0	58.1	58.1	8.4	8.4	4,644.5	4,556.9
South Dakota	295.0	295.0	909.7	893.7	71.4	71.4	477.3	475.0	0.0	0.0	209.1	214.1	0.0	0.0	1,962.5	1,949.2
South Atlantic	65,888.7	65,781.6	32,491.9	32,264.9	13,248.8	14,129.5	35,415.3	35,006.2	83.8	83.8	5,849.1	5,941.1	135.0	135.0	153,112.6	153,342.1
Delaware	1,496.0	1,496.0	314.0	314.0	723.8	723.8	41.0	41.0	0.0	0.0	111.1	111.1	135.0	135.0	3,189.9	3,189.9
District of Columbia	0.0	0.0	20.6	20.6	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	20.6	20.6
Florida	35,819.7	35,743.0	8,791.4	8,791.0	5,698.3	5,201.3	3,564.7	3,989.7	0.0	0.0	1,596.9	1,610.9	0.0	0.0	55,471.0	55,335.9
Georgia	8,090.8	8,067.0	7,446.1	7,569.1	850.1	850.1	5,780.0	5,780.0	83.8	83.8	1,107.7	1,107.0	0.0	0.0	23,358.5	23,457.0
Maryland	2,741.1	2,745.8	1,675.4	1,675.6	1,212.6	1,211.3	1,273.0	1,453.0	0.0	0.0	1,546.3	1,656.3	0.0	0.0	8,448.4	8,742.0
North Carolina	5,579.0	5,579.0	6,395.5	6,030.5	3,277.7	4,665.7	5,561.0	4,552.0	0.0	0.0	491.0	491.0	0.0	0.0	21,304.2	21,318.2
South Carolina	3,252.0	3,252.0	2,548.6	2,528.7	780.0	780.0	4,754.0	4,749.0	0.0	0.0	243.5	216.6	0.0	0.0	11,578.1	11,526.3
Virginia	8,910.1	8,988.8	4,212.0	4,245.9	590.9	581.8	1,530.1	1,530.1	0.0	0.0	741.8	737.2	0.0	0.0	15,984.6	15,993.8
West Virginia	0.0	0.0	1,088.2	1,089.5	115.5	115.5	12,542.5	12,542.4	0.0	0.0	11.0	11.0	0.0	0.0	13,757.3	13,758.4
East South Central	23,835.1	23,800.8	13,685.0	13,682.0	4,136.3	4,012.2	19,506.5	20,288.5	0.0	0.0	532.8	533.9	3.8	0.0	61,699.5	62,317.4
Alabama	11,138.3	11,172.2	3,284.8	3,307.8	1,776.5	1,883.4	4,728.0	4,728.0	0.0	0.0	42.6	42.6	3.8	0.0	20,974.0	21,134.0
Kentucky	1,791.0	1,789.0	5,599.6	5,599.6	714.0	483.0	8,631.0	9,162.0	0.0	0.0	10.8	11.9	0.0	0.0	16,746.4	17,045.5
Mississippi	8,450.7	8,384.5	1,395.3	1,369.3	1,512.3	1,512.3	1,444.0	1,444.0	0.0	0.0	9.0	9.0	0.0	0.0	12,811.3	12,719.1
Tennessee	2,455.1	2,455.1	3,405.3	3,405.3	133.5	133.5	4,703.5	4,954.5	0.0	0.0	470.4	470.4	0.0	0.0	11,167.8	11,418.8
West South Central	64,443.9	64,856.8	17,447.4	16,899.8	28,788.3	29,761.0	26,393.7	26,698.6	856.7	891.4	744.1	754.2	344.7	344.7	139,018.8	140,206.5
Arkansas	4,608.2	4,605.2	702.8	703.3	824.0	703.4	4,734.0	4,734.0	0.0	0.0	9.0	9.0	0.0	0.0	10,752.9	10,875.0
Louisiana	9,404.2	9,688.0	2,845.0	2,834.2	5,252.7	5,872.1	2,121.6	2,069.5	792.9	827.6	49.7	49.7	167.6	167.6	20,633.7	21,508.7
Oklahoma	7,299.7	7,327.6	1,653.2	1,649.2	5,567.8	5,909.1	3,258.9	3,272.5	0.0	0.0	45.2	53.9	0.0	0.0	17,824.8	18,212.3
Texas	43,131.8	43,236.0	12,246.4	11,713.6	17,264.5	17,155.8	16,283.6	16,622.6	63.8	63.8	640.2	641.6	177.1	177.1	89,807.4	89,610.5
Mountain	23,015.7	23,087.2	10,014.1	9,570.6	5,045.7	3,683.1	20,208.9	21,299.9	52.0	52.0	327.9	537.0	4.8	7.8	58,669.1	58,237.6
Arizona	10,138.6	10,181.6	3,129.0	3,061.8	1,278.6	1,097.6	2,936.0	2,939.0	0.0	0.0	86.2	268.5	0.0	0.0	17,568.4	17,548.5
Colorado	3,250.5	3,193.5	2,637.2	2,661.0	636.2	633.4	3,786.0	3,804.0	0.0	0.0	150.5	177.5	0.0	3.0	10,460.4	10,472.4
Idaho	515.5	601.0	573.7	619.2	16.7	16.7	0.0	0.0	0.0	0.0	5.6	5.4	0.0	0.0	1,111.5	1,242.3
Montana	0.0	0.0	315.8	315.8	237.8	72.2	1,626.5	1,626.5	52.0	52.0	0.0	0.0	1.5	1.5	2,233.6	2,068.0
Nevada	5,703.0	5,703.0	1,629.6	1,185.6	450.0	447.3	740.4	740.4	0.0	0.0	6.0	6.0	0.0	0.0	8,529.0	8,082.3
New Mexico	1,484.1	1,484.1	943.3	945.3	767.7	833.7	1,540.0	1,540.0	0.0	0.0	46.0	46.0	0.0	0.0	4,781.1	4,849.1
Utah	1,830.0	1,830.0	534.6	534.6	332.5	328.2	4,581.0	4,581.0	0.0	0.0	27.8	27.8	0.0	0.0	7,305.9	7,301.6
Wyoming	94.0	94.0	250.9	247.3	1,326.2	254.0	4,999.0	6,069.0	0.0	0.0	5.8	5.8	3.3	3.3	6,670.2	6,673.4
Pacific Contiguous	26,458.4	26,426.9	12,349.5	12,312.6	4,669.0	4,568.1	727.0	727.0	0.0	0.0	471.4	439.0	212.5	213.0	44,887.8	44,686.6
California	20,412.6	20,391.1	11,506.3	11,469.4	4,410.2	4,309.3	57.0	57.0	0.0	0.0	442.2	415.2	212.5	213.0	37,040.8	36,855.0
Oregon	3,409.2	3,409.2	124.0	124.0	229.2	229.2	0.0	0.0	0.0	0.0	6.6	6.6	0.0	0.0	3,769.0	3,769.0
Washington	2,636.6	2,626.6	719.2	719.2	29.6	29.6	670.0	670.0	0.0	0.0	22.6	17.2	0.0	0.0	4,076.0	4,062.6
Pacific Noncontiguous	374.6	374.6	708.5	708.5	174.4	174.4	167.9	167.9	0.0	0.0	2,751.8	2,731.0	0.0	0.0	4,177.0	4,156.4
Alaska	374.6	374.6	708.5	708.5	174.4	174.4	167.9	167.9	0.0	0.0	743.2	751.1	0.0	0.0	2,168.6	2,176.5
Hawaii	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	2,008.4	1,979.9	0.0	0.0	2,008.4	1,979.9
U.S. Total	291,807.8	294,270.0	133,106.8	132,069.3	81,456.6	81,196.5	174,177.6	178,441.7	1,287.2	1,321.9	27,362.4	28,118.6	1,678.1	1,866.8	710,876.5	717,284.8

NM = Not meaningful due to large relative standard error.
Values are final.

NOTES:
Capacity from facilities with a total generator nameplate capacity less than 1 MW are excluded from this report. This exclusion may represent a significant portion of existing or planned capacity for some technologies such as solar photovoltaic generation.

Sources: U.S. Energy Information Administration, Form EIA-860, 'Annual Electric Generator Report' and Form EIA-860M, 'Monthly Update to the Annual Electric Generator Report.'

Table 4.08.A. Capacity Factors for Utility Scale Generators Primarily Using Fossil Fuels

Year/Month	Coal		Natural Gas								Petroleum					
	Combined Cycle		Gas Turbine		Steam Turbine		Internal Combustion		Steam Turbine		Gas Turbine		Internal Combustion			
	Time Adjusted Capacity (MW)	Capacity Factor	Time Adjusted Capacity (MW)	Capacity Factor	Time Adjusted Capacity (MW)	Capacity Factor	Time Adjusted Capacity (MW)	Capacity Factor	Time Adjusted Capacity (MW)	Capacity Factor	Time Adjusted Capacity (MW)	Capacity Factor	Time Adjusted Capacity (MW)	Capacity Factor	Time Adjusted Capacity (MW)	Capacity Factor
Annual Data																
2014	299,064.7	60.5%	224,183.2	48.6%	124,736.9	8.3%	75,049.1	10.3%	3,026.7	10.8%	18,057.0	13.0%	16,791.5	1.2%	5,011.3	2.1%
2015	286,082.7	54.3%	231,467.5	55.8%	123,444.3	9.8%	80,348.0	11.3%	3,507.8	11.9%	14,965.4	14.0%	16,122.8	1.3%	5,075.2	2.1%
2016	269,477.1	52.8%	236,442.8	55.4%	125,148.4	11.0%	81,225.1	12.3%	3,684.3	11.5%	13,993.7	12.2%	15,114.0	1.3%	5,082.8	2.3%
2017	259,930.2	53.1%	242,839.1	51.2%	125,806.6	9.6%	79,149.4	10.7%	4,225.5	11.6%	13,290.9	13.7%	14,275.3	1.0%	5,153.3	2.1%
2018	246,866.8	53.6%	254,403.3	55.1%	126,763.4	11.9%	76,177.8	12.6%	4,446.6	13.0%	13,300.1	14.2%	14,234.9	1.3%	5,289.7	1.9%
2019	235,089.3	47.5%	266,846.5	57.4%	128,832.5	11.4%	72,797.3	14.1%	4,848.3	15.3%	11,214.7	12.8%	14,009.7	1.0%	5,287.8	2.0%
2020	220,623.2	40.5%	274,300.4	57.1%	129,085.6	11.6%	75,462.3	14.2%	5,123.0	15.1%	8,443.3	13.9%	13,875.8	1.2%	5,300.7	1.8%
2021	212,587.0	49.1%	277,618.5	55.0%	130,103.4	11.7%	74,003.4	12.5%	5,171.8	18.2%	8,385.5	14.2%	13,729.8	1.6%	5,522.7	1.8%
2022	196,396.3	48.4%	286,467.1	56.6%	130,170.6	12.9%	77,518.8	15.6%	5,526.9	18.1%	9,839.0	13.2%	15,005.7	1.6%	5,407.0	1.8%
2023	182,767.5	42.4%	291,134.7	59.7%	130,736.5	12.9%	76,908.1	17.4%	5,802.9	20.1%	8,743.2	10.1%	14,386.8	1.3%	5,418.9	1.8%
2024	176,028.6	42.6%	292,189.2	60.5%	132,099.1	13.9%	75,196.7	19.9%	6,044.6	18.0%	8,122.7	8.9%	14,167.2	1.9%	5,461.8	1.8%
Year 2022																
January	202,043.3	57.4%	284,236.2	55.6%	129,881.8	11.3%	78,088.0	14.8%	5,454.3	16.0%	9,839.0	19.6%	15,279.8	1.4%	5,401.4	2.2%
February	202,013.8	52.2%	284,236.2	52.4%	129,967.8	9.6%	78,088.0	11.7%	5,454.3	14.8%	9,839.0	15.3%	15,279.8	0.9%	5,402.0	1.8%
March	200,821.8	41.0%	284,247.2	46.6%	130,009.3	8.2%	77,514.0	8.5%	5,484.9	13.6%	9,839.0	9.8%	15,245.8	1.0%	5,392.6	1.7%
April	200,376.8	38.5%	284,450.3	44.2%	130,070.8	9.6%	77,514.0	9.6%	5,486.4	13.5%	9,839.0	10.1%	15,119.1	0.9%	5,395.3	1.7%
May	198,851.8	42.1%	283,899.1	49.6%	130,070.8	12.5%	77,514.0	14.6%	5,544.4	14.7%	9,839.0	12.0%	15,119.1	1.4%	5,399.7	1.8%
June	195,863.8	52.5%	286,389.0	61.2%	130,127.6	16.9%	77,510.0	20.2%	5,546.0	18.8%	9,839.0	12.2%	14,947.1	1.8%	5,407.0	1.9%
July	195,881.8	59.6%	287,485.0	70.5%	130,274.1	20.1%	77,510.0	28.1%	5,549.7	23.0%	9,839.0	10.3%	14,947.1	2.5%	5,410.4	1.7%
August	194,856.8	59.2%	288,566.5	72.4%	130,035.1	18.5%	77,379.0	22.4%	5,563.9	25.1%	9,839.0	11.8%	14,947.1	2.2%	5,410.7	1.7%
September	192,425.8	47.3%	288,493.5	63.9%	130,259.8	13.8%	77,374.0	16.3%	5,559.0	21.7%	9,839.0	13.1%	14,858.1	1.7%	5,409.2	1.8%
October	192,425.8	38.7%	288,458.5	53.0%	130,348.7	10.2%	77,374.0	13.3%	5,558.0	17.9%	9,839.0	12.3%	14,817.2	1.4%	5,413.1	1.8%
November	192,271.3	40.9%	288,485.6	52.0%	130,380.6	11.2%	77,379.8	13.7%	5,555.9	17.9%	9,839.0	13.6%	14,789.6	1.0%	5,420.9	1.6%
December	189,316.3	51.4%	288,504.6	56.8%	130,606.5	12.5%	77,026.8	14.1%	5,560.7	19.3%	9,839.0	18.2%	14,735.6	2.8%	5,421.2	2.2%
Year 2023																
January	186,822.6	44.6%	287,456.6	57.4%	130,416.1	9.3%	78,868.8	9.6%	5,738.6	18.7%	8,743.2	9.1%	14,494.8	1.0%	5,428.8	1.9%
February	186,812.0	37.3%	287,688.6	57.1%	130,416.1	9.2%	78,868.8	10.3%	5,742.7	18.0%	8,743.2	11.7%	14,494.8	1.4%	5,426.8	1.8%
March	186,007.1	36.2%	288,941.6	53.6%	130,356.1	10.5%	78,303.3	11.5%	5,744.2	19.5%	8,743.2	8.9%	14,494.8	1.1%	5,422.2	1.8%
April	186,007.1	30.6%	289,463.1	47.9%	130,356.1	11.2%	77,868.3	13.4%	5,746.9	16.2%	8,743.2	8.4%	14,494.8	1.2%	5,422.2	2.0%
May	184,515.1	32.6%	291,190.1	53.0%	130,248.2	12.4%	77,038.3	15.4%	5,745.0	16.0%	8,743.2	7.9%	14,463.5	1.2%	5,413.4	1.8%
June	182,361.9	44.5%	291,270.1	63.7%	130,403.5	15.0%	76,724.3	22.1%	5,752.6	21.4%	8,743.2	10.2%	14,315.1	1.3%	5,399.1	1.8%
July	181,713.0	58.3%	292,441.8	74.0%	130,558.5	19.4%	76,724.3	31.7%	5,752.6	26.0%	8,743.2	14.3%	14,315.1	1.6%	5,414.9	1.6%
August	181,099.7	58.0%	292,441.8	74.1%	131,221.5	19.0%	76,724.3	31.0%	5,884.2	26.7%	8,743.2	13.3%	14,315.1	1.9%	5,416.6	1.6%
September	180,234.7	46.4%	292,441.8	66.2%	131,221.5	13.6%	75,688.3	22.4%	5,878.3	22.0%	8,743.2	14.5%	14,315.1	1.3%	5,425.7	1.5%
October	179,749.7	38.6%	293,100.7	53.8%	131,221.5	12.6%	75,687.9	16.3%	5,879.5	18.9%	8,743.2	8.7%	14,315.1	1.3%	5,429.6	1.7%
November	179,749.7	39.7%	293,100.7	54.8%	131,217.5	11.5%	75,681.6	14.1%	5,880.7	18.8%	8,743.2	6.8%	14,315.1	1.0%	5,414.6	2.1%
December	178,441.7	42.3%	293,802.5	60.0%	131,178.5	10.1%	74,854.6	10.8%	5,885.5	18.6%	8,743.2	7.7%	14,315.1	1.2%	5,413.5	1.8%
Year 2024																
January	177,497.2	56.8%	293,471.8	64.1%	131,958.7	12.9%	75,752.5	15.9%	5,899.4	18.5%	8,122.7	10.8%	14,230.3	2.0%	5,471.1	1.8%
February	177,497.2	36.2%	293,471.8	56.6%	131,611.5	10.0%	75,745.5	10.4%	5,901.6	16.4%	8,122.7	8.2%	14,230.3	1.3%	5,471.3	1.6%
March	177,323.7	29.8%	293,471.8	51.1%	131,662.7	10.6%	75,334.8	13.0%	5,898.6	16.1%	8,122.7	8.0%	14,230.3	1.3%	5,472.2	1.8%
April	176,697.6	29.9%	292,884.3	46.9%	131,662.7	13.1%	75,334.8	15.9%	5,901.7	14.8%	8,122.7	8.0%	14,230.3	1.6%	5,474.9	2.2%
May	176,201.6	35.6%	292,984.3	53.9%	131,655.7	13.4%	75,334.8	20.4%	5,951.9	16.0%	8,122.7	8.5%	14,230.3	1.8%	5,466.3	1.7%
June	176,021.6	49.0%	291,603.0	65.7%	131,565.2	15.1%	75,084.8	26.3%	6,000.8	19.5%	8,122.7	8.6%	14,122.3	2.0%	5,457.1	1.9%
July	176,021.6	55.0%	291,603.0	75.8%	131,960.2	20.9%	75,084.8	32.0%	6,007.2	22.5%	8,122.7	10.2%	14,122.3	3.3%	5,470.8	1.7%
August	176,021.6	53.2%	291,064.9	75.3%	132,555.6	19.2%	75,084.8	32.4%	6,181.5	22.3%	8,122.7	9.5%	14,122.3	2.7%	5,465.5	1.9%
September	175,762.6	43.7%	291,601.2	67.6%	132,555.6	14.7%	75,084.8	21.6%	6,182.0	19.0%	8,122.7	7.8%	14,122.3	1.7%	5,454.9	1.6%
October	174,584.6	37.0%	291,454.9	55.6%	132,524.6	13.1%	74,879.0	19.5%	6,183.8	16.3%	8,122.7	8.2%	14,122.3	1.8%	5,455.3	1.8%
November	174,597.6	35.9%	291,464.9	54.9%	132,706.8	12.3%	74,875.6	16.4%	6,183.8	18.0%	8,122.7	8.3%	14,122.3	1.7%	5,448.1	1.7%
December	174,177.6	48.7%	291,238.9	58.5%	132,741.8	11.0%	74,786.7	14.2%	6,236.6	16.7%	8,122.7	10.5%	14,122.3	1.5%	5,434.3	1.9%

Values are final.
Time adjusted capacity for month rows is the summer capacity of generators in operation for the entire month; units that began operation during the month or that retired during the month are excluded. Time adjusted capacity for year rows is a time weighted average of the month rows.
Capacity factors are a comparison of net generation with available capacity. See the technical note for an explanation of how capacity factors are calculated.
Sources: U.S. Energy Information Administration, Form EIA-923, Power Plant Operations Report; U.S. Energy Information Administration, Form EIA-860, 'Annual Electric Generator Report' and Form EIA-860M, 'Monthly Update to the Annual Electric Generator Report.'

Table 4.08.B. Capacity Factors for Utility Scale Generators Primarily Using Non-Fossil Fuels

Year/Month	Geothermal		Hydroelectric		Nuclear		Other Biomass		Other Fossil Gas		Solar				Wind		Wood	
	Time Adjusted Capacity (MW)	Capacity Factor	Time Adjusted Capacity (MW)	Capacity Factor	Time Adjusted Capacity (MW)	Capacity Factor	Time Adjusted Capacity (MW)	Capacity Factor	Time Adjusted Capacity (MW)	Capacity Factor	Time Adjusted Capacity (MW)	Capacity Factor	Time Adjusted Capacity (MW)	Capacity Factor	Time Adjusted Capacity (MW)	Capacity Factor	Time Adjusted Capacity (MW)	Capacity Factor
Annual Data																		
2014	2,513.3	72.0%	79,582.8	37.2%	98,569.3	91.7%	5,114.6	62.7%	1,994.0	54.0%	6,555.6	25.6%	1,445.3	18.3%	60,587.8	34.0%	8,319.7	60.0%
2015	2,523.0	71.9%	79,650.8	35.7%	98,614.6	92.3%	5,104.5	62.6%	2,527.7	60.8%	9,521.6	25.5%	1,697.3	21.7%	67,106.2	32.2%	9,024.5	59.3%
2016	2,516.6	71.6%	79,806.0	38.2%	99,364.8	92.3%	5,099.5	62.7%	2,458.8	64.8%	14,161.4	25.0%	1,757.9	22.1%	74,162.7	34.5%	8,979.8	58.3%
2017	2,460.4	73.2%	79,696.8	43.0%	99,619.5	92.3%	5,125.6	61.8%	2,375.8	62.8%	21,940.9	25.6%	1,757.9	21.8%	83,355.6	34.6%	8,807.5	60.2%
2018	2,391.5	76.0%	79,771.9	41.9%	99,605.2	92.5%	5,059.0	61.8%	2,543.9	65.4%	27,143.3	25.1%	1,757.9	23.6%	89,228.5	34.6%	8,760.2	60.6%
2019	2,535.2	69.6%	79,838.0	41.2%	98,836.7	93.4%	4,786.5	62.5%	2,504.1	67.4%	31,840.8	24.3%	1,758.1	21.2%	97,564.8	34.4%	8,485.0	59.0%
2020	2,561.5	69.1%	79,810.4	40.7%	97,238.3	92.4%	4,653.8	62.5%	2,275.2	64.6%	39,458.1	24.2%	1,747.9	20.6%	107,387.7	35.3%	8,327.2	57.8%
2021	2,588.5	69.8%	79,878.4	36.0%	95,802.7	92.8%	4,490.4	63.2%	1,902.5	60.9%	51,219.7	24.4%	1,629.0	20.5%	123,757.1	34.4%	7,959.0	59.9%
2022	2,616.0	69.0%	80,054.5	36.3%	94,969.9	92.7%	4,402.5	60.2%	1,716.0	61.6%	64,501.0	24.4%	1,480.0	23.1%	136,669.4	35.9%	7,817.6	57.9%
2023	2,670.6	69.4%	79,982.5	35.0%	95,065.2	93.0%	4,162.6	60.4%	1,871.6	53.8%	77,130.8	23.2%	1,480.0	22.1%	143,443.5	33.2%	7,830.2	53.5%
2024	2,690.2	64.6%	79,883.9	34.6%	98,022.9	90.8%	4,054.5	59.5%	1,685.1	49.0%	102,319.5	23.2%	1,392.0	25.0%	149,299.0	34.3%	7,476.0	55.8%
Year 2022																		
January	2,592.8	75.1%	80,036.5	40.6%	95,406.4	99.4%	4,460.5	60.7%	1,664.2	64.2%	60,335.2	16.8%	1,480.0	11.3%	132,415.6	37.5%	7,829.0	60.8%
February	2,592.8	70.3%	80,040.6	39.6%	95,406.4	96.5%	4,459.1	60.6%	1,664.2	62.8%	61,350.2	21.2%	1,480.0	15.9%	133,711.4	41.6%	7,829.0	62.6%
March	2,592.8	65.7%	80,050.6	41.0%	95,406.4	89.0%	4,444.5	59.8%	1,664.2	63.4%	61,673.4	24.4%	1,480.0	23.1%	133,969.5	42.7%	7,829.0	57.4%
April	2,592.8	67.1%	80,054.7	34.8%	95,406.4	80.5%	4,437.0	60.0%	1,733.5	56.2%	62,666.8	28.5%	1,480.0	30.1%	135,080.4	46.6%	7,829.0	54.9%
May	2,609.8	67.4%	80,054.7	39.2%	95,427.4	89.3%	4,434.2	59.2%	1,733.5	59.9%	63,122.2	30.9%	1,480.0	33.5%	137,384.2	41.1%	7,811.3	55.4%
June	2,609.8	67.0%	80,057.2	45.1%	94,658.9	96.4%	4,434.2	61.7%	1,733.5	63.6%	63,890.6	33.2%	1,480.0	34.9%	137,594.2	33.9%	7,805.5	59.5%
July	2,609.8	67.1%	80,057.2	41.2%	94,658.9	97.8%	4,374.4	61.7%	1,733.5	63.7%	65,118.6	31.2%	1,480.0	26.2%	137,993.8	28.6%	7,805.5	61.5%
August	2,639.4	67.9%	80,057.2	35.5%	94,658.9	97.8%	4,378.3	60.7%	1,733.5	59.5%	65,707.2	28.4%	1,480.0	25.3%	137,999.4	24.0%	7,817.5	60.3%
September	2,661.3	68.6%	80,058.7	29.5%	94,658.9	93.5%	4,369.7	59.5%	1,733.5	61.6%	66,419.3	26.5%	1,480.0	26.7%	138,005.0	27.3%	7,817.5	56.4%
October	2,620.5	65.3%	80,059.2	24.1%	94,658.9	83.7%	4,366.5	59.2%	1,733.5	59.5%	67,201.8	22.9%	1,480.0	26.4%	138,005.0	31.6%	7,817.5	50.9%
November	2,620.5	72.6%	80,059.2	31.0%	94,658.9	91.0%	4,354.3	59.6%	1,733.5	63.2%	67,739.4	16.5%	1,480.0	14.1%	138,025.0	40.8%	7,817.5	56.7%
December	2,648.6	74.1%	80,067.7	34.3%	94,658.9	98.1%	4,322.3	60.1%	1,728.2	62.3%	68,569.5	12.5%	1,480.0	9.0%	139,628.0	36.8%	7,804.5	58.8%
Year 2023																		
January	2,657.6	71.2%	79,971.6	38.2%	94,598.2	100.7%	4,259.7	60.6%	1,896.8	48.4%	71,639.2	14.2%	1,480.0	7.7%	140,883.2	36.3%	7,933.1	57.5%
February	2,657.6	72.4%	79,989.6	37.1%	94,598.2	95.7%	4,158.1	59.7%	1,896.8	54.3%	72,849.9	18.6%	1,480.0	10.9%	141,532.3	43.1%	7,933.1	56.2%
March	2,623.3	73.2%	79,989.6	35.9%	94,598.2	89.3%	4,158.1	58.3%	1,866.8	54.7%	73,402.2	21.5%	1,480.0	14.0%	142,245.7	40.6%	7,933.1	53.5%
April	2,623.3	70.6%	80,007.4	34.4%	94,598.2	83.2%	4,158.1	55.6%	1,866.8	54.7%	73,948.2	26.8%	1,480.0	27.8%	142,659.5	41.2%	7,933.1	48.6%
May	2,684.3	66.9%	79,978.4	46.5%	94,598.2	86.9%	4,158.1	61.1%	1,866.8	51.1%	74,880.6	29.5%	1,480.0	27.4%	142,976.1	30.0%	7,888.1	51.9%
June	2,684.3	66.5%	79,979.8	37.5%	94,598.2	95.2%	4,158.1	62.4%	1,866.8	54.1%	75,981.9	30.9%	1,480.0	34.6%	143,730.8	26.4%	7,873.5	52.2%
July	2,684.3	64.6%	79,979.8	36.9%	94,598.2	99.1%	4,159.4	61.9%	1,866.8	57.0%	77,601.9	30.9%	1,480.0	35.0%	143,730.8	25.9%	7,788.5	54.0%
August	2,671.8	63.1%	79,979.8	35.8%	95,712.2	97.9%	4,155.4	61.4%	1,866.8	56.4%	78,928.8	28.7%	1,480.0	28.3%	144,230.3	26.2%	7,788.5	56.3%
September	2,671.8	67.4%	79,977.0	29.4%	95,712.2	95.1%	4,155.4	58.1%	1,866.8	52.9%	79,648.0	25.6%	1,480.0	27.7%	144,334.3	27.1%	7,756.3	52.6%
October	2,695.8	70.4%	79,974.9	26.3%	95,712.2	86.3%	4,147.2	59.4%	1,866.8	51.2%	80,606.0	22.0%	1,480.0	26.1%	144,417.5	33.1%	7,756.3	47.4%
November	2,695.8	73.7%	79,979.5	29.6%	95,712.2	90.3%	4,148.8	61.8%	1,866.8	54.0%	82,386.8	16.7%	1,480.0	15.7%	145,235.0	34.6%	7,693.1	54.5%
December	2,695.8	72.9%	79,983.6	32.1%	95,712.2	96.7%	4,133.2	63.8%	1,866.8	56.4%	83,392.8	13.5%	1,480.0	9.9%	145,232.0	34.6%	7,693.1	56.7%
Year 2024																		
January	2,689.6	69.3%	79,886.6	36.3%	97,277.2	95.6%	4,097.7	60.8%	1,706.1	53.7%	91,150.6	13.4%	1,392.0	7.5%	146,957.0	31.6%	7,540.4	60.2%
February	2,689.6	69.0%	79,886.6	37.4%	97,277.2	95.4%	4,099.2	59.2%	1,706.1	50.2%	93,683.5	18.6%	1,392.0	12.4%	147,815.2	39.6%	7,540.4	58.3%
March	2,689.6	67.4%	79,887.1	39.3%	97,277.2	87.5%	4,098.2	56.5%	1,706.1	46.7%	94,296.2	21.8%	1,392.0	21.0%	148,016.7	40.7%	7,540.4	55.6%
April	2,689.6	65.5%	79,887.1	36.4%	97,277.2	81.8%	4,073.4	55.8%	1,678.1	48.2%	97,257.0	26.3%	1,392.0	32.2%	148,176.7	43.7%	7,493.4	52.5%
May	2,675.5	61.9%	79,887.1	41.2%	98,391.2	88.8%	4,056.4	60.8%	1,678.1	49.3%	98,677.7	29.0%	1,392.0	38.8%	149,305.6	35.2%	7,493.4	53.6%
June	2,675.5	61.5%	79,878.6	38.9%	98,391.2	96.3%	4,052.8	59.6%	1,678.1	48.1%	101,220.5	31.6%	1,392.0	40.1%	149,391.1	35.7%	7,493.4	56.4%
July	2,695.5	60.4%	79,878.6	36.0%	98,391.2	95.4%	4,034.3	60.9%	1,678.1	48.5%	103,886.6	30.3%	1,392.0	33.7%	149,419.7	25.2%	7,481.9	57.4%
August	2,695.5	60.8%	79,884.2	34.5%	98,391.2	95.3%	4,034.3	62.1%	1,678.1	49.9%	104,868.2	29.7%	1,392.0	33.1%	150,120.2	26.1%	7,481.9	58.2%
September	2,695.5	61.5%	79,884.2	27.7%	98,391.2	88.5%	4,037.5	59.9%	1,678.1	49.4%	106,071.6	25.4%	1,392.0	32.7%	150,470.4	26.9%	7,481.9	54.5%
October	2,695.5	62.4%	79,874.9	25.8%	98,391.2	80.3%	4,037.5	58.7%	1,678.1	45.7%	108,568.7	23.1%	1,392.0	22.8%	150,623.5	35.3%	7,417.2	47.8%
November	2,695.5	67.3%	79,874.9	29.1%	98,391.2	87.4%	4,037.5	60.4%	1,678.1	48.7%	111,404.8	16.2%	1,392.0	13.8%	150,623.5	36.9%	7,374.8	55.9%
December	2,695.5	68.8%	79,897.0	32.9%	98,391.2	97.3%	3,997.0	60.0%	1,678.1	49.6%	116,407.3	13.8%	1,392.0	11.7%	150,620.0	35.0%	7,374.8	58.7%

Values are final.

Time adjusted capacity for month rows is the summer capacity of generators in operation for the entire month; units that began operation during the month or that retired during the month are excluded. Time adjusted capacity for year rows is a time weighted average of the month rows.

Capacity factors are a comparison of net generation with available capacity. See the technical note for an explanation of how capacity factors are calculated.

Sources: U.S. Energy Information Administration, Form EIA-923, Power Plant Operations Report; U.S. Energy Information Administration, Form EIA-860, 'Annual Electric Generator Report' and Form EIA-860M, 'Monthly Update to the Annual Electric Generator Report.'

Table 4.08.C. Usage Factors for Utility Scale Storage Generators

Year/Month	Battery		Pumped Storage	
	Time Adjusted Capacity (MW)	Usage Factor	Time Adjusted Capacity (MW)	Usage Factor
Annual Data				
2014	155.1	1.7%	22,477.9	10.2%
2015	206.8	3.6%	22,568.9	10.2%
2016	423.0	3.8%	22,752.7	11.2%
2017	632.8	6.8%	22,791.7	11.4%
2018	713.6	5.2%	22,815.4	10.8%
2019	949.8	5.4%	22,754.7	10.4%
2020	1,210.3	5.2%	22,938.6	10.5%
2021	2,627.6	6.1%	23,007.7	10.2%
2022	6,566.1	6.4%	23,033.9	11.1%
2023	11,225.7	6.6%	23,132.1	10.9%
2024	19,945.1	8.3%	23,178.5	11.4%
Year 2022				
January	4,926.4	5.5%	23,013.4	9.5%
February	4,996.7	6.6%	23,013.4	8.9%
March	5,069.2	5.7%	23,013.4	9.1%
April	5,316.2	6.0%	23,013.4	7.3%
May	6,055.5	6.4%	23,043.9	10.9%
June	6,064.5	7.1%	23,043.9	14.8%
July	6,555.2	6.9%	23,043.9	15.9%
August	6,941.6	6.6%	23,043.9	16.4%
September	7,489.9	6.1%	23,043.9	13.2%
October	7,958.4	6.7%	23,043.9	8.4%
November	8,630.7	6.7%	23,043.9	9.2%
December	8,696.4	6.5%	23,043.9	9.6%
Year 2023				
January	9,168.7	6.9%	23,057.8	9.2%
February	9,236.4	6.5%	23,057.8	9.6%
March	9,318.4	7.0%	23,137.8	9.2%
April	9,621.5	7.2%	23,147.4	8.8%
May	9,791.5	6.5%	23,147.4	10.9%
June	9,943.1	6.4%	23,147.4	13.8%
July	10,846.6	6.5%	23,147.4	15.7%
August	12,332.2	6.4%	23,147.4	15.5%
September	12,815.4	6.3%	23,147.4	13.3%
October	13,515.9	7.0%	23,147.4	8.7%
November	13,768.3	6.7%	23,147.4	8.3%
December	14,197.5	6.3%	23,147.4	8.0%
Year 2024				
January	15,989.6	6.2%	23,118.6	9.5%
February	16,276.4	7.3%	23,118.6	9.7%
March	16,312.3	7.9%	23,198.6	7.4%
April	17,352.7	8.4%	23,198.6	9.1%
May	18,040.6	8.0%	23,198.6	12.5%
June	19,187.2	8.1%	23,198.6	15.6%
July	20,434.9	8.8%	23,198.6	16.8%
August	21,174.1	9.0%	23,198.6	16.3%
September	22,411.1	8.3%	23,198.6	13.0%
October	23,219.6	9.0%	23,198.6	8.3%
November	23,961.5	8.8%	23,156.6	8.7%
December	24,826.7	8.6%	23,156.6	9.4%

Values are final.

Time adjusted capacity for month rows is the summer capacity of generators in operation for the entire month; units that began operation during the month or that retired during the month are excluded. Time adjusted capacity for year rows is a time weighted average of the month rows.

Usage factors are a comparison of gross generation with available capacity. See the technical note for an explanation of how usage factors are calculated.

Sources: U.S. Energy Information Administration, Form EIA-923, Power Plant Operations Report; U.S. Energy Information Administration, Form EIA-860, 'Annual Electric Generator Report' and Form EIA-860M, 'Monthly Update to the Annual Electric Generator Report.'

Table 4.9 Total Capacity of Non Net Metered Distributed Generators by Technology Type and Sector, 2014 through 2024

Generators by Technology and Sector						
Year	Residential	Commercial	Industrial	Transportation	Direct Connected	Total
Photovoltaic						
2014	-	-	-	-	-	692,034
2015	-	-	-	-	-	825,354
2016	80,577	988,811	132,970	-	112,927	715,385
2017	189,910	513,251	177,192	-	120,946	998,299
2018	289,151	584,977	189,874	-	124,793	1,198,895
2019	437,911	688,050	202,992	-	151,393	1,480,356
2020	666,125	872,946	211,173	-	139,251	1,887,495
2021	891,399	1,205,648	254,733	-	144,532	2,306,312
2022	1,334,849	1,506,717	185,959	-	150,015	2,787,531
2023	1,613,746	1,114,113	221,723	-	156,700	3,126,282
2024	2,032,152	1,064,858	233,024	-	157,285	3,428,259
Battery						
2014	-	-	-	-	-	7,227
2015	-	-	-	-	-	34,443
2016	0,070	32,678	8,714	-	1,240	42,702
2017	3,918	42,884	12,271	-	1,444	60,515
2018	4,926	79,643	10,874	-	2,275	103,551
2019	14,308	113,708	15,519	-	15,929	159,544
2020	26,048	136,448	16,876	-	17,243	196,617
2021	109,876	166,043	16,733	-	20,719	313,371
2022	171,343	221,150	16,084	-	20,535	429,622
2023	239,419	242,722	16,999	-	3,110	501,990
2024	343,046	287,214	16,780	-	3,330	630,370
Battery Energy (MWh)						
2014	-	-	-	-	-	-
2015	-	-	-	-	-	-
2016	-	-	-	-	-	-
2017	-	-	-	-	-	-
2018	-	-	-	-	-	-
2019	-	-	-	-	-	-
2020	-	-	-	-	-	-
2021	-	-	-	-	-	-
2022	-	-	-	-	-	-
2023	607,049	561,387	0,086	-	22,134	1,189,636
2024	423,115	629,892	2,398	-	4,033	1,057,518
Wind						
2014	-	-	-	-	-	33,727
2015	-	-	-	-	-	26,686
2016	2,616	15,742	1,366	-	8,628	28,552
2017	2,632	18,452	1,044	-	8,988	29,117
2018	2,579	13,527	1,441	-	9,977	28,525
2019	2,437	15,797	1,462	-	9,918	29,514
2020	3,184	13,547	1,549	-	9,523	28,803
2021	2,091	15,338	1,433	-	9,971	27,832
2022	1,884	13,303	1,171	-	9,572	25,930
2023	1,961	15,547	0,771	-	9,573	27,753
2024	2,451	15,339	1,909	-	10,452	29,851
Hydroelectric						
2014	-	-	-	-	-	108,793
2015	-	-	-	-	-	113,234
2016	6,140	39,330	8,933	-	101,146	155,749
2017	9,315	30,243	8,933	-	103,057	149,318
2018	5,452	35,648	5,903	-	113,193	160,196
2019	7,482	37,818	5,903	-	113,912	164,713
2020	2,827	39,339	2,730	-	124,253	169,449
2021	2,529	43,226	6,063	-	102,913	154,731
2022	2,529	45,880	4,893	-	99,542	152,854
2023	2,529	44,698	4,493	-	109,544	160,054
2024	2,524	44,234	2,430	-	87,973	147,159
Fuel Cell						
2014	-	-	-	-	-	-
2015	-	-	-	-	-	-
2016	0,161	6,229	3,700	-	0,225	10,315
2017	0,167	7,963	6,136	-	0,620	14,886
2018	0,150	12,730	3,969	-	0,620	17,527
2019	0,150	19,943	3,901	-	0,620	24,319
2020	1,123	18,699	4,499	-	0,620	24,941
2021	0,133	20,608	5,164	-	0,620	26,525
2022	0,134	23,207	5,310	-	0,620	29,271
2023	0,144	21,903	5,310	-	0,620	28,442
2024	0,117	26,600	3,285	-	0,640	30,641
Internal Combustion						
2014	-	-	-	-	-	813,841
2015	-	-	-	-	-	797,594
2016	46,974	679,238	223,937	-	69,217	1,019,467
2017	86,784	651,943	386,355	-	1,927,614	1,927,614
2018	69,428	609,278	336,970	-	81,159	1,496,835
2019	76,934	955,455	263,507	0,275	111,993	1,498,152
2020	66,475	662,210	299,456	-	61,832	1,309,751
2021	70,081	606,179	345,146	-	78,941	1,499,347
2022	85,208	644,505	295,954	-	77,522	1,443,244
2023	78,988	1,040,711	321,368	-	74,499	1,525,066
2024	78,772	1,095,684	300,771	-	69,395	1,534,108
Gas Turbine						
2014	-	-	-	-	-	81,321
2015	-	-	-	-	-	49,338
2016	0,230	62,127	24,415	-	2,728	89,503
2017	11,792	56,187	29,999	-	3,893	101,869
2018	0,070	75,151	24,568	-	3,488	103,277
2019	0,077	76,096	22,128	-	4,488	102,389
2020	0,077	84,936	21,658	-	4,488	110,209
2021	0,197	102,084	22,383	-	1,253	125,867
2022	0,213	109,087	21,598	-	1,253	132,151
2023	0,213	96,421	37,178	-	1,253	135,071
2024	0,588	95,359	49,287	-	1,013	141,197
Steam Turbine						
2014	-	-	-	-	-	12,921
2015	-	-	-	-	-	10,521
2016	-	2,995	0,524	-	0,431	3,950
2017	1,250	1,900	1,264	-	0,431	4,845
2018	4,626	0,039	0,039	-	2,581	7,740
2019	-	8,499	0,039	-	2,581	11,059
2020	-	7,444	0,039	-	1,981	10,504
2021	-	7,589	0,039	-	2,581	10,700
2022	-	9,259	0,019	-	2,581	11,869
2023	-	7,779	0,019	-	2,581	10,379
2024	-	7,779	0,074	-	2,581	11,034
Geothermal						
2014	-	-	-	-	-	100,991
2015	-	-	-	-	-	88,423
2016	0,750	24,080	20,389	-	0,050	45,269
2017	1,139	33,090	15,729	-	4,950	51,911
2018	0,629	36,452	16,309	-	3,310	56,600
2019	0,644	37,238	14,964	-	1,571	56,385
2020	0,117	38,642	16,349	-	2,979	58,187
2021	0,841	48,090	15,964	-	2,018	64,474
2022	0,951	48,094	15,984	-	2,018	68,046
2023	1,233	47,136	7,134	-	1,103	56,732
2024	1,582	37,898	9,789	-	1,113	50,389
Total						
2014	-	-	-	-	-	1,859,451
2015	-	-	-	-	-	1,994,564
2016	137,524	1,261,861	413,648	-	302,793	2,115,826
2017	306,445	1,553,887	560,243	-	305,064	2,726,639
2018	374,968	1,763,392	588,737	-	367,899	3,094,796
2019	529,763	1,853,751	530,102	0,275	384,482	3,418,292
2020	744,304	2,064,924	575,111	-	360,620	3,765,154
2021	1,165,938	2,341,954	627,616	-	366,751	4,502,267
2022	1,507,061	2,551,175	580,578	-	363,662	5,002,473
2023	1,936,103	2,632,812	614,666	-	362,662	5,546,274
2024	2,451,708	2,692,217	589,949	-	333,779	6,026,657
Total Number of Generators						
2014	-	-	-	-	-	203,090
2015	-	-	-	-	-	215,525
2016	-	-	-	-	-	176,751
2017	-	-	-	-	-	215,889
2018	-	-	-	-	-	231,220
2019	-	-	-	-	-	251,857
2020	-	-	-	-	-	279,730
2021	-	-	-	-	-	322,085
2022	-	-	-	-	-	389,187
2023	-	-	-	-	-	433,096
2024	-	-	-	-	-	461,159

Starting in 2023, capacity and energy capacity is now collected for batteries. Prior to 2023, the battery historical data was listed as storage.

Starting in 2019, PV Capacities have been converted to AC.

Starting in 2016, Capacity is now collected by technology and sector.

Starting in 2013, the residential sector is now included and at net metering units are excluded.

Distributed generators are generation 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.

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

Source: U.S. Energy Information Administration, Form EIA-881, "Annual Electric Power Industry Report."

Table 4.10. Net Metering Customers and Capacity by Technology Type, by End Use Sector, 2014 through 2024

Year	Capacity (MW)					Customers				
	Residential	Commercial	Industrial	Transportation	Total	Residential	Commercial	Industrial	Transportation	Total
Photovoltaic										
2014	3,452.987	2,933.122	710.719	--	7,096.828	642,276	43,335	3,131	--	688,742
2015	5,357.358	3,455.124	884.664	--	9,697.146	958,850	51,501	3,624	--	1,013,975
2016	7,487.643	3,975.813	1,078.607	--	12,542.064	1,321,277	60,456	4,391	--	1,386,124
2017	9,486.987	5,119.870	1,197.785	--	15,804.641	1,626,283	69,538	5,267	--	1,701,088
2018	11,356.711	6,173.324	1,378.863	--	18,908.896	1,911,892	78,912	5,844	--	1,996,648
2019	13,863.288	7,181.594	1,613.248	--	22,658.129	2,283,702	86,552	6,499	--	2,376,753
2020	16,432.611	8,223.285	1,853.604	--	26,509.501	2,661,029	95,037	7,330	--	2,763,396
2021	19,929.222	9,462.694	2,036.963	--	31,428.877	3,157,429	104,645	8,108	--	3,270,182
2022	24,668.240	11,091.920	2,194.394	--	37,954.553	3,788,427	112,054	8,670	--	3,909,151
2023	30,490.572	12,303.454	2,409.643	--	45,203.667	4,549,601	123,679	9,977	--	4,683,257
2024	34,226.260	13,801.814	2,566.347	--	50,594.412	5,077,543	138,495	10,586	--	5,226,624
Battery										
2016	4.489	7.575	11.698	--	23.762	793	79	31	--	903
2017	13.276	15.356	12.328	--	40.960	2,316	137	34	--	2,487
2018	65.199	40.141	24.526	--	129.866	10,633	303	61	--	10,997
2019	153.282	48.397	40.441	--	242.120	24,007	427	93	--	24,527
2020	309.866	67.428	56.081	--	433.375	45,042	552	126	--	45,720
2021	631.087	88.178	61.909	--	781.174	86,124	807	150	--	87,081
2022	922.394	129.782	65.323	--	1,117.499	128,360	1,011	168	--	129,539
2023	1,346.459	370.969	88.261	--	1,805.686	191,493	1,580	205	--	193,278
2024	2,271.932	456.687	93.705	--	2,822.320	299,998	2,012	213	--	302,223
Virtual PV										
2016	42.653	267.434	3.168	--	313.255	13,898	1,828	11	--	15,737
2017	53.120	416.987	7.136	--	477.244	14,948	2,907	19	--	17,874
2018	68.951	523.977	8.069	--	600.997	19,116	4,996	33	--	24,145
2019	77.492	624.588	10.684	--	712.763	20,753	5,908	40	--	26,701
2020	108.466	818.499	11.845	--	938.810	23,411	6,517	46	--	29,974
2021	156.792	1,081.457	12.242	--	1,250.492	28,880	11,215	49	--	40,144
2022	160.309	1,493.413	15.880	--	1,669.604	29,401	24,761	54	--	54,216
2023	286.277	2,346.135	19.165	--	2,651.579	59,901	55,194	63	--	115,158
2024	327.357	3,850.457	27.579	--	4,205.396	91,705	90,628	65	--	182,398
Wind										
2014	37.918	101.622	25.426	--	164.966	5,379	1,351	94	--	6,824
2015	34.893	103.086	29.137	--	167.116	5,387	1,434	109	--	6,930
2016	37.030	108.726	41.454	--	187.210	5,759	1,470	113	--	7,342
2017	35.005	119.651	49.507	--	204.163	5,258	1,429	111	--	6,798
2018	33.625	133.856	52.386	--	219.867	5,368	1,452	110	--	6,930
2019	33.668	148.594	52.580	--	234.842	5,218	1,438	107	--	6,763
2020	29.858	151.950	76.209	--	258.017	4,825	1,378	105	--	6,308
2021	28.103	152.021	76.253	--	256.377	4,711	1,350	106	--	6,167
2022	27.616	146.647	82.158	--	256.421	4,648	1,303	97	--	6,048
2023	27.566	146.114	72.127	--	245.807	4,696	1,296	102	--	6,094
2024	26.593	164.626	72.222	--	263.441	4,476	1,298	98	--	5,872
Other										
2014	7.633	102.797	98.277	--	208.707	857	397	201	--	1,455
2015	7.873	116.382	116.780	--	241.035	821	445	249	--	1,515
2016	7.952	155.889	149.608	--	313.449	862	592	325	--	1,779
2017	9.064	208.639	199.398	--	417.101	915	693	330	--	1,938
2018	6.351	258.601	241.416	--	506.368	692	826	347	--	1,865
2019	23.364	254.281	263.966	--	541.611	2,226	842	381	--	3,449
2020	12.983	281.848	282.195	--	577.026	850	814	385	--	2,049
2021	9.338	337.186	298.198	--	644.722	962	937	403	--	2,302
2022	12.129	364.602	317.492	--	694.223	1,256	972	402	--	2,630
2023	22.263	418.597	383.953	--	824.813	2,961	969	610	--	4,540
2024	22.610	426.952	295.952	--	745.514	2,301	955	403	--	3,659
All Technologies										
2014	3,498.538	3,137.541	834.422	--	7,470.501	648,512	45,083	3,426	--	697,021
2015	5,400.124	3,674.592	1,030.581	--	10,105.297	965,058	53,380	3,982	--	1,022,420
2016	7,715.715	4,576.384	1,289.946	--	13,582.045	1,341,796	64,346	4,840	--	1,410,982
2017	9,584.177	5,865.147	1,453.826	--	16,903.148	1,647,404	74,567	5,727	--	1,727,698
2018	11,465.638	7,089.758	1,680.734	--	20,236.128	1,937,068	86,186	6,334	--	2,029,588
2019	13,997.811	8,209.056	1,940.478	--	24,147.345	2,311,899	94,740	7,027	--	2,413,666
2020	16,583.921	9,475.582	2,223.853	--	28,283.355	2,690,115	103,746	7,866	--	2,801,727
2021	20,123.453	11,033.357	2,423.656	--	33,580.468	3,191,982	118,147	8,666	--	3,318,795
2022	24,868.296	13,096.584	2,609.924	--	40,574.800	3,823,732	139,090	9,223	--	3,972,045
2023	30,826.677	15,214.297	2,884.888	--	48,925.862	4,617,159	181,138	10,752	--	4,809,049
2024	34,602.819	18,243.845	2,962.100	--	55,808.760	5,176,025	231,376	11,152	--	5,418,553

Starting in 2023, capacity and customers are now collected for batteries. Prior to 2023, the battery historical data was listed as storage.

N/A = Not Available.

Total customer count for the years 2007, 2009, and 2010 were revised based on requests from respondents.

Capacity and customer count was not collected by technology type before 2010.

Starting in 2013, there is no maximum capacity on installed units.

Starting in 2016, utilities have the option to report photovoltaic in DC or AC. Values have been converted to AC.

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

Table 4.11. Fuel-Switching Capacity of Operable Generators Reporting Natural Gas as the Primary Fuel, by Producer Type, 2024
(Megawatts, Percent)

Producer Type	Fuel-Switchable Part of Total				
	Total Net Summer Capacity of All Generators Reporting Natural Gas as the Primary Fuel	Net Summer Capacity of Natural Gas-Fired Generators Reporting the Ability to Switch to Petroleum Liquids	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 Utilities	273,739.3	82,320.4	30.1%	77,918.4	19,091.0
Independent Power Producers, Non-Combined Heat and Power Plants	190,783.5	42,820.7	22.4%	39,475.6	7,386.8
Independent Power Producers, Combined Heat and Power Plants	23,371.7	3,543.3	15.2%	3,521.4	298.1
Electric Power Sector Subtotal	487,894.4	128,684.4	26.4%	120,915.5	26,775.9
Commercial Sector	2,408.3	965.9	40.1%	924.1	148.1
Industrial Sector	16,068.4	903.9	5.6%	880.9	66.8
All Sectors	506,371.0	130,554.2	25.8%	122,720.4	26,990.7

Notes: Petroleum liquids include 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, waste oil, and propane.
Source: U.S. Energy Information Administration, Form EIA-860, 'Annual Electric Generator Report.'

**Table 4.12. Fuel-Switching Capacity of Operable Generators Reporting Petroleum Liquids as the Primary Fuel,
by Producer Type, 2024 (Megawatts, Percent)**

Producer Type	Total Net Summer Capacity of All Generators Reporting Petroleum Liquids as the Primary Fuel	Fuel-Switchable Part of Total		
		Net Summer Capacity of Petroleum Liquids-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 Utilities	14,080.1	1,345.3	9.6%	1,330.6
Independent Power Producers, Non-Combined Heat and Power Plants	11,795.8	3,530.0	29.9%	2,406.8
Independent Power Producers, Combined Heat and Power Plants	259.6	--	0.0%	--
Electric Power Sector Subtotal	26,135.5	4,875.3	18.7%	3,737.4
Commercial Sector	985.8	--	0.0%	--
Industrial Sector	241.2	29.0	12.0%	25.0
All Sectors	27,362.5	4,904.3	17.9%	3,762.4

Notes: Petroleum liquids include 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, waste oil, and propane.

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

**Table 4.13. Fuel-Switching Capacity of Operable Generators Reporting Natural Gas as the Primary Fuel,
by Type of Prime Mover, 2024 (Megawatts, Percent)**

Prime Mover Type	Number of Natural Gas-Fired Generators Reporting the Ability to Switch to Petroleum Liquids	Net Summer Capacity of Natural Gas-Fired Generators Reporting the Ability to Switch to Petroleum Liquids	Fuel Switchable Net Summer Capacity Reported to Have No Factors that Limit the Ability to Switch to Petroleum Liquids
Steam Generator	158	23,611.9	9,356.6
Combined Cycle	364	49,509.6	5,658.1
Internal Combustion	303	1,192.7	344.7
Gas Turbine	806	56,239.9	11,631.4
All Fuel Switchable Prime Movers	1,631	130,554.2	26,990.7

Notes: Petroleum liquids include 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, waste oil, and propane.

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

Table 4.14. Fuel-Switching Capacity of Operable Generators Reporting Natural Gas as the Primary Fuel,

by Year of Initial Commercial Operation, 2024 (Megawatts, Percent)

Year of Initial Commercial Operation	Number of Natural Gas-Fired Generators Reporting the Ability to Switch to Petroleum Liquids	Net Summer Capacity of Natural Gas-Fired Generators Reporting the Ability to Switch to Petroleum Liquids	Fuel Switchable Net Summer Capacity Reported to Have No Factors that Limit the Ability to Switch to Petroleum Liquids
Pre-1970	230	9,461.1	3,497.8
1970-1974	203	11,085.5	4,182.5
1975-1979	84	10,009.2	3,960.4
1980-1984	39	844.6	205.6
1985-1989	72	2,144.4	184.8
1990-1994	175	10,849.3	1,301.6
1995-1999	119	8,765.6	946.0
2000-2004	393	37,351.6	5,639.1
2005-2009	120	15,929.1	1,970.8
2010-2014	99	11,461.6	243.3
2015-2019	68	9,417.9	2,678.1
2020-2024	29	3,234.3	2,180.8
Total	1,631	130,554.2	26,990.7

Notes: Petroleum liquids include 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, waste oil, and propane.

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

Chapter 5

Consumption of Fossil Fuels

**Table 5.1.A. Coal: Consumption for Electricity Generation,
by Sector, 2014 - 2024 (Thousand Tons)**

		Electric Power Sector			
Period	Total (all sectors)	Electric Utilities	Independent Power Producers	Commercial Sector	Industrial Sector
Annual Totals					
2014	853,634	624,235	224,568	202	4,629
2015	739,594	539,506	195,927	163	3,999
2016	677,371	496,192	178,047	111	3,021
2017	663,911	484,389	176,643	95	2,783
2018	636,213	473,617	159,976	87	2,534
2019	537,620	399,545	135,838	76	2,161
2020	435,351	325,352	108,125	72	1,802
2021	500,367	372,694	125,920	87	1,666
2022	471,576	349,320	120,514	87	1,655
2023	386,626	291,034	94,063	69	1,460
2024	372,931	284,849	86,586	65	1,431
Year 2022					
January	48,671	35,515	13,004	8	145
February	39,951	28,588	11,219	7	137
March	34,396	24,194	10,045	5	151
April	30,904	22,073	8,704	4	124
May	35,210	26,438	8,621	3	148
June	41,748	31,926	9,666	9	147
July	49,433	37,902	11,380	8	143
August	48,356	36,307	11,897	9	142
September	37,302	28,179	8,983	9	130
October	31,458	23,343	7,980	8	126
November	32,398	23,313	8,953	8	122
December	41,750	31,540	10,062	9	139
Year 2023					
January	35,506	27,360	7,998	9	138
February	26,854	19,980	6,749	8	118
March	28,671	21,207	7,345	6	114
April	22,889	16,155	6,616	7	111
May	25,484	18,557	6,799	6	122
June	33,541	26,111	7,308	3	120
July	44,412	34,525	9,752	4	131
August	43,887	34,029	9,730	4	123
September	34,223	26,184	7,913	5	121
October	29,580	21,997	7,460	6	117
November	29,549	21,115	8,310	6	117
December	32,031	23,814	8,083	7	127
Year 2024					
January	42,393	32,434	9,820	10	128
February	25,982	20,147	5,708	7	120
March	22,380	17,494	4,753	6	127
April	21,240	15,721	5,417	5	97
May	26,178	19,956	6,105	2	115
June	34,428	26,875	7,435	3	115
July	40,450	31,245	9,073	5	126
August	39,364	30,096	9,138	5	124
September	31,493	24,019	7,351	5	118
October	27,312	20,283	6,906	5	119
November	26,333	19,691	6,522	5	115
December	35,378	26,887	8,358	6	128

Notes: Beginning with the collection of Form EIA-923 in January 2008, the methodology to allocate total fuel consumption for electricity generation and consumption for useful thermal output was changed.

The new methodology was retroactively applied to 2004-2007 data. See the Technical Notes (Appendix C) for further information. See Glossary for definitions.

Values are final. See Technical Notes for a discussion of the sample design for the Form EIA-923 and predecessor forms.

Coal includes anthracite, bituminous, subbituminous, lignite, and waste coal; synthetic coal and refined coal; and beginning in 2011, coal-derived synthesis gas. Prior to 2011 coal-derived synthesis gas was included in Other Fossil Gas.

See the Technical Notes for fuel conversion factors.

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

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

Beginning with 2008 data, the Form EIA-923, Power Plant Operations Report, replaced the following: Form EIA-906, Power Plant Report; Form EIA-920, Combined Heat and Power Plant Report.

Table 5.1.B. Coal: Consumption for Useful Thermal Output, by Sector, 2014 - 2024 (Thousand Tons)

		Electric Power Sector			
Period	Total (all sectors)	Electric Utilities	Independent Power Producers	Commercial Sector	Industrial Sector
Annual Totals					
2014	18,107	978	1,821	861	14,448
2015	16,632	1,032	1,980	635	12,985
2016	16,586	2,979	1,336	572	11,700
2017	14,667	2,802	1,158	515	10,192
2018	13,813	2,268	1,356	490	9,700
2019	12,397	2,062	1,161	443	8,731
2020	10,402	1,635	715	401	7,651
2021	11,301	2,153	667	447	8,034
2022	11,356	2,269	731	448	7,908
2023	9,363	1,580	527	331	6,925
2024	8,883	1,485	338	356	6,703
Year 2022					
January	1,071	221	66	48	736
February	930	189	67	49	625
March	985	181	78	32	694
April	898	163	72	22	641
May	904	149	56	24	676
June	892	173	52	33	634
July	954	219	55	36	643
August	963	203	62	37	661
September	905	190	57	38	621
October	933	174	56	38	664
November	904	181	56	43	624
December	1,018	227	55	48	688
Year 2023					
January	922	157	53	43	669
February	787	127	47	37	576
March	839	142	65	33	600
April	710	88	40	29	553
May	744	119	33	22	569
June	731	117	43	20	552
July	811	167	36	21	586
August	771	157	38	22	553
September	753	146	34	22	551
October	734	114	47	22	551
November	760	115	43	28	574
December	802	131	48	33	591
Year 2024					
January	926	167	41	53	665
February	753	131	31	40	552
March	813	129	46	31	607
April	667	114	29	26	498
May	672	107	31	17	518
June	668	112	25	23	507
July	733	130	23	23	558
August	728	144	19	25	540
September	691	115	16	25	534
October	690	99	20	27	545
November	733	104	19	32	578
December	809	134	38	34	603

Notes: Beginning with the collection of Form EIA-923 in January 2008, the methodology to allocate total fuel consumption for electricity generation and consumption for useful thermal output was changed.

The new methodology was retroactively applied to 2004-2007 data. See the Technical Notes (Appendix C) for further information. See Glossary for definitions.

Values are final. See Technical Notes for a discussion of the sample design for the Form EIA-923 and predecessor forms.

Coal includes anthracite, bituminous, subbituminous, lignite, and waste coal; synthetic coal and refined coal; and beginning in 2011, coal-derived synthesis gas. Prior to 2011 coal-derived synthesis gas was included in Other Fossil Gas.

See the Technical Notes for fuel conversion factors.

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

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

Beginning with 2008 data, the Form EIA-923, Power Plant Operations Report, replaced the following: Form EIA-906, Power Plant Report; Form EIA-920, Combined Heat and Power Plant Report.

Table 5.1.C. Coal: Consumption for Electricity Generation and Useful Thermal Output, by Sector, 2014 - 2024 (Thousand Tons)

		Electric Power Sector			
Period	Total (all sectors)	Electric Utilities	Independent Power Producers	Commercial Sector	Industrial Sector
Annual Totals					
2014	871,741	625,212	226,389	1,063	19,076
2015	756,226	540,538	197,906	798	16,984
2016	693,958	499,172	179,383	683	14,720
2017	678,578	487,192	177,801	610	12,975
2018	650,027	475,885	161,332	577	12,233
2019	550,017	401,607	136,998	519	10,892
2020	445,753	326,987	108,840	473	9,453
2021	511,669	374,848	126,587	534	9,700
2022	482,931	351,589	121,245	535	9,563
2023	395,989	292,615	94,591	400	8,384
2024	381,814	286,334	86,924	422	8,134
Year 2022					
January	49,742	35,736	13,069	56	881
February	40,880	28,777	11,286	55	762
March	35,381	24,375	10,123	37	845
April	31,802	22,236	8,776	25	765
May	36,114	26,587	8,677	27	824
June	42,640	32,099	9,718	42	781
July	50,387	38,121	11,435	44	787
August	49,318	36,510	11,959	46	803
September	38,207	28,369	9,040	47	751
October	32,391	23,518	8,036	46	791
November	33,301	23,494	9,009	52	746
December	42,768	31,766	10,117	57	828
Year 2023					
January	36,428	27,518	8,051	51	808
February	27,641	20,107	6,796	44	694
March	29,511	21,349	7,409	39	714
April	23,599	16,243	6,656	36	664
May	26,227	18,677	6,832	28	691
June	34,273	26,228	7,351	22	672
July	45,223	34,692	9,788	26	718
August	44,658	34,186	9,768	26	677
September	34,975	26,329	7,948	27	671
October	30,313	22,111	7,507	27	668
November	30,308	21,231	8,353	34	691
December	32,833	23,945	8,131	39	718
Year 2024					
January	43,320	32,601	9,861	63	794
February	26,736	20,278	5,739	47	671
March	23,193	17,623	4,800	37	733
April	21,907	15,835	5,446	31	595
May	26,850	20,063	6,135	19	632
June	35,096	26,987	7,460	26	622
July	41,183	31,375	9,096	28	684
August	40,091	30,240	9,157	31	664
September	32,184	24,134	7,367	31	652
October	28,002	20,382	6,926	31	663
November	27,066	19,795	6,541	37	692
December	36,188	27,021	8,396	41	731

Notes: Beginning with the collection of Form EIA-923 in January 2008, the methodology to allocate total fuel consumption for electricity generation and consumption for useful thermal output was changed.

The new methodology was retroactively applied to 2004-2007 data. See the Technical Notes (Appendix C) for further information. See Glossary for definitions.

Values are final. See Technical Notes for a discussion of the sample design for the Form EIA-923 and predecessor forms.

Coal includes anthracite, bituminous, subbituminous, lignite, and waste coal; synthetic coal and refined coal; and beginning in 2011, coal-derived synthesis gas. Prior to 2011 coal-derived synthesis gas was included in Other Fossil Gas.

See the Technical Notes for fuel conversion factors.

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

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

Beginning with 2008 data, the Form EIA-923, Power Plant Operations Report, replaced the following: Form EIA-906, Power Plant Report; Form EIA-920, Combined Heat and Power Plant Report.

**Table 5.1.D. Coal: Consumption for Electricity Generation,
by Sector, 2014 - 2024 (Billion Btus)**

by Sector, 2014 - 2024 (Simon Data)		Electric Power Sector			
Period	Total (all sectors)	Electric Utilities	Independent Power Producers	Commercial Sector	Industrial Sector
Annual Totals					
2014	16,472,004	12,217,628	4,154,134	4,344	95,898
2015	14,167,878	10,456,910	3,624,869	3,443	82,656
2016	12,979,911	9,641,625	3,274,103	2,293	61,889
2017	12,606,527	9,328,961	3,219,833	1,914	55,820
2018	12,037,444	9,041,357	2,944,321	1,736	50,029
2019	10,166,309	7,623,281	2,498,944	1,509	42,575
2020	8,224,162	6,206,153	1,980,662	1,330	36,018
2021	9,482,946	7,124,244	2,323,722	1,577	33,403
2022	8,868,315	6,636,816	2,197,088	1,629	32,781
2023	7,240,596	5,556,006	1,655,101	1,182	28,307
2024	7,013,266	5,455,735	1,528,334	1,116	28,081
Year 2022					
January	932,465	681,662	247,758	162	2,884
February	755,759	541,928	210,989	131	2,711
March	648,077	457,992	186,983	100	3,002
April	586,192	425,501	158,133	68	2,491
May	664,220	508,370	152,870	58	2,922
June	782,819	606,620	173,150	154	2,895
July	929,477	719,031	207,472	145	2,828
August	907,079	685,213	218,881	166	2,820
September	695,932	531,013	162,189	170	2,561
October	575,870	435,090	138,144	153	2,484
November	601,968	442,289	157,075	154	2,450
December	788,457	602,109	183,445	169	2,733
Year 2023					
January	659,607	513,389	143,312	160	2,746
February	500,285	376,970	120,835	140	2,339
March	540,007	405,614	132,031	113	2,249
April	432,462	314,052	116,149	112	2,150
May	474,300	353,561	118,277	92	2,369
June	623,856	499,160	122,404	44	2,248
July	840,127	664,788	172,782	64	2,493
August	829,792	653,077	174,273	66	2,376
September	642,442	498,804	141,204	78	2,357
October	547,246	416,202	128,691	96	2,257
November	549,358	402,536	144,457	95	2,270
December	601,115	457,856	140,685	121	2,454
Year 2024					
January	800,706	618,577	179,448	188	2,494
February	480,064	379,572	98,009	130	2,354
March	417,432	335,607	79,205	104	2,516
April	399,867	303,921	93,958	81	1,907
May	495,782	385,244	108,257	34	2,247
June	658,338	520,787	135,242	56	2,254
July	768,748	602,294	163,872	81	2,501
August	743,448	578,541	162,374	88	2,445
September	586,255	457,869	126,009	89	2,287
October	506,627	384,006	120,233	74	2,314
November	489,182	374,337	112,516	89	2,240
December	666,817	514,980	149,212	103	2,522

Notes: Beginning with the collection of Form EIA-923 in January 2008, the methodology to allocate total fuel consumption for electricity generation and consumption for useful thermal output was changed.

The new methodology was retroactively applied to 2004-2007 data. See the Technical Notes (Appendix C) for further information. See Glossary for definitions.

Values are final. See Technical Notes for a discussion of the sample design for the Form EIA-923 and predecessor forms.

Coal includes anthracite, bituminous, subbituminous, lignite, and waste coal; synthetic coal and refined coal; and beginning in 2011, coal-derived synthesis gas. Prior to 2011 coal-derived synthesis gas was included in Other Fossil Gas.

See the Technical Notes for fuel conversion factors.

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

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

Beginning with 2008 data, the Form EIA-923, Power Plant Operations Report, replaced the following: Form EIA-906, Power Plant Report; Form EIA-920, Combined Heat and Power Plant Report.

**Table 5.1.E. Coal: Consumption for Useful Thermal Output,
by Sector, 2014 - 2024 (Billion Btus)**

by Sector, 2014 - 2024 (Simon Dzus)

		Electric Power Sector			
Period	Total (all sectors)	Electric Utilities	Independent Power Producers	Commercial Sector	Industrial Sector
Annual Totals					
2014	391,550	18,332	37,139	18,805	317,274
2015	356,895	18,640	37,815	13,483	286,956
2016	342,370	51,590	29,330	11,736	249,714
2017	297,521	48,745	24,682	10,284	213,810
2018	278,277	38,513	28,829	9,719	201,217
2019	247,251	33,559	25,686	8,571	179,436
2020	208,052	26,952	15,375	7,424	158,300
2021	224,841	35,397	14,246	8,211	166,986
2022	222,498	37,337	14,441	8,270	162,450
2023	181,221	25,906	10,216	5,839	139,259
2024	171,692	23,799	6,413	6,226	135,255
Year 2022					
January	21,216	3,619	1,375	942	15,279
February	18,306	3,109	1,362	895	12,939
March	19,606	2,963	1,560	592	14,491
April	17,720	2,720	1,303	384	13,314
May	17,823	2,433	1,097	407	13,886
June	17,248	2,787	967	605	12,889
July	18,598	3,623	1,062	684	13,229
August	18,804	3,331	1,213	699	13,561
September	17,542	3,149	1,155	701	12,537
October	18,133	2,905	1,112	687	13,429
November	17,783	2,985	1,157	780	12,861
December	19,719	3,713	1,078	893	14,035
Year 2023					
January	18,141	2,595	951	794	13,800
February	15,528	2,083	937	672	11,836
March	16,361	2,339	1,339	589	12,095
April	13,897	1,475	865	508	11,049
May	14,545	1,969	704	380	11,493
June	13,843	1,860	958	340	10,685
July	15,546	2,795	738	365	11,648
August	14,582	2,623	702	387	10,871
September	14,472	2,360	651	391	11,069
October	14,100	1,848	829	366	11,058
November	14,698	1,853	732	475	11,638
December	15,507	2,106	809	573	12,018
Year 2024					
January	17,751	2,649	751	1,000	13,351
February	14,619	2,113	626	723	11,158
March	15,856	2,021	788	527	12,520
April	12,908	1,866	529	453	10,061
May	12,991	1,715	582	282	10,413
June	12,904	1,798	509	397	10,200
July	14,368	2,098	445	410	11,415
August	14,120	2,403	364	435	10,918
September	13,278	1,894	333	435	10,617
October	13,417	1,554	423	439	11,002
November	14,017	1,606	384	537	11,490
December	15,463	2,082	679	591	12,111

Notes: Beginning with the collection of Form EIA-923 in January 2008, the methodology to allocate total fuel consumption for electricity generation and consumption for useful thermal output was changed.

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Coal includes anthracite, bituminous, subbituminous, lignite, and waste coal; synthetic coal and refined coal; and beginning in 2011, coal-derived synthesis gas. Prior to 2011 coal-derived synthesis gas was included in Other Fossil Gas.

See the Technical Notes for fuel conversion factors.

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

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

Beginning with 2008 data, the Form EIA-923, Power Plant Operations Report, replaced the following: Form EIA-906, Power Plant Report; Form EIA-920, Combined Heat and Power Plant Report.

Table 5.1.F. Coal: Consumption for Electricity Generation and Useful Thermal Output, by Sector, 2014 - 2024 (Billion Btus)

			Electric Power Sector			
Period	Total (all sectors)	Electric Utilities	Independent Power Producers	Commercial Sector	Industrial Sector	
Annual Totals						
2014	16,863,554	12,235,960	4,191,273	23,149	413,173	
2015	14,524,773	10,475,551	3,662,685	16,926	369,612	
2016	13,322,281	9,693,215	3,303,433	14,029	311,604	
2017	12,904,048	9,377,705	3,244,514	12,198	269,630	
2018	12,315,720	9,079,870	2,973,150	11,455	251,245	
2019	10,413,560	7,656,840	2,524,630	10,080	222,011	
2020	8,432,214	6,233,105	1,996,036	8,754	194,318	
2021	9,707,787	7,159,642	2,337,968	9,788	200,389	
2022	9,090,813	6,674,153	2,211,529	9,900	195,231	
2023	7,421,817	5,581,912	1,665,316	7,022	167,567	
2024	7,184,959	5,479,534	1,534,747	7,342	163,336	
Year 2022						
January	953,681	685,281	249,133	1,104	18,163	
February	774,064	545,038	212,351	1,026	15,650	
March	667,683	460,955	188,543	692	17,494	
April	603,912	428,220	159,436	452	15,804	
May	682,042	510,802	153,967	465	16,808	
June	800,067	609,407	174,117	759	15,784	
July	948,074	722,654	208,534	830	16,057	
August	925,883	688,544	220,093	864	16,381	
September	713,474	534,161	163,344	871	15,097	
October	594,004	437,995	139,256	839	15,913	
November	619,751	445,273	158,232	934	15,311	
December	808,176	605,822	184,523	1,063	16,768	
Year 2023						
January	677,748	515,984	144,264	954	16,546	
February	515,813	379,053	121,772	812	14,176	
March	556,368	407,953	133,370	702	14,343	
April	446,359	315,527	117,014	620	13,198	
May	488,845	355,530	118,981	472	13,862	
June	637,699	501,020	123,362	385	12,932	
July	855,673	667,583	173,520	429	14,141	
August	844,374	655,700	174,975	452	13,247	
September	656,915	501,164	141,855	470	13,426	
October	561,346	418,049	129,520	462	13,315	
November	564,056	404,389	145,189	570	13,908	
December	616,622	459,962	141,494	694	14,472	
Year 2024						
January	818,457	621,226	180,198	1,189	15,844	
February	494,683	381,685	98,634	852	13,512	
March	433,288	337,628	79,993	631	15,036	
April	412,775	305,787	94,487	533	11,967	
May	508,773	386,958	108,839	315	12,660	
June	671,243	522,585	135,751	452	12,454	
July	783,116	604,392	164,317	490	13,916	
August	757,567	580,944	162,738	522	13,363	
September	599,533	459,763	126,342	524	12,904	
October	520,044	385,560	120,656	513	13,316	
November	503,199	375,943	112,900	626	13,730	
December	682,280	517,063	149,890	693	14,633	

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See the Technical Notes for fuel conversion factors.

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

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

Beginning with 2008 data, the Form EIA-923, Power Plant Operations Report, replaced the following: Form EIA-906, Power Plant Report; Form EIA-920, Combined Heat and Power Plant Report.

Table 5.2.A. Petroleum Liquids: Consumption for Electricity Generation, by Sector, 2014 - 2024 (Thousand Barrels)

		Electric Power Sector			
Period	Total (all sectors)	Electric Utilities	Independent Power Producers	Commercial Sector	Industrial Sector
Annual Totals					
2014	31,531	19,652	10,689	451	739
2015	28,925	18,562	9,473	249	641
2016	22,405	16,137	5,624	108	536
2017	21,696	15,567	5,461	191	476
2018	28,614	18,345	9,467	269	534
2019	20,836	15,677	4,464	251	444
2020	18,008	13,913	3,447	238	410
2021	21,633	16,850	4,102	250	432
2022	28,760	18,375	9,474	254	657
2023	21,335	16,366	4,253	200	517
2024	20,787	16,058	4,137	179	414
Year 2022					
January	5,217	2,325	2,794	44	54
February	2,067	1,239	768	16	43
March	1,732	1,304	365	14	48
April	1,408	1,098	250	17	43
May	1,588	1,275	252	20	42
June	1,704	1,286	351	20	46
July	2,020	1,375	576	21	48
August	1,896	1,301	537	19	39
September	1,738	1,341	335	12	49
October	1,814	1,370	387	14	43
November	1,700	1,339	304	15	42
December	5,876	3,121	2,553	42	160
Year 2023					
January	1,821	1,453	283	24	61
February	2,432	1,558	791	36	47
March	1,677	1,305	303	16	53
April	1,605	1,262	292	11	40
May	1,689	1,348	290	15	36
June	1,680	1,370	256	11	43
July	1,778	1,318	405	13	41
August	1,789	1,445	289	13	41
September	1,666	1,277	339	12	38
October	1,825	1,351	423	13	37
November	1,671	1,313	304	15	38
December	1,704	1,366	277	21	41
Year 2024					
January	2,757	1,991	690	30	47
February	1,385	1,142	183	14	46
March	1,419	1,154	214	18	34
April	1,592	1,229	311	17	35
May	1,576	1,253	274	18	32
June	1,614	1,224	334	23	32
July	1,832	1,324	468	8	33
August	1,813	1,448	326	9	30
September	1,485	1,232	217	7	28
October	1,651	1,364	247	7	33
November	1,535	1,242	252	10	31
December	2,128	1,455	620	18	35

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Petroleum Liquids includes distillate and residual fuel oils, jet fuel, kerosene, waste oil, and beginning in 2011, propane. Prior to 2011 propane was included in Other Fossil Gas.

See the Technical Notes for fuel conversion factors.

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

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Table 5.2.B. Petroleum Liquids: Consumption for Useful Thermal Output, by Sector, 2014 - 2024 (Thousand Barrels)

		Electric Power Sector			
Period	Total (all sectors)	Electric Utilities	Independent Power Producers	Commercial Sector	Industrial Sector
Annual Totals					
2014	3,099	64	1,170	216	1,650
2015	3,142	62	1,155	282	1,643
2016	2,277	68	245	245	1,719
2017	2,012	72	220	238	1,482
2018	2,614	103	354	350	1,807
2019	2,162	71	226	419	1,446
2020	1,730	59	179	269	1,223
2021	2,072	80	278	330	1,384
2022	4,181	106	403	495	3,177
2023	3,133	65	330	363	2,374
2024	2,238	66	612	440	1,120
Year 2022					
January	425	28	68	114	214
February	239	14	18	30	177
March	336	6	35	33	263
April	335	4	27	26	277
May	310	5	27	34	244
June	345	5	28	18	294
July	360	5	25	38	292
August	243	3	27	30	183
September	302	4	28	10	259
October	317	5	32	14	266
November	310	4	33	16	257
December	659	21	55	131	451
Year 2023					
January	406	6	35	62	303
February	373	9	29	30	305
March	326	4	26	25	271
April	329	5	29	8	288
May	163	7	26	10	120
June	166	5	26	16	120
July	174	5	25	16	129
August	204	5	23	16	161
September	207	3	25	20	158
October	193	6	32	17	137
November	247	5	25	37	181
December	344	5	29	107	203
Year 2024					
January	324	18	59	87	160
February	170	3	23	45	98
March	189	4	26	63	96
April	215	6	75	41	94
May	191	4	51	59	77
June	199	5	38	86	69
July	182	4	93	6	79
August	128	5	52	5	67
September	104	3	24	5	72
October	144	5	34	7	98
November	142	5	37	12	89
December	251	4	101	24	122

Notes: Beginning with the collection of Form EIA-923 in January 2008, the methodology to allocate total fuel consumption for electricity generation and consumption for useful thermal output was changed.

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Petroleum Liquids includes distillate and residual fuel oils, jet fuel, kerosene, waste oil, and beginning in 2011, propane. Prior to 2011 propane was included in Other Fossil Gas.

See the Technical Notes for fuel conversion factors.

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

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

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Table 5.2.C. Petroleum Liquids: Consumption for Electricity Generation and Useful Thermal Output, by Sector, 2014 - 2024 (Thousand Barrels)

		Electric Power Sector			
Period	Total (all sectors)	Electric Utilities	Independent Power Producers	Commercial Sector	Industrial Sector
Annual Totals					
2014	34,630	19,716	11,859	667	2,389
2015	32,067	18,624	10,629	531	2,283
2016	24,682	16,205	5,869	352	2,255
2017	23,708	15,640	5,681	429	1,958
2018	31,228	18,448	9,820	619	2,341
2019	22,998	15,748	4,690	670	1,890
2020	19,738	13,972	3,626	507	1,633
2021	23,705	16,929	4,379	580	1,816
2022	32,940	18,480	9,877	749	3,835
2023	24,468	16,431	4,583	563	2,891
2024	23,025	16,124	4,748	619	1,534
Year 2022					
January	5,642	2,353	2,863	158	268
February	2,306	1,253	786	47	220
March	2,068	1,310	400	47	311
April	1,742	1,102	277	43	320
May	1,898	1,280	279	54	285
June	2,049	1,291	379	38	341
July	2,380	1,380	601	59	340
August	2,139	1,305	564	48	222
September	2,040	1,345	364	23	308
October	2,131	1,375	419	28	310
November	2,011	1,344	337	31	299
December	6,534	3,142	2,608	173	611
Year 2023					
January	2,227	1,460	318	86	363
February	2,805	1,566	820	66	352
March	2,003	1,309	329	41	324
April	1,934	1,267	321	18	328
May	1,852	1,355	317	25	155
June	1,846	1,374	281	27	163
July	1,952	1,323	430	29	170
August	1,993	1,450	312	29	202
September	1,872	1,280	364	32	197
October	2,018	1,357	456	30	174
November	1,918	1,319	329	52	219
December	2,049	1,371	306	127	245
Year 2024					
January	3,081	2,009	749	117	207
February	1,555	1,146	206	60	144
March	1,609	1,158	239	81	130
April	1,807	1,235	386	58	129
May	1,767	1,256	325	77	109
June	1,812	1,230	373	109	101
July	2,014	1,328	561	14	111
August	1,941	1,452	378	14	97
September	1,589	1,235	242	11	100
October	1,795	1,369	282	14	130
November	1,677	1,246	289	22	119
December	2,379	1,459	721	42	157

Notes: Beginning with the collection of Form EIA-923 in January 2008, the methodology to allocate total fuel consumption for electricity generation and consumption for useful thermal output was changed.

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Table 5.2.D. Petroleum Liquids: Consumption for Electricity Generation, by Sector, 2014 - 2024 (Billion Btus)

		Electric Power Sector			
Period	Total (all sectors)	Electric Utilities	Independent Power Producers	Commercial Sector	Industrial Sector
Annual Totals					
2014	188,814	118,226	63,488	2,765	4,335
2015	172,884	111,808	55,979	1,482	3,616
2016	133,457	96,967	32,922	639	2,928
2017	128,649	92,975	31,895	1,125	2,654
2018	169,663	109,734	55,433	1,579	2,916
2019	122,591	93,088	25,678	1,466	2,359
2020	105,735	82,276	19,821	1,396	2,241
2021	126,799	99,374	23,648	1,466	2,312
2022	169,716	108,473	56,212	1,482	3,548
2023	126,106	96,840	25,293	1,162	2,810
2024	123,273	95,103	24,872	1,038	2,259
Year 2022					
January	31,071	13,759	16,747	260	306
February	12,135	7,285	4,511	96	243
March	10,220	7,691	2,173	84	272
April	8,301	6,485	1,483	97	235
May	9,410	7,568	1,498	115	228
June	9,991	7,555	2,064	116	255
July	11,966	8,119	3,456	123	267
August	11,188	7,674	3,192	108	214
September	10,277	7,960	1,981	71	265
October	10,721	8,139	2,258	79	245
November	10,022	7,902	1,795	86	239
December	34,416	18,335	15,055	247	779
Year 2023					
January	10,680	8,575	1,639	143	322
February	14,494	9,267	4,754	208	266
March	9,884	7,698	1,797	90	298
April	9,464	7,453	1,727	61	223
May	9,973	7,977	1,717	89	191
June	9,913	8,120	1,501	64	228
July	10,546	7,801	2,454	76	215
August	10,580	8,554	1,731	75	220
September	9,901	7,598	2,023	71	209
October	10,793	8,015	2,501	77	201
November	9,851	7,754	1,800	88	209
December	10,027	8,029	1,648	121	229
Year 2024					
January	16,257	11,733	4,090	173	261
February	8,181	6,774	1,086	82	239
March	8,383	6,799	1,290	103	191
April	9,362	7,230	1,841	99	192
May	9,391	7,463	1,656	102	170
June	9,560	7,223	2,029	136	172
July	10,864	7,830	2,811	46	177
August	10,805	8,614	1,972	53	166
September	8,872	7,346	1,332	39	155
October	9,842	8,116	1,507	42	177
November	9,107	7,354	1,529	59	166
December	12,648	8,622	3,729	104	193

Notes: Beginning with the collection of Form EIA-923 in January 2008, the methodology to allocate total fuel consumption for electricity generation and consumption for useful thermal output was changed.

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Table 5.2.E. Petroleum Liquids: Consumption for Useful Thermal Output, by Sector, 2014 - 2024 (Billion Btus)

		Electric Power Sector			
Period	Total (all sectors)	Electric Utilities	Independent Power Producers	Commercial Sector	Industrial Sector
Annual Totals					
2014	18,181	395	6,802	1,311	9,672
2015	18,449	379	6,748	1,755	9,568
2016	13,164	395	1,391	1,496	9,882
2017	11,825	405	1,253	1,432	8,736
2018	15,163	598	1,951	2,082	10,533
2019	12,383	403	1,319	2,472	8,189
2020	9,962	317	1,056	1,595	6,994
2021	11,989	453	1,624	1,964	7,948
2022	24,130	613	2,452	2,920	18,145
2023	18,007	370	2,027	2,160	13,450
2024	12,990	374	3,583	2,602	6,431
Year 2022					
January	2,487	166	397	665	1,260
February	1,414	79	108	181	1,045
March	1,958	34	215	192	1,517
April	1,916	23	167	155	1,570
May	1,781	29	169	199	1,384
June	1,977	27	174	108	1,667
July	2,072	31	157	225	1,660
August	1,397	20	168	174	1,035
September	1,749	25	176	63	1,485
October	1,843	29	195	84	1,535
November	1,835	26	198	99	1,512
December	3,702	125	327	775	2,474
Year 2023					
January	2,322	37	211	369	1,705
February	2,154	50	176	185	1,743
March	1,883	25	162	149	1,547
April	1,895	26	180	48	1,641
May	940	40	164	62	675
June	942	26	159	95	662
July	987	28	155	93	711
August	1,159	26	141	94	898
September	1,181	18	155	118	890
October	1,109	35	198	102	774
November	1,452	29	150	218	1,055
December	1,984	30	177	627	1,150
Year 2024					
January	1,890	101	340	514	935
February	972	19	135	270	549
March	1,107	24	156	374	553
April	1,238	32	429	240	538
May	1,103	20	298	347	438
June	1,152	31	229	501	391
July	1,039	23	532	39	445
August	740	26	303	29	382
September	612	18	148	28	419
October	849	30	211	42	566
November	827	26	221	72	509
December	1,461	24	582	145	709

Notes: Beginning with the collection of Form EIA-923 in January 2008, the methodology to allocate total fuel consumption for electricity generation and consumption for useful thermal output was changed.

The new methodology was retroactively applied to 2004-2007 data. See the Technical Notes (Appendix C) for further information. See Glossary for definitions.

Values are final. See Technical Notes for a discussion of the sample design for the Form EIA-923 and predecessor forms.

Petroleum Liquids includes distillate and residual fuel oils, jet fuel, kerosene, waste oil, and beginning in 2011, propane. Prior to 2011 propane was included in Other Fossil Gas.

See the Technical Notes for fuel conversion factors.

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

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

Beginning with 2008 data, the Form EIA-923, Power Plant Operations Report, replaced the following: Form EIA-906, Power Plant Report; Form EIA-920, Combined Heat and Power Plant Report.

Table 5.2.F. Petroleum Liquids: Consumption for Electricity Generation and Useful Thermal Output, by Sector, 2014 - 2024 (Billion Btus)

			Electric Power Sector			
Period	Total (all sectors)		Electric Utilities	Independent Power Producers	Commercial Sector	Industrial Sector
Annual Totals						
2014	206,995		118,621	70,291	4,076	14,008
2015	191,333		112,186	62,727	3,236	13,184
2016	146,621		97,363	34,313	2,135	12,810
2017	140,474		93,380	33,148	2,557	11,389
2018	184,826		110,332	57,383	3,661	13,449
2019	134,974		93,491	26,998	3,937	10,548
2020	115,697		82,594	20,877	2,991	9,235
2021	138,788		99,827	25,271	3,430	10,259
2022	193,845		109,086	58,664	4,402	21,693
2023	144,113		97,210	27,320	3,323	16,260
2024	136,263		95,477	28,455	3,641	8,690
Year 2022						
January	33,558		13,924	17,144	924	1,566
February	13,549		7,365	4,619	277	1,288
March	12,178		7,725	2,388	276	1,789
April	10,216		6,509	1,651	252	1,805
May	11,190		7,597	1,666	314	1,613
June	11,968		7,582	2,239	225	1,923
July	14,037		8,150	3,613	348	1,927
August	12,585		7,694	3,359	282	1,249
September	12,026		7,985	2,157	134	1,750
October	12,564		8,169	2,453	163	1,780
November	11,857		7,928	1,993	184	1,751
December	38,117		18,460	15,382	1,022	3,253
Year 2023						
January	13,002		8,612	1,850	513	2,028
February	16,648		9,317	4,929	393	2,009
March	11,767		7,723	1,959	239	1,845
April	11,359		7,479	1,907	109	1,864
May	10,913		8,017	1,881	151	865
June	10,855		8,146	1,661	159	889
July	11,533		7,829	2,609	170	926
August	11,739		8,580	1,873	169	1,118
September	11,082		7,617	2,178	189	1,098
October	11,902		8,050	2,699	179	974
November	11,302		7,783	1,950	306	1,264
December	12,011		8,058	1,825	747	1,380
Year 2024						
January	18,146		11,834	4,430	687	1,195
February	9,153		6,794	1,221	351	788
March	9,489		6,822	1,446	477	743
April	10,600		7,262	2,270	338	730
May	10,494		7,483	1,953	449	608
June	10,712		7,253	2,258	637	563
July	11,903		7,853	3,343	85	621
August	11,546		8,640	2,275	82	548
September	9,484		7,363	1,480	68	573
October	10,691		8,146	1,717	85	743
November	9,935		7,380	1,749	131	674
December	14,109		8,646	4,311	249	902

Notes: Beginning with the collection of Form EIA-923 in January 2008, the methodology to allocate total fuel consumption for electricity generation and consumption for useful thermal output was changed.

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Petroleum Liquids includes distillate and residual fuel oils, jet fuel, kerosene, waste oil, and beginning in 2011, propane. Prior to 2011 propane was included in Other Fossil Gas.

See the Technical Notes for fuel conversion factors.

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

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

Beginning with 2008 data, the Form EIA-923, Power Plant Operations Report, replaced the following: Form EIA-906, Power Plant Report; Form EIA-920, Combined Heat and Power Plant Report.

**Table 5.3.A. Petroleum Coke: Consumption for Electricity Generation,
by Sector, 2014 - 2024 (Thousand Tons)**

		Electric Power Sector				
Period	Total (all sectors)	Electric Utilities	Independent Power Producers	Commercial Sector	Industrial Sector	
Annual Totals						
2014	4,412	3,440	599	2	371	
2015	4,044	3,120	669	2	253	
2016	4,253	3,427	591	2	233	
2017	3,490	2,731	542	3	214	
2018	3,623	2,740	704	2	177	
2019	2,724	2,067	478	1	177	
2020	3,077	2,260	658	1	158	
2021	3,070	2,323	618	1	127	
2022	2,985	2,271	578	3	132	
2023	2,028	1,328	594	1	105	
2024	1,662	960	596	1	104	
Year 2022						
January	240	166	63	0	11	
February	248	180	55	0	13	
March	216	143	62	0	10	
April	225	156	59	0	10	
May	248	212	22	0	12	
June	281	224	46	0	10	
July	219	177	31	0	11	
August	241	178	52	0	11	
September	280	210	60	0	10	
October	263	192	60	0	11	
November	227	178	36	0	13	
December	296	254	31	0	10	
Year 2023						
January	179	116	52	0	11	
February	163	107	47	0	9	
March	135	73	49	0	12	
April	124	74	43	0	7	
May	144	76	60	0	8	
June	162	107	48	0	7	
July	266	196	59	0	10	
August	265	197	59	0	9	
September	238	175	55	0	8	
October	125	76	41	0	8	
November	80	49	24	0	8	
December	147	81	57	0	8	
Year 2024						
January	163	95	59	0	9	
February	120	69	42	0	8	
March	89	22	58	0	9	
April	125	66	51	0	8	
May	140	76	56	0	8	
June	171	115	47	0	9	
July	199	131	58	0	10	
August	193	128	57	0	9	
September	109	70	32	0	7	
October	113	72	33	0	8	
November	102	44	49	0	9	
December	137	72	55	0	10	

Notes: Beginning with the collection of Form EIA-923 in January 2008, the methodology to allocate total fuel consumption for electricity generation and consumption for useful thermal output was changed.

The new methodology was retroactively applied to 2004-2007 data. See the Technical Notes (Appendix C) for further information. See Glossary for definitions.

Values are final. See Technical Notes for a discussion of the sample design for the Form EIA-923 and predecessor forms.

Petroleum Coke includes petroleum coke-derived synthesis gas. Prior to 2011, petroleum coke-derived synthesis gas was included in Other Fossil Gas. See the Technical Notes for fuel conversion factors.

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

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

Beginning with 2008 data, the Form EIA-923, Power Plant Operations Report, replaced the following: Form EIA-906, Power Plant Report; Form EIA-920, Combined Heat and Power Plant Report.

**Table 5.3.B. Petroleum Coke: Consumption for Useful Thermal Output,
by Sector, 2014 - 2024 (Thousand Tons)**

		Electric Power Sector			
Period	Total (all sectors)	Electric Utilities	Independent Power Producers	Commercial Sector	Industrial Sector
Annual Totals					
2014	1,283	3	90	16	1,174
2015	1,144	9	109	16	1,010
2016	1,099	6	113	9	971
2017	977	11	115	15	836
2018	929	12	93	10	814
2019	839	17	93	6	724
2020	780	16	124	3	637
2021	760	21	113	6	621
2022	718	23	92	13	589
2023	622	8	115	3	495
2024	608	0	103	5	499
Year 2022					
January	55	2	8	2	44
February	67	8	11	2	46
March	60	1	9	2	48
April	56	0	8	1	47
May	68	1	8	2	57
June	52	1	6	2	44
July	51	1	1	1	47
August	69	1	8	0	60
September	49	1	8	0	40
October	62	1	8	0	53
November	71	6	8	1	56
December	58	0	9	1	48
Year 2023					
January	49	1	9	1	37
February	38	1	10	0	26
March	60	2	10	0	47
April	52	2	8	0	41
May	56	0	10	0	46
June	51	0	10	0	41
July	52	1	10	0	41
August	56	1	10	0	45
September	53	0	11	0	41
October	53	0	8	0	45
November	49	0	8	0	41
December	53	0	10	1	41
Year 2024					
January	57	0	9	1	46
February	43	0	8	1	35
March	45	0	9	0	36
April	49	0	7	0	42
May	47	0	7	1	39
June	52	0	10	1	41
July	57	0	10	0	47
August	56	0	12	0	44
September	47	0	8	0	39
October	43	0	1	0	42
November	51	0	9	0	42
December	62	0	13	1	48

Notes: Beginning with the collection of Form EIA-923 in January 2008, the methodology to allocate total fuel consumption for electricity generation and consumption for useful thermal output was changed.

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Values are final. See Technical Notes for a discussion of the sample design for the Form EIA-923 and predecessor forms.

Petroleum Coke includes petroleum coke-derived synthesis gas. Prior to 2011, petroleum coke-derived synthesis gas was included in Other Fossil Gas. See the Technical Notes for fuel conversion factors.

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

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

Beginning with 2008 data, the Form EIA-923, Power Plant Operations Report, replaced the following: Form EIA-906, Power Plant Report; Form EIA-920, Combined Heat and Power Plant Report.

Table 5.3.C. Petroleum Coke: Consumption for Electricity Generation and Useful Thermal Output, by Sector, 2014 - 2024 (Thousand Tons)

		Electric Power Sector			
Period	Total (all sectors)	Electric Utilities	Independent Power Producers	Commercial Sector	Industrial Sector
Annual Totals					
2014	5,695	3,443	689	18	1,545
2015	5,188	3,128	779	18	1,263
2016	5,352	3,433	705	10	1,204
2017	4,467	2,742	657	17	1,050
2018	4,552	2,752	797	12	991
2019	3,563	2,083	571	7	900
2020	3,856	2,276	782	4	795
2021	3,830	2,344	731	7	748
2022	3,702	2,294	671	16	721
2023	2,649	1,336	709	4	600
2024	2,270	960	699	6	604
Year 2022					
January	295	168	71	2	54
February	315	188	66	2	59
March	275	144	71	2	58
April	282	156	67	2	57
May	315	214	30	2	69
June	333	225	53	2	53
July	270	178	33	1	58
August	310	179	59	0	72
September	330	211	68	0	51
October	325	193	68	0	64
November	298	184	44	1	69
December	355	255	40	2	58
Year 2023					
January	228	116	62	2	48
February	201	108	57	0	35
March	195	75	60	0	59
April	175	77	51	0	48
May	200	76	70	0	54
June	213	107	57	0	49
July	318	197	69	0	52
August	321	197	69	0	54
September	290	175	66	0	49
October	178	76	49	0	53
November	129	49	32	0	49
December	200	81	67	1	50
Year 2024					
January	220	95	68	2	55
February	163	69	50	1	43
March	134	22	67	0	45
April	174	66	58	0	50
May	187	76	63	1	46
June	223	115	57	1	50
July	256	131	68	0	57
August	248	128	68	0	52
September	156	70	40	0	46
October	156	72	33	0	50
November	153	44	58	0	50
December	199	72	68	1	58

Notes: Beginning with the collection of Form EIA-923 in January 2008, the methodology to allocate total fuel consumption for electricity generation and consumption for useful thermal output was changed.

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Values are final. See Technical Notes for a discussion of the sample design for the Form EIA-923 and predecessor forms.

Petroleum Coke includes petroleum coke-derived synthesis gas. Prior to 2011, petroleum coke-derived synthesis gas was included in Other Fossil Gas. See the Technical Notes for fuel conversion factors.

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

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

Beginning with 2008 data, the Form EIA-923, Power Plant Operations Report, replaced the following: Form EIA-906, Power Plant Report; Form EIA-920, Combined Heat and Power Plant Report.

Table 5.3.D. Petroleum Coke: Consumption for Electricity Generation, by Sector, 2014 - 2024 (Billion Btus)

		Electric Power Sector			
Period	Total (all sectors)	Electric Utilities	Independent Power Producers	Commercial Sector	Industrial Sector
Annual Totals					
2014	123,736	95,642	17,032	59	11,003
2015	113,568	87,210	18,889	58	7,411
2016	118,303	94,892	16,591	47	6,774
2017	94,136	72,919	15,100	72	6,045
2018	100,362	73,895	21,327	57	5,083
2019	74,970	56,411	13,472	37	5,050
2020	84,427	61,343	18,446	18	4,619
2021	83,779	62,714	17,234	32	3,799
2022	79,689	59,461	16,174	81	3,973
2023	53,489	33,329	16,961	16	3,183
2024	41,450	21,300	16,984	28	3,137
Year 2022					
January	6,687	4,613	1,750	10	314
February	6,925	5,013	1,523	10	380
March	5,799	3,783	1,702	10	304
April	5,978	4,010	1,660	9	299
May	6,475	5,449	643	11	372
June	7,360	5,737	1,321	10	293
July	5,639	4,423	886	6	324
August	6,432	4,643	1,452	0	337
September	7,444	5,440	1,689	2	313
October	6,735	4,743	1,647	0	345
November	6,147	4,750	1,005	4	388
December	8,067	6,858	897	8	304
Year 2023					
January	4,615	2,789	1,484	8	334
February	4,475	2,860	1,349	2	264
March	3,677	1,909	1,402	1	365
April	3,282	1,854	1,222	0	206
May	3,714	1,754	1,713	0	247
June	4,382	2,763	1,399	0	220
July	7,156	5,123	1,715	0	318
August	7,008	5,049	1,682	0	277
September	6,291	4,496	1,563	0	232
October	3,107	1,710	1,154	0	242
November	2,046	1,130	688	0	228
December	3,736	1,892	1,588	5	251
Year 2024					
January	4,055	2,135	1,637	6	276
February	2,840	1,400	1,183	3	253
March	2,403	450	1,674	0	279
April	3,164	1,454	1,459	0	251
May	3,491	1,667	1,585	6	232
June	4,287	2,653	1,364	6	265
July	5,001	3,034	1,666	0	301
August	4,926	3,043	1,627	0	256
September	2,655	1,523	916	0	216
October	2,602	1,431	921	0	250
November	2,649	979	1,408	0	261
December	3,377	1,530	1,543	7	297

Notes: Beginning with the collection of Form EIA-923 in January 2008, the methodology to allocate total fuel consumption for electricity generation and consumption for useful thermal output was changed.

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

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

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Table 5.3.E. Petroleum Coke: Consumption for Useful Thermal Output, by Sector, 2014 - 2024 (Billion Btus)

		Electric Power Sector			
Period	Total (all sectors)	Electric Utilities	Independent Power Producers	Commercial Sector	Industrial Sector
Annual Totals					
2014	36,602	90	2,597	449	33,467
2015	33,138	255	3,167	446	29,269
2016	32,473	159	3,255	241	28,817
2017	28,680	297	3,335	403	24,645
2018	27,398	332	2,693	284	24,088
2019	24,348	470	2,681	164	21,032
2020	22,623	453	3,563	87	18,521
2021	22,772	594	3,182	152	18,844
2022	21,600	665	2,646	366	17,924
2023	18,788	241	3,297	87	15,163
2024	18,416	6	2,976	140	15,294
Year 2022					
January	1,642	46	233	47	1,317
February	1,998	246	305	43	1,404
March	1,809	34	261	46	1,468
April	1,679	5	229	39	1,406
May	2,045	35	224	50	1,736
June	1,593	29	179	45	1,340
July	1,546	27	36	32	1,450
August	2,088	23	224	0	1,841
September	1,502	18	225	9	1,250
October	1,856	20	232	0	1,604
November	2,117	175	238	19	1,686
December	1,726	7	261	36	1,422
Year 2023					
January	1,392	14	265	39	1,075
February	1,112	35	292	8	777
March	1,808	63	299	6	1,440
April	1,574	72	235	0	1,267
May	1,710	0	293	0	1,418
June	1,571	2	276	0	1,293
July	1,577	22	277	0	1,279
August	1,708	20	286	0	1,402
September	1,604	8	310	0	1,286
October	1,623	3	238	0	1,382
November	1,496	0	230	0	1,266
December	1,612	3	295	35	1,279
Year 2024					
January	1,699	6	270	36	1,387
February	1,300	0	232	15	1,052
March	1,364	0	270	0	1,094
April	1,482	0	200	0	1,282
May	1,444	0	212	28	1,205
June	1,586	0	295	30	1,261
July	1,713	0	290	0	1,423
August	1,689	0	344	0	1,346
September	1,445	0	227	0	1,218
October	1,323	0	21	0	1,302
November	1,523	0	251	0	1,272
December	1,847	0	365	31	1,452

Notes: Beginning with the collection of Form EIA-923 in January 2008, the methodology to allocate total fuel consumption for electricity generation and consumption for useful thermal output was changed.

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See the Technical Notes for fuel conversion factors.

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

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

Beginning with 2008 data, the Form EIA-923, Power Plant Operations Report, replaced the following: Form EIA-906, Power Plant Report; Form EIA-920, Combined Heat and Power Plant Report.

Table 5.3.F. Petroleum Coke: Consumption for Electricity Generation and Useful Thermal Output, by Sector, 2014 - 2024 (Billion Btus)

		Electric Power Sector			
Period	Total (all sectors)	Electric Utilities	Independent Power Producers	Commercial Sector	Industrial Sector
Annual Totals					
2014	160,338	95,731	19,629	508	44,470
2015	146,706	87,465	22,056	505	36,680
2016	150,776	95,051	19,846	288	35,591
2017	122,816	73,216	18,435	475	30,690
2018	127,760	74,227	24,020	341	29,171
2019	99,318	56,881	16,153	201	26,083
2020	107,050	61,796	22,009	105	23,140
2021	106,551	63,308	20,416	184	22,644
2022	101,289	60,125	18,820	446	21,897
2023	72,276	33,570	20,257	103	18,347
2024	59,865	21,306	19,960	168	18,431
Year 2022					
January	8,330	4,659	1,983	57	1,631
February	8,923	5,259	1,828	52	1,784
March	7,608	3,817	1,963	57	1,772
April	7,657	4,015	1,889	48	1,705
May	8,520	5,484	867	61	2,108
June	8,953	5,766	1,499	54	1,633
July	7,185	4,450	922	38	1,774
August	8,520	4,666	1,676	0	2,178
September	8,946	5,459	1,914	11	1,563
October	8,591	4,763	1,879	0	1,949
November	8,263	4,924	1,242	23	2,074
December	9,793	6,865	1,158	44	1,726
Year 2023					
January	6,007	2,803	1,749	46	1,408
February	5,588	2,895	1,641	10	1,041
March	5,485	1,973	1,700	7	1,805
April	4,856	1,926	1,457	0	1,472
May	5,425	1,754	2,006	0	1,665
June	5,953	2,765	1,675	0	1,513
July	8,733	5,145	1,992	0	1,596
August	8,715	5,068	1,969	0	1,679
September	7,895	4,504	1,874	0	1,518
October	4,730	1,713	1,393	0	1,624
November	3,542	1,130	918	0	1,494
December	5,347	1,895	1,883	39	1,530
Year 2024					
January	5,754	2,141	1,907	42	1,663
February	4,140	1,400	1,416	19	1,306
March	3,767	450	1,945	0	1,372
April	4,646	1,454	1,659	0	1,532
May	4,935	1,667	1,796	34	1,437
June	5,874	2,653	1,659	36	1,526
July	6,714	3,034	1,956	0	1,724
August	6,616	3,043	1,971	0	1,602
September	4,100	1,523	1,143	0	1,434
October	3,925	1,431	942	0	1,552
November	4,172	979	1,659	0	1,534
December	5,225	1,530	1,908	37	1,749

Notes: Beginning with the collection of Form EIA-923 in January 2008, the methodology to allocate total fuel consumption for electricity generation and consumption for useful thermal output was changed.

The new methodology was retroactively applied to 2004-2007 data. See the Technical Notes (Appendix C) for further information. See Glossary for definitions.

Values are final. See Technical Notes for a discussion of the sample design for the Form EIA-923 and predecessor forms.

Petroleum Coke includes petroleum coke-derived synthesis gas. Prior to 2011, petroleum coke-derived synthesis gas was included in Other Fossil Gas.

See the Technical Notes for fuel conversion factors.

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

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

Beginning with 2008 data, the Form EIA-923, Power Plant Operations Report, replaced the following: Form EIA-906, Power Plant Report; Form EIA-920, Combined Heat and Power Plant Report.

Table 5.4.A. Natural Gas: Consumption for Electricity Generation, by Sector, 2014 - 2024 (Million Cubic Feet)

		Electric Power Sector			
Period	Total (all sectors)	Electric Utilities	Independent Power Producers	Commercial Sector	Industrial Sector
Annual Totals					
2014	8,544,387	3,895,008	3,954,032	71,957	623,390
2015	10,016,576	4,745,255	4,576,683	70,092	624,545
2016	10,170,110	5,018,894	4,571,375	46,304	533,537
2017	9,508,062	4,754,893	4,161,984	50,060	541,126
2018	10,842,129	5,560,267	4,663,935	52,650	565,276
2019	11,612,858	5,980,679	4,958,798	55,575	617,805
2020	11,928,104	6,196,152	5,061,569	51,827	618,556
2021	11,502,569	5,876,442	4,995,247	45,537	585,343
2022	12,384,086	6,376,041	5,364,050	48,658	595,337
2023	13,245,495	6,821,490	5,766,810	49,069	608,127
2024	13,754,749	7,282,518	5,831,864	47,993	592,373
Year 2022					
January	972,571	499,668	416,488	3,980	52,436
February	823,713	414,497	360,403	3,525	45,288
March	800,152	407,227	339,907	3,791	49,227
April	767,572	391,895	325,930	3,536	46,211
May	947,250	488,790	406,341	3,767	48,352
June	1,168,712	623,023	491,993	4,050	49,645
July	1,430,805	752,312	619,375	4,873	54,246
August	1,407,824	722,888	625,436	5,064	54,436
September	1,149,683	579,459	517,292	4,325	48,606
October	971,750	491,554	428,251	3,632	48,313
November	928,162	480,119	394,845	3,849	49,349
December	1,015,891	524,610	437,787	4,265	49,229
Year 2023					
January	987,973	509,721	424,167	4,015	50,070
February	887,314	452,645	385,437	3,707	45,525
March	960,860	498,746	408,397	3,937	49,780
April	883,667	460,878	375,346	3,608	43,836
May	1,016,179	541,909	421,533	3,794	48,943
June	1,205,103	629,369	519,772	4,171	51,790
July	1,502,219	772,992	669,249	4,980	54,998
August	1,499,764	785,760	653,790	4,761	55,453
September	1,226,450	620,224	549,340	4,449	52,437
October	1,041,989	527,917	459,521	3,948	50,603
November	987,442	487,374	445,387	3,784	50,897
December	1,046,536	533,955	454,871	3,915	53,796
Year 2024					
January	1,162,832	599,189	505,458	4,128	54,057
February	934,713	485,159	397,568	3,745	48,241
March	941,501	495,352	393,681	3,746	48,722
April	905,025	476,354	377,984	3,512	47,174
May	1,070,779	580,971	438,725	3,519	47,565
June	1,260,404	676,543	531,767	4,168	47,925
July	1,551,563	834,670	659,202	4,998	52,693
August	1,521,577	822,175	639,987	4,741	54,674
September	1,244,270	662,026	529,221	3,974	49,050
October	1,089,749	575,812	465,530	3,720	44,687
November	1,009,898	531,088	428,789	3,798	46,223
December	1,062,440	543,180	463,952	3,945	51,363

Notes: Beginning with the collection of Form EIA-923 in January 2008, the methodology to allocate total fuel consumption for electricity generation and consumption for useful thermal output was changed.

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Values are final. See Technical Notes for a discussion of the sample design for the Form EIA-923 and predecessor forms.

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

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

Beginning with 2008 data, the Form EIA-923, Power Plant Operations Report, replaced the following: Form EIA-906, Power Plant Report; Form EIA-920, Combined Heat and Power Plant Report.

Table 5.4.B. Natural Gas: Consumption for Useful Thermal Output, by Sector, 2014 - 2024 (Million Cubic Feet)

		Electric Power Sector			
Period	Total (all sectors)	Electric Utilities	Independent Power Producers	Commercial Sector	Industrial Sector
Annual Totals					
2014	865,146	4,926	292,016	46,635	521,569
2015	935,098	8,060	283,372	46,287	597,379
2016	1,151,866	38,096	356,905	80,943	675,922
2017	1,168,544	38,740	309,949	104,324	715,532
2018	1,205,962	43,156	331,952	81,856	748,997
2019	1,196,025	42,645	317,231	79,734	756,415
2020	1,292,624	47,025	326,976	78,844	839,778
2021	1,221,841	49,103	307,795	71,094	793,849
2022	1,206,250	46,329	305,125	74,683	780,113
2023	1,210,187	46,531	306,058	69,832	787,767
2024	1,246,683	48,851	313,214	80,431	804,187
Year 2022					
January	111,979	4,635	28,424	7,331	71,588
February	98,435	3,929	25,170	6,465	62,872
March	102,253	3,852	25,861	6,384	66,156
April	92,922	2,748	22,502	5,734	61,937
May	95,766	3,356	24,200	5,623	62,587
June	97,703	3,887	25,622	5,855	62,339
July	106,539	4,604	28,679	6,816	66,440
August	106,095	4,242	27,578	6,894	67,381
September	96,584	3,583	24,804	5,816	62,381
October	95,266	3,073	23,556	5,412	63,225
November	98,143	4,017	23,125	5,694	65,307
December	104,564	4,401	25,603	6,659	67,900
Year 2023					
January	105,723	4,357	25,508	6,329	69,529
February	96,304	3,879	24,676	5,808	61,940
March	103,019	3,925	25,733	5,947	67,415
April	93,580	3,302	23,341	5,165	61,771
May	94,810	3,414	22,583	5,196	63,617
June	98,931	3,707	24,782	5,484	64,959
July	105,392	4,560	27,941	6,314	66,578
August	104,094	4,161	27,825	5,996	66,113
September	99,792	3,791	25,380	5,797	64,824
October	97,361	3,239	25,276	5,602	63,245
November	102,875	3,964	26,458	6,009	66,444
December	108,306	4,232	26,556	6,186	71,332
Year 2024					
January	115,493	4,354	27,991	7,908	75,239
February	101,815	3,991	25,995	6,931	64,898
March	103,186	4,285	25,888	6,646	66,368
April	94,071	3,262	22,280	5,730	62,799
May	98,002	3,599	24,380	5,331	64,691
June	100,201	4,040	26,090	6,319	63,752
July	109,041	4,795	28,982	7,424	67,841
August	109,971	4,683	29,645	7,236	68,407
September	102,699	4,298	27,052	6,464	64,886
October	99,916	3,508	25,663	6,278	64,469
November	102,011	3,645	23,961	6,680	67,725
December	110,274	4,390	25,287	7,484	73,112

Notes: Beginning with the collection of Form EIA-923 in January 2008, the methodology to allocate total fuel consumption for electricity generation and consumption for useful thermal output was changed.

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Values are final. See Technical Notes for a discussion of the sample design for the Form EIA-923 and predecessor forms.

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

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

Beginning with 2008 data, the Form EIA-923, Power Plant Operations Report, replaced the following: Form EIA-906, Power Plant Report; Form EIA-920, Combined Heat and Power Plant Report.

Table 5.4.C. Natural Gas: Consumption for Electricity Generation and Useful Thermal Output, by Sector, 2014 - 2024 (Million Cubic Feet)

		Electric Power Sector			
Period	Total (all sectors)	Electric Utilities	Independent Power Producers	Commercial Sector	Industrial Sector
Annual Totals					
2014	9,409,532	3,899,934	4,246,048	118,591	1,144,959
2015	10,951,674	4,753,315	4,860,055	116,380	1,221,924
2016	11,321,975	5,056,990	4,928,280	127,246	1,209,459
2017	10,676,606	4,793,632	4,471,933	154,383	1,256,658
2018	12,048,091	5,603,423	4,995,888	134,507	1,314,273
2019	12,808,883	6,023,324	5,276,029	135,310	1,374,220
2020	13,220,728	6,243,178	5,388,546	130,671	1,458,334
2021	12,724,410	5,925,545	5,303,041	116,631	1,379,193
2022	13,590,336	6,422,369	5,669,175	123,342	1,375,449
2023	14,455,682	6,868,021	6,072,868	118,901	1,395,893
2024	15,001,432	7,331,369	6,145,078	128,424	1,396,561
Year 2022					
January	1,084,549	504,303	444,912	11,311	124,023
February	922,149	418,426	385,573	9,989	108,160
March	902,405	411,079	365,768	10,175	115,382
April	860,494	394,643	348,432	9,270	108,148
May	1,043,016	492,145	430,541	9,390	110,939
June	1,266,415	626,911	517,616	9,905	111,984
July	1,537,345	756,916	648,054	11,689	120,685
August	1,513,919	727,130	653,015	11,958	121,816
September	1,246,267	583,042	542,096	10,141	110,987
October	1,067,017	494,626	451,807	9,044	111,539
November	1,026,306	484,136	417,970	9,543	114,656
December	1,120,455	529,011	463,390	10,924	117,129
Year 2023					
January	1,093,696	514,078	449,675	10,344	119,599
February	983,618	456,525	410,113	9,514	107,465
March	1,063,879	502,671	434,129	9,884	117,195
April	977,247	464,180	398,687	8,774	105,607
May	1,110,989	545,322	444,116	8,990	112,560
June	1,304,034	633,076	544,554	9,655	116,748
July	1,607,611	777,552	697,190	11,294	121,576
August	1,603,858	789,921	681,615	10,757	121,565
September	1,326,241	624,014	574,721	10,246	117,261
October	1,139,351	531,156	484,797	9,550	113,848
November	1,090,317	491,338	471,844	9,793	117,342
December	1,154,842	538,187	481,427	10,101	125,127
Year 2024					
January	1,278,325	603,544	533,449	12,036	129,296
February	1,036,528	489,150	423,563	10,676	113,139
March	1,044,687	499,637	419,569	10,392	115,089
April	999,096	479,616	400,264	9,242	109,973
May	1,168,782	584,570	463,105	8,850	112,256
June	1,360,605	680,584	557,858	10,487	111,677
July	1,660,604	839,464	688,184	12,422	120,534
August	1,631,548	826,858	669,632	11,976	123,081
September	1,346,969	666,324	556,272	10,438	113,936
October	1,189,665	579,319	491,192	9,998	109,156
November	1,111,910	534,733	452,750	10,478	113,948
December	1,172,713	547,570	489,239	11,429	124,475

Notes: Beginning with the collection of Form EIA-923 in January 2008, the methodology to allocate total fuel consumption for electricity generation and consumption for useful thermal output was changed.

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Values are final. See Technical Notes for a discussion of the sample design for the Form EIA-923 and predecessor forms.

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

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

Beginning with 2008 data, the Form EIA-923, Power Plant Operations Report, replaced the following: Form EIA-906, Power Plant Report; Form EIA-920, Combined Heat and Power Plant Report.

**Table 5.4.D. Natural Gas: Consumption for Electricity Generation,
by Sector, 2014 - 2024 (Billion Btus)**

		Electric Power Sector			
Period	Total (all sectors)	Electric Utilities	Independent Power Producers	Commercial Sector	Industrial Sector
Annual Totals					
2014	8,795,303	4,001,826	4,076,787	74,194	642,495
2015	10,360,990	4,905,009	4,739,438	71,929	644,615
2016	10,515,826	5,189,543	4,728,444	47,550	550,288
2017	9,827,794	4,911,629	4,308,241	51,592	556,331
2018	11,200,796	5,739,753	4,825,957	54,390	580,696
2019	12,008,434	6,178,186	5,137,826	57,028	635,394
2020	12,324,847	6,398,560	5,239,106	53,175	634,006
2021	11,892,547	6,071,668	5,172,999	46,896	600,984
2022	12,792,589	6,580,269	5,550,639	50,198	611,483
2023	13,684,878	7,041,713	5,967,921	50,769	624,475
2024	14,226,488	7,528,352	6,040,206	49,538	608,392
Year 2022					
January	1,005,525	516,084	431,435	4,104	53,901
February	851,167	427,737	373,226	3,640	46,563
March	825,945	419,799	351,669	3,910	50,566
April	791,873	403,696	337,071	3,637	47,469
May	976,896	503,588	419,789	3,875	49,643
June	1,205,401	642,072	508,210	4,180	50,938
July	1,476,117	775,494	640,021	5,013	55,590
August	1,455,041	746,891	647,073	5,212	55,865
September	1,189,365	599,087	535,910	4,476	49,894
October	1,003,933	507,308	443,201	3,758	49,666
November	958,728	495,304	408,724	3,979	50,722
December	1,052,598	543,210	454,311	4,413	50,664
Year 2023					
January	1,023,822	528,227	439,936	4,156	51,503
February	917,770	468,004	399,184	3,842	46,740
March	993,060	515,120	422,752	4,081	51,106
April	911,874	474,690	388,440	3,729	45,014
May	1,048,194	558,303	435,700	3,922	50,269
June	1,244,180	649,299	537,412	4,315	53,155
July	1,551,623	797,788	692,277	5,146	56,412
August	1,548,587	810,543	676,215	4,925	56,904
September	1,265,777	639,723	567,639	4,602	53,813
October	1,075,631	544,341	475,223	4,088	51,978
November	1,020,346	502,764	461,393	3,912	52,278
December	1,084,013	552,910	471,749	4,051	55,304
Year 2024					
January	1,205,058	621,082	524,115	4,262	55,598
February	968,732	502,543	412,709	3,869	49,611
March	974,061	511,931	408,216	3,869	50,045
April	934,104	490,734	391,304	3,624	48,441
May	1,104,003	598,023	453,505	3,626	48,848
June	1,301,428	697,766	550,162	4,300	49,200
July	1,606,334	864,343	682,739	5,155	54,098
August	1,575,288	851,390	662,885	4,892	56,121
September	1,286,659	684,448	547,770	4,101	50,340
October	1,126,414	594,946	481,782	3,846	45,839
November	1,044,383	548,971	444,017	3,921	47,473
December	1,100,025	562,174	481,001	4,071	52,779

Notes: Beginning with the collection of Form EIA-923 in January 2008, the methodology to allocate total fuel consumption for electricity generation and consumption for useful thermal output was changed.

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

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

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**Table 5.4.E. Natural Gas: Consumption for Useful Thermal Output,
by Sector, 2014 - 2024 (Billion Btus)**

		Electric Power Sector			
Period	Total (all sectors)	Electric Utilities	Independent Power Producers	Commercial Sector	Industrial Sector
Annual Totals					
2014	891,994	5,033	300,870	47,579	538,514
2015	965,573	8,254	292,629	47,573	617,118
2016	1,188,399	39,123	367,919	83,938	697,418
2017	1,204,582	39,828	318,611	107,987	738,156
2018	1,242,771	44,393	341,707	85,108	771,563
2019	1,232,925	43,862	327,203	82,455	779,405
2020	1,330,225	48,377	337,024	81,490	863,334
2021	1,258,705	50,514	316,694	73,588	817,909
2022	1,241,812	47,619	313,753	77,225	803,214
2023	1,245,459	47,866	314,352	72,281	810,961
2024	1,283,047	50,258	321,517	83,211	828,062
Year 2022					
January	115,425	4,763	29,244	7,589	73,829
February	101,428	4,030	25,905	6,706	64,787
March	105,152	3,945	26,566	6,606	68,035
April	95,492	2,808	23,111	5,921	63,651
May	98,439	3,439	24,825	5,804	64,370
June	100,539	3,996	26,351	6,061	64,131
July	109,613	4,736	29,480	7,039	68,358
August	109,239	4,375	28,378	7,127	69,360
September	99,549	3,697	25,602	6,017	64,232
October	98,163	3,163	24,207	5,599	65,194
November	101,006	4,130	23,735	5,878	67,263
December	107,768	4,538	26,349	6,877	70,004
Year 2023					
January	108,883	4,492	26,208	6,550	71,633
February	99,105	3,990	25,368	6,007	63,740
March	105,904	4,034	26,442	6,149	69,279
April	96,246	3,387	23,983	5,324	63,552
May	97,552	3,502	23,200	5,368	65,482
June	101,827	3,807	25,465	5,671	66,884
July	108,416	4,694	28,686	6,530	68,506
August	107,213	4,289	28,645	6,211	68,068
September	102,648	3,905	26,025	6,004	66,714
October	100,203	3,331	25,929	5,799	65,144
November	105,925	4,079	27,145	6,241	68,460
December	111,537	4,357	27,254	6,427	73,499
Year 2024					
January	119,009	4,487	28,786	8,185	77,551
February	104,900	4,103	26,740	7,181	66,877
March	106,209	4,399	26,598	6,879	68,332
April	96,649	3,339	22,832	5,924	64,554
May	100,760	3,696	24,987	5,509	66,568
June	103,083	4,148	26,755	6,531	65,649
July	112,169	4,947	29,732	7,673	69,818
August	113,213	4,835	30,475	7,485	70,418
September	105,660	4,431	27,720	6,683	66,827
October	102,836	3,604	26,312	6,509	66,411
November	104,992	3,750	24,583	6,912	69,747
December	113,568	4,520	25,997	7,740	75,310

Notes: Beginning with the collection of Form EIA-923 in January 2008, the methodology to allocate total fuel consumption for electricity generation and consumption for useful thermal output was changed.

The new methodology was retroactively applied to 2004-2007 data. See the Technical Notes (Appendix C) for further information. See Glossary for definitions.

Values are final. See Technical Notes for a discussion of the sample design for the Form EIA-923 and predecessor forms.

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

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

Beginning with 2008 data, the Form EIA-923, Power Plant Operations Report, replaced the following: Form EIA-906, Power Plant Report; Form EIA-920, Combined Heat and Power Plant Report.

Table 5.4.F. Natural Gas: Consumption for Electricity Generation and Useful Thermal Output, by Sector, 2014 - 2024 (Billion Btus)

		Electric Power Sector			
Period	Total (all sectors)	Electric Utilities	Independent Power Producers	Commercial Sector	Industrial Sector
Annual Totals					
2014	9,687,297	4,006,859	4,377,657	121,773	1,181,009
2015	11,326,564	4,913,263	5,032,066	119,502	1,261,732
2016	11,704,224	5,228,667	5,096,363	131,489	1,247,706
2017	11,032,375	4,951,457	4,626,852	159,580	1,294,487
2018	12,443,568	5,784,146	5,167,665	139,498	1,352,259
2019	13,241,359	6,222,048	5,465,029	139,483	1,414,799
2020	13,655,071	6,446,937	5,576,130	134,665	1,497,340
2021	13,151,252	6,122,182	5,489,692	120,485	1,418,893
2022	14,034,401	6,627,889	5,864,392	127,423	1,414,697
2023	14,930,337	7,089,579	6,282,273	123,050	1,435,435
2024	15,509,535	7,578,610	6,361,723	132,749	1,436,454
Year 2022					
January	1,120,949	520,847	460,679	11,693	127,730
February	952,594	431,767	399,131	10,346	111,350
March	931,097	423,744	378,235	10,516	118,601
April	887,365	406,504	360,181	9,559	111,120
May	1,075,335	507,028	444,615	9,679	114,014
June	1,305,940	646,069	534,561	10,241	115,069
July	1,585,730	780,229	669,501	12,052	123,948
August	1,564,279	751,266	675,450	12,339	125,225
September	1,288,914	602,784	561,511	10,493	114,126
October	1,102,096	510,470	467,408	9,358	114,860
November	1,059,735	499,433	432,459	9,857	117,985
December	1,160,366	547,747	480,661	11,290	120,668
Year 2023					
January	1,132,704	532,719	466,145	10,706	123,135
February	1,016,876	471,994	424,553	9,848	110,480
March	1,098,964	519,154	449,195	10,230	120,385
April	1,008,120	478,077	412,424	9,054	108,566
May	1,145,746	561,805	458,900	9,290	115,751
June	1,346,007	653,106	562,877	9,986	120,039
July	1,660,039	802,482	720,962	11,676	124,918
August	1,655,800	814,832	704,860	11,136	124,972
September	1,368,425	643,628	593,665	10,606	120,526
October	1,175,834	547,672	501,153	9,887	117,121
November	1,126,271	506,842	488,538	10,153	120,738
December	1,195,550	557,267	499,003	10,478	128,802
Year 2024					
January	1,324,066	625,568	552,902	12,447	133,149
February	1,073,631	506,646	439,449	11,049	116,488
March	1,080,270	516,331	434,813	10,748	118,377
April	1,030,753	494,073	414,136	9,548	112,996
May	1,204,763	601,720	478,492	9,135	115,415
June	1,404,511	701,914	576,917	10,832	114,849
July	1,718,503	869,289	712,471	12,827	123,916
August	1,688,501	856,226	693,360	12,377	126,539
September	1,392,319	688,878	575,489	10,784	117,167
October	1,229,250	598,550	508,095	10,355	112,250
November	1,149,375	552,721	468,600	10,833	117,220
December	1,213,593	566,694	506,999	11,812	128,088

Notes: Beginning with the collection of Form EIA-923 in January 2008, the methodology to allocate total fuel consumption for electricity generation and consumption for useful thermal output was changed.

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Values are final. See Technical Notes for a discussion of the sample design for the Form EIA-923 and predecessor forms.

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

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

Beginning with 2008 data, the Form EIA-923, Power Plant Operations Report, replaced the following: Form EIA-906, Power Plant Report; Form EIA-920, Combined Heat and Power Plant Report.

Table 5.5.D. Wood / Wood Waste Biomass: Consumption for Electricity Generation, by Sector, 2014 - 2024 (Billion Btus)

		Electric Power Sector			
Period	Total (all sectors)	Electric Utilities	Independent Power Producers	Commercial Sector	Industrial Sector
Annual Totals					
2014	431,285	45,643	174,513	961	210,167
2015	406,650	43,919	171,387	504	190,840
2016	359,983	41,036	149,516	473	168,959
2017	363,646	42,806	151,877	460	168,503
2018	361,703	45,856	143,288	520	172,039
2019	338,317	42,240	128,980	583	166,514
2020	318,381	31,606	125,695	608	160,472
2021	328,253	41,868	129,554	998	155,833
2022	323,820	46,357	125,125	1,140	151,198
2023	289,996	38,914	110,338	732	140,012
2024	279,132	35,766	104,307	709	138,350
Year 2022					
January	28,590	4,116	11,148	102	13,225
February	27,354	4,072	10,966	94	12,223
March	26,834	3,220	10,911	69	12,633
April	24,378	2,638	9,297	73	12,370
May	26,094	3,542	9,711	110	12,731
June	27,667	4,060	10,713	129	12,766
July	30,189	4,960	11,506	119	13,604
August	29,708	5,264	11,129	171	13,144
September	26,117	3,722	10,273	81	12,041
October	23,854	3,181	9,295	42	11,335
November	25,533	3,117	9,864	72	12,481
December	27,502	4,466	10,313	77	12,647
Year 2023					
January	26,972	3,947	10,564	76	12,384
February	23,316	3,531	8,879	47	10,859
March	24,472	2,504	9,943	55	11,971
April	21,340	1,966	8,038	46	11,290
May	24,408	2,836	9,447	24	12,101
June	24,292	3,798	9,164	68	11,262
July	26,080	4,560	9,783	58	11,678
August	27,025	4,473	10,163	85	12,304
September	23,669	3,310	8,832	82	11,446
October	20,337	2,193	7,284	61	10,800
November	22,798	2,521	8,717	56	11,503
December	25,286	3,276	9,522	74	12,414
Year 2024					
January	26,093	4,339	9,893	99	11,762
February	23,434	3,273	9,003	37	11,121
March	23,476	1,944	9,739	24	11,770
April	20,826	2,962	6,634	9	11,221
May	22,584	2,707	8,149	33	11,696
June	24,318	3,708	8,842	66	11,702
July	25,152	3,598	9,419	111	12,025
August	25,625	4,069	9,488	60	12,008
September	22,153	2,006	9,021	83	11,044
October	19,018	1,403	6,868	45	10,702
November	21,812	2,012	8,127	76	11,596
December	24,640	3,744	9,124	68	11,704

Notes: Beginning with the collection of Form EIA-923 in January 2008, the methodology to allocate total fuel consumption for electricity generation and consumption for useful thermal output was changed.

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Values are final. See Technical Notes for a discussion of the sample design for the Form EIA-923 and predecessor forms.

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

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

Beginning with 2008 data, the Form EIA-923, Power Plant Operations Report, replaced the following: Form EIA-906, Power Plant Report; Form EIA-920, Combined Heat and Power Plant Report.

Table 5.5.E. Wood / Wood Waste Biomass: Consumption for Useful Thermal Output, by Sector, 2014 - 2024 (Billion Btus)

		Electric Power Sector			
Period	Total (all sectors)	Electric Utilities	Independent Power Producers	Commercial Sector	Industrial Sector
Annual Totals					
2014	946,344	8,835	22,262	3,766	911,481
2015	943,962	9,351	19,200	3,714	911,697
2016	969,841	10,950	22,905	4,520	931,465
2017	939,633	11,656	22,986	4,522	900,469
2018	929,365	10,297	21,623	4,806	892,639
2019	907,420	3,564	25,740	4,969	873,147
2020	860,062	3,051	25,022	3,595	828,394
2021	870,986	3,520	21,804	2,958	842,704
2022	819,538	4,629	21,579	3,158	790,172
2023	754,615	4,076	20,744	2,343	727,452
2024	740,218	4,445	17,219	2,295	716,259
Year 2022					
January	72,157	390	2,158	282	69,327
February	65,478	385	1,740	281	63,071
March	68,069	443	1,613	228	65,785
April	68,138	403	1,617	171	65,947
May	70,011	269	1,639	274	67,828
June	68,973	296	1,688	367	66,623
July	71,267	330	1,709	327	68,901
August	70,484	360	1,819	375	67,931
September	64,897	408	1,977	199	62,313
October	65,076	230	1,763	149	62,935
November	66,976	513	1,895	250	64,318
December	68,011	603	1,960	256	65,192
Year 2023					
January	69,277	456	1,721	249	66,851
February	60,917	377	1,949	163	58,427
March	66,831	438	2,692	223	63,478
April	59,109	391	1,725	162	56,830
May	63,132	91	1,803	81	61,157
June	58,285	266	1,869	254	55,897
July	61,598	295	1,451	129	59,723
August	62,979	339	1,215	221	61,204
September	60,896	182	866	256	59,592
October	61,213	344	2,393	185	58,292
November	64,741	433	1,506	179	62,623
December	65,636	464	1,555	241	63,377
Year 2024					
January	63,467	474	1,688	285	61,020
February	60,551	431	1,485	138	58,497
March	62,314	473	1,366	75	60,401
April	61,443	433	1,324	65	59,621
May	60,090	252	1,392	147	58,299
June	60,041	365	1,310	223	58,143
July	61,068	410	1,461	318	58,879
August	62,242	346	1,483	185	60,227
September	62,115	364	1,566	233	59,953
October	58,196	169	1,301	150	56,576
November	62,481	343	1,262	218	60,659
December	66,211	387	1,582	259	63,983

Notes: Beginning with the collection of Form EIA-923 in January 2008, the methodology to allocate total fuel consumption for electricity generation and consumption for useful thermal output was changed.

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Values are final. See Technical Notes for a discussion of the sample design for the Form EIA-923 and predecessor forms.

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

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

Beginning with 2008 data, the Form EIA-923, Power Plant Operations Report, replaced the following: Form EIA-906, Power Plant Report; Form EIA-920, Combined Heat and Power Plant Report.

Table 5.5.F. Wood / Wood Waste Biomass: Consumption for Electricity Generation and Useful Thermal Output, by Sector, 2014 - 2024 (Billion Btus)

		Electric Power Sector			
Period	Total (all sectors)	Electric Utilities	Independent Power Producers	Commercial Sector	Industrial Sector
Annual Totals					
2014	1,377,629	54,478	196,775	4,727	1,121,648
2015	1,350,612	53,269	190,587	4,219	1,102,537
2016	1,329,824	51,986	172,421	4,993	1,100,424
2017	1,303,279	54,462	174,862	4,982	1,068,972
2018	1,291,068	56,153	164,911	5,326	1,064,678
2019	1,245,737	45,804	154,720	5,552	1,039,661
2020	1,178,443	34,657	150,717	4,203	988,866
2021	1,199,240	45,387	151,359	3,957	998,537
2022	1,143,358	50,986	146,704	4,297	941,370
2023	1,044,610	42,990	131,082	3,075	867,464
2024	1,019,350	40,211	121,526	3,004	854,608
Year 2022					
January	100,746	4,505	13,306	384	82,552
February	92,833	4,457	12,706	376	75,294
March	94,902	3,663	12,524	297	78,418
April	92,516	3,041	10,914	244	78,317
May	96,104	3,810	11,350	384	80,559
June	96,641	4,356	12,401	495	79,388
July	101,457	5,290	13,216	446	82,505
August	100,192	5,624	12,948	545	81,075
September	91,014	4,131	12,251	280	74,354
October	88,930	3,412	11,058	191	74,270
November	92,510	3,630	11,759	322	76,800
December	95,513	5,068	12,273	334	77,839
Year 2023					
January	96,249	4,403	12,285	325	79,236
February	84,233	3,908	10,828	210	69,287
March	91,304	2,942	12,635	278	75,449
April	80,449	2,357	9,763	209	68,121
May	87,540	2,927	11,250	105	73,258
June	82,577	4,064	11,032	322	67,159
July	87,677	4,855	11,234	187	71,401
August	90,005	4,812	11,378	306	73,508
September	84,565	3,492	9,698	338	71,037
October	81,550	2,537	9,677	246	69,091
November	87,538	2,954	10,223	235	74,126
December	90,923	3,740	11,078	315	75,791
Year 2024					
January	89,560	4,813	11,581	384	72,782
February	83,985	3,704	10,488	175	69,618
March	85,790	2,416	11,105	98	72,171
April	82,268	3,394	7,958	74	70,842
May	82,674	2,959	9,540	180	69,995
June	84,359	4,073	10,152	289	69,845
July	86,220	4,008	10,880	429	70,903
August	87,867	4,415	10,972	245	72,236
September	84,269	2,370	10,586	315	70,997
October	77,215	1,573	8,169	195	67,278
November	84,293	2,355	9,389	294	72,255
December	90,851	4,131	10,707	326	75,687

Notes: Beginning with the collection of Form EIA-923 in January 2008, the methodology to allocate total fuel consumption for electricity generation and consumption for useful thermal output was changed.

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

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

Beginning with 2008 data, the Form EIA-923, Power Plant Operations Report, replaced the following: Form EIA-906, Power Plant Report; Form EIA-920, Combined Heat and Power Plant Report.

Table 5.6.A. Landfill Gas: Consumption for Electricity Generation, by Sector, 2014 - 2024 (Million Cubic Feet)

		Electric Power Sector			
Period	Total (all sectors)	Electric Utilities	Independent Power Producers	Commercial Sector	Industrial Sector
Annual Totals					
2014	285,982	25,819	228,447	27,038	4,678
2015	282,530	25,257	227,381	25,250	4,642
2016	273,557	24,280	224,993	20,445	3,839
2017	278,112	25,074	229,050	20,121	3,866
2018	270,235	23,580	223,513	19,790	3,352
2019	257,494	22,726	214,819	16,874	3,075
2020	252,501	23,571	208,196	18,136	2,597
2021	231,876	22,831	190,031	16,472	2,542
2022	211,866	18,486	176,160	14,898	2,323
2023	194,292	15,815	162,861	13,392	2,224
2024	181,646	14,369	152,452	12,687	2,137
Year 2022					
January	18,515	1,725	15,257	1,343	190
February	17,347	1,602	14,349	1,216	180
March	19,127	1,751	15,882	1,301	192
April	17,226	1,547	14,618	900	161
May	17,953	1,594	14,955	1,209	195
June	17,609	1,531	14,651	1,225	202
July	17,975	1,543	14,919	1,314	198
August	17,540	1,487	14,533	1,315	207
September	17,102	1,461	14,174	1,275	192
October	17,877	1,480	14,857	1,337	202
November	16,933	1,419	14,149	1,177	188
December	16,663	1,347	13,815	1,285	216
Year 2023					
January	16,986	1,407	14,217	1,180	182
February	15,093	1,220	12,583	1,094	196
March	16,449	1,392	13,673	1,145	238
April	15,225	1,273	12,683	1,075	193
May	17,019	1,411	14,329	1,104	175
June	16,409	1,356	13,731	1,113	208
July	16,595	1,332	13,925	1,162	176
August	16,660	1,320	13,972	1,207	162
September	15,396	1,188	12,927	1,133	149
October	15,747	1,271	13,387	930	160
November	15,859	1,284	13,301	1,100	174
December	16,855	1,360	14,133	1,150	212
Year 2024					
January	15,763	1,189	13,278	1,108	189
February	14,939	1,216	12,519	1,002	203
March	15,785	1,228	13,266	1,081	211
April	14,426	1,123	12,149	981	172
May	15,722	1,216	13,318	1,060	128
June	14,687	1,148	12,406	993	139
July	15,423	1,218	12,945	1,074	187
August	15,793	1,290	13,244	1,074	184
September	14,907	1,205	12,489	1,040	172
October	15,054	1,201	12,582	1,046	224
November	14,542	1,188	12,077	1,105	172
December	14,604	1,146	12,179	1,124	155

Notes: Beginning with the collection of Form EIA-923 in January 2008, the methodology to allocate total fuel consumption for electricity generation and consumption for useful thermal output was changed.

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

Beginning with 2008 data, the Form EIA-923, Power Plant Operations Report, replaced the following: Form EIA-906, Power Plant Report; Form EIA-920, Combined Heat and Power Plant Report.

**Table 5.6.B. Landfill Gas: Consumption for Useful Thermal Output,
by Sector, 2014 - 2024 (Million Cubic Feet)**

		Electric Power Sector			
Period	Total (all sectors)	Electric Utilities	Independent Power Producers	Commercial Sector	Industrial Sector
Annual Totals					
2014	1,710	176	525	674	335
2015	1,522	2	644	515	362
2016	4,163	3	2,339	1,034	788
2017	3,940	2	1,948	1,099	891
2018	3,621	0	1,867	911	843
2019	3,570	5	1,933	820	812
2020	4,011	3	2,187	820	1,000
2021	4,030	6	2,155	741	1,129
2022	4,280	15	1,996	817	1,451
2023	3,411	10	1,722	705	973
2024	3,228	33	1,709	523	964
Year 2022					
January	401	1	197	81	121
February	374	1	186	69	118
March	436	1	218	78	138
April	330	1	157	70	102
May	293	1	116	51	125
June	344	1	163	65	115
July	362	1	170	66	125
August	362	1	164	74	122
September	355	1	160	76	117
October	355	1	163	69	122
November	315	1	130	64	120
December	354	1	173	55	124
Year 2023					
January	298	1	153	64	80
February	267	1	135	52	79
March	282	1	144	49	88
April	297	1	142	65	89
May	221	1	103	40	78
June	294	1	152	53	88
July	310	1	161	65	83
August	309	1	160	70	78
September	279	1	155	61	63
October	293	1	147	72	73
November	247	1	104	60	83
December	314	1	166	54	93
Year 2024					
January	295	3	166	46	80
February	281	2	144	51	84
March	291	3	151	52	85
April	304	2	132	38	131
May	218	3	120	32	63
June	226	3	133	18	72
July	266	3	148	26	88
August	305	3	156	50	95
September	284	3	143	52	86
October	284	3	147	55	79
November	221	3	112	53	53
December	254	3	155	48	48

Notes: Beginning with the collection of Form EIA-923 in January 2008, the methodology to allocate total fuel consumption for electricity generation and consumption for useful thermal output was changed.

The new methodology was retroactively applied to 2004-2007 data. See the Technical Notes (Appendix C) for further information. See Glossary for definitions.

Values are final. See Technical Notes for a discussion of the sample design for the Form EIA-923 and predecessor forms.

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

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

Beginning with 2008 data, the Form EIA-923, Power Plant Operations Report, replaced the following: Form EIA-906, Power Plant Report; Form EIA-920, Combined Heat and Power Plant Report.

Table 5.6.C. Landfill Gas: Consumption for Electricity Generation and Useful Thermal Output, by Sector, 2014 - 2024 (Million Cubic Feet)

		Electric Power Sector			
Period	Total (all sectors)	Electric Utilities	Independent Power Producers	Commercial Sector	Industrial Sector
Annual Totals					
2014	287,692	25,995	228,971	27,713	5,013
2015	284,052	25,259	228,024	25,765	5,004
2016	277,720	24,283	227,332	21,479	4,626
2017	282,051	25,076	230,998	21,220	4,757
2018	273,856	23,580	225,380	20,701	4,196
2019	261,064	22,731	216,753	17,694	3,887
2020	256,512	23,575	210,383	18,956	3,598
2021	235,906	22,836	192,186	17,212	3,671
2022	216,146	18,501	178,155	15,715	3,774
2023	197,703	15,825	164,584	14,097	3,197
2024	184,874	14,402	154,161	13,210	3,100
Year 2022					
January	18,916	1,726	15,454	1,424	311
February	17,721	1,603	14,535	1,285	298
March	19,562	1,753	16,100	1,379	330
April	17,556	1,548	14,775	971	263
May	18,246	1,595	15,070	1,260	321
June	17,953	1,532	14,813	1,290	318
July	18,337	1,545	15,089	1,380	323
August	17,902	1,488	14,696	1,389	329
September	17,456	1,462	14,334	1,350	309
October	18,232	1,482	15,020	1,406	324
November	17,247	1,420	14,279	1,241	308
December	17,017	1,348	13,988	1,340	340
Year 2023					
January	17,284	1,408	14,370	1,244	262
February	15,360	1,221	12,719	1,146	275
March	16,731	1,393	13,817	1,194	326
April	15,522	1,274	12,826	1,140	282
May	17,240	1,412	14,432	1,144	253
June	16,702	1,357	13,884	1,166	295
July	16,905	1,333	14,085	1,227	259
August	16,969	1,321	14,132	1,277	239
September	15,675	1,189	13,082	1,193	211
October	16,040	1,272	13,534	1,001	233
November	16,106	1,285	13,405	1,159	257
December	17,169	1,361	14,299	1,204	305
Year 2024					
January	16,058	1,192	13,444	1,154	268
February	15,220	1,218	12,662	1,053	286
March	16,076	1,231	13,417	1,133	295
April	14,730	1,126	12,282	1,019	303
May	15,940	1,219	13,438	1,092	191
June	14,913	1,151	12,540	1,012	211
July	15,689	1,221	13,093	1,100	275
August	16,097	1,293	13,400	1,125	280
September	15,191	1,208	12,632	1,092	258
October	15,338	1,204	12,729	1,102	303
November	14,763	1,191	12,189	1,158	225
December	14,858	1,149	12,334	1,172	204

Notes: Beginning with the collection of Form EIA-923 in January 2008, the methodology to allocate total fuel consumption for electricity generation and consumption for useful thermal output was changed.

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Values are final. See Technical Notes for a discussion of the sample design for the Form EIA-923 and predecessor forms.

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

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

Beginning with 2008 data, the Form EIA-923, Power Plant Operations Report, replaced the following: Form EIA-906, Power Plant Report; Form EIA-920, Combined Heat and Power Plant Report.

**Table 5.6.D. Landfill Gas: Consumption for Electricity Generation,
by Sector, 2014 - 2024 (Billion Btus)**

		Electric Power Sector			
Period	Total (all sectors)	Electric Utilities	Independent Power Producers	Commercial Sector	Industrial Sector
Annual Totals					
2014	140,779	13,132	114,333	10,937	2,377
2015	138,085	12,846	112,911	10,023	2,304
2016	135,365	12,294	112,770	8,374	1,927
2017	137,635	13,071	114,131	8,508	1,926
2018	133,957	12,395	111,769	8,104	1,689
2019	127,540	11,794	107,100	7,086	1,560
2020	124,647	12,337	103,453	7,510	1,348
2021	113,839	11,897	93,819	6,826	1,297
2022	103,630	9,661	86,766	6,007	1,197
2023	95,684	8,251	80,667	5,640	1,126
2024	89,564	7,341	75,604	5,533	1,086
Year 2022					
January	9,050	900	7,506	546	98
February	8,482	837	7,060	492	93
March	9,339	916	7,813	511	99
April	8,482	812	7,202	385	83
May	8,781	836	7,372	473	100
June	8,624	800	7,221	498	105
July	8,813	806	7,376	529	102
August	8,603	776	7,187	534	106
September	8,359	763	6,979	518	98
October	8,707	773	7,298	531	104
November	8,282	741	6,968	476	96
December	8,108	700	6,784	513	111
Year 2023					
January	8,356	735	7,049	481	91
February	7,401	636	6,224	442	99
March	8,098	728	6,780	470	120
April	7,498	667	6,276	458	98
May	8,365	739	7,070	469	88
June	8,078	708	6,798	468	104
July	8,190	696	6,910	495	89
August	8,221	688	6,937	514	83
September	7,572	617	6,404	475	76
October	7,805	661	6,650	412	82
November	7,809	668	6,587	465	88
December	8,290	707	6,984	490	109
Year 2024					
January	7,775	607	6,587	485	95
February	7,388	623	6,220	442	103
March	7,799	629	6,584	478	109
April	7,135	575	6,031	440	89
May	7,787	620	6,625	474	67
June	7,260	585	6,170	432	72
July	7,607	621	6,425	466	95
August	7,807	659	6,587	466	95
September	7,351	616	6,200	447	89
October	7,396	614	6,229	449	104
November	7,116	608	5,951	470	87
December	7,144	584	5,996	484	81

Notes: Beginning with the collection of Form EIA-923 in January 2008, the methodology to allocate total fuel consumption for electricity generation and consumption for useful thermal output was changed.

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Values are final. See Technical Notes for a discussion of the sample design for the Form EIA-923 and predecessor forms.

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

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

Beginning with 2008 data, the Form EIA-923, Power Plant Operations Report, replaced the following: Form EIA-906, Power Plant Report; Form EIA-920, Combined Heat and Power Plant Report.

**Table 5.6.E. Landfill Gas: Consumption for Useful Thermal Output,
by Sector, 2014 - 2024 (Billion Btus)**

		Electric Power Sector			
Period	Total (all sectors)	Electric Utilities	Independent Power Producers	Commercial Sector	Industrial Sector
Annual Totals					
2014	852	88	266	326	173
2015	756	1	326	250	179
2016	2,236	1	1,266	589	380
2017	2,196	1	1,066	698	431
2018	1,964	0	966	594	403
2019	1,960	2	1,034	531	394
2020	2,225	1	1,168	535	521
2021	2,210	2	1,151	504	553
2022	2,363	5	1,081	547	729
2023	1,876	3	944	464	465
2024	1,772	10	938	362	462
Year 2022					
January	224	0	107	55	61
February	207	0	101	47	60
March	240	0	117	53	70
April	186	0	86	48	51
May	159	0	64	32	63
June	193	0	89	45	59
July	199	0	93	43	63
August	201	0	89	50	61
September	196	0	87	50	58
October	196	0	88	46	61
November	174	0	71	43	60
December	189	0	89	37	62
Year 2023					
January	163	0	83	42	38
February	145	0	74	34	38
March	156	0	79	34	42
April	163	0	78	43	43
May	121	0	59	25	37
June	160	0	83	34	42
July	171	0	88	43	39
August	172	0	87	47	37
September	155	0	84	40	30
October	163	0	81	47	35
November	134	0	58	37	39
December	174	0	91	37	45
Year 2024					
January	162	1	90	33	38
February	154	1	79	34	40
March	159	1	83	35	41
April	166	1	74	27	65
May	119	1	67	21	30
June	121	1	73	13	34
July	142	1	81	18	42
August	168	1	85	36	46
September	157	1	78	37	41
October	155	1	80	38	36
November	125	1	62	37	25
December	144	1	85	34	24

Notes: Beginning with the collection of Form EIA-923 in January 2008, the methodology to allocate total fuel consumption for electricity generation and consumption for useful thermal output was changed.

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Values are final. See Technical Notes for a discussion of the sample design for the Form EIA-923 and predecessor forms.

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

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

Beginning with 2008 data, the Form EIA-923, Power Plant Operations Report, replaced the following: Form EIA-906, Power Plant Report; Form EIA-920, Combined Heat and Power Plant Report.

Table 5.6.F. Landfill Gas: Consumption for Electricity Generation and Useful Thermal Output, by Sector, 2014 - 2024 (Billion Btus)

		Electric Power Sector			
Period	Total (all sectors)	Electric Utilities	Independent Power Producers	Commercial Sector	Industrial Sector
Annual Totals					
2014	141,632	13,220	114,599	11,263	2,550
2015	138,841	12,847	113,238	10,273	2,483
2016	137,600	12,295	114,036	8,963	2,307
2017	139,831	13,072	115,197	9,206	2,357
2018	135,921	12,395	112,736	8,698	2,092
2019	129,500	11,795	108,134	7,617	1,954
2020	126,872	12,338	104,621	8,045	1,868
2021	116,049	11,899	94,971	7,330	1,850
2022	105,993	9,666	87,846	6,554	1,926
2023	97,560	8,254	81,611	6,104	1,591
2024	91,336	7,351	76,542	5,895	1,548
Year 2022					
January	9,274	901	7,612	601	160
February	8,689	838	7,160	538	153
March	9,579	917	7,930	564	169
April	8,668	812	7,288	433	135
May	8,939	836	7,436	505	163
June	8,817	800	7,310	543	163
July	9,012	806	7,468	572	166
August	8,804	776	7,277	584	168
September	8,554	764	7,066	568	156
October	8,903	774	7,386	577	166
November	8,456	742	7,039	519	156
December	8,297	700	6,873	550	173
Year 2023					
January	8,519	735	7,132	523	129
February	7,547	637	6,298	476	136
March	8,254	729	6,859	504	162
April	7,661	667	6,353	500	140
May	8,486	739	7,128	494	125
June	8,238	709	6,881	503	146
July	8,361	697	6,997	539	128
August	8,393	688	7,024	561	120
September	7,727	617	6,488	515	106
October	7,969	662	6,732	459	117
November	7,943	669	6,645	502	128
December	8,464	707	7,075	527	154
Year 2024					
January	7,937	608	6,678	518	133
February	7,543	624	6,299	477	143
March	7,959	630	6,667	513	150
April	7,300	576	6,104	467	154
May	7,906	621	6,692	495	97
June	7,380	586	6,244	444	106
July	7,749	622	6,506	484	137
August	7,975	660	6,672	502	141
September	7,508	616	6,278	484	130
October	7,552	615	6,309	487	140
November	7,241	609	6,013	507	112
December	7,287	585	6,081	517	105

Notes: Beginning with the collection of Form EIA-923 in January 2008, the methodology to allocate total fuel consumption for electricity generation and consumption for useful thermal output was changed.

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Beginning with 2008 data, the Form EIA-923, Power Plant Operations Report, replaced the following: Form EIA-906, Power Plant Report; Form EIA-920, Combined Heat and Power Plant Report.

Table 5.7.A. Biogenic Municipal Solid Waste: Consumption for Electricity Generation, by Sector, 2014 - 2024 (Thousand Tons)

		Electric Power Sector			
Period	Total (all sectors)	Electric Utilities	Independent Power Producers	Commercial Sector	Industrial Sector
Annual Totals					
2014	16,706	444	13,809	2,447	6
2015	16,631	452	13,797	2,375	8
2016	16,994	464	13,953	2,566	11
2017	16,348	422	13,381	2,537	8
2018	16,783	467	13,859	2,448	9
2019	15,559	297	12,941	2,310	10
2020	15,516	280	12,975	2,251	10
2021	15,223	252	12,442	2,521	7
2022	14,589	274	7,346	6,969	0
2023	13,916	283	6,960	6,674	0
2024	13,636	283	6,721	6,632	0
Year 2022					
January	1,214	22	645	547	0
February	1,117	20	567	530	0
March	1,215	17	638	560	0
April	1,207	23	592	591	0
May	1,225	28	607	589	0
June	1,248	25	622	601	0
July	1,272	25	634	612	0
August	1,246	28	623	595	0
September	1,199	18	604	577	0
October	1,211	24	592	595	0
November	1,212	23	593	595	0
December	1,224	21	626	577	0
Year 2023					
January	1,205	24	616	564	0
February	1,048	15	539	494	0
March	1,112	21	575	516	0
April	1,065	21	533	512	0
May	1,170	21	591	558	0
June	1,180	26	582	572	0
July	1,248	24	620	604	0
August	1,235	28	614	592	0
September	1,140	24	572	544	0
October	1,156	27	564	565	0
November	1,131	26	546	559	0
December	1,226	24	607	595	0
Year 2024					
January	1,182	21	582	578	0
February	1,065	17	531	516	0
March	1,105	13	565	527	0
April	1,070	20	504	546	0
May	1,172	29	567	575	0
June	1,137	27	555	555	0
July	1,201	28	595	578	0
August	1,228	27	604	597	0
September	1,117	24	560	533	0
October	1,118	27	544	547	0
November	1,113	24	554	535	0
December	1,129	25	558	546	0

Notes: Beginning with the collection of Form EIA-923 in January 2008, the methodology to allocate total fuel consumption for electricity generation and consumption for useful thermal output was changed.

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

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

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Table 5.7.B. Biogenic Municipal Solid Waste: Consumption for Useful Thermal Output, by Sector, 2014 - 2024 (Thousand Tons)

		Electric Power Sector			
Period	Total (all sectors)	Electric Utilities	Independent Power Producers	Commercial Sector	Industrial Sector
Annual Totals					
2014	1,955	0	650	1,104	200
2015	1,986	0	655	1,127	203
2016	2,232	0	885	1,134	213
2017	2,124	0	814	1,102	208
2018	2,050	0	752	1,109	189
2019	1,667	0	743	737	187
2020	1,650	0	757	705	188
2021	1,712	0	873	666	173
2022	1,647	0	401	1,246	0
2023	1,667	0	449	1,218	0
2024	1,611	0	417	1,194	0
Year 2022					
January	148	0	38	110	0
February	130	0	31	99	0
March	129	0	30	100	0
April	125	0	29	96	0
May	143	0	34	109	0
June	141	0	32	108	0
July	148	0	37	111	0
August	151	0	34	117	0
September	137	0	32	104	0
October	127	0	32	95	0
November	139	0	34	106	0
December	129	0	38	91	0
Year 2023					
January	135	0	38	97	0
February	129	0	33	96	0
March	137	0	34	103	0
April	129	0	32	97	0
May	141	0	33	108	0
June	128	0	33	95	0
July	148	0	41	107	0
August	153	0	40	113	0
September	140	0	40	101	0
October	122	0	37	85	0
November	145	0	44	102	0
December	159	0	43	115	0
Year 2024					
January	153	0	43	110	0
February	141	0	35	106	0
March	137	0	33	103	0
April	121	0	35	85	0
May	146	0	36	109	0
June	137	0	31	106	0
July	141	0	35	106	0
August	124	0	36	87	0
September	124	0	33	91	0
October	126	0	30	96	0
November	126	0	31	95	0
December	136	0	37	99	0

Notes: Beginning with the collection of Form EIA-923 in January 2008, the methodology to allocate total fuel consumption for electricity generation and consumption for useful thermal output was changed.

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

Beginning with 2008 data, the Form EIA-923, Power Plant Operations Report, replaced the following: Form EIA-906, Power Plant Report; Form EIA-920, Combined Heat and Power Plant Report.

Table 5.7.C. Biogenic Municipal Solid Waste: Consumption for Electricity Generation and Useful Thermal Output, by Sector, 2014 - 2024 (Thousand Tons)

		Electric Power Sector			
Period	Total (all sectors)	Electric Utilities	Independent Power Producers	Commercial Sector	Industrial Sector
Annual Totals					
2014	18,661	444	14,459	3,551	206
2015	18,617	452	14,452	3,502	211
2016	19,226	464	14,838	3,700	224
2017	18,473	422	14,195	3,639	216
2018	18,833	467	14,611	3,557	197
2019	17,225	297	13,684	3,047	197
2020	17,166	280	13,732	2,956	198
2021	16,934	252	13,315	3,187	180
2022	16,236	274	7,747	8,215	0
2023	15,584	283	7,408	7,892	0
2024	15,247	283	7,138	7,827	0
Year 2022					
January	1,362	22	683	657	0
February	1,248	20	598	629	0
March	1,344	17	668	660	0
April	1,332	23	621	687	0
May	1,368	28	642	697	0
June	1,389	25	655	709	0
July	1,420	25	671	723	0
August	1,397	28	657	712	0
September	1,336	18	636	682	0
October	1,338	24	624	690	0
November	1,351	23	627	701	0
December	1,353	21	664	668	0
Year 2023					
January	1,340	24	654	662	0
February	1,177	15	571	591	0
March	1,250	21	609	619	0
April	1,194	21	564	609	0
May	1,311	21	625	665	0
June	1,309	26	615	668	0
July	1,396	24	661	711	0
August	1,388	28	654	705	0
September	1,281	24	612	644	0
October	1,278	27	601	649	0
November	1,276	26	590	660	0
December	1,385	24	650	710	0
Year 2024					
January	1,335	21	626	688	0
February	1,206	17	566	623	0
March	1,242	13	599	630	0
April	1,191	20	539	631	0
May	1,317	29	604	684	0
June	1,274	27	586	661	0
July	1,342	28	630	684	0
August	1,352	27	641	684	0
September	1,241	24	593	624	0
October	1,244	27	575	642	0
November	1,239	24	585	630	0
December	1,265	25	595	645	0

Notes: Beginning with the collection of Form EIA-923 in January 2008, the methodology to allocate total fuel consumption for electricity generation and consumption for useful thermal output was changed.

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Values are final. See Technical Notes for a discussion of the sample design for the Form EIA-923 and predecessor forms.

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

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

Beginning with 2008 data, the Form EIA-923, Power Plant Operations Report, replaced the following: Form EIA-906, Power Plant Report; Form EIA-920, Combined Heat and Power Plant Report.

Table 5.7.D. Biogenic Municipal Solid Waste: Consumption for Electricity Generation, by Sector, 2014 - 2024 (Billion Btus)

		Electric Power Sector			
Period	Total (all sectors)	Electric Utilities	Independent Power Producers	Commercial Sector	Industrial Sector
Annual Totals					
2014	134,408	4,429	110,569	19,366	45,054
2015	133,117	4,295	109,691	19,068	63,063
2016	135,957	4,434	111,003	20,431	89,093
2017	130,942	4,172	106,382	20,320	67,050
2018	134,465	4,568	110,452	19,374	72,071
2019	115,114	2,454	95,638	16,946	76,076
2020	114,814	2,284	95,941	16,511	77,078
2021	113,173	2,029	92,144	18,944	56,056
2022	108,508	2,212	54,250	52,046	0
2023	103,306	2,275	51,190	49,841	0
2024	100,831	2,273	49,294	49,263	0
Year 2022					
January	9,109	172	4,796	4,141	0
February	8,332	161	4,204	3,967	0
March	9,091	134	4,797	4,160	0
April	9,014	186	4,404	4,424	0
May	9,156	227	4,528	4,401	0
June	9,285	203	4,602	4,480	0
July	9,451	205	4,699	4,547	0
August	9,222	227	4,574	4,420	0
September	8,817	143	4,423	4,251	0
October	8,960	192	4,319	4,449	0
November	8,977	188	4,321	4,468	0
December	9,095	174	4,584	4,338	0
Year 2023					
January	8,952	198	4,517	4,237	0
February	7,833	124	3,984	3,725	0
March	8,285	174	4,245	3,866	0
April	7,938	169	3,923	3,846	0
May	8,740	173	4,378	4,188	0
June	8,746	208	4,274	4,264	0
July	9,244	195	4,584	4,465	0
August	9,066	227	4,465	4,373	0
September	8,403	194	4,194	4,015	0
October	8,593	215	4,161	4,217	0
November	8,403	204	4,003	4,196	0
December	9,104	193	4,462	4,449	0
Year 2024					
January	8,780	167	4,308	4,305	0
February	7,906	137	3,911	3,857	0
March	8,207	106	4,164	3,937	0
April	7,900	156	3,723	4,021	0
May	8,714	237	4,182	4,294	0
June	8,334	211	4,059	4,063	0
July	8,825	219	4,333	4,273	0
August	8,959	225	4,354	4,380	0
September	8,199	192	4,090	3,918	0
October	8,281	225	3,994	4,062	0
November	8,305	198	4,064	4,043	0
December	8,420	200	4,112	4,108	0

Notes: Beginning with the collection of Form EIA-923 in January 2008, the methodology to allocate total fuel consumption for electricity generation and consumption for useful thermal output was changed.

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Beginning with 2008 data, the Form EIA-923, Power Plant Operations Report, replaced the following: Form EIA-906, Power Plant Report; Form EIA-920, Combined Heat and Power Plant Report.

Table 5.7.E. Biogenic Municipal Solid Waste: Consumption for Useful Thermal Output, by Sector, 2014 - 2024 (Billion Btus)

		Electric Power Sector			
Period	Total (all sectors)	Electric Utilities	Independent Power Producers	Commercial Sector	Industrial Sector
Annual Totals					
2014	15,783	0	5,140	9,046	1,597
2015	16,623	0	5,195	9,752	1,676
2016	18,259	0	6,877	9,665	1,717
2017	17,720	0	6,475	9,474	1,772
2018	16,724	0	5,887	9,312	1,524
2019	12,308	0	5,362	5,527	1,419
2020	11,939	0	5,420	5,117	1,401
2021	12,721	0	6,371	5,050	1,300
2022	12,244	0	2,966	9,278	0
2023	12,535	0	3,367	9,168	0
2024	12,179	0	3,101	9,079	0
Year 2022					
January	1,125	0	281	845	0
February	959	0	231	728	0
March	949	0	220	729	0
April	912	0	211	701	0
May	1,051	0	254	797	0
June	1,042	0	238	803	0
July	1,125	0	274	851	0
August	1,117	0	254	862	0
September	1,020	0	237	783	0
October	929	0	232	696	0
November	1,063	0	253	810	0
December	952	0	279	673	0
Year 2023					
January	995	0	282	713	0
February	955	0	245	710	0
March	1,024	0	254	770	0
April	965	0	237	728	0
May	1,064	0	251	813	0
June	975	0	249	726	0
July	1,102	0	307	795	0
August	1,121	0	292	829	0
September	1,051	0	297	754	0
October	942	0	291	650	0
November	1,129	0	334	795	0
December	1,211	0	327	884	0
Year 2024					
January	1,170	0	329	840	0
February	1,064	0	259	805	0
March	1,042	0	250	792	0
April	900	0	259	640	0
May	1,064	0	260	804	0
June	1,025	0	231	794	0
July	1,052	0	262	790	0
August	921	0	269	652	0
September	951	0	250	701	0
October	972	0	228	745	0
November	981	0	232	749	0
December	1,039	0	273	766	0

Notes: Beginning with the collection of Form EIA-923 in January 2008, the methodology to allocate total fuel consumption for electricity generation and consumption for useful thermal output was changed.

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

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

Beginning with 2008 data, the Form EIA-923, Power Plant Operations Report, replaced the following: Form EIA-906, Power Plant Report; Form EIA-920, Combined Heat and Power Plant Report.

Table 5.7.F. Biogenic Municipal Solid Waste: Consumption for Electricity Generation and Useful Thermal Output, by Sector, 2014 - 2024 (Billion Btus)

		Electric Power Sector			
Period	Total (all sectors)	Electric Utilities	Independent Power Producers	Commercial Sector	Industrial Sector
Annual Totals					
2014	150,191	4,429	115,709	28,411	1,643
2015	149,740	4,295	114,886	28,821	1,739
2016	154,216	4,434	117,880	30,095	1,806
2017	148,662	4,172	112,857	29,794	1,839
2018	151,188	4,568	116,339	28,686	1,596
2019	127,422	2,454	101,000	22,473	1,495
2020	126,752	2,284	101,362	21,629	1,478
2021	125,894	2,029	98,516	23,994	1,355
2022	120,753	2,212	57,217	61,324	0
2023	115,841	2,275	54,557	59,009	0
2024	113,010	2,273	52,395	58,341	0
Year 2022					
January	10,234	172	5,077	4,986	0
February	9,291	161	4,435	4,696	0
March	10,040	134	5,018	4,889	0
April	9,926	186	4,615	5,125	0
May	10,207	227	4,782	5,198	0
June	10,327	203	4,841	5,283	0
July	10,576	205	4,973	5,398	0
August	10,338	227	4,829	5,283	0
September	9,837	143	4,660	5,033	0
October	9,889	192	4,551	5,146	0
November	10,040	188	4,575	5,277	0
December	10,047	174	4,863	5,010	0
Year 2023					
January	9,947	198	4,799	4,950	0
February	8,788	124	4,229	4,436	0
March	9,310	174	4,499	4,637	0
April	8,903	169	4,160	4,573	0
May	9,804	173	4,630	5,001	0
June	9,721	208	4,523	4,989	0
July	10,346	195	4,891	5,260	0
August	10,187	227	4,757	5,202	0
September	9,455	194	4,491	4,769	0
October	9,534	215	4,452	4,867	0
November	9,532	204	4,337	4,991	0
December	10,316	193	4,789	5,333	0
Year 2024					
January	9,950	167	4,637	5,146	0
February	8,970	137	4,170	4,662	0
March	9,249	106	4,414	4,729	0
April	8,800	156	3,982	4,662	0
May	9,778	237	4,442	5,098	0
June	9,358	211	4,290	4,857	0
July	9,877	219	4,595	5,063	0
August	9,880	225	4,623	5,032	0
September	9,150	192	4,339	4,619	0
October	9,254	225	4,222	4,807	0
November	9,286	198	4,297	4,792	0
December	9,458	200	4,385	4,874	0

Notes: Beginning with the collection of Form EIA-923 in January 2008, the methodology to allocate total fuel consumption for electricity generation and consumption for useful thermal output was changed.

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Table 5.8.D. Other Waste Biomass: Consumption for Electricity Generation, by Sector, 2014 - 2024 (Billion Btus)

		Electric Power Sector			
Period	Total (all sectors)	Electric Utilities	Independent Power Producers	Commercial Sector	Industrial Sector
Annual Totals					
2014	38,361	2,360	21,628	5,745	8,627
2015	41,785	2,853	25,058	5,935	7,939
2016	33,786	2,553	18,194	5,504	7,536
2017	35,755	1,845	22,517	5,288	6,105
2018	29,407	1,343	16,874	5,867	5,324
2019	23,947	1,133	12,606	5,668	4,540
2020	22,234	1,024	11,195	5,014	5,001
2021	22,623	1,007	11,536	5,075	5,005
2022	19,910	638	9,809	4,548	4,915
2023	20,807	865	11,019	4,700	4,224
2024	21,130	842	10,266	5,320	4,702
Year 2022					
January	1,896	57	934	436	470
February	1,712	40	904	351	417
March	1,800	45	851	414	490
April	1,502	34	665	356	447
May	1,427	64	566	355	442
June	1,610	55	858	365	331
July	1,648	63	883	373	329
August	1,701	48	903	378	372
September	1,593	70	840	375	307
October	1,709	44	848	398	419
November	1,535	59	675	373	428
December	1,777	59	882	374	462
Year 2023					
January	1,708	78	882	335	412
February	1,932	80	1,138	354	360
March	1,614	60	784	388	383
April	1,540	85	759	337	360
May	1,727	66	844	439	379
June	1,604	47	840	420	298
July	1,655	61	895	402	297
August	1,716	60	966	390	300
September	1,642	73	943	374	252
October	1,783	105	879	419	380
November	1,773	66	889	408	409
December	2,112	84	1,200	435	393
Year 2024					
January	1,875	47	924	458	446
February	1,745	45	852	429	418
March	1,763	68	729	500	466
April	1,545	62	631	447	406
May	1,742	84	741	478	439
June	1,715	92	876	449	299
July	1,654	99	792	436	327
August	1,784	105	946	382	350
September	1,765	63	970	396	337
October	1,829	64	936	440	389
November	1,795	53	875	443	424
December	1,917	61	994	461	400

Notes: Beginning with the collection of Form EIA-923 in January 2008, the methodology to allocate total fuel consumption for electricity generation and consumption for useful thermal output was changed.

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Table 5.8.E. Other Waste Biomass: Consumption for Useful Thermal Output, by Sector, 2014 - 2024 (Billion Btus)

		Electric Power Sector			
Period	Total (all sectors)	Electric Utilities	Independent Power Producers	Commercial Sector	Industrial Sector
Annual Totals					
2014	65,201	15	6,930	1,543	56,712
2015	67,512	1	7,845	2,000	57,666
2016	57,123	18	11,252	3,569	42,284
2017	50,518	15	10,543	3,218	36,742
2018	50,338	14	10,753	3,673	35,898
2019	41,084	39	10,452	3,282	27,312
2020	43,383	18	9,358	3,166	30,841
2021	45,209	9	9,499	2,907	32,793
2022	45,181	13	9,088	2,633	33,446
2023	39,471	15	9,646	2,666	27,144
2024	40,916	12	8,722	2,601	29,581
Year 2022					
January	4,959	0	1,143	247	3,568
February	4,327	0	1,079	237	3,010
March	5,115	0	1,158	244	3,712
April	4,088	0	672	196	3,219
May	3,785	0	364	221	3,199
June	2,664	0	515	222	1,927
July	2,521	0	612	197	1,712
August	2,727	0	558	197	1,972
September	2,339	2	440	228	1,671
October	3,637	3	536	231	2,867
November	4,198	3	953	198	3,044
December	4,821	2	1,058	214	3,546
Year 2023					
January	4,601	4	1,199	257	3,141
February	3,837	4	1,010	215	2,607
March	4,177	0	1,186	234	2,757
April	3,713	4	1,004	210	2,495
May	3,571	0	705	214	2,652
June	2,156	0	348	211	1,596
July	2,108	0	467	202	1,439
August	2,082	0	486	206	1,390
September	1,922	0	410	230	1,281
October	3,457	0	813	243	2,401
November	3,638	0	978	212	2,448
December	4,211	0	1,042	232	2,937
Year 2024					
January	4,557	1	1,111	248	3,196
February	4,093	1	911	233	2,948
March	4,057	1	959	251	2,846
April	3,876	1	752	225	2,898
May	3,672	1	437	234	3,000
June	2,089	1	343	214	1,531
July	2,241	1	437	211	1,592
August	2,312	1	456	186	1,669
September	2,272	1	368	214	1,689
October	3,388	1	634	210	2,543
November	4,180	1	1,180	177	2,822
December	4,179	1	1,132	198	2,848

Notes: Beginning with the collection of Form EIA-923 in January 2008, the methodology to allocate total fuel consumption for electricity generation and consumption for useful thermal output was changed.

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Table 5.8.F. Other Waste Biomass: Consumption for Electricity Generation and Useful Thermal Output, by Sector, 2014 - 2024 (Billion Btus)

		Electric Power Sector			
Period	Total (all sectors)	Electric Utilities	Independent Power Producers	Commercial Sector	Industrial Sector
Annual Totals					
2014	103,561	2,375	28,558	7,289	65,339
2015	109,297	2,854	32,903	7,935	65,605
2016	90,909	2,571	29,446	9,073	49,820
2017	86,274	1,860	33,060	8,506	42,848
2018	79,745	1,357	27,627	9,540	41,221
2019	65,031	1,172	23,057	8,950	31,852
2020	65,617	1,043	20,552	8,180	35,842
2021	67,832	1,017	21,035	7,982	37,798
2022	65,090	652	18,897	7,181	38,361
2023	60,278	879	20,665	7,366	31,368
2024	62,046	854	18,988	7,921	34,283
Year 2022					
January	6,855	57	2,077	683	4,038
February	6,039	40	1,983	588	3,428
March	6,915	46	2,009	658	4,202
April	5,590	35	1,338	552	3,666
May	5,211	64	930	577	3,641
June	4,273	56	1,373	587	2,258
July	4,169	63	1,495	570	2,041
August	4,428	49	1,461	574	2,344
September	3,932	72	1,280	603	1,978
October	5,346	47	1,385	629	3,285
November	5,733	62	1,628	571	3,472
December	6,598	61	1,940	589	4,008
Year 2023					
January	6,309	82	2,081	593	3,553
February	5,769	84	2,148	570	2,967
March	5,791	60	1,969	622	3,140
April	5,253	89	1,762	547	2,855
May	5,298	66	1,548	653	3,030
June	3,760	47	1,188	631	1,894
July	3,763	61	1,363	603	1,736
August	3,799	60	1,452	596	1,690
September	3,563	73	1,353	604	1,534
October	5,240	106	1,692	662	2,781
November	5,411	67	1,867	620	2,858
December	6,324	85	2,242	668	3,330
Year 2024					
January	6,432	48	2,035	706	3,642
February	5,838	46	1,764	663	3,366
March	5,820	69	1,688	750	3,312
April	5,422	63	1,383	673	3,304
May	5,414	85	1,178	712	3,439
June	3,804	93	1,219	663	1,830
July	3,896	100	1,229	647	1,920
August	4,096	106	1,402	568	2,019
September	4,038	64	1,338	610	2,025
October	5,217	65	1,571	650	2,931
November	5,974	54	2,055	620	3,246
December	6,096	62	2,127	659	3,248

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Table 5.9. Consumption of Coal for Electricity Generation by State by Sector, 2024 and 2023 (Thousand Tons)

Census Division and State				Electric Power Sector							
	All Sectors			Electric Utilities		Independent Power Producers		Commercial Sector		Industrial Sector	
	Year 2024	Year 2023	Percentage Change	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023
New England	106	82	29.0%	0	0	106	82	0	0	0	0
Connecticut	0	0	--	0	0	0	0	0	0	0	0
Maine	8	12	-39.0%	0	0	8	12	0	0	0	0
Massachusetts	0	0	--	0	0	0	0	0	0	0	0
New Hampshire	98	70	41.0%	0	0	98	70	0	0	0	0
Rhode Island	0	0	--	0	0	0	0	0	0	0	0
Vermont	0	0	--	0	0	0	0	0	0	0	0
Middle Atlantic	9,432	9,769	-3.5%	0	0	9,413	9,749	0	0	19	20
New Jersey	0	0	--	0	0	0	0	0	0	0	0
New York	0	0	--	0	0	0	0	0	0	0	0
Pennsylvania	9,432	9,769	-3.5%	0	0	9,413	9,749	0	0	19	20
East North Central	75,333	74,465	1.2%	47,788	46,314	27,304	27,808	6	11	234	332
Illinois	16,293	16,078	1.3%	731	768	15,349	15,033	3	5	210	272
Indiana	20,579	20,998	-2.0%	18,956	19,025	1,621	1,966	3	6	0	0
Michigan	14,405	12,777	13.0%	14,328	12,684	76	92	0	0	1	0
Ohio	12,369	12,788	-3.3%	2,110	2,071	10,259	10,717	0	0	0	0
Wisconsin	11,686	11,825	-1.2%	11,663	11,765	0	0	0	0	23	60
West North Central	76,664	81,912	-6.4%	75,844	81,126	0	0	5	5	815	780
Iowa	8,424	9,380	-10.0%	7,937	8,935	0	0	2	3	485	443
Kansas	8,480	10,482	-19.0%	8,480	10,482	0	0	0	0	0	0
Minnesota	6,618	7,425	-11.0%	6,574	7,380	0	0	2	2	42	43
Missouri	22,880	24,046	-4.8%	22,879	24,046	0	0	1	1	0	0
Nebraska	10,021	10,954	-8.5%	9,772	10,702	0	0	0	0	249	252
North Dakota	19,261	18,646	3.3%	19,222	18,604	0	0	0	0	39	41
South Dakota	981	978	0.3%	981	978	0	0	0	0	0	0
South Atlantic	47,950	46,873	2.3%	43,937	42,046	3,915	4,735	6	3	92	89
Delaware	107	13	706.0%	0	0	107	13	0	0	0	0
District of Columbia	0	0	--	0	0	0	0	0	0	0	0
Florida	3,818	5,456	-30.0%	3,814	5,451	0	0	0	0	4	5
Georgia	9,295	8,641	7.6%	9,267	8,616	0	0	0	0	27	25
Maryland	1,130	815	39.0%	0	0	1,130	815	0	0	0	0
North Carolina	7,135	5,913	21.0%	7,123	5,897	0	0	6	3	6	13
South Carolina	7,356	6,452	14.0%	7,353	6,432	0	15	0	0	2	4
Virginia	1,138	816	39.0%	1,085	775	0	0	0	0	53	41
West Virginia	17,972	18,766	-4.2%	15,294	14,875	2,678	3,892	0	0	0	0
East South Central	45,511	43,869	3.7%	43,329	40,859	2,082	2,926	0	0	100	85
Alabama	11,880	10,966	8.3%	11,880	10,966	0	0	0	0	0	0
Kentucky	21,546	20,594	4.6%	21,546	20,594	0	0	0	0	0	0
Mississippi	3,045	3,888	-22.0%	964	962	2,082	2,926	0	0	0	0
Tennessee	9,039	8,421	7.3%	8,939	8,336	0	0	0	0	100	85
West South Central	63,051	67,421	-6.5%	29,106	30,377	33,916	37,029	0	0	29	15
Arkansas	9,459	10,095	-6.3%	7,629	8,159	1,824	1,929	0	0	6	6
Louisiana	2,556	3,096	-17.0%	1,974	2,133	582	963	0	0	0	0
Oklahoma	4,177	3,525	19.0%	4,154	3,516	0	0	0	0	23	9
Texas	46,860	50,706	-7.6%	15,349	16,569	31,510	34,137	0	0	0	0
Mountain	52,289	58,839	-11.0%	44,417	49,930	7,794	8,822	0	0	79	87
Arizona	5,956	7,301	-18.0%	5,956	7,301	0	0	0	0	0	0
Colorado	9,599	10,964	-12.0%	9,599	10,964	0	0	0	0	0	0
Idaho	0	0	--	0	0	0	0	0	0	0	0
Montana	6,304	7,371	-14.0%	0	0	6,301	7,368	0	0	3	3
Nevada	1,459	1,300	12.0%	799	675	660	625	0	0	0	0
New Mexico	4,630	4,033	15.0%	4,630	4,033	0	0	0	0	0	0
Utah	8,122	7,867	3.2%	7,714	7,533	408	334	0	0	0	0
Wyoming	16,220	20,002	-19.0%	15,719	19,423	425	495	0	0	76	84
Pacific Contiguous	2,016	2,848	-29.0%	0	0	1,954	2,795	0	0	62	53
California	56	47	20.0%	0	0	0	0	0	0	56	47
Oregon	0	0	--	0	0	0	0	0	0	0	0
Washington	1,960	2,802	-30.0%	0	0	1,954	2,795	0	0	6	7
Pacific Noncontiguous	580	549	5.6%	429	381	102	118	49	50	0	0
Alaska	580	549	5.6%	429	381	102	118	49	50	0	0
Hawaii	0	0	--	0	0	0	0	0	0	0	0
U.S. Total	372,931	386,626	-3.5%	284,849	291,034	86,586	94,063	65	69	1,431	1,460

Displayed values of zero may represent small values that round to zero. The Excel version of this table provides additional precision which may be accessed by selecting individual cells.

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Totals may not equal sum of components because of independent rounding. Percentage change is calculated before rounding.

Source: U.S. Energy Information Administration, Form EIA-923, Power Plant Operations Report.

Table 5.10. Consumption of Petroleum Liquids for Electricity Generation by State, by Sector, 2024 and 2023 (Thousand Barrels)

Census Division and State	Electric Power Sector										
	All Sectors			Electric Utilities		Independent Power Producers		Commercial Sector		Industrial Sector	
	Year 2024	Year 2023	Percentage Change	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023
New England	645	737	-12.0%	83	66	522	633	28	25	12	14
Connecticut	172	265	-35.0%	7	8	163	253	1	1	2	2
Maine	91	110	-17.0%	0	0	82	99	0	0	10	11
Massachusetts	292	195	50.0%	64	49	211	135	16	10	1	0
New Hampshire	68	115	-41.0%	0	0	57	103	10	11	0	0
Rhode Island	11	45	-75.0%	0	0	10	43	NM	2	0	0
Vermont	12	8	39.0%	12	8	0	0	0	0	0	0
Middle Atlantic	864	1,034	-16.0%	329	262	463	679	30	50	43	43
New Jersey	49	60	-19.0%	0	0	47	58	2	2	0	0
New York	579	795	-27.0%	324	260	230	490	19	33	6	12
Pennsylvania	236	178	32.0%	4	2	185	132	10	15	36	30
East North Central	845	853	-0.9%	596	588	238	253	2	4	9	8
Illinois	53	64	-17.0%	16	14	37	50	0	0	0	0
Indiana	191	205	-7.0%	189	188	0	16	1	0	0	1
Michigan	179	177	1.5%	177	173	0	0	0	0	2	3
Ohio	255	217	17.0%	51	27	201	186	1	1	3	3
Wisconsin	167	190	-12.0%	162	185	0	1	1	2	4	1
West North Central	1,117	1,059	5.5%	1,107	1,050	5	4	3	2	3	3
Iowa	132	147	-10.0%	127	143	4	3	0	NM	0	0
Kansas	248	156	59.0%	248	156	0	0	0	0	0	0
Minnesota	51	160	-68.0%	46	155	1	1	2	2	3	2
Missouri	416	340	22.0%	416	340	0	0	0	0	0	0
Nebraska	128	96	33.0%	128	96	0	0	0	0	0	0
North Dakota	89	107	-17.0%	89	107	0	0	0	0	0	0
South Dakota	53	53	-0.6%	53	53	0	0	NM	NM	0	0
South Atlantic	2,288	1,772	29.0%	1,377	1,188	765	355	65	78	81	151
Delaware	62	36	75.0%	0	2	62	33	0	0	0	0
District of Columbia	0	0	-36.0%	0	0	0	0	0	0	0	0
Florida	327	396	-17.0%	306	366	17	24	0	0	4	6
Georgia	226	191	18.0%	109	67	64	10	2	1	51	112
Maryland	484	183	164.0%	3	2	480	181	NM	1	0	NM
North Carolina	314	187	68.0%	263	159	39	11	6	3	6	14
South Carolina	196	172	15.0%	183	160	4	4	1	0	9	7
Virginia	449	307	47.0%	283	133	99	88	56	73	10	12
West Virginia	229	301	-24.0%	229	297	0	4	0	0	0	0
East South Central	413	419	-1.4%	393	397	1	NM	0	0	19	21
Alabama	35	49	-29.0%	18	29	1	NM	0	0	15	19
Kentucky	126	122	3.1%	126	122	0	0	0	0	0	0
Mississippi	13	11	12.0%	10	10	0	0	0	0	3	1
Tennessee	240	236	1.4%	240	236	NM	0	0	0	0	0
West South Central	511	623	-18.0%	281	358	222	260	0	0	8	5
Arkansas	94	81	17.0%	82	62	12	18	0	0	0	0
Louisiana	18	18	1.5%	18	18	0	0	0	0	0	0
Oklahoma	53	40	32.0%	49	38	0	0	0	0	5	3
Texas	346	485	-29.0%	132	240	210	242	0	0	3	2
Mountain	359	905	-60.0%	322	878	36	26	0	0	0	1
Arizona	60	62	-3.4%	60	62	0	0	0	0	0	0
Colorado	96	508	-81.0%	89	506	7	1	0	0	0	1
Idaho	0	0	-52.0%	0	0	0	0	0	0	0	0
Montana	37	18	103.0%	13	0	24	18	0	0	0	0
Nevada	13	18	-30.0%	10	15	3	3	0	0	0	0
New Mexico	2	151	-99.0%	2	151	0	0	0	0	0	0
Utah	61	56	9.5%	59	51	2	5	0	0	0	0
Wyoming	90	91	-1.9%	90	91	0	0	0	0	0	0
Pacific Contiguous	254	190	34.0%	173	95	33	25	34	23	15	47
California	130	142	-8.6%	65	64	18	14	33	21	13	42
Oregon	24	0	NM	24	0	0	0	0	0	0	0
Washington	101	48	112.0%	84	30	15	11	0	1	1	5
Pacific Noncontiguous	13,490	13,744	-1.8%	11,398	11,486	1,851	2,016	16	18	225	224
Alaska	1,688	1,626	3.8%	1,616	1,556	0	0	3	2	69	68
Hawaii	11,803	12,118	-2.6%	9,782	9,930	1,851	2,016	13	16	157	156
U.S. Total	20,787	21,335	-2.6%	16,058	16,366	4,137	4,253	179	200	414	517

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Source: U.S. Energy Information Administration, Form EIA-923, Power Plant Operations Report.

Table 5.11. Consumption of Petroleum Coke for Electricity Generation by State, by Sector,
2024 and 2023 (Thousand Tons)

Census Division and State	Electric Power Sector										
	All Sectors			Electric Utilities		Independent Power Producers		Commercial Sector		Industrial Sector	
	Year 2024	Year 2023	Percentage Change	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023
New England	0	0	--	0	0	0	0	0	0	0	0
Connecticut	0	0	--	0	0	0	0	0	0	0	0
Maine	0	0	--	0	0	0	0	0	0	0	0
Massachusetts	0	0	--	0	0	0	0	0	0	0	0
New Hampshire	0	0	--	0	0	0	0	0	0	0	0
Rhode Island	0	0	--	0	0	0	0	0	0	0	0
Vermont	0	0	--	0	0	0	0	0	0	0	0
Middle Atlantic	0	0	--	0	0	0	0	0	0	0	0
New Jersey	0	0	--	0	0	0	0	0	0	0	0
New York	0	0	--	0	0	0	0	0	0	0	0
Pennsylvania	0	0	--	0	0	0	0	0	0	0	0
East North Central	1,202	1,028	17.0%	686	548	457	416	0	0	59	64
Illinois	0	0	--	0	0	0	0	0	0	0	0
Indiana	0	0	--	0	0	0	0	0	0	0	0
Michigan	744	594	25.0%	685	530	0	0	0	0	59	64
Ohio	457	416	9.8%	0	0	457	416	0	0	0	0
Wisconsin	1	18	-93.0%	1	18	0	0	0	0	0	0
West North Central	1	1	99.0%	0	0	0	0	1	1	0	0
Iowa	1	1	99.0%	0	0	0	0	1	1	0	0
Kansas	0	0	--	0	0	0	0	0	0	0	0
Minnesota	0	0	--	0	0	0	0	0	0	0	0
Missouri	0	0	--	0	0	0	0	0	0	0	0
Nebraska	0	0	--	0	0	0	0	0	0	0	0
North Dakota	0	0	--	0	0	0	0	0	0	0	0
South Dakota	0	0	--	0	0	0	0	0	0	0	0
South Atlantic	279	399	-30.0%	259	383	0	0	0	0	21	16
Delaware	0	0	--	0	0	0	0	0	0	0	0
District of Columbia	0	0	--	0	0	0	0	0	0	0	0
Florida	259	383	-33.0%	259	383	0	0	0	0	0	0
Georgia	21	16	30.0%	0	0	0	0	0	0	21	16
Maryland	0	0	--	0	0	0	0	0	0	0	0
North Carolina	0	0	--	0	0	0	0	0	0	0	0
South Carolina	0	0	--	0	0	0	0	0	0	0	0
Virginia	0	0	--	0	0	0	0	0	0	0	0
West Virginia	0	0	--	0	0	0	0	0	0	0	0
East South Central	0	0	--	0	0	0	0	0	0	0	0
Alabama	0	0	--	0	0	0	0	0	0	0	0
Kentucky	0	0	--	0	0	0	0	0	0	0	0
Mississippi	0	0	--	0	0	0	0	0	0	0	0
Tennessee	0	0	--	0	0	0	0	0	0	0	0
West South Central	40	421	-91.0%	15	396	0	0	0	0	24	25
Arkansas	0	0	--	0	0	0	0	0	0	0	0
Louisiana	15	396	-96.0%	15	396	0	0	0	0	0	0
Oklahoma	0	0	--	0	0	0	0	0	0	0	0
Texas	24	25	-1.9%	0	0	0	0	0	0	24	25
Mountain	139	178	-22.0%	0	0	139	178	0	0	0	0
Arizona	0	0	--	0	0	0	0	0	0	0	0
Colorado	0	0	--	0	0	0	0	0	0	0	0
Idaho	0	0	--	0	0	0	0	0	0	0	0
Montana	139	178	-22.0%	0	0	139	178	0	0	0	0
Nevada	0	0	--	0	0	0	0	0	0	0	0
New Mexico	0	0	--	0	0	0	0	0	0	0	0
Utah	0	0	--	0	0	0	0	0	0	0	0
Wyoming	0	0	--	0	0	0	0	0	0	0	0
Pacific Contiguous	0	0	--	0	0	0	0	0	0	0	0
California	0	0	--	0	0	0	0	0	0	0	0
Oregon	0	0	--	0	0	0	0	0	0	0	0
Washington	0	0	--	0	0	0	0	0	0	0	0
Pacific Noncontiguous	0	0	--	0	0	0	0	0	0	0	0
Alaska	0	0	--	0	0	0	0	0	0	0	0
Hawaii	0	0	--	0	0	0	0	0	0	0	0
U.S. Total	1,662	2,028	-18.0%	960	1,328	596	594	1	1	104	105

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Source: U.S. Energy Information Administration, Form EIA-923, Power Plant Operations Report.

Table 5.12. Consumption of Nautral Gas for Electricity Generation by State, by Sector, 2024 and 2023 (Million Cubic Feet)

Census Division and State	Electric Power Sector										
	All Sectors			Electric Utilities		Independent Power Producers		Commercial Sector		Industrial Sector	
	Year 2024	Year 2023	Percentage Change	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023
New England	439,569	409,759	7.3%	2,579	1,681	423,397	394,951	6,843	5,743	6,749	7,384
Connecticut	179,512	172,421	4.1%	770	794	173,297	166,191	1,755	1,706	3,690	3,730
Maine	43,463	27,059	61.0%	0	0	42,652	25,875	153	150	658	1,034
Massachusetts	118,088	106,935	10.0%	1,802	884	110,768	101,528	4,706	3,610	812	914
New Hampshire	31,961	31,076	2.8%	0	0	31,758	30,849	54	55	149	172
Rhode Island	66,535	72,259	-7.9%	0	0	64,922	70,507	172	218	1,441	1,534
Vermont	10	8	24.0%	8	3	0	0	3	5	0	0
Middle Atlantic	1,712,403	1,657,419	3.3%	116,650	104,837	1,562,121	1,515,554	7,841	8,003	25,791	29,025
New Jersey	208,860	232,173	-10.0%	1,366	1,543	203,469	226,561	1,883	1,816	2,142	2,253
New York	494,919	459,614	7.7%	115,053	103,135	370,658	347,478	5,261	5,399	3,946	3,601
Pennsylvania	1,008,624	965,633	4.5%	231	159	987,994	941,515	696	788	19,703	23,170
East North Central	1,698,855	1,596,860	6.4%	690,581	634,104	965,309	919,184	8,100	8,408	34,864	35,164
Illinois	214,217	206,544	3.7%	23,822	20,805	181,856	177,320	2,138	2,465	6,401	5,954
Indiana	297,409	271,610	9.5%	163,255	139,670	116,369	113,133	1,053	1,048	16,733	17,760
Michigan	402,532	386,488	4.2%	238,814	227,125	156,514	152,889	3,085	3,114	4,119	3,360
Ohio	595,059	546,691	8.8%	81,180	67,796	510,570	475,843	1,381	1,302	1,927	1,751
Wisconsin	189,638	185,526	2.2%	183,511	178,708	0	0	443	479	5,684	6,339
West North Central	368,146	353,576	4.1%	302,971	287,973	52,180	54,245	2,060	2,034	10,935	9,325
Iowa	66,374	70,472	-5.8%	61,924	66,557	0	1	845	829	3,604	3,085
Kansas	53,937	43,392	24.0%	51,272	40,877	0	0	0	0	2,665	2,514
Minnesota	114,753	100,974	14.0%	74,847	63,753	35,822	33,824	446	466	3,638	2,932
Missouri	77,227	79,501	-2.9%	60,024	58,210	16,358	20,420	707	722	137	149
Nebraska	14,018	14,311	-2.0%	13,742	14,226	0	0	61	17	215	68
North Dakota	22,672	26,949	-16.0%	22,493	26,836	0	0	0	0	179	114
South Dakota	19,165	17,977	6.6%	18,669	17,514	0	0	0	0	496	463
South Atlantic	3,083,361	2,968,871	3.9%	2,575,550	2,479,796	473,275	453,816	7,053	7,014	27,483	28,245
Delaware	31,948	32,510	-1.7%	723	187	26,501	26,787	0	0	4,724	5,536
District of Columbia	1,036	929	12.0%	0	0	0	0	1,036	929	0	0
Florida	1,461,029	1,411,685	3.5%	1,380,249	1,334,485	73,002	69,181	733	611	7,044	7,408
Georgia	409,570	432,544	-5.3%	339,623	351,745	64,680	75,916	0	0	5,267	4,883
Maryland	103,528	113,908	-9.1%	20,415	29,849	79,201	79,968	3,615	3,804	297	287
North Carolina	432,828	402,323	7.6%	372,923	341,537	57,880	58,451	1,373	1,506	652	829
South Carolina	171,963	181,285	-5.1%	160,623	176,155	10,479	4,138	0	0	861	993
Virginia	437,577	359,769	22.0%	295,279	239,745	136,004	114,036	295	163	5,998	5,825
West Virginia	33,882	33,917	-0.1%	5,716	6,094	25,527	25,339	0	0	2,640	2,484
East South Central	1,159,126	1,070,452	8.3%	907,887	796,214	227,201	252,010	970	930	23,069	21,298
Alabama	457,530	440,871	3.8%	226,527	185,032	220,316	246,231	0	0	10,687	9,608
Kentucky	140,930	111,679	26.0%	133,280	105,150	6,792	5,692	0	0	858	837
Mississippi	433,715	404,776	7.1%	430,590	401,631	NM	87	0	0	3,032	3,058
Tennessee	126,952	113,126	12.0%	117,490	104,401	0	0	970	930	8,492	7,795
West South Central	3,291,213	3,174,679	3.7%	1,416,933	1,294,209	1,488,843	1,475,232	3,633	4,364	381,805	400,874
Arkansas	181,207	188,232	-3.7%	173,722	180,167	6,050	6,709	380	426	1,056	930
Louisiana	541,815	527,984	2.6%	366,776	336,771	32,496	37,130	258	408	142,285	153,677
Oklahoma	385,146	361,639	6.5%	272,505	252,811	108,984	104,869	3	1	3,654	3,957
Texas	2,183,045	2,096,823	4.1%	603,930	524,460	1,341,313	1,326,524	2,992	3,529	234,810	242,309
Mountain	1,055,921	1,003,818	5.2%	853,253	796,598	186,897	192,413	2,362	2,270	13,409	12,536
Arizona	419,403	401,841	4.4%	296,100	282,480	122,700	118,779	603	582	0	0
Colorado	143,210	134,799	6.2%	118,100	113,708	23,884	19,907	26	14	1,200	1,170
Idaho	53,862	47,138	14.0%	43,740	34,166	9,217	12,190	171	170	734	611
Montana	9,941	10,315	-3.6%	8,262	9,265	1,671	1,043	0	0	8	7
Nevada	185,103	180,100	2.8%	173,263	167,450	7,700	8,331	257	267	3,883	4,053
New Mexico	101,168	121,525	-17.0%	79,264	89,193	20,533	31,014	542	518	829	800
Utah	90,034	89,405	0.7%	85,936	86,091	1,181	1,140	763	719	2,154	1,455
Wyoming	53,200	18,694	185.0%	48,587	14,245	12	9	0	0	4,600	4,440
Pacific Contiguous	919,250	982,282	-6.4%	389,374	398,570	452,640	509,403	9,131	10,302	68,105	64,007
California	618,772	680,050	-9.0%	205,190	209,418	342,082	402,638	8,889	9,126	62,610	58,868
Oregon	174,275	162,894	7.0%	93,414	92,367	79,929	69,745	212	165	720	617
Washington	126,204	139,338	-9.4%	90,770	96,784	30,630	37,019	29	1,012	4,776	4,522
Pacific Noncontiguous	26,906	27,780	-3.1%	26,742	27,509	0	0	2	1	162	270
Alaska	26,906	27,780	-3.1%	26,742	27,509	0	0	2	1	162	270
Hawaii	0	0	--	0	0	0	0	0	0	0	0
U.S. Total	13,754,749	13,245,495	3.8%	7,282,518	6,821,490	5,831,864	5,766,810	47,993	49,069	592,373	608,127

Displayed values of zero may represent small values that round to zero. The Excel version of this table provides additional precision which may be accessed by selecting individual cells.

Notes: See Glossary for definitions. Values are final. See Technical Notes for a discussion of the sample design for the Form EIA-923.

Totals may not equal sum of components because of independent rounding. Percentage change is calculated before rounding.

Source: U.S. Energy Information Administration, Form EIA-923, Power Plant Operations Report.

Table 5.13. Consumption of Landfill Gas for Electricity Generation by State, by Sector, 2024 and 2023 (Million Cubic Feet)

Census Division and State	Electric Power Sector										
	All Sectors			Electric Utilities		Independent Power Producers		Commercial Sector		Industrial Sector	
	Year 2024	Year 2023	Percentage Change	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023
New England	10,127	11,098	-8.7%	1,259	1,154	8,657	9,729	211	216	0	0
Connecticut	130	144	-9.6%	0	0	130	144	0	0	0	0
Maine	408	412	-1.0%	0	0	408	412	0	0	0	0
Massachusetts	1,961	2,163	-9.3%	0	0	1,961	2,163	0	0	0	0
New Hampshire	2,186	2,123	3.0%	0	0	1,975	1,907	211	216	0	0
Rhode Island	4,183	4,907	-15.0%	0	0	4,183	4,907	0	0	0	0
Vermont	1,259	1,350	-6.8%	1,259	1,154	0	196	0	0	0	0
Middle Atlantic	30,882	31,878	-3.1%	0	0	29,372	30,367	290	351	1,220	1,160
New Jersey	3,550	3,929	-9.7%	0	0	3,478	3,905	71	24	0	0
New York	14,373	14,421	-0.3%	0	0	14,373	14,421	0	0	0	0
Pennsylvania	12,960	13,528	-4.2%	0	0	11,521	12,041	219	327	1,220	1,160
East North Central	38,928	42,136	-7.6%	4,243	5,868	34,405	35,814	93	243	188	211
Illinois	7,033	7,218	-2.6%	2,448	2,428	4,585	4,790	0	0	0	0
Indiana	2,864	4,744	-40.0%	1,795	3,440	1,069	1,304	0	0	0	0
Michigan	17,046	18,055	-5.6%	0	0	17,046	18,055	0	0	0	0
Ohio	2,933	3,342	-12.0%	0	0	2,933	3,342	0	0	0	0
Wisconsin	9,052	8,777	3.1%	0	0	8,772	8,324	93	243	188	211
West North Central	6,830	7,223	-5.4%	2,160	2,211	4,654	4,999	0	0	17	13
Iowa	2,242	2,221	0.9%	0	0	2,242	2,221	0	0	0	0
Kansas	1,200	1,453	-17.0%	0	0	1,200	1,453	0	0	0	0
Minnesota	507	484	4.8%	7	31	499	453	0	0	0	0
Missouri	1,274	1,360	-6.3%	562	488	713	872	0	0	0	0
Nebraska	1,591	1,692	-6.0%	1,591	1,692	0	0	0	0	0	0
North Dakota	0	0	--	0	0	0	0	0	0	0	0
South Dakota	17	13	30.0%	0	0	0	0	0	0	17	13
South Atlantic	35,243	39,744	-11.0%	2,301	2,421	32,294	36,606	291	205	357	512
Delaware	757	1,284	-41.0%	0	0	617	1,160	0	0	140	124
District of Columbia	0	0	--	0	0	0	0	0	0	0	0
Florida	8,417	8,133	3.5%	1,053	723	7,363	7,410	0	0	0	0
Georgia	6,455	6,577	-1.8%	0	0	6,450	6,558	0	0	5	19
Maryland	1,341	1,501	-11.0%	0	0	1,339	1,499	2	2	0	0
North Carolina	6,239	7,945	-21.0%	0	0	6,239	7,945	0	0	0	0
South Carolina	1,459	2,083	-30.0%	1,247	1,699	0	15	0	0	212	369
Virginia	10,486	12,115	-13.0%	0	0	10,198	11,912	289	203	0	0
West Virginia	89	107	-18.0%	0	0	89	107	0	0	0	0
East South Central	5,211	4,288	22.0%	2,080	1,955	3,131	2,333	0	0	0	0
Alabama	943	875	7.8%	0	0	943	875	0	0	0	0
Kentucky	2,438	2,216	10.0%	2,080	1,955	358	261	0	0	0	0
Mississippi	144	150	-4.4%	0	0	144	150	0	0	0	0
Tennessee	1,686	1,047	61.0%	0	0	1,686	1,047	0	0	0	0
West South Central	4,098	5,046	-19.0%	0	0	4,098	5,046	0	0	0	0
Arkansas	625	614	1.8%	0	0	625	614	0	0	0	0
Louisiana	0	0	--	0	0	0	0	0	0	0	0
Oklahoma	528	378	40.0%	0	0	528	378	0	0	0	0
Texas	2,945	4,054	-27.0%	0	0	2,945	4,054	0	0	0	0
Mountain	7,093	6,974	1.7%	830	547	5,330	5,581	932	846	0	0
Arizona	406	427	-4.8%	0	0	406	427	0	0	0	0
Colorado	1,019	891	14.0%	0	0	1,019	891	0	0	0	0
Idaho	1,555	1,617	-3.9%	419	397	382	630	754	590	0	0
Montana	411	150	175.0%	411	150	0	0	0	0	0	0
Nevada	1,714	1,718	-0.2%	0	0	1,714	1,718	0	0	0	0
New Mexico	417	0	--	0	0	417	0	0	0	0	0
Utah	1,571	2,171	-28.0%	0	0	1,392	1,915	179	256	0	0
Wyoming	0	0	--	0	0	0	0	0	0	0	0
Pacific Contiguous	42,414	45,143	-6.0%	1,497	1,659	30,510	32,386	10,051	10,769	356	329
California	36,559	38,921	-6.1%	85	104	26,549	28,062	9,570	10,426	356	329
Oregon	5,043	5,248	-3.9%	1,412	1,555	3,150	3,350	482	343	0	0
Washington	811	974	-17.0%	0	0	811	974	0	0	0	0
Pacific Noncontiguous	818	762	7.4%	0	0	0	0	818	762	0	0
Alaska	818	762	7.4%	0	0	0	0	818	762	0	0
Hawaii	0	0	--	0	0	0	0	0	0	0	0
U.S. Total	181,646	194,292	-6.5%	14,369	15,815	152,452	162,861	12,687	13,392	2,137	2,224

Displayed values of zero may represent small values that round to zero. The Excel version of this table provides additional precision which may be accessed by selecting individual cells.
Notes: See Glossary for definitions. Values are final. See Technical Notes for a discussion of the sample design for the Form EIA-923.
Totals may not equal sum of components because of independent rounding. Percentage change is calculated before rounding.
Source: U.S. Energy Information Administration, Form EIA-923, Power Plant Operations Report.

Table 5.14. Consumption of Biogenic Municipal Solid Waste for Electricity Generation by State, by Sector, 2024 and 2023 (Thousand Tons)

Census Division and State	Electric Power Sector										
	All Sectors			Electric Utilities		Independent Power Producers		Commercial Sector		Industrial Sector	
	Year 2024	Year 2023	Percentage Change	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023
New England	2,941,593	2,980,013	-1.3%	0	0	1,885,646	1,908,674	1,055,947	1,071,339	0	0
Connecticut	855,203	860,460	-0.6%	0	0	855,203	860,460	0	0	0	0
Maine	131,430	153,208	-14.0%	0	0	93,772	106,137	37,658	47,071	0	0
Massachusetts	1,845,975	1,856,682	-0.6%	0	0	827,686	832,414	1,018,289	1,024,268	0	0
New Hampshire	108,985	109,663	-0.6%	0	0	108,985	109,663	0	0	0	0
Rhode Island	0	0	--	0	0	0	0	0	0	0	0
Vermont	0	0	--	0	0	0	0	0	0	0	0
Middle Atlantic	4,872,619	4,841,993	0.6%	0	0	1,976,231	2,031,713	2,896,388	2,810,280	0	0
New Jersey	1,271,226	1,266,075	0.4%	0	0	348,364	346,491	922,862	919,584	0	0
New York	1,790,301	1,737,122	3.1%	0	0	303,760	303,946	1,486,541	1,433,176	0	0
Pennsylvania	1,811,092	1,838,796	-1.5%	0	0	1,324,107	1,381,276	486,985	457,520	0	0
East North Central	167,088	162,756	2.7%	38,580	35,569	0	0	128,508	127,187	0	0
Illinois	0	0	--	0	0	0	0	0	0	0	0
Indiana	15,058	16,411	-8.2%	0	0	0	0	15,058	16,411	0	0
Michigan	113,450	110,776	2.4%	0	0	0	0	113,450	110,776	0	0
Ohio	0	0	--	0	0	0	0	0	0	0	0
Wisconsin	38,580	35,569	8.5%	38,580	35,569	0	0	0	0	0	0
West North Central	482,382	474,670	1.6%	244,164	247,635	222,651	213,909	15,567	13,126	0	0
Iowa	0	0	--	0	0	0	0	0	0	0	0
Kansas	0	0	--	0	0	0	0	0	0	0	0
Minnesota	482,382	474,670	1.6%	244,164	247,635	222,651	213,909	15,567	13,126	0	0
Missouri	0	0	--	0	0	0	0	0	0	0	0
Nebraska	0	0	--	0	0	0	0	0	0	0	0
North Dakota	0	0	--	0	0	0	0	0	0	0	0
South Dakota	0	0	--	0	0	0	0	0	0	0	0
South Atlantic	4,456,333	4,615,485	-3.4%	0	0	2,397,035	2,465,758	2,059,298	2,149,727	0	0
Delaware	0	0	--	0	0	0	0	0	0	0	0
District of Columbia	0	0	--	0	0	0	0	0	0	0	0
Florida	2,935,805	3,113,542	-5.7%	0	0	1,822,867	1,957,695	1,112,938	1,155,847	0	0
Georgia	0	0	--	0	0	0	0	0	0	0	0
Maryland	574,168	508,063	13.0%	0	0	574,168	508,063	0	0	0	0
North Carolina	0	0	--	0	0	0	0	0	0	0	0
South Carolina	0	0	--	0	0	0	0	0	0	0	0
Virginia	946,360	993,880	-4.8%	0	0	0	0	946,360	993,880	0	0
West Virginia	0	0	--	0	0	0	0	0	0	0	0
East South Central	0	0	--	0	0	0	0	0	0	0	0
Alabama	0	0	--	0	0	0	0	0	0	0	0
Kentucky	0	0	--	0	0	0	0	0	0	0	0
Mississippi	0	0	--	0	0	0	0	0	0	0	0
Tennessee	0	0	--	0	0	0	0	0	0	0	0
West South Central	4,839	1,150	321.0%	0	0	0	0	4,839	1,150	0	0
Arkansas	0	0	--	0	0	0	0	0	0	0	0
Louisiana	0	0	--	0	0	0	0	0	0	0	0
Oklahoma	4,839	1,150	321.0%	0	0	0	0	4,839	1,150	0	0
Texas	0	0	--	0	0	0	0	0	0	0	0
Mountain	0	0	--	0	0	0	0	0	0	0	0
Arizona	0	0	--	0	0	0	0	0	0	0	0
Colorado	0	0	--	0	0	0	0	0	0	0	0
Idaho	0	0	--	0	0	0	0	0	0	0	0
Montana	0	0	--	0	0	0	0	0	0	0	0
Nevada	0	0	--	0	0	0	0	0	0	0	0
New Mexico	0	0	--	0	0	0	0	0	0	0	0
Utah	0	0	--	0	0	0	0	0	0	0	0
Wyoming	0	0	--	0	0	0	0	0	0	0	0
Pacific Contiguous	324,958	465,926	-30.0%	0	0	239,399	339,670	85,559	126,256	0	0
California	95,180	248,135	-62.0%	0	0	9,621	121,879	85,559	126,256	0	0
Oregon	75,894	71,939	5.5%	0	0	75,894	71,939	0	0	0	0
Washington	153,884	145,852	5.5%	0	0	153,884	145,852	0	0	0	0
Pacific Noncontiguous	386,197	374,493	3.1%	0	0	0	0	386,197	374,493	0	0
Alaska	0	0	--	0	0	0	0	0	0	0	0
Hawaii	386,197	374,493	3.1%	0	0	0	0	386,197	374,493	0	0
U.S. Total	13,636,009	13,916,486	-2.0%	282,744	283,204	6,720,962	6,959,724	6,632,303	6,673,558	0	0

Displayed values of zero may represent small values that round to zero. The Excel version of this table provides additional precision which may be accessed by selecting individual cells.

Notes: See Glossary for definitions. Values are final. See Technical Notes for a discussion of the sample design for the Form EIA-923.

Totals may not equal sum of components because of independent rounding. Percentage change is calculated before rounding.

Source: U.S. Energy Information Administration, Form EIA-923, Power Plant Operations Report.

Chapter 6

Fossil Fuel Stocks for Electricity Generation

Table 6.1. Stocks of Coal, Petroleum Liquids, and Petroleum Coke: Electric Power Sector, 2014 - 2024

Period	Electric Power Sector			Electric Utilities			Independent Power Producers		
	Coal (Thousand Tons)	Petroleum Liquids (Thousand Barrels)	Petroleum Coke (Thousand Tons)	Coal (Thousand Tons)	Petroleum Liquids (Thousand Barrels)	Petroleum Coke (Thousand Tons)	Coal (Thousand Tons)	Petroleum Liquids (Thousand Barrels)	Petroleum Coke (Thousand Tons)
End of Year Stocks									
2014	151,548	32,322	827	116,684	21,304	686	34,864	11,018	142
2015	195,548	31,694	1,340	153,226	20,253	1,163	42,322	11,441	177
2016	162,009	30,593	845	130,885	19,767	603	31,124	10,827	241
2017	137,687	28,089	864	114,782	19,047	692	22,905	9,041	171
2018	102,793	25,977	539	84,728	16,553	521	18,065	9,423	19
2019	128,102	25,960	471	104,265	16,435	428	23,837	9,525	43
2020	131,431	26,063	298	107,965	15,941	273	23,466	10,123	25
2021	91,884	26,002	302	75,231	15,634	290	16,653	10,368	12
2022	88,861	22,812	318	74,917	14,204	297	13,943	8,608	21
2023	133,028	24,402	427	111,524	15,353	421	21,504	9,050	7
2024	127,826	23,014	438	105,219	14,659	431	22,607	8,355	7
Year 2022, End of Month Stocks									
January	84,541	24,166	336	70,468	14,938	324	14,073	9,228	12
February	81,034	24,252	299	68,800	15,159	287	12,234	9,092	12
March	86,143	23,755	350	73,271	15,156	340	12,872	8,599	10
April	90,746	23,758	424	76,913	15,311	416	13,833	8,446	8
May	92,692	24,025	454	78,852	15,053	425	13,840	8,972	29
June	86,869	24,078	423	73,119	15,309	408	13,750	8,769	16
July	79,172	25,707	474	66,434	15,384	459	12,738	10,323	15
August	75,570	22,794	490	64,278	14,882	479	11,292	7,912	11
September	79,354	22,484	405	67,442	14,704	397	11,912	7,780	8
October	87,342	22,771	351	73,276	14,779	344	14,066	7,992	7
November	93,203	23,678	408	78,597	14,925	393	14,605	8,753	15
December	88,861	22,812	318	74,917	14,204	297	13,943	8,608	21
Year 2023, End of Month Stocks									
January	92,714	24,410	385	77,005	15,167	360	15,709	9,243	25
February	99,760	24,622	380	82,205	15,413	355	17,554	9,209	24
March	109,041	24,059	534	89,836	15,370	505	19,205	8,689	29
April	119,460	24,068	644	98,558	15,363	598	20,902	8,704	46
May	127,788	23,882	600	105,620	15,175	591	22,168	8,708	9
June	129,191	24,066	533	106,412	15,299	525	22,778	8,767	8
July	122,916	24,065	440	101,603	15,422	434	21,313	8,643	6
August	117,898	23,416	356	97,758	15,018	348	20,140	8,398	8
September	118,054	23,469	279	98,026	15,117	273	20,027	8,352	6
October	123,046	23,257	284	102,453	14,998	279	20,593	8,258	5
November	130,985	23,335	369	109,555	14,910	356	21,430	8,425	13
December	133,028	24,402	427	111,524	15,353	421	21,504	9,050	7
Year 2024, End of Month Stocks									
January	123,854	24,275	312	104,292	15,319	306	19,562	8,956	6
February	129,170	24,355	308	108,070	15,307	300	21,100	9,047	8
March	135,537	24,275	333	112,576	15,275	328	22,961	9,000	5
April	138,839	24,011	309	115,173	15,191	302	23,666	8,820	7
May	139,893	23,834	311	116,439	15,072	305	23,454	8,762	6
June	135,229	23,974	332	112,260	15,154	317	22,970	8,820	15
July	127,378	23,442	410	105,766	14,843	379	21,611	8,600	31
August	121,756	22,743	399	100,925	14,416	384	20,831	8,327	15
September	122,555	22,927	470	101,105	14,630	439	21,450	8,298	31
October	127,747	22,567	428	105,127	14,270	421	22,620	8,297	7
November	131,091	22,697	404	107,639	14,251	400	23,452	8,446	4
December	127,826	23,014	438	105,219	14,659	431	22,607	8,355	7

Notes: See Glossary for definitions. Values are final.

See Technical Notes for a discussion of the sample design for the Form EIA-923 and predecessor forms. Totals may not equal sum of components because of independent rounding.

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

Beginning with 2008 data, the Form EIA-923, Power Plant Operations Report, replaced the following: 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 Federal Energy Regulatory Commission, FERC Form 423, Monthly Report of Cost and Quality of Fuels for Electric Plants.

Table 6.2 Stocks of Coal, Petroleum Liquids, and Petroleum Coke:
Electric Power Sector, by State, 2024 and 2023

Census Division and State	Coal (Thousand Tons)			Petroleum Liquids (Thousand Barrels)			Petroleum Coke (Thousand Tons)		
	December 2024	December 2023	Percentage Change	December 2024	December 2023	Percentage Change	December 2024	December 2023	Percentage Change
New England	W	W	W	1,952	2,315	-15.7%	0	0	--
Connecticut	0	0	--	496	644	-23.0%	0	0	--
Maine	W	0	W	252	294	-14.4%	0	0	--
Massachusetts	0	0	--	804	986	-18.5%	0	0	--
New Hampshire	W	W	W	242	235	3.1%	0	0	--
Rhode Island	0	0	--	130	126	2.9%	0	0	--
Vermont	0	0	--	29	29	-2.4%	0	0	--
Middle Atlantic	1,971	2,627	-25.0%	4,647	5,047	-7.9%	0	0	--
New Jersey	0	0	--	500	520	-3.9%	0	0	--
New York	0	0	--	2,874	3,165	-9.2%	0	0	--
Pennsylvania	1,971	2,627	-25.0%	1,273	1,361	-6.5%	0	0	--
East North Central	26,580	27,100	-1.9%	1,066	1,040	2.4%	W	W	W
Illinois	6,776	5,591	21.2%	134	102	31.0%	0	0	--
Indiana	9,294	9,574	-2.9%	98	110	-10.9%	0	0	--
Michigan	3,297	3,730	-11.6%	164	190	-13.9%	W	W	W
Ohio	4,173	4,122	1.2%	452	428	5.7%	0	0	--
Wisconsin	3,041	4,083	-25.5%	218	210	3.7%	W	W	W
West North Central	25,740	27,153	-5.2%	1,241	1,178	5.4%	0	0	--
Iowa	4,669	5,094	-8.3%	84	94	-10.4%	0	0	--
Kansas	5,753	5,151	11.7%	210	206	1.9%	0	0	--
Minnesota	2,356	2,879	-18.1%	95	117	-18.9%	0	0	--
Missouri	8,047	8,458	-4.9%	588	569	3.4%	0	0	--
Nebraska	3,015	3,556	-15.2%	159	91	73.6%	0	0	--
North Dakota	1,483	1,561	-5.0%	36	36	-0.9%	0	0	--
South Dakota	W	W	W	70	64	8.2%	0	0	--
South Atlantic	18,942	21,166	-10.5%	9,360	9,578	-2.3%	W	W	W
Delaware	W	W	W	416	518	-19.7%	0	0	--
District of Columbia	0	0	--	0	0	--	0	0	--
Florida	1,838	1,996	-7.9%	3,815	3,846	-0.8%	W	W	W
Georgia	W	W	W	1,221	1,211	0.8%	0	0	--
Maryland	W	799	W	637	641	-0.7%	0	0	--
North Carolina	3,973	3,654	8.7%	1,099	1,144	-3.9%	0	0	--
South Carolina	1,759	2,353	-25.2%	567	574	-1.2%	0	0	--
Virginia	W	W	W	1,457	1,491	-2.3%	0	0	--
West Virginia	6,380	6,852	-6.9%	149	153	-2.6%	W	W	W
East South Central	11,175	13,032	-14.2%	1,067	1,099	-2.9%	0	0	--
Alabama	3,220	4,180	-23.0%	254	258	-1.4%	0	0	--
Kentucky	5,570	6,731	-17.2%	285	278	2.6%	0	0	--
Mississippi	W	W	W	18	4	295.2%	0	0	--
Tennessee	1,748	1,573	11.1%	510	559	-8.7%	0	0	--
West South Central	24,985	26,728	-6.5%	2,099	2,164	-3.0%	W	W	W
Arkansas	4,071	4,679	-13.0%	170	165	3.0%	0	0	--
Louisiana	4,279	3,563	20.1%	181	185	-1.9%	W	W	W
Oklahoma	4,240	5,042	-15.9%	18	38	-51.6%	0	0	--
Texas	12,395	13,444	-7.8%	1,729	1,776	-2.6%	0	0	--
Mountain	17,702	14,249	24.2%	350	330	6.0%	W	W	W
Arizona	3,886	3,585	8.4%	148	126	17.7%	0	0	--
Colorado	3,563	3,566	-0.1%	116	117	-1.6%	0	0	--
Idaho	0	0	--	0	0	141.9%	0	0	--
Montana	W	W	W	14	12	13.6%	W	W	W
Nevada	W	W	W	2	3	-24.9%	0	0	--
New Mexico	0	0	--	4	5	-10.5%	0	0	--
Utah	3,743	2,438	53.5%	37	28	33.2%	0	0	--
Wyoming	5,102	3,530	44.5%	28	39	-27.3%	0	0	--
Pacific Contiguous	W	W	W	337	351	-3.9%	0	0	--
California	0	0	--	165	173	-4.6%	0	0	--
Oregon	0	0	--	51	72	-29.4%	0	0	--
Washington	W	W	W	122	107	14.3%	0	0	--
Pacific Noncontiguous	W	W	W	896	1,301	-31.2%	0	0	--
Alaska	W	W	W	38	62	-38.6%	0	0	--
Hawaii	0	0	--	858	1,240	-30.8%	0	0	--
U.S. Total	127,826	133,028	-3.9%	23,014	24,402	-5.7%	438	427	2.5%

Displayed values of zero may represent small values that round to zero. The Excel version of this table provides additional precision which may be accessed by selecting individual cells.

NM = Not meaningful due to large relative standard error or excessive percentage change.

W = Withheld to avoid disclosure of individual company data.

Notes: See Glossary for definitions. Values are final. See Technical Notes for a discussion of the sample design for the Form EIA-923.

Negative generation denotes that electric power consumed for plant use exceeds gross generation.

Totals may not equal sum of components because of independent rounding. Percentage change is calculated before rounding.

Source: U.S. Energy Information Administration, Form EIA-923, Power Plant Operations Report.

**Table 6.3 Stocks of Coal, Petroleum Liquids, and Petroleum Coke:
Electric Power Sector, by Census Divison, 2024 and 2023**

Census Division	Electric Power Sector			Electric Utilities		Independent Power Producers	
	December 2024	December 2023	Percentage Change	December 2024	December 2023	December 2024	December 2023
Coal (Thousand Tons)							
New England	W	W	W	0	0	W	W
Middle Atlantic	1,971	2,627	-25.0%	W	W	1,711	2,366
East North Central	26,580	27,100	-1.9%	17,185	18,108	9,396	8,992
West North Central	25,740	27,153	-5.2%	25,740	27,153	0	0
South Atlantic	18,942	21,166	-10.5%	18,180	19,855	761	1,311
East South Central	11,175	13,032	-14.2%	11,175	13,032	0	0
West South Central	24,985	26,728	-6.5%	15,642	19,496	9,342	7,232
Mountain	17,702	14,249	24.2%	16,971	13,558	W	W
Pacific Contiguous	W	W	W	0	0	W	W
Pacific Noncontiguous	W	W	W	W	W	W	W
U.S. Total	127,826	133,028	-3.9%	105,219	111,524	22,607	21,504
Petroleum Liquids (Thousand Barrels)							
New England	1,952	2,315	-15.7%	253	255	1,699	2,060
Middle Atlantic	4,647	5,047	-7.9%	1,947	2,085	2,700	2,962
East North Central	1,066	1,040	2.4%	672	687	393	353
West North Central	1,241	1,178	5.4%	1,215	1,150	26	27
South Atlantic	9,360	9,578	-2.3%	7,225	7,348	2,135	2,230
East South Central	1,067	1,099	-2.9%	1,029	1,060	38	39
West South Central	2,099	2,164	-3.0%	883	919	1,216	1,244
Mountain	350	330	6.0%	323	305	26	24
Pacific Contiguous	337	351	-3.9%	255	270	82	81
Pacific Noncontiguous	896	1,301	-31.2%	858	1,273	38	29
U.S. Total	23,014	24,402	-5.7%	14,659	15,353	8,355	9,050
Petroleum Coke (Thousand Tons)							
New England	0	0	--	0	0	0	0
Middle Atlantic	0	0	--	0	0	0	0
East North Central	W	W	W	W	W	0	0
West North Central	0	0	--	0	0	0	0
South Atlantic	W	W	W	W	W	W	W
East South Central	0	0	--	0	0	0	0
West South Central	W	W	W	W	W	0	0
Mountain	W	W	W	0	0	W	W
Pacific Contiguous	0	0	--	0	0	0	0
Pacific Noncontiguous	0	0	--	0	0	0	0
U.S. Total	438	427	2.5%	431	421	7	7

W = Withheld to avoid disclosure of individual company data.

Notes: See Glossary for definitions. Values are final. See Technical Notes for a discussion of the sample design for the Form-923.

Totals may not equal sum of components because of independent rounding. Percentage change is calculated before rounding.

Source: U.S. Energy Information Administration, Form-923, 'Power Plant Operations Report.'

Table 6.4. Stocks of Coal by Coal Rank: Electric Power Sector, 2014 - 2024
(Thousand Tons)

Period	Electric Power Sector			
	Bituminous Coal	Subbituminous Coal	Lignite Coal	Total
End of Year Stocks				
2014	72,771	72,552	6,225	151,548
2015	82,004	108,614	4,931	195,548
2016	67,241	90,376	4,393	162,009
2017	56,140	77,875	3,672	137,687
2018	41,507	58,247	3,039	102,793
2019	54,769	69,942	3,124	128,102
2020	50,649	77,033	3,556	131,431
2021	34,560	54,726	2,598	91,884
2022	35,194	50,704	2,956	88,861
2023	46,574	83,013	3,439	133,028
2024	43,844	80,772	3,198	127,826
Year 2022, End of Month Stocks				
January	30,697	51,157	2,686	84,541
February	29,288	49,029	2,717	81,034
March	31,687	51,304	3,152	86,143
April	33,868	53,609	3,269	90,746
May	33,202	56,289	3,191	92,692
June	30,392	53,338	3,129	86,869
July	28,769	47,358	3,040	79,172
August	28,730	44,005	2,826	75,570
September	30,766	45,802	2,776	79,354
October	34,061	50,366	2,905	87,342
November	35,998	54,329	2,867	93,203
December	35,194	50,704	2,956	88,861
Year 2023, End of Month Stocks				
January	37,880	51,812	3,014	92,714
February	40,066	56,667	3,022	99,760
March	41,614	64,432	2,991	109,041
April	43,352	72,772	3,330	119,460
May	46,598	77,685	3,500	127,788
June	47,911	77,671	3,601	129,191
July	44,256	75,155	3,499	122,916
August	42,345	72,129	3,424	117,898
September	42,659	72,147	3,247	118,054
October	44,914	74,948	3,184	123,046
November	46,999	80,588	3,393	130,985
December	46,574	83,013	3,439	133,028
Year 2024, End of Month Stocks				
January	42,859	77,766	3,220	123,854
February	44,581	81,459	3,124	129,170
March	47,285	85,012	3,232	135,537
April	48,624	86,824	3,388	138,839
May	49,199	87,376	3,311	139,893
June	46,915	84,931	3,374	135,229
July	43,890	80,227	3,251	127,378
August	42,163	76,310	3,273	121,756
September	42,608	76,769	3,171	122,555
October	44,603	79,892	3,245	127,747
November	46,116	81,733	3,231	131,091
December	43,844	80,772	3,198	127,826

Notes: See Glossary for definitions.

Values are final. See Technical Notes for a discussion of the sample design for the Form EIA-923, and predecessor forms. Totals may not equal sum of components because of independent rounding.

Sources: U.S. Energy Information Administration, Form EIA-906, Power Plant Report; U.S. Energy Information Administration, Form EIA-920 Combined Heat and Power Plant Report, and predecessor forms. Beginning with 2008 data, the Form EIA-923, Power Plant Operations Report, replaced the following:

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

Chapter 7

Receipts, Cost, and Quality of Fossil Fuels

Table 7.1. Receipts, Average Cost, and Quality of Fossil Fuels for the Electric Power Industry, 2014 through 2024

Period	Coal				Petroleum				Natural Gas		All Fossil Fuels
	Receipts (Thousand Tons)		Average Cost		Receipts (Thousand Barrels)		Average Cost		Receipts (Thousand Mcf)	Average Cost	Average Cost
			Average Sulfur Percent by Weight	(Dollars per MMBtu)			Average Sulfur Percent by Weight	(Dollars per MMBtu)		(Dollars per MMBtu)	(Dollars per MMBtu)
				(Dollars per Ton)				(Dollars per Barrel)			
2014	854,560	1.32	2.37	45.96	54,488	3.56	11.60	68.12	8,431,423	5.00	3.31
2015	782,929	1.29	2.22	42.86	48,804	3.38	6.74	39.51	9,842,581	3.23	2.65
2016	650,770	1.34	2.11	40.64	37,637	3.69	5.24	30.46	10,271,180	2.87	2.47
2017	642,364	1.28	2.06	39.27	32,672	3.59	7.10	41.23	9,628,733	3.37	2.65
2018	596,215	1.31	2.06	39.25	37,341	3.31	9.68	56.82	10,894,849	3.55	2.83
2019	560,153	1.31	2.02	38.70	24,556	3.03	9.07	53.55	11,704,743	2.88	2.50
2020	439,636	1.28	1.92	36.36	24,846	3.45	5.98	34.92	11,981,552	2.40	2.22
2021	461,477	1.30	1.98	37.48	27,783	3.11	10.08	58.93	11,578,254	5.20	3.82
2022	469,718	1.28	2.36	44.69	30,792	2.91	16.53	97.42	12,436,074	7.21	5.22
2023	431,375	1.23	2.51	47.23	25,590	2.44	15.98	94.80	13,237,380	3.36	3.12
2024	369,134	1.27	2.47	46.66	19,275	2.14	14.70	87.70	13,741,165	2.76	2.73

* = Value is less than half of the smallest unit of measure. (e.g., for values with no decimals, the smallest unit is 1 then values under 0.5 are shown as *.)

NM = Not meaningful due to large relative standard error or excessive percentage change.

W = Withheld to avoid disclosure of individual company data.

Notes:

Beginning in January 2013, the threshold for reporting fuel receipts data was changed from 50 megawatts to 200 megawatts of nameplate capacity for plants primarily fueled by natural gas, petroleum coke, distillate fuel oil, and residual fuel oil. In addition, the requirement to report self-produced and minor fuels, i.e., blast furnace gas, other manufactured gases, kerosene, jet fuel, propane, and waste oils was eliminated. The threshold for coal plants remained at 50 megawatts. The following caveats for each fuel type should be noted:

COAL - includes anthracite, bituminous, subbituminous, lignite, waste coal, and coal-derived synthesis gas. Prior to 2011, synthesis gas was included in the category of Other Gases.

PETROLEUM - includes petroleum liquids (distillate fuel oil and residual fuel oil) and petroleum coke which includes petroleum coke-derived synthesis gas. Prior to 2011, petroleum coke-derived synthesis gas was included in Other Gases. Prior to 2013, petroleum liquids included distillate fuel oil, residual fuel oil, kerosene, jet fuel, waste oil, and, beginning in 2011, propane. Prior to 2011, propane was included in the category of Other Gases.

NATURAL GAS - includes natural gas only. Prior to 2011, includes Other Gases.

- All values are final.

- See Glossary for definitions.

- Starting in January 2013, there may have been a shift in the continuity of Chapter 7 tables due to changes in the sample design of Form EIA-923 and the imputation process.

- See the EIA-923 section of the Technical Notes for a discussion of the sample design for the Form EIA-923 and predecessor forms.

- See the Technical Notes for fuel conversion factors.

- Totals may not equal the sum of components because of independent rounding.

Sources: U.S. Energy Information Administration (EIA), Form EIA-923, "Power Plant Operations Report" and predecessor forms 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 7.2. Receipts and Quality of Coal Delivered for the Electric Power Industry, 2014 through 2024

Period	Bituminous			Subbituminous			Lignite		
	Receipts (Thousand Tons)	Average Sulfur Percent by Weight	Average Ash Percent by Weight	Receipts (Thousand Tons)	Average Sulfur Percent by Weight	Average Ash Percent by Weight	Receipts (Thousand Tons)	Average Sulfur Percent by Weight	Average Ash Percent by Weight
2014	334,082	2.34	10.3	440,013	0.31	5.8	71,534	0.90	14.1
2015	289,093	2.40	10.4	421,127	0.32	5.8	65,826	0.89	14.1
2016	245,141	2.43	10.3	333,241	0.31	5.8	64,426	0.91	14.0
2017	224,500	2.45	10.3	350,580	0.31	5.6	59,665	0.96	14.0
2018	205,783	2.55	10.1	329,974	0.31	5.7	52,438	0.91	13.4
2019	198,016	2.52	10.0	309,029	0.32	5.7	46,781	0.90	13.3
2020	144,966	2.57	10.3	245,158	0.32	5.8	43,862	0.86	13.1
2021	149,031	2.66	10.3	262,770	0.31	5.6	43,018	0.86	13.3
2022	148,785	2.64	10.2	271,258	0.32	5.8	41,887	0.89	13.5
2023	133,921	2.59	10.4	253,550	0.30	5.4	37,150	0.84	12.7
2024	120,985	2.57	10.6	206,952	0.30	5.4	34,677	0.87	13.0

* = Value is less than half of the smallest unit of measure. (e.g., for values with no decimals, the smallest unit is 1 then values under 0.5 are shown as *.)

NM = Not meaningful due to large relative standard error or excessive percentage change.

W = Withheld to avoid disclosure of individual company data.

Notes:

Bituminous coal includes anthracite and beginning in 2011, coal-derived synthesis gas. Prior to 2011 coal-derived synthesis gas was included in Other Gases.

- All values are final.
- See Glossary for definitions.
- Starting in January 2013, there may have been a shift in the continuity of Chapter 7 tables due to changes in the sample design of Form EIA-923 and the imputation process.
- See the EIA-923 section of the Technical Notes for a discussion of the sample design for the Form EIA-923 and predecessor forms.
- See the Technical Notes for fuel conversion factors.
- Totals may not equal the sum of components because of independent rounding.

Sources: U.S. Energy Information Administration (EIA), Form EIA-923, "Power Plant Operations Report" and predecessor forms 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 7.3. Average Quality of Fossil Fuel Receipts for the Electric Power Industry, 2014 through 2024

Period	Coal			Petroleum			Natural Gas
	Average Btu per Pound	Average Sulfur Percent by Weight	Average Ash Percent by Weight	Average Btu per Gallon	Average Sulfur Percent by Weight	Average Ash Percent by Weight	Average Btu per Cubic Foot
2014	9,710	1.32	8.6	139,713	3.56	0.5	1,029
2015	9,634	1.29	8.6	139,681	3.38	0.5	1,034
2016	9,617	1.34	8.7	138,384	3.69	0.5	1,034
2017	9,544	1.28	8.4	138,324	3.59	0.4	1,034
2018	9,536	1.31	8.3	139,762	3.31	0.3	1,033
2019	9,592	1.31	8.3	140,549	3.03	0.3	1,034
2020	9,473	1.28	8.4	138,976	3.45	0.3	1,033
2021	9,485	1.30	8.3	139,137	3.11	0.3	1,034
2022	9,448	1.28	8.4	140,441	2.91	0.4	1,033
2023	9,403	1.23	8.1	141,246	2.44	0.4	1,033
2024	9,435	1.27	8.4	142,048	2.14	0.4	1,034

* = Value is less than half of the smallest unit of measure. (e.g., for values with no decimals, the smallest unit is 1 then values under 0.5 are shown as *.)

NM = Not meaningful due to large relative standard error or excessive percentage change.

W = Withheld to avoid disclosure of individual company data.

Notes:

Beginning in January 2013, the threshold for reporting fuel receipts data was changed from 50 megawatts to 200 megawatts of nameplate capacity for plants primarily fueled by natural gas, petroleum coke, distillate fuel oil, and residual fuel oil. In addition, the requirement to report self-produced and minor fuels, i.e., blast furnace gas, other manufactured gases, kerosene, jet fuel, propane, and waste oils was eliminated. The threshold for coal plants remained at 50 megawatts. The following caveats for each fuel type should be noted:

COAL - includes anthracite, bituminous, subbituminous, lignite, waste coal, and coal-derived synthesis gas. Prior to 2011, synthesis gas was included in the category of Other Gases.

PETROLEUM - includes petroleum liquids (distillate fuel oil and residual fuel oil) and petroleum coke which includes petroleum coke-derived synthesis gas. Prior to 2011, petroleum coke-derived synthesis gas was included in Other Gases. Prior to 2013, petroleum liquids included distillate fuel oil, residual fuel oil, kerosene, jet fuel, waste oil, and, beginning in 2011, propane. Prior to 2011, propane was included in the category of Other Gases.

NATURAL GAS - includes natural gas only. Prior to 2011, includes Other Gases.

- All values are final.
- See Glossary for definitions.
- Starting in January 2013, there may have been a shift in the continuity of Chapter 7 tables due to changes in the sample design of Form EIA-923 and the imputation process.
- See the EIA-923 section of the Technical Notes for a discussion of the sample design for the Form EIA-923 and predecessor forms.
- See the Technical Notes for fuel conversion factors.
- Totals may not equal the sum of components because of independent rounding.

Sources: U.S. Energy Information Administration (EIA), Form EIA-923, "Power Plant Operations Report" and predecessor forms 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 7.4. Weighted Average Cost of Fossil Fuels for the Electric Power Industry, 2014 through 2024

Period	Coal								Petroleum		Natural Gas		Total Fossil	
	Bituminous		Subbituminous		Lignite		All Coal Ranks							
	Receipts (Trillion Btu)	Average Cost (Dollars per MMBtu)	Receipts (Trillion Btu)	Average Cost (Dollars per MMBtu)	Receipts (Trillion Btu)	Average Cost (Dollars per MMBtu)	Receipts (Trillion Btu)	Average Cost (Dollars per MMBtu)	Receipts (Trillion Btu)	Average Cost (Dollars per MMBtu)	Receipts (Trillion Btu)	Average Cost (Dollars per MMBtu)	Receipts (Trillion Btu)	Average Cost (Dollars per MMBtu)
2014	7,883	2.74	7,681	2.06	934	1.77	16,595	2.37	320	11.60	8,679	5.00	25,594	3.31
2015	6,797	2.58	7,353	1.94	855	1.92	15,086	2.22	286	6.74	10,174	3.23	25,546	2.65
2016	5,770	2.40	5,818	1.89	840	1.74	12,516	2.11	219	5.24	10,619	2.87	23,354	2.47
2017	5,279	2.31	6,123	1.90	773	1.66	12,261	2.06	190	7.10	9,952	3.37	22,403	2.65
2018	4,838	2.31	5,765	1.90	677	1.71	11,371	2.06	219	9.68	11,254	3.55	22,844	2.83
2019	4,670	2.26	5,401	1.86	601	1.68	10,746	2.02	145	9.07	12,105	2.89	22,996	2.50
2020	3,399	2.11	4,300	1.78	566	1.90	8,329	1.92	145	5.98	12,381	2.40	20,855	2.22
2021	3,513	2.13	4,610	1.85	553	2.09	8,754	1.98	162	10.08	11,967	5.20	20,883	3.82
2022	3,499	2.74	4,748	2.17	538	1.78	8,876	2.36	182	16.53	12,840	7.21	21,898	5.22
2023	3,130	3.15	4,428	2.15	481	1.79	8,112	2.51	152	15.98	13,669	3.36	21,934	3.12
2024	2,813	3.08	3,628	2.08	451	1.94	6,965	2.47	115	14.70	14,206	2.76	21,286	2.73

* = Value is less than half of the smallest unit of measure. (e.g., for values with no decimals, the smallest unit is 1 then values under 0.5 are shown as *.)

NM = Not meaningful due to large relative standard error or excessive percentage change.

W = Withheld to avoid disclosure of individual company data.

Notes:

Beginning in January 2013, the threshold for reporting fuel receipts data was changed from 50 megawatts to 200 megawatts of nameplate capacity for plants primarily fueled by natural gas, petroleum coke, distillate fuel oil, and residual fuel oil. In addition, the requirement to report self-produced and minor fuels, i.e., blast furnace gas, other manufactured gases, kerosene, jet fuel, propane, and waste oils was eliminated. The threshold for coal plants remained at 50 megawatts. The following caveats for each fuel type should be noted:

COAL - All coal ranks subtotal includes anthracite, bituminous, subbituminous, lignite, waste coal, and coal-derived synthesis gas. Prior to 2011, synthesis gas was included in the category of Other Gases.

Bituminous coal includes anthracite coal and beginning in 2011, coal-derived synthesis gas.

PETROLEUM - includes petroleum liquids (distillate fuel oil and residual fuel oil) and petroleum coke which includes petroleum coke-derived synthesis gas. Prior to 2011, petroleum coke-derived synthesis gas was included in Other Gases. Prior to 2013, petroleum liquids included distillate fuel oil, residual fuel oil, kerosene, jet fuel, waste oil, and, beginning in 2011, propane. Prior to 2011, propane was included in the category of Other Gases.

NATURAL GAS - includes natural gas only. Prior to 2011, includes Other Gases.

- All values are final.

- See Glossary for definitions.

- Starting in January 2013, there may have been a shift in the continuity of Chapter 7 tables due to changes in the sample design of Form EIA-923 and the imputation process.

- See the EIA-923 section of the Technical Notes for a discussion of the sample design for the Form EIA-923 and predecessor forms.

- See the Technical Notes for fuel conversion factors.

- Totals may not equal the sum of components because of independent rounding.

Sources: U.S. Energy Information Administration (EIA), Form EIA-923, "Power Plant Operations Report" and predecessor forms 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 7.5. Receipts, Average Cost, and Quality of Fossil Fuels: Electric Utilities, 2014 - 2024

Table 7.5. Receipts, Average Cost, and Quantity of Fossil Fuels: Electric Utilities, 2014 - 2024													
	Coal						Petroleum Liquids						
	Receipts		Average Cost				Receipts		Average Cost				
	(Billion Btu)	(Thousand Tons)	(Dollars per MMBtu)	(Dollars per Ton)	Average Sulfur Percent by Weight	Percentage of Consumption	(Billion Btu)	(Thousand Barrels)	(Dollars per MMBtu)	(Dollars per Barrel)	Average Sulfur Percent by Weight	Percentage of Consumption	
Period													
Annual Totals													
2014	12,064,810	614,728	2.39	46.95	1.21	98.3	98,357	16,161	19.90	121.14	0.44	82.0	
2015	11,088,631	571,707	2.25	43.71	1.17	105.8	90,041	14,747	11.32	69.13	0.46	79.2	
2016	9,256,878	476,207	2.16	42.01	1.21	95.4	73,294	11,985	9.16	56.02	0.45	74.0	
2017	9,011,629	467,595	2.12	40.81	1.16	96.0	70,422	11,640	11.60	70.19	0.47	74.4	
2018	8,351,036	435,964	2.11	40.35	1.18	91.6	84,050	13,896	14.39	87.09	0.37	75.3	
2019	7,970,069	413,915	2.08	39.99	1.18	103.1	66,789	11,010	13.40	81.29	0.46	69.9	
2020	6,256,811	327,488	1.96	37.49	1.15	100.2	56,530	9,371	9.84	59.37	0.47	67.1	
2021	6,448,846	338,205	2.03	38.68	1.14	90.2	69,111	11,468	14.53	87.56	0.47	67.7	
2022	6,594,794	346,120	2.41	45.96	1.15	98.4	73,400	12,131	24.43	147.80	0.48	65.6	
2023	6,224,613	326,208	2.56	48.88	1.15	111.5	78,893	13,023	20.48	124.06	0.46	79.3	
2024	5,332,739	277,592	2.55	48.93	1.20	97.0	63,680	10,480	18.22	110.71	0.43	65.0	
Year 2022													
January	546,113	29,056	2.24	42.12	1.06	81.3	6,596	1,103	17.23	103.03	0.46	46.9	
February	500,644	26,344	2.19	41.69	1.05	91.5	6,361	1,045	18.65	113.52	0.48	83.4	
March	537,576	28,123	2.18	41.71	1.14	115.4	5,580	926	22.53	135.80	0.49	70.7	
April	486,354	25,278	2.24	43.02	1.17	113.7	5,684	934	26.28	159.85	0.48	84.8	
May	552,474	28,904	2.29	43.87	1.16	108.7	4,509	747	28.14	169.81	0.48	58.4	
June	537,295	28,300	2.35	44.64	1.14	88.2	7,089	1,166	28.58	173.77	0.48	90.3	
July	557,748	29,313	2.47	47.07	1.18	76.9	6,739	1,115	28.96	175.11	0.48	80.8	
August	627,619	32,918	2.53	48.27	1.19	90.2	5,736	947	26.06	157.81	0.47	72.6	
September	599,306	31,443	2.60	49.50	1.17	110.8	5,857	966	24.83	150.60	0.48	71.8	
October	579,715	30,502	2.53	48.08	1.16	129.7	6,272	1,028	23.81	145.25	0.48	74.8	
November	542,727	28,448	2.55	48.63	1.14	121.1	5,760	953	26.15	158.05	0.46	70.9	
December	527,223	27,491	2.69	51.67	1.22	86.5	7,217	1,202	23.01	138.22	0.48	38.2	
Year 2023													
January	559,118	29,346	2.65	50.44	1.13	106.6	11,620	1,944	22.15	132.38	0.47	133.2	
February	477,280	25,125	2.67	50.72	1.17	125.0	6,931	1,155	22.13	132.74	0.48	73.8	
March	549,894	28,881	2.53	48.18	1.19	135.3	5,960	986	20.64	124.72	0.48	75.3	
April	481,181	25,153	2.51	47.98	1.16	154.9	5,523	905	19.34	117.99	0.47	71.5	
May	486,120	25,332	2.54	48.84	1.14	135.6	6,074	1,006	18.86	113.90	0.48	74.2	
June	504,353	26,328	2.50	47.98	1.16	100.4	6,134	1,010	17.52	106.44	0.47	73.5	
July	552,719	29,116	2.53	48.00	1.13	83.9	7,002	1,138	17.18	105.70	0.44	86.0	
August	583,320	30,491	2.55	48.69	1.14	89.2	4,863	797	19.97	121.81	0.47	55.0	
September	517,934	27,065	2.59	49.49	1.12	102.8	6,073	992	22.75	139.30	0.43	77.5	
October	504,437	26,340	2.58	49.51	1.14	119.1	5,203	855	22.31	135.80	0.40	63.0	
November	509,063	26,715	2.57	48.89	1.14	125.8	5,628	932	21.72	131.14	0.43	70.7	
December	499,194	26,316	2.52	47.89	1.17	109.9	7,883	1,303	20.21	122.26	0.45	95.1	
Year 2024													
January	466,667	24,584	2.54	48.26	1.17	75.4	8,252	1,370	18.93	114.00	0.45	68.2	
February	447,767	23,505	2.57	48.91	1.13	115.9	5,312	874	19.54	118.80	0.46	76.3	
March	427,408	21,930	2.59	50.39	1.29	124.4	4,824	788	19.77	121.10	0.46	68.0	
April	365,902	18,583	2.67	52.51	1.33	117.4	4,798	785	19.55	119.45	0.43	63.6	
May	405,066	20,695	2.65	51.86	1.33	103.2	4,762	789	19.00	114.67	0.38	62.8	
June	431,887	22,308	2.58	50.00	1.28	82.7	4,898	808	18.10	109.70	0.41	65.7	
July	479,544	25,008	2.56	49.01	1.21	79.7	4,041	664	18.56	112.97	0.36	50.0	
August	490,835	25,647	2.50	47.79	1.18	84.8	5,085	835	18.26	111.11	0.46	57.5	
September	460,696	24,152	2.47	47.11	1.09	100.1	4,706	771	17.20	104.95	0.36	62.4	
October	455,323	23,814	2.56	48.96	1.12	116.8	6,392	1,051	16.29	99.08	0.41	76.7	
November	434,798	22,677	2.48	47.64	1.17	114.6	4,408	725	17.02	103.55	0.45	58.1	
December	466,846	24,692	2.45	46.28	1.10	91.4	6,202	1,020	16.76	101.96	0.47	69.9	

Displayed values of zero may represent small values that round to zero.

NM = Not meaningful due to large relative standard error or excessive percentage change.

W = Withheld to avoid disclosure of individual company data.

Notes:

Beginning in January 2013, the threshold for reporting fuel receipts data was changed from 50 megawatts to 200 megawatts of nameplate capacity for plants primarily fueled by natural gas, petroleum coke, distillate fuel oil, and residual fuel oil. In addition, the requirement to report self-produced and minor fuels, i.e., blast furnace gas, other manufactured gases, kerosene, jet fuel, propane, and waste oils was eliminated. The threshold for coal plants remained at 50 megawatts. The following caveats for each fuel type should be noted:

COAL - includes anthracite, bituminous, subbituminous, lignite, waste coal, and coal-derived synthesis gas. Prior to 2011, synthesis gas was included in the category of Other Gases.

PETROLEUM LIQUIDS - includes distillate fuel oil and residual fuel oil. Prior to 2013, petroleum liquids included distillate fuel oil, residual fuel oil, kerosene, jet fuel, waste oil, and, beginning in 2011, propane. Prior to 2011, propane was included in the category of Other Gases.

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Table 7.6. Receipts, Average Cost, and Quality of Fossil Fuels: Electric Utilities, 2014 - 2024 (continued)

Table 7.6. Receipts, Average Cost, and Quality of Fossil Fuels: Electric Utilities, 2014 - 2024 (continued)													
	Petroleum Coke						Natural Gas						All Fossil Fuels
	Receipts		Average Cost				Receipts		Average Cost			Average Cost	
Period	(Billion Btu)	(Thousand Tons)	(Dollars per MMBtu)	(Dollars per Ton)	Average Sulfur Percent by Weight	Percentage of Consumption	(Billion Btu)	(Thousand Mcf)	(Dollars per MMBtu)	(Dollars per Mcf)	Percentage of Consumption	(Dollars per MMBtu)	
Annual Totals													
2014	123,793	4,349	1.89	53.77	5.56	126.3	3,876,549	3,772,596	5.17	5.31	96.7	3.16	
2015	115,929	4,069	1.77	50.44	5.23	130.1	4,717,748	4,565,040	3.52	3.64	96.0	2.67	
2016	99,706	3,538	1.52	42.85	5.38	103.1	5,075,337	4,907,538	3.15	3.26	97.0	2.54	
2017	90,481	3,224	2.15	60.31	5.55	117.6	4,794,383	4,640,827	3.62	3.74	96.8	2.68	
2018	83,211	2,940	2.56	72.34	5.74	106.8	5,562,903	5,388,544	3.68	3.80	96.2	2.80	
2019	54,266	1,896	1.92	54.88	5.50	91.0	6,038,432	5,842,392	3.03	3.13	97.0	2.53	
2020	65,684	2,317	1.70	48.07	5.39	101.8	6,207,039	6,011,244	2.63	2.72	96.3	2.32	
2021	64,891	2,296	3.16	89.27	5.24	98.0	5,901,472	5,713,855	5.21	5.39	96.4	3.60	
2022	64,607	2,283	4.35	122.99	5.52	99.5	6,393,812	6,200,191	7.49	7.73	96.5	5.01	
2023	40,716	1,450	4.05	113.73	5.61	108.5	6,803,788	6,596,937	3.81	3.92	96.1	3.32	
2024	26,786	953	2.96	83.22	5.60	99.2	7,249,583	7,018,235	3.03	3.13	95.7	2.90	
Year 2022													
January	5,343	189	4.32	122.16	5.11	112.6	503,615	487,628	7.15	7.39	96.7	4.67	
February	4,050	141	4.24	121.53	5.80	75.1	414,806	402,121	6.13	6.32	96.1	4.08	
March	5,791	205	4.84	136.40	5.31	142.5	408,255	396,288	5.28	5.43	96.4	3.63	
April	6,637	235	4.80	135.31	5.57	150.6	395,234	383,835	6.25	6.44	97.3	4.17	
May	5,992	212	4.97	140.62	5.48	99.1	494,026	479,966	7.53	7.75	97.5	4.86	
June	4,887	173	4.50	126.93	5.51	76.9	621,160	603,483	8.29	8.53	96.3	5.66	
July	5,781	205	4.65	131.34	5.54	115.1	749,263	727,668	7.75	7.98	96.1	5.61	
August	6,465	228	5.02	142.06	5.62	127.5	723,303	700,993	9.35	9.65	96.4	6.25	
September	3,818	134	2.32	66.08	5.74	63.7	579,405	560,966	8.53	8.81	96.2	5.58	
October	4,060	144	3.35	94.31	5.74	74.8	493,094	478,019	6.19	6.38	96.6	4.31	
November	6,485	229	3.84	108.96	5.53	124.4	482,176	467,566	6.05	6.24	96.6	4.31	
December	5,298	187	4.19	118.73	5.50	73.4	529,475	511,657	9.05	9.36	96.7	5.97	
Year 2023													
January	4,871	176	4.54	126.02	5.67	151.3	509,603	492,284	8.55	8.85	95.8	5.62	
February	3,886	136	4.80	136.95	5.62	125.8	447,571	433,509	4.89	5.05	95.0	3.88	
March	4,905	172	4.66	132.76	5.71	228.6	493,900	478,430	3.76	3.88	95.2	3.22	
April	4,768	168	4.70	133.61	5.72	218.3	460,793	447,538	3.05	3.14	96.4	2.88	
May	1,985	72	3.14	86.86	5.76	94.2	543,700	528,159	2.86	2.94	96.9	2.81	
June	1,853	66	3.48	98.25	5.77	61.3	627,911	609,220	2.92	3.01	96.2	2.81	
July	2,787	100	3.62	101.16	5.45	50.5	767,356	743,822	3.26	3.36	95.7	3.03	
August	2,311	84	3.39	93.79	5.73	42.4	781,288	757,734	3.30	3.40	95.9	3.04	
September	3,289	118	3.76	104.81	5.48	67.3	618,399	600,954	3.28	3.38	96.3	3.07	
October	2,404	86	3.84	107.56	5.50	112.5	528,905	513,656	3.32	3.41	96.7	3.06	
November	3,097	111	3.60	100.64	5.35	228.6	488,206	473,567	3.79	3.91	96.4	3.27	
December	4,559	163	3.39	94.99	5.53	199.5	536,155	518,063	3.73	3.86	96.3	3.27	
Year 2024													
January	909	33	2.65	73.16	5.53	34.6	592,967	572,724	4.98	5.16	94.9	4.02	
February	1,385	50	2.63	73.05	5.56	72.1	487,202	470,741	3.35	3.47	96.2	3.07	
March	1,054	38	2.63	73.51	5.49	173.2	498,041	482,291	2.48	2.56	96.5	2.62	
April	1,078	38	2.62	73.50	5.51	57.9	469,587	455,940	2.32	2.39	95.1	2.57	
May	2,177	78	2.86	80.18	5.46	101.9	575,740	559,701	2.57	2.64	95.8	2.68	
June	3,620	127	3.11	88.55	5.54	110.7	676,666	656,292	2.99	3.08	96.4	2.90	
July	5,356	189	3.23	91.69	5.52	144.2	828,531	801,114	2.78	2.88	95.4	2.75	
August	3,756	134	3.08	86.70	5.70	104.8	808,451	781,275	2.51	2.60	94.5	2.57	
September	3,518	125	3.09	87.22	5.49	178.0	662,215	640,859	2.60	2.69	96.2	2.61	
October	1,008	37	2.63	72.20	6.78	50.7	581,102	562,732	2.94	3.04	97.1	2.86	
November	1,280	46	2.64	72.99	5.91	104.8	534,520	517,612	2.93	3.03	96.8	2.79	
December	1,645	59	2.66	74.04	5.43	82.1	534,561	516,955	4.11	4.25	94.4	3.42	

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Notes:

Beginning in January 2013, the threshold for reporting fuel receipts data was changed from 50 megawatts to 200 megawatts of nameplate capacity for plants primarily fueled by natural gas, petroleum coke, distillate fuel oil, and residual fuel oil. In addition, the requirement to report self-produced and minor fuels, i.e., blast furnace gas, other manufactured gases, kerosene, jet fuel, propane, and waste oils was eliminated. The threshold for coal receipts remained at 50 megawatts. The following caveats for each fuel type should be noted:

PETROLEUM COKE - includes petroleum coke-derived synthesis gas. Prior to 2011, petroleum coke-derived synthesis gas was included in Other Gases.

NATURAL GAS - includes natural gas only. Prior to 2011, includes Other Gases.

- Values are final.

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- Totals may not equal the sum of components because of independent rounding.

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Table 7.7 Receipts, Average Cost, and Quality of Fossil Fuels: Independent Power Producers, 2014 - 2024

Table 7.7 Receipts, Average Cost, and Quality of Fossil Fuels: Independent Power Producers, 2014 - 2024												
	Coal						Petroleum Liquids					
	Receipts		Average Cost				Receipts		Average Cost			
	(Billion Btu)	(Thousand Tons)	(Dollars per MMBtu)	(Dollars per Ton)	Average Sulfur Percent by Weight	Percentage of Consumption	(Billion Btu)	(Thousand Barrels)	(Dollars per MMBtu)	(Dollars per Barrel)	Average Sulfur Percent by Weight	Percentage of Consumption
Period												
Annual Totals												
2014	4,243,949	226,600	2.25	42.20	1.61	100.1	71,774	11,980	19.90	119.36	0.45	101.0
2015	3,731,508	198,982	2.10	39.39	1.66	100.5	55,248	9,189	11.69	70.36	0.46	86.5
2016	3,047,358	164,648	1.93	35.69	1.73	91.8	25,975	4,410	9.93	58.56	0.48	75.1
2017	3,056,215	165,567	1.85	34.19	1.64	93.1	24,704	4,190	12.67	74.73	0.46	73.8
2018	2,849,062	152,015	1.89	35.41	1.70	94.2	47,699	8,022	14.52	86.39	0.44	81.7
2019	2,629,405	139,141	1.81	34.16	1.74	101.6	20,188	3,425	14.40	84.89	0.50	73.0
2020	1,937,714	105,627	1.74	31.92	1.72	97.1	18,954	3,216	9.44	55.61	0.49	88.7
2021	2,163,331	116,480	1.79	33.35	1.79	92.0	25,972	4,447	15.38	89.84	0.47	101.6
2022	2,142,472	116,864	2.19	40.16	1.69	96.4	41,066	6,827	22.83	137.45	0.39	69.1
2023	1,763,719	98,990	2.28	40.63	1.52	104.7	29,337	4,849	20.59	124.91	0.36	105.8
2024	1,513,856	85,656	2.17	38.37	1.54	98.5	22,399	3,685	18.64	113.35	0.38	77.6
Year 2022												
January	190,059	10,391	2.06	37.66	1.62	79.5	8,892	1,482	18.48	111.05	0.39	51.8
February	169,787	9,274	2.07	37.95	1.56	82.2	4,566	762	18.20	109.02	0.36	96.9
March	191,644	10,240	2.04	38.27	1.72	101.2	1,540	252	22.72	138.89	0.45	63.0
April	175,332	9,448	1.99	37.03	1.86	107.7	1,498	247	27.01	163.98	0.48	89.1
May	170,813	9,355	2.01	36.76	1.87	107.8	1,250	205	28.43	173.23	0.48	73.6
June	170,764	9,296	2.20	40.47	1.83	95.7	1,651	275	30.73	185.03	0.41	72.6
July	188,956	10,384	2.45	44.55	1.71	90.8	1,756	293	30.58	183.42	0.47	48.7
August	189,136	10,350	2.41	44.15	1.63	86.5	2,286	381	27.18	162.89	0.47	67.6
September	175,484	9,589	2.16	39.62	1.72	106.1	2,185	358	23.44	143.49	0.41	98.3
October	185,852	10,141	2.18	40.02	1.67	126.2	2,848	471	23.30	140.86	0.35	112.5
November	164,764	9,127	2.20	39.71	1.49	101.3	3,910	654	26.55	158.67	0.37	194.2
December	169,882	9,269	2.47	45.38	1.65	91.6	8,682	1,447	19.92	119.50	0.33	55.5
Year 2023												
January	160,350	8,640	2.36	43.91	1.70	107.3	3,706	618	22.40	134.71	0.41	194.5
February	150,824	8,308	2.25	40.84	1.63	122.3	3,914	637	17.39	107.13	0.37	77.7
March	156,569	8,706	2.31	41.52	1.54	117.5	1,599	261	21.45	131.58	0.47	79.2
April	143,467	8,154	2.27	39.94	1.50	122.5	1,844	305	20.51	124.08	0.37	95.0
May	145,409	8,086	2.32	41.86	1.59	118.4	1,720	282	19.41	118.27	0.43	89.2
June	136,863	7,723	2.28	40.48	1.52	105.1	1,623	269	18.98	114.73	0.46	95.4
July	142,931	8,208	2.24	38.98	1.44	83.9	2,180	361	18.91	114.20	0.35	83.9
August	148,108	8,433	2.23	39.31	1.46	86.3	2,952	490	21.29	129.36	0.26	157.0
September	135,357	7,629	2.24	39.75	1.41	96.0	1,974	327	23.62	143.13	0.30	89.9
October	138,346	7,862	2.28	40.14	1.50	104.7	2,214	362	22.47	137.36	0.33	79.5
November	153,037	8,666	2.27	40.16	1.46	103.8	2,920	484	20.22	121.98	0.38	147.1
December	152,457	8,573	2.27	40.45	1.52	105.4	2,692	453	21.47	128.27	0.29	148.0
Year 2024												
January	136,350	7,689	2.25	39.91	1.54	78.0	2,732	457	19.22	114.73	0.35	61.1
February	125,437	7,169	2.12	37.19	1.56	124.9	1,128	186	20.22	122.40	0.42	90.7
March	111,385	6,300	2.10	37.16	1.63	131.3	1,259	206	21.01	128.52	0.45	86.0
April	97,606	5,729	2.02	34.36	1.45	105.2	1,632	269	20.39	123.79	0.44	69.7
May	104,074	5,887	2.20	38.90	1.59	96.0	2,004	329	19.41	118.21	0.38	101.2
June	120,305	6,732	2.20	39.37	1.65	90.3	2,044	335	18.17	110.82	0.46	89.9
July	137,833	7,806	2.15	37.95	1.60	85.8	1,836	301	19.09	116.28	0.29	53.8
August	147,122	8,293	2.23	39.55	1.49	90.6	1,705	280	18.63	113.61	0.40	74.0
September	133,554	7,466	2.20	39.42	1.47	101.3	1,454	236	17.80	109.92	0.39	97.5
October	141,888	7,921	2.15	38.56	1.54	114.4	1,923	313	16.68	102.39	0.32	111.3
November	128,787	7,226	2.17	38.75	1.59	110.5	2,482	408	17.54	106.75	0.37	141.1
December	129,516	7,437	2.19	38.19	1.44	88.6	2,202	365	17.27	104.34	0.39	50.6

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Notes:

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COAL - includes anthracite, bituminous, subbituminous, lignite, waste coal, and coal-derived synthesis gas. Prior to 2011, synthesis gas was included in the category of Other Gases.

PETROLEUM LIQUIDS - includes distillate fuel oil and residual fuel oil. Prior to 2013, petroleum liquids included distillate fuel oil, residual fuel oil, kerosene, jet fuel, waste oil, and, beginning in 2011, propane. Prior to 2011, propane was included in the category of Other Gases.

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- See Glossary for definitions.

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- See the EIA-923 section of the Technical Notes for a discussion of the sample design for the Form EIA-923 and predecessor forms.

- See the Technical Notes for fuel conversion factors.

- Totals may not equal the sum of components because of independent rounding.

Sources: U.S. Energy Information Administration (EIA), Form EIA-923, "Power Plant Operations Report" and predecessor forms 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 7.8. Receipts, Average Cost, and Quality of Fossil Fuels: Independent Power Producers, 2014 - 2024 (continued)

	Petroleum Coke						Natural Gas					All Fossil Fuels
	Receipts		Average Cost				Receipts		Average Cost			Average Cost
Period	(Billion Btu)	(Thousand Tons)	(Dollars per MMBtu)	(Dollars per Ton)	Average Sulfur Percent by Weight	Percentage of Consumption	(Billion Btu)	(Thousand Mcf)	(Dollars per MMBtu)	(Dollars per Mcf)	Percentage of Consumption	(Dollars per MMBtu)
Annual Totals												
2014	13,781	488	2.48	70.31	5.33	70.9	4,054,540	3,934,672	4.90	5.05	92.7	3.52
2015	14,550	524	2.45	68.22	5.26	67.3	4,683,291	4,530,195	2.94	3.04	93.2	2.57
2016	13,573	492	2.50	68.88	5.44	69.9	4,791,729	4,634,518	2.54	2.63	94.0	2.29
2017	0	0	--	--	--	0.0	4,346,156	4,201,573	3.08	3.19	94.0	2.54
2018	0	0	--	--	--	0.0	4,889,212	4,727,692	3.40	3.52	94.6	2.84
2019	0	0	--	--	--	0.0	5,242,547	5,062,877	2.70	2.80	96.0	2.40
2020	0	0	--	--	--	0.0	5,359,545	5,178,938	2.10	2.17	96.1	2.01
2021	0	0	--	--	--	0.0	5,255,390	5,077,009	5.29	5.48	95.7	4.16
2022	0	0	--	--	--	--	5,602,375	5,414,698	6.95	7.20	95.5	5.50
2023	0	0	--	--	--	--	6,038,310	5,836,072	2.82	2.92	96.1	2.75
2024	0	0	--	--	--	--	6,133,734	5,923,429	2.41	2.50	96.4	2.41
Year 2022												
January	0	0	--	--	--	--	440,567	425,442	6.15	6.38	95.6	4.92
February	0	0	--	--	--	--	375,891	363,057	5.88	6.09	94.2	4.62
March	0	0	--	--	--	--	359,407	347,490	4.96	5.14	95.0	3.87
April	0	0	--	--	--	--	344,208	332,882	6.22	6.44	95.5	4.66
May	0	0	--	--	--	--	428,890	414,929	7.60	7.86	96.4	5.80
June	0	0	--	--	--	--	513,920	497,609	7.55	7.81	96.1	6.03
July	0	0	--	--	--	--	644,066	623,293	7.29	7.54	96.2	6.04
August	0	0	--	--	--	--	645,276	623,863	8.56	8.86	95.5	6.95
September	0	0	--	--	--	--	538,145	519,483	7.58	7.86	95.8	6.04
October	0	0	--	--	--	--	446,464	431,379	5.29	5.48	95.5	4.32
November	0	0	--	--	--	--	407,043	393,319	5.35	5.54	94.1	4.44
December	0	0	--	--	--	--	458,497	441,951	9.26	9.61	95.4	7.27
Year 2023												
January	0	0	--	--	--	--	446,640	430,815	5.37	5.57	95.8	4.57
February	0	0	--	--	--	--	407,924	394,009	3.92	4.06	96.1	3.50
March	0	0	--	--	--	--	428,537	414,070	2.95	3.06	95.4	2.81
April	0	0	--	--	--	--	393,827	380,548	2.28	2.36	95.5	2.35
May	0	0	--	--	--	--	444,722	430,350	2.12	2.19	96.9	2.23
June	0	0	--	--	--	--	542,599	524,807	2.17	2.24	96.4	2.24
July	0	0	--	--	--	--	691,161	668,245	2.67	2.76	95.9	2.63
August	0	0	--	--	--	--	677,647	655,199	2.46	2.55	96.1	2.48
September	0	0	--	--	--	--	571,702	553,460	2.35	2.43	96.3	2.39
October	0	0	--	--	--	--	483,231	467,338	2.42	2.51	96.4	2.47
November	0	0	--	--	--	--	469,276	453,150	2.94	3.05	96.0	2.85
December	0	0	--	--	--	--	481,043	464,082	2.76	2.86	96.4	2.70
Year 2024												
January	0	0	--	--	--	--	535,112	516,165	4.90	5.08	96.8	4.33
February	0	0	--	--	--	--	422,449	407,092	2.34	2.42	96.1	2.32
March	0	0	--	--	--	--	417,748	402,983	1.85	1.92	96.1	1.96
April	0	0	--	--	--	--	398,022	384,553	1.69	1.75	96.1	1.83
May	0	0	--	--	--	--	462,442	447,391	1.92	1.99	96.6	2.05
June	0	0	--	--	--	--	554,335	535,943	2.25	2.33	96.1	2.30
July	0	0	--	--	--	--	687,681	664,168	2.10	2.18	96.5	2.16
August	0	0	--	--	--	--	666,449	643,563	1.88	1.95	96.1	2.00
September	0	0	--	--	--	--	557,352	538,490	2.04	2.11	96.8	2.11
October	0	0	--	--	--	--	485,365	469,303	2.14	2.21	95.5	2.19
November	0	0	--	--	--	--	455,042	439,462	2.27	2.35	97.1	2.32
December	0	0	--	--	--	--	491,738	474,316	3.60	3.73	97.0	3.31

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Notes:

Beginning in January 2013, the threshold for reporting fuel receipts data was changed from 50 megawatts to 200 megawatts of nameplate capacity for plants primarily fueled by natural gas, petroleum coke, distillate fuel oil, and residual fuel oil. In addition, the requirement to report self-produced and minor fuels, i.e., blast furnace gas, other manufactured gases, kerosene, jet fuel, propane, and waste oils was eliminated. The threshold for coal plants remained at 50 megawatts. The following caveats for each fuel type should be noted:

PETROLEUM COKE - includes petroleum coke-derived synthesis gas. Prior to 2011, petroleum coke-derived synthesis gas was included in Other Gases.

NATURAL GAS - includes natural gas only. Prior to 2011, includes Other Gases.

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Sources: U.S. Energy Information Administration (EIA), Form EIA-923, "Power Plant Operations Report" and predecessor forms 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 7.9. Receipts, Average Cost, and Quality of Fossil Fuels: Commercial Sector, 2014 - 2024

Table 7.9. Receipts, Average Cost, and Quantity of Fossil Fuels: Commercial Sector, 2014 - 2024												
	Coal						Petroleum Liquids					
	Receipts		Average Cost				Receipts		Average Cost			
Period	(Billion Btu)	(Thousand Tons)	(Dollars per MMBtu)	(Dollars per Ton)	Average Sulfur Percent by Weight	Percentage of Consumption	(Billion Btu)	(Thousand Barrels)	(Dollars per MMBtu)	(Dollars per Barrel)	Average Sulfur Percent by Weight	Percentage of Consumption
Annual Totals												
2014	4,096	182	3.12	70.30	2.50	17.1	0	0	--	--	--	0.0
2015	2,439	109	2.85	63.90	2.55	13.6	0	0	--	--	--	0.0
2016	1,288	57	2.69	60.89	3.03	8.3	0	0	--	--	--	0.0
2017	548	24	2.78	63.31	2.99	3.9	0	0	--	--	--	0.0
2018	290	13	2.94	66.52	3.04	2.2	0	0	--	--	--	0.0
2019	193	8	2.92	66.55	3.01	1.6	0	0	--	--	--	0.0
2020	132	6	2.96	67.66	2.93	1.2	0	0	--	--	--	0.0
2021	262	11	3.03	69.50	2.94	2.1	0	0	--	--	--	0.0
2022	268	12	4.17	94.87	3.08	2.2	0	0	--	--	--	--
2023	66	3	4.28	96.92	3.22	0.7	0	0	--	--	--	--
2024	128	6	4.28	96.74	3.06	1.3	0	0	--	--	--	--
Year 2022												
January	74	3	3.95	90.18	3.03	5.8	0	0	--	--	--	--
February	19	1	3.95	90.65	3.00	1.5	0	0	--	--	--	--
March	0	0	--	--	--	0.0	0	0	--	--	--	--
April	0	0	--	--	--	0.0	0	0	--	--	--	--
May	0	0	--	--	--	0.0	0	0	--	--	--	--
June	0	0	--	--	--	--	0	0	--	--	--	--
July	0	0	--	--	--	--	0	0	--	--	--	--
August	0	0	--	--	--	--	0	0	--	--	--	--
September	106	5	4.28	97.46	3.05	10.0	0	0	--	--	--	--
October	54	2	4.28	97.11	3.24	5.2	0	0	--	--	--	--
November	0	0	--	--	--	0.0	0	0	--	--	--	--
December	15	1	4.28	96.94	3.02	1.1	0	0	--	--	--	--
Year 2023												
January	21	1	4.28	96.60	3.06	1.8	0	0	--	--	--	--
February	22	1	4.28	97.20	3.12	2.1	0	0	--	--	--	--
March	0	0	--	--	--	--	0	0	--	--	--	--
April	0	0	--	--	--	--	0	0	--	--	--	--
May	0	0	--	--	--	--	0	0	--	--	--	--
June	0	0	--	--	--	--	0	0	--	--	--	--
July	0	0	--	--	--	--	0	0	--	--	--	--
August	0	0	--	--	--	--	0	0	--	--	--	--
September	0	0	--	--	--	--	0	0	--	--	--	--
October	0	0	--	--	--	--	0	0	--	--	--	--
November	0	0	--	--	--	--	0	0	--	--	--	--
December	24	1	4.28	96.94	3.46	2.6	0	0	--	--	--	--
Year 2024												
January	85	4	4.28	96.86	3.06	5.9	0	0	--	--	--	--
February	43	2	4.28	96.51	3.06	4.1	0	0	--	--	--	--
March	0	0	--	--	--	0.0	0	0	--	--	--	--
April	0	0	--	--	--	--	0	0	--	--	--	--
May	0	0	--	--	--	--	0	0	--	--	--	--
June	0	0	--	--	--	--	0	0	--	--	--	--
July	0	0	--	--	--	--	0	0	--	--	--	--
August	0	0	--	--	--	0.0	0	0	--	--	--	--
September	0	0	--	--	--	0.0	0	0	--	--	--	--
October	0	0	--	--	--	0.0	0	0	--	--	--	--
November	0	0	--	--	--	0.0	0	0	--	--	--	--
December	0	0	--	--	--	0.0	0	0	--	--	--	--

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COAL - includes anthracite, bituminous, subbituminous, lignite, waste coal, and coal-derived synthesis gas. Prior to 2011, synthesis gas was included in the category of Other Gases.

PETROLEUM LIQUIDS - includes distillate fuel oil and residual fuel oil. Prior to 2013, petroleum liquids included distillate fuel oil, residual fuel oil, kerosene, jet fuel, waste oil, and, beginning in 2011, propane. Prior to 2011, propane was included in the category of Other Gases.

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Table 7.10. Receipts, Average Cost, and Quality of Fossil Fuels: Commerical Sector, 2014 - 2024 (continued)

Table 7.10. Receipts, Average Cost, and Quality of Fossil Fuels: Commercial Sector, 2014 - 2024 (continued)														
	Petroleum Coke							Natural Gas					All Fossil Fuels	
	Receipts		Average Cost					Receipts		Average Cost			Average Cost	
Period	(Billion Btu)	(Thousand Tons)	(Dollars per MMBtu)	(Dollars per Ton)	Average Sulfur Percent by Weight	Percentage of Consumption	(Billion Btu)	(Thousand Mcf)	(Dollars per MMBtu)	(Dollars per Mcf)	Percentage of Consumption	(Dollars per MMBtu)		
Annual Totals														
2014	0	0	--	--	--	0.0	5,849	5,795	5.42	5.47	4.9	4.47		
2015	0	0	--	--	--	0.0	6,499	6,371	4.11	4.19	5.5	3.76		
2016	0	0	--	--	--	0.0	8,005	7,766	3.85	3.97	6.1	3.69		
2017	0	0	--	--	--	0.0	7,841	7,593	3.82	3.95	4.9	3.75		
2018	0	0	--	--	--	0.0	9,090	8,823	3.49	3.59	6.6	3.47		
2019	0	0	--	--	--	0.0	9,429	9,087	3.26	3.39	6.7	3.26		
2020	0	0	--	--	--	0.0	8,532	8,188	3.07	3.20	6.3	3.07		
2021	0	0	--	--	--	0.0	8,869	8,528	3.42	3.56	7.3	3.41		
2022	0	0	--	--	--	--	8,636	8,322	3.88	4.02	6.8	3.89		
2023	0	0	--	--	--	--	8,130	7,861	3.04	3.15	6.6	3.05		
2024	0	0	--	--	--	--	7,834	7,544	3.28	3.41	5.9	3.30		
Year 2022														
January	0	0	--	--	--	--	759	731	3.29	3.42	6.5	3.35		
February	0	0	--	--	--	--	711	683	3.32	3.45	6.8	3.33		
March	0	0	--	--	--	--	712	687	3.30	3.42	6.8	3.30		
April	0	0	--	--	--	--	786	758	4.35	4.51	8.2	4.35		
May	0	0	--	--	--	--	686	661	4.13	4.29	7.0	4.13		
June	0	0	--	--	--	--	628	603	3.89	4.05	6.1	3.89		
July	0	0	--	--	--	--	693	668	3.86	4.00	5.7	3.86		
August	0	0	--	--	--	--	732	703	4.86	5.06	5.9	4.86		
September	0	0	--	--	--	--	766	738	4.56	4.73	7.3	4.53		
October	0	0	--	--	--	--	657	634	3.98	4.12	7.0	4.00		
November	0	0	--	--	--	--	656	636	3.18	3.28	6.7	3.18		
December	0	0	--	--	--	--	850	821	3.73	3.86	7.5	3.74		
Year 2023														
January	0	0	--	--	--	--	707	682	3.11	3.22	6.6	3.14		
February	0	0	--	--	--	--	707	683	3.01	3.11	7.2	3.05		
March	0	0	--	--	--	--	680	655	3.05	3.17	6.6	3.05		
April	0	0	--	--	--	--	720	700	2.89	2.97	8.0	2.89		
May	0	0	--	--	--	--	748	726	2.84	2.92	8.1	2.84		
June	0	0	--	--	--	--	617	598	2.89	2.99	6.2	2.89		
July	0	0	--	--	--	--	629	607	3.07	3.18	5.4	3.07		
August	0	0	--	--	--	--	670	646	3.09	3.21	6.0	3.09		
September	0	0	--	--	--	--	619	597	3.10	3.21	5.8	3.10		
October	0	0	--	--	--	--	685	664	3.03	3.13	7.0	3.03		
November	0	0	--	--	--	--	687	664	3.19	3.31	6.8	3.19		
December	0	0	--	--	--	--	661	638	3.27	3.38	6.3	3.30		
Year 2024														
January	0	0	--	--	--	--	715	686	3.29	3.43	5.7	3.40		
February	0	0	--	--	--	--	666	641	3.29	3.42	6.0	3.35		
March	0	0	--	--	--	--	572	552	3.18	3.29	5.3	3.18		
April	0	0	--	--	--	--	648	629	3.14	3.24	6.8	3.14		
May	0	0	--	--	--	--	577	554	3.18	3.31	6.3	3.18		
June	0	0	--	--	--	--	486	469	3.10	3.21	4.5	3.10		
July	0	0	--	--	--	--	652	629	3.31	3.42	5.1	3.31		
August	0	0	--	--	--	--	764	733	3.26	3.40	6.1	3.26		
September	0	0	--	--	--	--	618	595	3.42	3.56	5.7	3.42		
October	0	0	--	--	--	--	642	620	3.38	3.50	6.2	3.38		
November	0	0	--	--	--	--	772	740	3.30	3.44	7.1	3.30		
December	0	0	--	--	--	--	722	695	3.43	3.56	6.1	3.43		

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Notes:

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NATURAL GAS - includes natural gas only. Prior to 2011, includes Other Gases.

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- Totals may not equal the sum of components because of independent rounding.

Sources: U.S. Energy Information Administration (EIA), Form EIA-923, "Power Plant Operations Report" and predecessor forms 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 7.11. Receipts, Average Cost, and Quality of Fossil Fuels: Industrial Sector, 2014 - 2024

Period	Coal						Petroleum Liquids					
	Receipts		Average Cost				Receipts		Average Cost			
	(Billion Btu)	(Thousand Tons)	(Dollars per MMBtu)	(Dollars per Ton)	Average Sulfur Percent by Weight	Percentage of Consumption	(Billion Btu)	(Thousand Barrels)	(Dollars per MMBtu)	(Dollars per Barrel)	Average Sulfur Percent by Weight	Percentage of Consumption
Annual Totals												
2014	281,867	13,050	2.97	64.15	1.33	68.4	2,290	373	17.91	109.99	1.43	15.6
2015	263,630	12,132	2.72	59.17	1.35	71.4	2,359	385	13.45	82.47	1.42	16.9
2016	210,749	9,859	2.67	57.01	1.30	67.0	2,541	412	10.51	64.79	1.27	18.3
2017	192,637	9,178	2.49	52.29	1.35	70.7	1,850	297	11.18	69.57	1.42	15.2
2018	170,730	8,224	2.47	51.38	1.30	67.2	2,319	372	13.46	83.97	1.35	15.9
2019	146,324	7,088	2.55	52.69	1.19	65.1	1,684	275	13.19	80.82	1.47	14.5
2020	134,523	6,515	2.49	51.38	1.27	68.9	1,700	277	10.52	64.54	1.20	17.0
2021	141,492	6,781	2.33	48.60	1.33	69.9	2,380	387	12.90	79.39	1.46	21.3
2022	138,708	6,721	2.78	57.30	1.27	70.3	2,475	404	18.35	112.54	1.26	10.5
2023	123,941	6,174	3.26	65.45	1.02	73.6	2,862	468	17.32	105.80	1.35	16.2
2024	118,599	5,880	2.94	59.35	1.03	72.3	2,130	346	16.58	102.07	1.57	22.6
Year 2022												
January	12,244	593	2.58	53.22	1.35	67.4	301	49	14.12	86.62	1.46	18.3
February	10,697	520	2.65	54.46	1.17	68.2	229	37	15.76	97.63	1.27	16.8
March	12,941	626	2.53	52.28	1.39	74.0	219	36	15.78	97.43	1.06	11.4
April	10,674	504	2.78	58.94	1.37	65.8	112	18	19.33	118.47	1.55	5.7
May	12,282	597	2.49	51.10	1.38	72.5	175	29	19.13	117.32	0.90	10.0
June	11,491	564	2.36	48.06	1.45	72.2	144	23	21.21	129.90	1.07	6.9
July	12,246	595	2.65	54.47	1.30	75.6	156	26	19.35	118.47	1.57	7.5
August	10,874	533	2.67	54.52	1.21	66.4	157	25	20.21	124.53	1.54	11.4
September	11,393	556	3.10	63.58	1.06	74.0	202	33	18.30	112.79	1.13	10.7
October	11,143	541	3.52	72.50	0.91	68.4	223	36	17.89	109.96	1.15	11.7
November	10,179	488	3.21	66.97	1.29	65.4	219	36	23.10	140.27	1.11	12.1
December	12,543	605	2.91	60.37	1.36	73.2	337	56	19.51	118.50	1.38	9.1
Year 2023												
January	11,082	548	2.99	60.56	1.21	67.8	336	55	17.76	108.25	1.35	15.2
February	10,894	523	3.79	78.83	1.06	75.4	332	55	17.22	104.12	1.55	15.6
March	10,570	525	3.64	73.24	0.78	73.6	440	73	16.48	99.40	1.62	22.5
April	11,351	563	3.48	70.15	0.97	84.9	300	50	17.07	103.34	1.55	15.1
May	10,576	520	3.41	69.33	1.16	75.3	309	51	15.64	95.51	1.12	32.7
June	10,155	532	2.82	53.77	0.82	79.2	93	15	16.41	103.52	1.09	9.0
July	9,652	499	2.86	55.29	0.73	69.5	141	23	16.54	102.83	1.00	13.4
August	10,109	515	3.10	60.84	0.91	76.1	136	22	17.84	111.00	1.20	10.9
September	8,716	431	3.73	75.33	1.07	64.2	154	25	16.85	104.23	1.13	12.6
October	10,465	521	3.22	64.67	1.08	77.9	232	38	20.00	122.63	1.47	21.7
November	9,969	489	3.04	62.05	1.15	70.7	198	32	19.26	117.80	1.37	14.8
December	10,403	508	3.04	62.22	1.25	70.8	191	31	17.47	108.06	1.32	12.6
Year 2024												
January	9,556	480	2.78	55.44	0.87	60.5	313	51	16.91	104.56	1.20	24.5
February	11,198	553	3.08	62.42	1.01	82.4	195	32	18.01	108.28	1.65	22.5
March	10,962	527	3.18	66.06	0.99	71.9	148	24	15.74	95.28	1.53	18.8
April	8,753	436	2.86	57.41	1.03	73.3	132	21	17.82	109.90	1.57	16.7
May	9,654	481	2.86	57.39	0.85	76.0	128	21	16.69	103.83	1.60	18.9
June	9,675	483	3.00	60.11	0.97	77.7	142	23	16.94	104.50	1.23	22.8
July	10,223	503	2.93	59.57	1.21	73.5	183	30	16.48	101.78	1.58	26.7
August	9,931	491	2.94	59.46	1.16	73.9	162	26	15.32	95.00	1.65	27.1
September	9,443	478	2.86	56.60	0.90	73.3	181	29	16.22	100.75	1.63	29.0
October	9,747	476	3.11	63.70	1.11	71.8	160	26	15.84	96.88	1.76	20.0
November	9,621	485	2.77	54.98	1.02	70.1	144	23	15.94	98.83	1.80	19.4
December	9,836	488	2.87	57.79	1.25	66.7	243	39	16.63	102.58	1.83	25.2

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Notes:

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COAL - includes anthracite, bituminous, subbituminous, lignite, waste coal, and coal-derived synthesis gas. Prior to 2011, synthesis gas was included in the category of Other Gases.

PETROLEUM LIQUIDS - includes distillate fuel oil and residual fuel oil. Prior to 2013, petroleum liquids included distillate fuel oil, residual fuel oil, kerosene, jet fuel, waste oil, and, beginning in 2011, propane. Prior to 2011, propane was included in the category of Other Gases.

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Table 7.12. Receipts, Average Cost, and Quality of Fossil Fuels: Industrial Sector, 2014 - 2024 (continued)

Table 7.12. Receipts, Average Cost, and Quality of Fossil Fuels: Industrial Sector, 2014 - 2024 (continued)													
	Petroleum Coke						Natural Gas						All Fossil Fuels
	Receipts		Average Cost				Receipts		Average Cost			Average Cost	
Period	(Billion Btu)	(Thousand Tons)	(Dollars per MMBtu)	(Dollars per Ton)	Average Sulfur Percent by Weight	Percentage of Consumption	(Billion Btu)	(Thousand Mcf)	(Dollars per MMBtu)	(Dollars per Mcf)	Percentage of Consumption	(Dollars per MMBtu)	
Annual Totals													
2014	9,736	358	2.56	69.67	5.83	23.2	742,347	718,360	4.54	4.69	62.7	4.12	
2015	8,189	304	1.73	46.72	5.50	24.1	765,964	740,975	2.83	2.93	60.6	2.82	
2016	3,664	135	2.00	54.12	5.84	11.2	744,034	721,358	2.65	2.74	59.6	2.68	
2017	2,356	85	1.59	44.08	5.84	8.1	803,435	778,741	3.18	3.28	62.0	3.06	
2018	1,911	71	1.75	47.47	5.74	7.1	792,297	769,790	3.39	3.49	58.6	3.25	
2019	2,028	73	1.69	46.99	5.81	8.1	814,483	790,388	2.82	2.91	57.5	2.80	
2020	2,157	80	1.73	46.84	5.89	10.0	805,785	783,182	2.28	2.34	53.7	2.32	
2021	0	0	--	--	--	0.0	801,054	778,861	4.65	4.79	56.5	4.33	
2022	82	3	4.46	124.88	5.99	0.4	835,428	812,863	6.51	6.69	59.1	6.01	
2023	0	0	--	--	--	--	819,270	796,511	2.96	3.05	57.1	3.04	
2024	0	0	--	--	--	--	814,871	791,957	2.47	2.55	56.7	2.57	
Year 2022													
January	0	0	--	--	--	--	76,455	74,275	4.68	4.82	59.9	4.42	
February	0	0	--	--	--	--	65,784	63,860	5.74	5.91	59.0	5.34	
March	0	0	--	--	--	--	71,461	69,559	4.69	4.82	60.3	4.39	
April	0	0	--	--	--	--	67,470	65,714	5.97	6.13	60.8	5.55	
May	0	0	--	--	--	--	67,025	65,283	7.68	7.89	58.9	6.90	
June	0	0	--	--	--	--	68,964	67,264	8.29	8.50	60.1	7.47	
July	0	0	--	--	--	--	72,749	70,916	6.93	7.11	58.8	6.33	
August	0	0	--	--	--	--	73,848	72,011	8.69	8.91	59.1	7.94	
September	0	0	--	--	--	--	66,052	64,306	8.40	8.63	57.9	7.65	
October	82	3	4.46	124.88	5.99	4.6	65,621	63,673	5.82	5.99	57.1	5.52	
November	0	0	--	--	--	--	69,498	67,553	5.11	5.26	58.9	4.92	
December	0	0	--	--	--	--	70,500	68,450	6.26	6.45	58.4	5.81	
Year 2023													
January	0	0	--	--	--	--	71,716	69,675	5.00	5.14	58.3	4.78	
February	0	0	--	--	--	--	64,329	62,549	3.21	3.31	58.2	3.36	
March	0	0	--	--	--	--	69,643	67,835	2.75	2.82	57.9	2.94	
April	0	0	--	--	--	--	63,498	61,740	2.31	2.38	58.5	2.55	
May	0	0	--	--	--	--	66,713	64,886	2.36	2.43	57.7	2.56	
June	0	0	--	--	--	--	66,989	65,355	2.48	2.54	56.0	2.54	
July	0	0	--	--	--	--	67,515	65,565	2.84	2.93	53.9	2.87	
August	0	0	--	--	--	--	68,641	66,678	2.82	2.90	54.9	2.88	
September	0	0	--	--	--	--	67,506	65,578	2.80	2.88	55.9	2.93	
October	0	0	--	--	--	--	67,344	65,433	2.86	2.94	57.5	2.96	
November	0	0	--	--	--	--	70,348	68,333	3.08	3.18	58.2	3.12	
December	0	0	--	--	--	--	75,027	72,883	2.86	2.95	58.3	2.92	
Year 2024													
January	0	0	--	--	--	--	74,708	72,490	3.68	3.79	56.1	3.62	
February	0	0	--	--	--	--	65,778	63,867	2.58	2.65	56.5	2.69	
March	0	0	--	--	--	--	67,919	66,041	1.83	1.88	57.4	2.04	
April	0	0	--	--	--	--	67,078	65,299	1.94	1.99	59.4	2.07	
May	0	0	--	--	--	--	66,345	64,508	1.98	2.04	57.5	2.12	
June	0	0	--	--	--	--	64,633	62,797	2.52	2.59	56.2	2.61	
July	0	0	--	--	--	--	67,769	65,866	2.46	2.53	54.7	2.55	
August	0	0	--	--	--	--	69,890	67,923	2.08	2.14	55.2	2.21	
September	0	0	--	--	--	--	66,925	65,081	2.22	2.29	57.1	2.34	
October	0	0	--	--	--	--	63,855	62,024	2.53	2.61	56.8	2.64	
November	0	0	--	--	--	--	65,486	63,669	2.32	2.39	55.9	2.40	
December	0	0	--	--	--	--	74,487	72,393	3.37	3.46	58.2	3.35	

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Table 7.13. Receipts of Coal Delivered for Electricity Generation by State, 2024 and 2023
(Thousand Tons)

Census Division and State				Electric Power Sector							
	All Sectors			Electric Utilities		Independent Power Producers		Commercial Sector		Industrial Sector	
	Year 2024	Year 2023	Percentage Change	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023
New England	42	120	-65.0%	0	0	42	120	0	0	0	0
Connecticut	0	0	--	0	0	0	0	0	0	0	0
Maine	42	66	-36.0%	0	0	42	66	0	0	0	0
Massachusetts	0	0	--	0	0	0	0	0	0	0	0
New Hampshire	0	54	-100.0%	0	0	0	54	0	0	0	0
Rhode Island	0	0	--	0	0	0	0	0	0	0	0
Vermont	0	0	--	0	0	0	0	0	0	0	0
Middle Atlantic	7,790	8,551	-8.9%	0	0	7,683	8,443	0	0	107	108
New Jersey	0	0	--	0	0	0	0	0	0	0	0
New York	0	0	--	0	0	0	0	0	0	0	0
Pennsylvania	7,790	8,551	-8.9%	0	0	7,683	8,443	0	0	107	108
East North Central	75,082	86,520	-13.0%	45,885	52,619	27,796	32,298	0	0	1,401	1,603
Illinois	21,009	23,125	-9.2%	3,833	4,040	15,775	17,482	0	0	1,401	1,603
Indiana	17,079	21,554	-21.0%	15,478	19,257	1,601	2,298	0	0	0	0
Michigan	13,764	13,700	0.5%	13,764	13,598	0	102	0	0	0	0
Ohio	12,622	14,980	-16.0%	2,202	2,563	10,420	12,417	0	0	0	0
Wisconsin	10,608	13,161	-19.0%	10,608	13,161	0	0	0	0	0	0
West North Central	79,285	95,536	-17.0%	76,573	92,829	0	0	6	3	2,706	2,704
Iowa	9,928	13,137	-24.0%	7,788	11,043	0	0	0	0	2,140	2,094
Kansas	9,142	12,351	-26.0%	9,142	12,351	0	0	0	0	0	0
Minnesota	6,583	8,693	-24.0%	6,583	8,693	0	0	0	0	0	0
Missouri	22,243	27,819	-20.0%	22,238	27,816	0	0	6	3	0	0
Nebraska	9,803	12,365	-21.0%	9,237	11,754	0	0	0	0	567	610
North Dakota	20,498	20,090	2.0%	20,498	20,090	0	0	0	0	0	0
South Dakota	1,087	1,082	0.4%	1,087	1,082	0	0	0	0	0	0
South Atlantic	44,613	52,480	-15.0%	40,845	47,058	3,447	5,006	0	0	321	416
Delaware	0	95	-100.0%	0	0	0	95	0	0	0	0
District of Columbia	0	0	--	0	0	0	0	0	0	0	0
Florida	3,625	5,943	-39.0%	3,595	5,913	0	0	0	0	30	30
Georgia	8,291	10,336	-20.0%	8,178	10,204	0	0	0	0	113	132
Maryland	703	1,135	-38.0%	0	0	703	1,135	0	0	0	0
North Carolina	6,460	5,608	15.0%	6,460	5,531	0	0	0	0	0	77
South Carolina	6,778	7,443	-8.9%	6,756	7,319	0	88	0	0	22	37
Virginia	1,118	1,089	2.7%	962	949	0	0	0	0	156	140
West Virginia	17,638	20,830	-15.0%	14,894	17,142	2,744	3,688	0	0	0	0
East South Central	43,938	47,995	-8.5%	41,355	44,448	1,867	2,926	0	0	716	622
Alabama	10,876	13,185	-18.0%	10,876	13,185	0	0	0	0	0	0
Kentucky	25,989	27,297	-4.8%	25,989	27,297	0	0	0	0	0	0
Mississippi	2,869	4,098	-30.0%	1,002	1,172	1,867	2,926	0	0	0	0
Tennessee	4,203	3,415	23.0%	3,488	2,793	0	0	0	0	716	622
West South Central	60,627	76,160	-20.0%	24,949	36,967	35,615	39,009	0	0	63	184
Arkansas	8,762	11,174	-22.0%	7,108	9,042	1,607	2,076	0	0	47	56
Louisiana	3,134	4,928	-36.0%	1,743	2,906	1,391	2,022	0	0	0	0
Oklahoma	3,250	5,869	-45.0%	3,235	5,741	0	0	0	0	15	129
Texas	45,481	54,190	-16.0%	12,864	19,279	32,617	34,911	0	0	0	0
Mountain	55,176	60,535	-8.9%	47,600	51,947	7,576	8,589	0	0	0	0
Arizona	6,244	8,510	-27.0%	6,244	8,510	0	0	0	0	0	0
Colorado	9,556	12,453	-23.0%	9,556	12,453	0	0	0	0	0	0
Idaho	0	0	--	0	0	0	0	0	0	0	0
Montana	6,096	7,092	-14.0%	0	0	6,096	7,092	0	0	0	0
Nevada	1,699	1,467	16.0%	1,036	800	662	667	0	0	0	0
New Mexico	4,630	3,504	32.0%	4,630	3,504	0	0	0	0	0	0
Utah	9,452	7,177	32.0%	9,060	6,843	392	334	0	0	0	0
Wyoming	17,499	20,333	-14.0%	17,074	19,838	425	495	0	0	0	0
Pacific Contiguous	2,196	3,135	-30.0%	0	0	1,629	2,599	0	0	566	536
California	566	536	5.6%	0	0	0	0	0	0	566	536
Oregon	0	0	--	0	0	0	0	0	0	0	0
Washington	1,629	2,599	-37.0%	0	0	1,629	2,599	0	0	0	0
Pacific Noncontiguous	386	342	13.0%	386	342	0	0	0	0	0	0
Alaska	386	342	13.0%	386	342	0	0	0	0	0	0
Hawaii	0	0	--	0	0	0	0	0	0	0	0
U.S. Total	369,134	431,375	-14.0%	277,592	326,208	85,656	98,990	6	3	5,880	6,174

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Notes:

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Totals may not equal sum of components because of independent rounding. Percentage change is calculated before rounding.

Coal includes anthracite, bituminous, subbituminous, lignite, waste coal, and coal-derived synthesis gas.

Source: U.S. Energy Information Administration, Form EIA-923, "Power Plant Operations Report."

Table 7.14. Receipts of Petroleum Liquids Delivered for Electricity Generation by State, 2024 and 2023
(Thousand Barrels)

Census Division and State				Electric Power Sector							
	All Sectors			Electric Utilities		Independent Power Producers		Commercial Sector		Industrial Sector	
	Year 2024	Year 2023	Percentage Change	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023
New England	421	987	-57.0%	61	101	360	885	0	0	0	0
Connecticut	92	100	-8.0%	0	0	92	100	0	0	0	0
Maine	103	331	-69.0%	0	0	103	331	0	0	0	0
Massachusetts	76	336	-77.0%	61	101	14	234	0	0	0	0
New Hampshire	135	164	-17.0%	0	0	135	164	0	0	0	0
Rhode Island	14	55	-74.0%	0	0	14	55	0	0	0	0
Vermont	0	0	--	0	0	0	0	0	0	0	0
Middle Atlantic	369	1,768	-79.0%	96	806	212	897	0	0	61	65
New Jersey	16	28	-45.0%	0	0	16	28	0	0	0	0
New York	160	1,355	-88.0%	96	806	64	549	0	0	0	0
Pennsylvania	193	384	-50.0%	0	0	132	320	0	0	61	64
East North Central	726	831	-13.0%	401	510	280	269	0	0	45	51
Illinois	76	78	-2.8%	20	21	56	56	0	0	0	0
Indiana	185	185	0.1%	185	185	0	0	0	0	0	0
Michigan	153	251	-39.0%	139	223	0	0	0	0	14	28
Ohio	289	297	-2.5%	34	61	224	213	0	0	31	23
Wisconsin	22	20	14.0%	22	20	0	0	0	0	0	0
West North Central	871	950	-8.4%	871	950	0	1	0	0	0	0
Iowa	106	115	-7.6%	106	115	0	0	0	0	0	0
Kansas	245	152	60.0%	245	152	0	0	0	0	0	0
Minnesota	28	154	-82.0%	28	154	0	1	0	0	0	0
Missouri	368	390	-5.6%	368	390	0	0	0	0	0	0
Nebraska	24	22	6.3%	24	22	0	0	0	0	0	0
North Dakota	90	105	-14.0%	90	105	0	0	0	0	0	0
South Dakota	10	12	-13.0%	10	12	0	0	0	0	0	0
South Atlantic	1,794	2,905	-38.0%	1,043	2,063	514	495	0	0	237	347
Delaware	18	86	-80.0%	0	0	18	86	0	0	0	0
District of Columbia	0	0	--	0	0	0	0	0	0	0	0
Florida	192	745	-74.0%	171	661	0	55	0	0	21	29
Georgia	283	438	-35.0%	116	263	12	9	0	0	155	166
Maryland	416	211	97.0%	0	0	416	211	0	0	0	0
North Carolina	111	348	-68.0%	111	266	0	0	0	0	0	82
South Carolina	190	228	-17.0%	162	186	0	12	0	0	28	30
Virginia	384	530	-28.0%	283	400	69	91	0	0	32	39
West Virginia	201	317	-37.0%	201	287	0	30	0	0	0	0
East South Central	184	515	-64.0%	181	510	0	0	0	0	3	5
Alabama	10	52	-80.0%	10	52	0	0	0	0	0	0
Kentucky	140	184	-24.0%	140	184	0	0	0	0	0	0
Mississippi	10	7	48.0%	10	7	0	0	0	0	0	0
Tennessee	24	273	-91.0%	21	267	0	0	0	0	3	5
West South Central	461	490	-5.9%	245	165	217	325	0	0	0	0
Arkansas	91	83	9.8%	73	62	17	21	0	0	0	0
Louisiana	17	12	45.0%	17	12	0	0	0	0	0	0
Oklahoma	35	45	-23.0%	35	45	0	0	0	0	0	0
Texas	319	351	-9.1%	119	46	199	304	0	0	0	0
Mountain	236	221	6.3%	207	200	28	21	0	0	0	0
Arizona	46	56	-17.0%	46	56	0	0	0	0	0	0
Colorado	25	18	41.0%	25	18	0	0	0	0	0	0
Idaho	0	0	--	0	0	0	0	0	0	0	0
Montana	35	13	175.0%	12	0	24	13	0	0	0	0
Nevada	12	16	-27.0%	10	13	2	3	0	0	0	0
New Mexico	0	0	--	0	0	0	0	0	0	0	0
Utah	52	37	40.0%	50	32	2	5	0	0	0	0
Wyoming	65	81	-20.0%	65	81	0	0	0	0	0	0
Pacific Contiguous	43	43	2.0%	29	32	15	11	0	0	0	0
California	0	0	--	0	0	0	0	0	0	0	0
Oregon	0	0	--	0	0	0	0	0	0	0	0
Washington	43	43	2.0%	29	32	15	11	0	0	0	0
Pacific Noncontiguous	9,404	9,631	-2.4%	7,345	7,686	2,059	1,945	0	0	0	0
Alaska	14	18	-23.0%	14	18	0	0	0	0	0	0
Hawaii	9,390	9,614	-2.3%	7,332	7,669	2,059	1,945	0	0	0	0
U.S. Total	14,510	18,341	-21.0%	10,480	13,023	3,685	4,849	0	0	346	468

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 Totals may not equal sum of components because of independent rounding. Percentage change is calculated before rounding.
 Petroleum Liquids includes distillate and residual fuel oils.
 See the Technical Notes for fuel conversion factors.

Source: U.S. Energy Information Administration, Form EIA-923, "Power Plant Operations Report."

Table 7.15. Receipts of Petroleum Coke Delivered for Electricity Generation by State, 2024 and 2023
(Thousand Tons)

Census Division and State				Electric Power Sector							
	All Sectors			Electric Utilities		Independent Power Producers		Commercial Sector		Industrial Sector	
	Year 2024	Year 2023	Percentage Change	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023
New England	0	0	--	0	0	0	0	0	0	0	0
Connecticut	0	0	--	0	0	0	0	0	0	0	0
Maine	0	0	--	0	0	0	0	0	0	0	0
Massachusetts	0	0	--	0	0	0	0	0	0	0	0
New Hampshire	0	0	--	0	0	0	0	0	0	0	0
Rhode Island	0	0	--	0	0	0	0	0	0	0	0
Vermont	0	0	--	0	0	0	0	0	0	0	0
Middle Atlantic	0	0	--	0	0	0	0	0	0	0	0
New Jersey	0	0	--	0	0	0	0	0	0	0	0
New York	0	0	--	0	0	0	0	0	0	0	0
Pennsylvania	0	0	--	0	0	0	0	0	0	0	0
East North Central	615	641	-4.2%	615	641	0	0	0	0	0	0
Illinois	0	0	--	0	0	0	0	0	0	0	0
Indiana	0	0	--	0	0	0	0	0	0	0	0
Michigan	612	619	-1.2%	612	619	0	0	0	0	0	0
Ohio	0	0	--	0	0	0	0	0	0	0	0
Wisconsin	3	22	-86.0%	3	22	0	0	0	0	0	0
West North Central	0	0	--	0	0	0	0	0	0	0	0
Iowa	0	0	--	0	0	0	0	0	0	0	0
Kansas	0	0	--	0	0	0	0	0	0	0	0
Minnesota	0	0	--	0	0	0	0	0	0	0	0
Missouri	0	0	--	0	0	0	0	0	0	0	0
Nebraska	0	0	--	0	0	0	0	0	0	0	0
North Dakota	0	0	--	0	0	0	0	0	0	0	0
South Dakota	0	0	--	0	0	0	0	0	0	0	0
South Atlantic	229	431	-47.0%	229	431	0	0	0	0	0	0
Delaware	0	0	--	0	0	0	0	0	0	0	0
District of Columbia	0	0	--	0	0	0	0	0	0	0	0
Florida	229	431	-47.0%	229	431	0	0	0	0	0	0
Georgia	0	0	--	0	0	0	0	0	0	0	0
Maryland	0	0	--	0	0	0	0	0	0	0	0
North Carolina	0	0	--	0	0	0	0	0	0	0	0
South Carolina	0	0	--	0	0	0	0	0	0	0	0
Virginia	0	0	--	0	0	0	0	0	0	0	0
West Virginia	0	0	--	0	0	0	0	0	0	0	0
East South Central	0	0	--	0	0	0	0	0	0	0	0
Alabama	0	0	--	0	0	0	0	0	0	0	0
Kentucky	0	0	--	0	0	0	0	0	0	0	0
Mississippi	0	0	--	0	0	0	0	0	0	0	0
Tennessee	0	0	--	0	0	0	0	0	0	0	0
West South Central	109	378	-71.0%	109	378	0	0	0	0	0	0
Arkansas	0	0	--	0	0	0	0	0	0	0	0
Louisiana	109	378	-71.0%	109	378	0	0	0	0	0	0
Oklahoma	0	0	--	0	0	0	0	0	0	0	0
Texas	0	0	--	0	0	0	0	0	0	0	0
Mountain	0	0	--	0	0	0	0	0	0	0	0
Arizona	0	0	--	0	0	0	0	0	0	0	0
Colorado	0	0	--	0	0	0	0	0	0	0	0
Idaho	0	0	--	0	0	0	0	0	0	0	0
Montana	0	0	--	0	0	0	0	0	0	0	0
Nevada	0	0	--	0	0	0	0	0	0	0	0
New Mexico	0	0	--	0	0	0	0	0	0	0	0
Utah	0	0	--	0	0	0	0	0	0	0	0
Wyoming	0	0	--	0	0	0	0	0	0	0	0
Pacific Contiguous	0	0	--	0	0	0	0	0	0	0	0
California	0	0	--	0	0	0	0	0	0	0	0
Oregon	0	0	--	0	0	0	0	0	0	0	0
Washington	0	0	--	0	0	0	0	0	0	0	0
Pacific Noncontiguous	0	0	--	0	0	0	0	0	0	0	0
Alaska	0	0	--	0	0	0	0	0	0	0	0
Hawaii	0	0	--	0	0	0	0	0	0	0	0
U.S. Total	953	1,450	-34.0%	953	1,450	0	0	0	0	0	0

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Totals may not equal sum of components because of independent rounding. Percentage change is calculated before rounding.

Petroleum Coke includes petroleum coke-derived synthesis gas.

See the Technical Notes for fuel conversion factors.

Source: U.S. Energy Information Administration, Form EIA-923, "Power Plant Operations Report."

Table 7.16. Receipts of Natural Gas Delivered for Electricity Generation by State, 2024 and 2023
(Million Cubic Feet)

Census Division and State	Electric Power Sector										
	All Sectors			Electric Utilities		Independent Power Producers		Commercial Sector		Industrial Sector	
	Year 2024	Year 2023	Percentage Change	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023
New England	423,716	400,731	5.7%	347	318	423,368	400,413	0	0	0	0
Connecticut	168,669	163,651	3.1%	0	0	168,669	163,651	0	0	0	0
Maine	43,467	26,981	61.0%	0	0	43,467	26,981	0	0	0	0
Massachusetts	114,967	106,804	7.6%	347	318	114,620	106,486	0	0	0	0
New Hampshire	31,526	30,878	2.1%	0	0	31,526	30,878	0	0	0	0
Rhode Island	65,086	72,417	-10.0%	0	0	65,086	72,417	0	0	0	0
Vermont	0	0	--	0	0	0	0	0	0	0	0
Middle Atlantic	1,682,696	1,613,381	4.3%	112,428	102,567	1,546,911	1,486,256	0	0	23,356	24,558
New Jersey	218,212	240,430	-9.2%	0	0	218,212	240,430	0	0	0	0
New York	475,862	433,635	9.7%	112,428	102,567	356,388	324,377	0	0	7,045	6,692
Pennsylvania	988,622	939,315	5.2%	0	0	972,311	921,449	0	0	16,311	17,866
East North Central	1,651,296	1,547,784	6.7%	655,446	596,441	988,555	925,377	5,228	5,488	22,067	20,478
Illinois	202,165	196,069	3.1%	21,028	19,106	175,098	170,809	0	0	6,039	6,154
Indiana	275,410	245,235	12.0%	155,680	127,925	119,731	117,310	0	0	0	0
Michigan	395,420	382,379	3.4%	214,369	207,219	171,219	164,590	5,228	5,488	4,604	5,082
Ohio	590,626	545,984	8.2%	81,324	67,570	502,508	472,668	0	0	6,794	5,745
Wisconsin	187,675	178,118	5.4%	183,045	174,621	0	0	0	0	4,630	3,498
West North Central	347,393	332,994	4.3%	289,328	273,532	49,742	51,408	2,317	2,372	6,007	5,683
Iowa	72,015	75,387	-4.5%	66,009	69,705	0	0	0	0	6,007	5,683
Kansas	44,659	34,113	31.0%	44,659	34,113	0	0	0	0	0	0
Minnesota	102,420	89,633	14.0%	67,423	56,907	34,980	32,709	16	17	0	0
Missouri	75,918	77,363	-1.9%	58,856	56,310	14,762	18,698	2,300	2,355	0	0
Nebraska	12,821	13,670	-6.2%	12,821	13,670	0	0	0	0	0	0
North Dakota	25,139	28,868	-13.0%	25,139	28,868	0	0	0	0	0	0
South Dakota	14,421	13,960	3.3%	14,421	13,960	0	0	0	0	0	0
South Atlantic	3,050,531	2,956,451	3.2%	2,557,166	2,481,716	454,802	438,180	0	0	38,564	36,555
Delaware	24,242	24,782	-2.2%	0	0	24,242	24,782	0	0	0	0
District of Columbia	0	0	--	0	0	0	0	0	0	0	0
Florida	1,428,330	1,377,415	3.7%	1,363,618	1,319,876	59,989	53,407	0	0	4,723	4,131
Georgia	410,473	442,228	-7.2%	340,633	359,343	58,880	72,776	0	0	10,960	10,108
Maryland	99,892	109,516	-8.8%	20,546	30,070	79,346	79,446	0	0	0	0
North Carolina	430,335	403,276	6.7%	369,735	341,075	60,600	61,117	0	0	0	1,084
South Carolina	169,953	188,627	-9.9%	161,819	183,305	5,416	3,086	0	0	2,718	2,236
Virginia	448,881	372,762	20.0%	295,424	242,564	140,695	117,904	0	0	12,761	12,294
West Virginia	38,425	37,846	1.5%	5,391	5,482	25,634	25,662	0	0	7,400	6,702
East South Central	1,160,002	1,069,590	8.5%	902,465	786,335	229,237	258,275	0	0	28,300	24,980
Alabama	436,723	428,575	1.9%	214,403	176,158	222,320	252,417	0	0	0	0
Kentucky	139,124	107,514	29.0%	132,332	101,821	6,792	5,692	0	0	0	0
Mississippi	438,365	404,871	8.3%	438,240	404,704	125	167	0	0	0	0
Tennessee	145,789	128,631	13.0%	117,490	103,651	0	0	0	0	28,300	24,980
West South Central	3,639,532	3,538,619	2.9%	1,350,215	1,250,595	1,642,022	1,630,050	0	0	647,295	657,974
Arkansas	172,753	188,168	-8.2%	158,827	173,665	10,477	11,743	0	0	3,449	2,759
Louisiana	590,712	582,914	1.3%	350,549	328,480	37,713	42,319	0	0	202,450	212,115
Oklahoma	361,359	344,298	5.0%	256,520	237,147	98,702	100,248	0	0	6,137	6,903
Texas	2,514,707	2,423,240	3.8%	584,318	511,303	1,495,130	1,475,740	0	0	435,260	436,196
Mountain	957,752	910,018	5.2%	789,327	740,999	168,053	168,870	0	0	372	149
Arizona	411,133	389,864	5.5%	293,122	279,143	118,011	110,721	0	0	0	0
Colorado	129,967	126,143	3.0%	108,565	108,562	21,401	17,581	0	0	0	0
Idaho	33,433	29,658	13.0%	24,216	17,468	9,217	12,190	0	0	0	0
Montana	5,793	6,226	-7.0%	5,743	6,171	50	56	0	0	0	0
Nevada	175,017	168,209	4.0%	175,017	168,209	0	0	0	0	0	0
New Mexico	85,286	99,119	-14.0%	65,925	70,806	19,361	28,313	0	0	0	0
Utah	76,661	76,793	-0.2%	76,289	76,644	0	0	0	0	372	149
Wyoming	40,463	14,005	189.0%	40,451	13,996	12	9	0	0	0	0
Pacific Contiguous	815,788	854,903	-4.6%	349,054	351,527	440,738	477,243	0	0	25,997	26,133
California	535,140	579,502	-7.7%	177,538	181,047	331,605	372,322	0	0	25,997	26,133
Oregon	174,285	161,864	7.7%	95,782	93,963	78,503	67,901	0	0	0	0
Washington	106,363	113,537	-6.3%	75,734	76,517	30,630	37,019	0	0	0	0
Pacific Noncontiguous	12,460	12,908	-3.5%	12,460	12,908	0	0	0	0	0	0
Alaska	12,460	12,908	-3.5%	12,460	12,908	0	0	0	0	0	0
Hawaii	0	0	--	0	0	0	0	0	0	0	0
U.S. Total	13,741,165	13,237,380	3.8%	7,018,235	6,596,937	5,923,429	5,836,072	7,544	7,861	791,957	796,511

Displayed values of zero may represent small values that round to zero.

NM = Not meaningful due to large relative standard error or excessive percentage change.

W = Withheld to avoid disclosure of individual company data.

Notes:

See Glossary for definitions. Values are final. See Technical Notes for a discussion of the sample design for the Form EIA-923.

Totals may not equal sum of components because of independent rounding. Percentage change is calculated before rounding.

Source: U.S. Energy Information Administration, Form EIA-923, "Power Plant Operations Report."

Table 7.17. Average Cost of Coal Delivered for Electricity Generation by State, 2024 and 2023
(Dollars per MMBtu)

Census Division and State	Electric Power Sector			Electric Utilities		Independent Power Producers	
	Year 2024	Year 2023	Percentage Change	Year 2024	Year 2023	Year 2024	Year 2023
New England	W	W	W	--	--	W	W
Connecticut	--	--	--	--	--	--	--
Maine	W	W	W	--	--	W	W
Massachusetts	--	--	--	--	--	--	--
New Hampshire	--	W	W	--	--	--	W
Rhode Island	--	--	--	--	--	--	--
Vermont	--	--	--	--	--	--	--
Middle Atlantic	2.23	2.31	-3.5%	--	--	2.23	2.31
New Jersey	--	--	--	--	--	--	--
New York	--	--	--	--	--	--	--
Pennsylvania	2.23	2.31	-3.5%	--	--	2.23	2.31
East North Central	2.41	2.54	-5.1%	2.59	2.69	2.12	2.32
Illinois	1.80	1.85	-2.7%	2.02	2.09	1.75	1.79
Indiana	W	W	W	2.87	2.99	W	W
Michigan	2.53	W	W	2.53	2.58	--	W
Ohio	2.55	2.67	-4.5%	2.77	2.56	2.50	2.69
Wisconsin	2.32	2.48	-6.5%	2.32	2.48	--	--
West North Central	1.81	1.83	-1.1%	1.81	1.83	--	--
Iowa	1.89	1.76	7.4%	1.89	1.76	--	--
Kansas	1.61	1.70	-5.3%	1.61	1.70	--	--
Minnesota	2.29	2.40	-4.6%	2.29	2.40	--	--
Missouri	1.84	1.92	-4.2%	1.84	1.92	--	--
Nebraska	1.32	1.33	-0.8%	1.32	1.33	--	--
North Dakota	1.90	1.86	2.2%	1.90	1.86	--	--
South Dakota	2.36	2.25	4.9%	2.36	2.25	--	--
South Atlantic	3.45	3.55	-2.8%	3.53	3.64	2.47	2.72
Delaware	--	W	W	--	--	--	W
District of Columbia	--	--	--	--	--	--	--
Florida	3.62	3.37	7.4%	3.62	3.37	--	--
Georgia	4.14	4.48	-7.6%	4.14	4.48	--	--
Maryland	W	W	W	--	--	W	W
North Carolina	4.50	4.68	-3.8%	4.50	4.68	--	--
South Carolina	3.28	W	W	3.28	3.57	--	W
Virginia	4.46	5.20	-14.0%	4.46	5.20	--	--
West Virginia	2.78	2.81	-1.1%	2.90	2.94	2.10	2.13
East South Central	W	W	W	2.54	2.74	W	W
Alabama	2.65	3.04	-13.0%	2.65	3.04	--	--
Kentucky	2.40	2.50	-4.0%	2.40	2.50	--	--
Mississippi	W	W	W	3.70	3.96	W	W
Tennessee	3.01	3.54	-15.0%	3.01	3.54	--	--
West South Central	2.10	2.17	-3.2%	2.08	2.21	2.12	2.12
Arkansas	W	W	W	2.02	2.19	W	W
Louisiana	W	W	W	2.80	2.97	W	W
Oklahoma	2.16	2.27	-4.8%	2.16	2.27	--	--
Texas	2.02	2.03	-0.5%	1.98	2.08	2.04	2.00
Mountain	2.61	W	W	2.69	2.39	2.05	W
Arizona	3.24	3.04	6.6%	3.24	3.04	--	--
Colorado	2.23	2.11	5.7%	2.23	2.11	--	--
Idaho	--	--	--	--	--	--	--
Montana	W	W	W	--	--	W	W
Nevada	W	W	W	4.52	5.15	W	W
New Mexico	3.66	3.57	2.5%	3.66	3.57	--	--
Utah	3.64	2.51	45.0%	3.64	2.51	--	--
Wyoming	W	W	W	1.71	1.88	W	W
Pacific Contiguous	W	W	W	--	--	W	W
California	--	--	--	--	--	--	--
Oregon	--	--	--	--	--	--	--
Washington	W	W	W	--	--	W	W
Pacific Noncontiguous	4.43	4.57	-3.1%	4.43	4.57	--	--
Alaska	4.43	4.57	-3.1%	4.43	4.57	--	--
Hawaii	--	--	--	--	--	--	--
U.S. Total	2.46	2.50	-1.6%	2.55	2.56	2.17	2.28

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Coal includes anthracite, bituminous, subbituminous, lignite, waste coal, and coal-derived synthesis gas.

Source: U.S. Energy Information Administration, Form EIA-923, "Power Plant Operations Report."

Table 7.18. Average Cost of Petroleum Liquids Delivered for Electricity Generation by State, 2024 and 2023
(Dollars per MMBtu)

Census Division and State	Electric Power Sector			Electric Utilities		Independent Power Producers	
	Year 2024	Year 2023	Percentage Change	Year 2024	Year 2023	Year 2024	Year 2023
New England	16.78	17.21	-2.5%	15.83	21.04	16.96	16.76
Connecticut	23.86	27.98	-15.0%	--	--	23.86	27.98
Maine	W	15.78	W	--	--	W	15.78
Massachusetts	W	W	W	15.83	21.04	W	W
New Hampshire	W	W	W	--	--	W	W
Rhode Island	W	W	W	--	--	W	W
Vermont	--	--	--	--	--	--	--
Middle Atlantic	18.37	19.57	-6.1%	18.48	18.25	18.32	21.05
New Jersey	W	23.54	W	--	--	W	23.54
New York	W	18.78	W	18.48	18.25	W	19.65
Pennsylvania	19.21	24.22	-21.0%	--	--	19.21	24.22
East North Central	18.34	20.20	-9.2%	18.05	19.82	18.75	20.95
Illinois	20.40	23.48	-13.0%	20.71	23.88	20.29	23.28
Indiana	18.25	21.24	-14.0%	18.25	21.24	--	--
Michigan	17.48	17.31	1.0%	17.48	17.31	--	--
Ohio	18.35	21.15	-13.0%	18.23	23.56	18.37	20.47
Wisconsin	17.35	19.67	-12.0%	17.35	19.67	--	--
West North Central	18.28	W	W	18.28	21.38	--	W
Iowa	18.35	21.80	-16.0%	18.35	21.80	--	--
Kansas	18.50	20.56	-10.0%	18.50	20.56	--	--
Minnesota	17.68	W	W	17.68	20.07	--	W
Missouri	18.12	22.06	-18.0%	18.12	22.06	--	--
Nebraska	17.84	21.75	-18.0%	17.84	21.75	--	--
North Dakota	18.93	21.07	-10.0%	18.93	21.07	--	--
South Dakota	15.16	24.42	-38.0%	15.16	24.42	--	--
South Atlantic	18.65	22.30	-16.0%	19.40	22.10	17.12	23.37
Delaware	W	W	W	--	--	W	W
District of Columbia	--	--	--	--	--	--	--
Florida	19.72	W	W	19.72	21.70	--	W
Georgia	22.43	W	W	22.43	24.66	--	W
Maryland	16.83	21.36	-21.0%	--	--	16.83	21.36
North Carolina	18.80	24.50	-23.0%	18.80	24.50	--	--
South Carolina	18.34	W	W	18.34	22.28	--	W
Virginia	W	W	W	19.62	19.71	W	W
West Virginia	18.27	W	W	18.27	21.71	--	W
East South Central	18.46	21.61	-15.0%	18.46	21.61	--	--
Alabama	19.27	23.02	-16.0%	19.27	23.02	--	--
Kentucky	18.54	22.14	-16.0%	18.54	22.14	--	--
Mississippi	18.63	20.99	-11.0%	18.63	20.99	--	--
Tennessee	17.38	20.98	-17.0%	17.38	20.98	--	--
West South Central	18.86	22.02	-14.0%	18.42	21.55	19.36	22.26
Arkansas	W	W	W	18.42	22.02	W	W
Louisiana	16.53	19.58	-16.0%	16.53	19.58	--	--
Oklahoma	17.77	22.10	-20.0%	17.77	22.10	--	--
Texas	19.16	22.04	-13.0%	18.82	20.90	19.37	22.22
Mountain	W	24.78	W	20.19	24.67	W	25.81
Arizona	21.56	23.97	-10.0%	21.56	23.97	--	--
Colorado	19.63	26.51	-26.0%	19.63	26.51	--	--
Idaho	--	--	--	--	--	--	--
Montana	W	W	W	20.32	--	W	W
Nevada	W	W	W	22.74	26.76	W	W
New Mexico	--	--	--	--	--	--	--
Utah	W	W	W	19.42	24.65	W	W
Wyoming	19.60	24.40	-20.0%	19.60	24.40	--	--
Pacific Contiguous	W	W	W	24.76	25.90	W	W
California	--	--	--	--	--	--	--
Oregon	--	--	--	--	--	--	--
Washington	W	W	W	24.76	25.90	W	W
Pacific Noncontiguous	W	W	W	17.99	20.02	W	W
Alaska	21.28	25.12	-15.0%	21.28	25.12	--	--
Hawaii	W	W	W	17.98	20.01	W	W
U.S. Total	18.33	20.51	-11.0%	18.22	20.48	18.64	20.59

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Petroleum Liquids includes distillate and residual fuel oils.

See the Technical Notes for fuel conversion factors.

Source: U.S. Energy Information Administration, Form EIA-923, "Power Plant Operations Report."

Table 7.19. Average Cost of Petroleum Coke Delivered for Electricity Generation by State, 2024 and 2023
(Dollars per MMBtu)

Census Division and State	Electric Power Sector			Electric Utilities		Independent Power Producers	
	Year 2024	Year 2023	Percentage Change	Year 2024	Year 2023	Year 2024	Year 2023
New England	--	--	--	--	--	--	--
Connecticut	--	--	--	--	--	--	--
Maine	--	--	--	--	--	--	--
Massachusetts	--	--	--	--	--	--	--
New Hampshire	--	--	--	--	--	--	--
Rhode Island	--	--	--	--	--	--	--
Vermont	--	--	--	--	--	--	--
Middle Atlantic	--	--	--	--	--	--	--
New Jersey	--	--	--	--	--	--	--
New York	--	--	--	--	--	--	--
Pennsylvania	--	--	--	--	--	--	--
East North Central	2.63	2.97	-11.0%	2.63	2.97	--	--
Illinois	--	--	--	--	--	--	--
Indiana	--	--	--	--	--	--	--
Michigan	2.63	2.89	-9.0%	2.63	2.89	--	--
Ohio	--	--	--	--	--	--	--
Wisconsin	2.36	5.15	-54.0%	2.36	5.15	--	--
West North Central	--	--	--	--	--	--	--
Iowa	--	--	--	--	--	--	--
Kansas	--	--	--	--	--	--	--
Minnesota	--	--	--	--	--	--	--
Missouri	--	--	--	--	--	--	--
Nebraska	--	--	--	--	--	--	--
North Dakota	--	--	--	--	--	--	--
South Dakota	--	--	--	--	--	--	--
South Atlantic	3.64	5.20	-30.0%	3.64	5.20	--	--
Delaware	--	--	--	--	--	--	--
District of Columbia	--	--	--	--	--	--	--
Florida	3.64	5.20	-30.0%	3.64	5.20	--	--
Georgia	--	--	--	--	--	--	--
Maryland	--	--	--	--	--	--	--
North Carolina	--	--	--	--	--	--	--
South Carolina	--	--	--	--	--	--	--
Virginia	--	--	--	--	--	--	--
West Virginia	--	--	--	--	--	--	--
East South Central	--	--	--	--	--	--	--
Alabama	--	--	--	--	--	--	--
Kentucky	--	--	--	--	--	--	--
Mississippi	--	--	--	--	--	--	--
Tennessee	--	--	--	--	--	--	--
West South Central	3.34	4.49	-26.0%	3.34	4.49	--	--
Arkansas	--	--	--	--	--	--	--
Louisiana	3.34	4.49	-26.0%	3.34	4.49	--	--
Oklahoma	--	--	--	--	--	--	--
Texas	--	--	--	--	--	--	--
Mountain	--	--	--	--	--	--	--
Arizona	--	--	--	--	--	--	--
Colorado	--	--	--	--	--	--	--
Idaho	--	--	--	--	--	--	--
Montana	--	--	--	--	--	--	--
Nevada	--	--	--	--	--	--	--
New Mexico	--	--	--	--	--	--	--
Utah	--	--	--	--	--	--	--
Wyoming	--	--	--	--	--	--	--
Pacific Contiguous	--	--	--	--	--	--	--
California	--	--	--	--	--	--	--
Oregon	--	--	--	--	--	--	--
Washington	--	--	--	--	--	--	--
Pacific Noncontiguous	--	--	--	--	--	--	--
Alaska	--	--	--	--	--	--	--
Hawaii	--	--	--	--	--	--	--
U.S. Total	2.96	4.05	-27.0%	2.96	4.05	--	--

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Petroleum Coke includes petroleum coke-derived synthesis gas.

See the Technical Notes for fuel conversion factors.

Source: U.S. Energy Information Administration, Form EIA-923, "Power Plant Operations Report."

Table 7.20. Average Cost of Natural Gas Delivered for Electricity Generation by State, 2024 and 2023
(Dollars per MMBtu)

Census Division and State	Electric Power Sector			Electric Utilities		Independent Power Producers	
	Year 2024	Year 2023	Percentage Change	Year 2024	Year 2023	Year 2024	Year 2023
New England	3.60	4.43	-19.0%	3.37	5.70	3.60	4.43
Connecticut	3.06	3.75	-18.0%	--	--	3.06	3.75
Maine	W	W	W	--	--	W	W
Massachusetts	4.85	6.91	-30.0%	3.37	5.70	4.85	6.92
New Hampshire	W	W	W	--	--	W	W
Rhode Island	2.95	2.97	-0.7%	--	--	2.95	2.97
Vermont	--	--	--	--	--	--	--
Middle Atlantic	2.28	2.32	-1.7%	2.63	3.07	2.24	2.26
New Jersey	2.34	2.07	13.0%	--	--	2.34	2.07
New York	2.71	2.93	-7.5%	2.63	3.07	2.73	2.87
Pennsylvania	2.03	2.09	-2.9%	--	--	2.03	2.09
East North Central	2.38	2.67	-11.0%	2.60	3.14	2.23	2.37
Illinois	2.39	2.55	-6.3%	2.35	2.84	2.40	2.52
Indiana	2.48	2.88	-14.0%	2.68	3.12	2.22	2.63
Michigan	2.36	2.69	-12.0%	2.51	2.80	2.18	2.55
Ohio	2.23	2.24	-0.4%	2.46	2.50	2.20	2.20
Wisconsin	2.74	3.84	-29.0%	2.74	3.84	--	--
West North Central	2.77	3.31	-16.0%	2.79	3.38	2.56	2.69
Iowa	2.47	2.92	-15.0%	2.47	2.92	--	--
Kansas	2.70	3.07	-12.0%	2.70	3.07	--	--
Minnesota	W	W	W	3.04	4.94	W	W
Missouri	W	W	W	2.82	2.85	W	W
Nebraska	4.16	3.45	21.0%	4.16	3.45	--	--
North Dakota	2.57	2.74	-6.2%	2.57	2.74	--	--
South Dakota	2.53	3.35	-24.0%	2.53	3.35	--	--
South Atlantic	3.51	3.84	-8.6%	3.64	3.99	2.62	2.81
Delaware	--	--	--	--	--	--	--
District of Columbia	--	--	--	--	--	--	--
Florida	3.62	3.99	-9.3%	3.64	4.00	2.93	3.47
Georgia	W	W	W	2.93	3.05	W	W
Maryland	3.04	2.90	4.8%	2.83	2.45	3.09	3.07
North Carolina	W	4.97	W	4.79	5.35	W	2.79
South Carolina	3.59	3.95	-9.1%	3.59	3.95	--	--
Virginia	2.85	3.30	-14.0%	3.10	3.71	2.17	2.18
West Virginia	1.91	W	W	2.22	1.93	1.84	W
East South Central	2.77	2.92	-5.1%	2.77	2.94	2.77	2.84
Alabama	2.77	3.00	-7.7%	2.77	3.18	2.78	2.85
Kentucky	W	W	W	3.11	3.41	W	W
Mississippi	W	W	W	2.70	2.75	W	W
Tennessee	2.64	2.83	-6.7%	2.64	2.83	--	--
West South Central	2.34	2.66	-12.0%	2.53	2.79	2.15	2.55
Arkansas	W	W	W	2.72	2.69	W	W
Louisiana	2.60	2.80	-7.1%	2.64	2.84	2.29	2.50
Oklahoma	W	W	W	3.23	2.97	W	W
Texas	2.13	2.60	-18.0%	2.10	2.70	2.15	2.56
Mountain	2.47	5.12	-52.0%	2.46	5.19	2.58	4.51
Arizona	2.24	4.30	-48.0%	2.19	4.16	2.51	4.86
Colorado	W	W	W	2.64	3.84	W	W
Idaho	2.88	6.57	-56.0%	2.88	6.57	--	--
Montana	W	W	W	1.41	2.29	W	W
Nevada	2.97	7.23	-59.0%	2.97	7.23	--	--
New Mexico	0.99	2.62	-62.0%	0.99	2.62	--	--
Utah	3.14	7.98	-61.0%	3.14	7.98	--	--
Wyoming	W	W	W	2.52	6.91	W	W
Pacific Contiguous	3.32	6.39	-48.0%	3.42	6.78	3.18	5.87
California	3.85	7.31	-47.0%	4.25	8.33	3.43	6.41
Oregon	W	W	W	2.21	5.07	W	W
Washington	W	W	W	3.28	5.78	W	W
Pacific Noncontiguous	6.38	7.29	-12.0%	6.38	7.29	--	--
Alaska	6.38	7.29	-12.0%	6.38	7.29	--	--
Hawaii	--	--	--	--	--	--	--
U.S. Total	2.77	3.39	-18.0%	3.03	3.81	2.41	2.82

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Source: U.S. Energy Information Administration, Form EIA-923, "Power Plant Operations Report."

Table 7.21. Receipts and Quality of Coal by Rank Delivered for Electricity Generation:
Total (All Sectors) by State, 2024

Census Division and State	Bituminous			Subbituminous			Lignite		
	Receipts (Thousand Tons)	Average Sulfur Percent by Weight	Average Ash Percent by Weight	Receipts (Thousand Tons)	Average Sulfur Percent by Weight	Average Ash Percent by Weight	Receipts (Thousand Tons)	Average Sulfur Percent by Weight	Average Ash Percent by Weight
New England	42	0.97	5.1	0	--	--	0	--	--
Connecticut	0	--	--	0	--	--	0	--	--
Maine	42	0.97	5.1	0	--	--	0	--	--
Massachusetts	0	--	--	0	--	--	0	--	--
New Hampshire	0	--	--	0	--	--	0	--	--
Rhode Island	0	--	--	0	--	--	0	--	--
Vermont	0	--	--	0	--	--	0	--	--
Middle Atlantic	2,377	2.68	8.1	0	--	--	0	--	--
New Jersey	0	--	--	0	--	--	0	--	--
New York	0	--	--	0	--	--	0	--	--
Pennsylvania	2,377	2.68	8.1	0	--	--	0	--	--
East North Central	39,211	3.14	11.2	35,871	0.25	4.7	0	--	--
Illinois	8,268	3.38	22.1	12,742	0.23	4.6	0	--	--
Indiana	16,640	2.92	9.2	439	0.26	4.7	0	--	--
Michigan	1,097	2.37	7.8	12,667	0.26	4.7	0	--	--
Ohio	12,622	3.39	8.8	0	--	--	0	--	--
Wisconsin	584	2.57	7.8	10,024	0.25	4.8	0	--	--
West North Central	466	3.21	8.6	58,320	0.26	4.9	20,386	0.77	10.7
Iowa	186	3.65	8.7	9,742	0.27	4.8	0	--	--
Kansas	0	--	--	9,142	0.27	5.1	0	--	--
Minnesota	0	--	--	6,583	0.27	5.0	0	--	--
Missouri	280	2.93	8.5	21,963	0.23	4.7	0	--	--
Nebraska	0	--	--	9,803	0.27	5.1	0	--	--
North Dakota	0	--	--	0	--	--	20,386	0.77	10.7
South Dakota	0	--	--	1,087	0.33	5.3	0	--	--
South Atlantic	39,465	2.51	9.9	4,608	0.35	5.3	0	--	--
Delaware	0	--	--	0	--	--	0	--	--
District of Columbia	0	--	--	0	--	--	0	--	--
Florida	3,625	2.83	8.9	0	--	--	0	--	--
Georgia	3,683	2.55	9.0	4,608	0.35	5.3	0	--	--
Maryland	703	2.76	8.9	0	--	--	0	--	--
North Carolina	6,460	1.54	10.1	0	--	--	0	--	--
South Carolina	6,778	2.02	9.2	0	--	--	0	--	--
Virginia	1,118	1.00	20.8	0	--	--	0	--	--
West Virginia	17,098	3.05	9.9	0	--	--	0	--	--
East South Central	23,918	2.83	9.7	18,153	0.25	4.9	1,867	0.57	14.1
Alabama	1,072	1.21	13.0	9,804	0.27	5.0	0	--	--
Kentucky	19,588	2.99	9.7	6,401	0.22	4.8	0	--	--
Mississippi	207	1.79	10.6	795	0.23	4.7	1,867	0.57	14.1
Tennessee	3,051	2.42	8.7	1,153	0.22	4.9	0	--	--
West South Central	270	2.85	9.1	48,256	0.29	5.1	12,102	1.09	16.9
Arkansas	47	0.86	12.2	8,715	0.23	4.7	0	--	--
Louisiana	222	3.31	8.4	2,912	0.25	4.8	0	--	--
Oklahoma	0	--	--	3,250	0.25	5.2	0	--	--
Texas	0	--	--	33,379	0.32	5.3	12,102	1.09	16.9
Mountain	14,669	0.68	13.5	40,115	0.45	7.1	0	--	--
Arizona	0	--	--	6,244	0.47	8.9	0	--	--
Colorado	841	0.43	10.5	8,715	0.31	6.4	0	--	--
Idaho	0	--	--	0	--	--	0	--	--
Montana	5	0.45	5.7	6,091	0.71	8.9	0	--	--
Nevada	562	0.39	7.3	1,137	0.38	4.6	0	--	--
New Mexico	4,630	0.83	19.5	0	--	--	0	--	--
Utah	8,631	0.65	11.5	429	0.25	5.0	0	--	--
Wyoming	0	--	--	17,499	0.42	6.5	0	--	--
Pacific Contiguous	566	0.37	6.7	1,629	0.38	8.2	0	--	--
California	566	0.37	6.7	0	--	--	0	--	--
Oregon	0	--	--	0	--	--	0	--	--
Washington	0	--	--	1,629	0.38	8.2	0	--	--
Pacific Noncontiguous	0	--	--	0	--	--	321	0.14	7.9
Alaska	0	--	--	0	--	--	321	0.14	7.9
Hawaii	0	--	--	0	--	--	0	--	--
U.S. Total	120,985	2.57	10.6	206,952	0.30	5.4	34,677	0.87	13.0

Displayed values of zero may represent small values that round to zero.
NM = Not meaningful due to large relative standard error or excessive percentage change.
W = Withheld to avoid disclosure of individual company data.

Notes:
Bituminous coal includes anthracite coal and coal-derived synthesis gas.
See Glossary for definitions. Values are final. See Technical Notes for a discussion of the sample design for the Form EIA-923.

Source: U.S. Energy Information Administration, Form EIA-923, "Power Plant Operations Report."

**Table 7.22. Receipts and Quality of Coal by Rank Delivered for Electricity Generation:
Electric Utilities by State, 2024**

Census Division and State	Bituminous			Subbituminous			Lignite		
	Receipts (Thousand Tons)	Average Sulfur Percent by Weight	Average Ash Percent by Weight	Receipts (Thousand Tons)	Average Sulfur Percent by Weight	Average Ash Percent by Weight	Receipts (Thousand Tons)	Average Sulfur Percent by Weight	Average Ash Percent by Weight
New England	0	--	--	0	--	--	0	--	--
Connecticut	0	--	--	0	--	--	0	--	--
Maine	0	--	--	0	--	--	0	--	--
Massachusetts	0	--	--	0	--	--	0	--	--
New Hampshire	0	--	--	0	--	--	0	--	--
Rhode Island	0	--	--	0	--	--	0	--	--
Vermont	0	--	--	0	--	--	0	--	--
Middle Atlantic	0	--	--	0	--	--	0	--	--
New Jersey	0	--	--	0	--	--	0	--	--
New York	0	--	--	0	--	--	0	--	--
Pennsylvania	0	--	--	0	--	--	0	--	--
East North Central	19,729	2.87	9.2	26,156	0.25	4.7	0	--	--
Illinois	807	2.57	10.9	3,026	0.21	4.6	0	--	--
Indiana	15,039	2.87	9.3	439	0.26	4.7	0	--	--
Michigan	1,097	2.37	7.8	12,667	0.26	4.7	0	--	--
Ohio	2,202	3.31	8.8	0	--	--	0	--	--
Wisconsin	584	2.57	7.8	10,024	0.25	4.8	0	--	--
West North Central	277	2.92	8.5	55,798	0.26	4.9	20,386	0.77	10.7
Iowa	2	3.16	8.7	7,786	0.27	4.8	0	--	--
Kansas	0	--	--	9,142	0.27	5.1	0	--	--
Minnesota	0	--	--	6,583	0.27	5.0	0	--	--
Missouri	275	2.92	8.5	21,963	0.23	4.7	0	--	--
Nebraska	0	--	--	9,237	0.27	5.1	0	--	--
North Dakota	0	--	--	0	--	--	20,386	0.77	10.7
South Dakota	0	--	--	1,087	0.33	5.3	0	--	--
South Atlantic	36,237	2.47	10.0	4,608	0.35	5.3	0	--	--
Delaware	0	--	--	0	--	--	0	--	--
District of Columbia	0	--	--	0	--	--	0	--	--
Florida	3,595	2.85	8.9	0	--	--	0	--	--
Georgia	3,570	2.60	9.0	4,608	0.35	5.3	0	--	--
Maryland	0	--	--	0	--	--	0	--	--
North Carolina	6,460	1.54	10.1	0	--	--	0	--	--
South Carolina	6,756	2.03	9.2	0	--	--	0	--	--
Virginia	962	0.98	23.7	0	--	--	0	--	--
West Virginia	14,894	3.01	10.1	0	--	--	0	--	--
East South Central	23,202	2.89	9.8	18,153	0.25	4.9	0	--	--
Alabama	1,072	1.21	13.0	9,804	0.27	5.0	0	--	--
Kentucky	19,588	2.99	9.7	6,401	0.22	4.8	0	--	--
Mississippi	207	1.79	10.6	795	0.23	4.7	0	--	--
Tennessee	2,335	2.91	8.9	1,153	0.22	4.9	0	--	--
West South Central	222	3.31	8.4	23,256	0.26	4.9	1,471	2.36	29.5
Arkansas	0	--	--	7,108	0.23	4.7	0	--	--
Louisiana	222	3.31	8.4	1,521	0.21	4.6	0	--	--
Oklahoma	0	--	--	3,235	0.25	5.2	0	--	--
Texas	0	--	--	11,393	0.30	5.1	1,471	2.36	29.5
Mountain	14,664	0.68	13.5	32,936	0.40	6.9	0	--	--
Arizona	0	--	--	6,244	0.47	8.9	0	--	--
Colorado	841	0.43	10.5	8,715	0.31	6.4	0	--	--
Idaho	0	--	--	0	--	--	0	--	--
Montana	0	--	--	0	--	--	0	--	--
Nevada	562	0.39	7.3	474	0.51	4.0	0	--	--
New Mexico	4,630	0.83	19.5	0	--	--	0	--	--
Utah	8,631	0.65	11.5	429	0.25	5.0	0	--	--
Wyoming	0	--	--	17,074	0.42	6.5	0	--	--
Pacific Contiguous	0	--	--	0	--	--	0	--	--
California	0	--	--	0	--	--	0	--	--
Oregon	0	--	--	0	--	--	0	--	--
Washington	0	--	--	0	--	--	0	--	--
Pacific Noncontiguous	0	--	--	0	--	--	321	0.14	7.9
Alaska	0	--	--	0	--	--	321	0.14	7.9
Hawaii	0	--	--	0	--	--	0	--	--
U.S. Total	94,331	2.41	10.2	160,906	0.29	5.3	22,178	0.84	11.6

Displayed values of zero may represent small values that round to zero.
 NM = Not meaningful due to large relative standard error or excessive percentage change.
 W = Withheld to avoid disclosure of individual company data.

Notes:
 Bituminous coal includes anthracite coal and coal-derived synthesis gas.
 See Glossary for definitions. Values are final. See Technical Notes for a discussion of the sample design for the Form EIA-923.

Source: U.S. Energy Information Administration, Form EIA-923, "Power Plant Operations Report."

**Table 7.23. Receipts and Quality of Coal by Rank Delivered for Electricity Generation:
Independent Power Producers by State, 2024**

Census Division and State	Bituminous			Subbituminous			Lignite		
	Receipts (Thousand Tons)	Average Sulfur Percent by Weight	Average Ash Percent by Weight	Receipts (Thousand Tons)	Average Sulfur Percent by Weight	Average Ash Percent by Weight	Receipts (Thousand Tons)	Average Sulfur Percent by Weight	Average Ash Percent by Weight
New England	42	0.97	5.1	0	--	--	0	--	--
Connecticut	0	--	--	0	--	--	0	--	--
Maine	42	0.97	5.1	0	--	--	0	--	--
Massachusetts	0	--	--	0	--	--	0	--	--
New Hampshire	0	--	--	0	--	--	0	--	--
Rhode Island	0	--	--	0	--	--	0	--	--
Vermont	0	--	--	0	--	--	0	--	--
Middle Atlantic	2,270	2.71	8.1	0	--	--	0	--	--
New Jersey	0	--	--	0	--	--	0	--	--
New York	0	--	--	0	--	--	0	--	--
Pennsylvania	2,270	2.71	8.1	0	--	--	0	--	--
East North Central	18,753	3.41	13.5	9,043	0.23	4.6	0	--	--
Illinois	6,732	3.47	25.5	9,043	0.23	4.6	0	--	--
Indiana	1,601	3.29	8.1	0	--	--	0	--	--
Michigan	0	--	--	0	--	--	0	--	--
Ohio	10,420	3.41	8.8	0	--	--	0	--	--
Wisconsin	0	--	--	0	--	--	0	--	--
West North Central	0	--	--	0	--	--	0	--	--
Iowa	0	--	--	0	--	--	0	--	--
Kansas	0	--	--	0	--	--	0	--	--
Minnesota	0	--	--	0	--	--	0	--	--
Missouri	0	--	--	0	--	--	0	--	--
Nebraska	0	--	--	0	--	--	0	--	--
North Dakota	0	--	--	0	--	--	0	--	--
South Dakota	0	--	--	0	--	--	0	--	--
South Atlantic	2,908	3.21	8.9	0	--	--	0	--	--
Delaware	0	--	--	0	--	--	0	--	--
District of Columbia	0	--	--	0	--	--	0	--	--
Florida	0	--	--	0	--	--	0	--	--
Georgia	0	--	--	0	--	--	0	--	--
Maryland	703	2.76	8.9	0	--	--	0	--	--
North Carolina	0	--	--	0	--	--	0	--	--
South Carolina	0	--	--	0	--	--	0	--	--
Virginia	0	--	--	0	--	--	0	--	--
West Virginia	2,205	3.36	8.8	0	--	--	0	--	--
East South Central	0	--	--	0	--	--	1,867	0.57	14.1
Alabama	0	--	--	0	--	--	0	--	--
Kentucky	0	--	--	0	--	--	0	--	--
Mississippi	0	--	--	0	--	--	1,867	0.57	14.1
Tennessee	0	--	--	0	--	--	0	--	--
West South Central	0	--	--	24,984	0.32	5.3	10,631	0.96	15.5
Arkansas	0	--	--	1,607	0.25	4.7	0	--	--
Louisiana	0	--	--	1,391	0.29	5.0	0	--	--
Oklahoma	0	--	--	0	--	--	0	--	--
Texas	0	--	--	21,986	0.33	5.4	10,631	0.96	15.5
Mountain	5	0.45	5.7	7,179	0.65	8.5	0	--	--
Arizona	0	--	--	0	--	--	0	--	--
Colorado	0	--	--	0	--	--	0	--	--
Idaho	0	--	--	0	--	--	0	--	--
Montana	5	0.45	5.7	6,091	0.71	8.9	0	--	--
Nevada	0	--	--	662	0.26	5.1	0	--	--
New Mexico	0	--	--	0	--	--	0	--	--
Utah	0	--	--	0	--	--	0	--	--
Wyoming	0	--	--	425	0.49	6.9	0	--	--
Pacific Contiguous	0	--	--	1,629	0.38	8.2	0	--	--
California	0	--	--	0	--	--	0	--	--
Oregon	0	--	--	0	--	--	0	--	--
Washington	0	--	--	1,629	0.38	8.2	0	--	--
Pacific Noncontiguous	0	--	--	0	--	--	0	--	--
Alaska	0	--	--	0	--	--	0	--	--
Hawaii	0	--	--	0	--	--	0	--	--
U.S. Total	23,978	3.31	12.3	42,836	0.36	5.8	12,498	0.91	15.4

Displayed values of zero may represent small values that round to zero.

NM = Not meaningful due to large relative standard error or excessive percentage change.

W = Withheld to avoid disclosure of individual company data.

Notes:

Bituminous coal includes anthracite coal and coal-derived synthesis gas.

See Glossary for definitions. Values are final. See Technical Notes for a discussion of the sample design for the Form EIA-923.

Source: U.S. Energy Information Administration, Form EIA-923, "Power Plant Operations Report."

Table 7.24. Receipts and Quality of Coal by Rank Delivered for Electricity Generation:
Commercial Sector by State, 2024

Census Division and State	Bituminous			Subbituminous			Lignite		
	Receipts (Thousand Tons)	Average Sulfur Percent by Weight	Average Ash Percent by Weight	Receipts (Thousand Tons)	Average Sulfur Percent by Weight	Average Ash Percent by Weight	Receipts (Thousand Tons)	Average Sulfur Percent by Weight	Average Ash Percent by Weight
New England	0	--	--	0	--	--	0	--	--
Connecticut	0	--	--	0	--	--	0	--	--
Maine	0	--	--	0	--	--	0	--	--
Massachusetts	0	--	--	0	--	--	0	--	--
New Hampshire	0	--	--	0	--	--	0	--	--
Rhode Island	0	--	--	0	--	--	0	--	--
Vermont	0	--	--	0	--	--	0	--	--
Middle Atlantic	0	--	--	0	--	--	0	--	--
New Jersey	0	--	--	0	--	--	0	--	--
New York	0	--	--	0	--	--	0	--	--
Pennsylvania	0	--	--	0	--	--	0	--	--
East North Central	0	--	--	0	--	--	0	--	--
Illinois	0	--	--	0	--	--	0	--	--
Indiana	0	--	--	0	--	--	0	--	--
Michigan	0	--	--	0	--	--	0	--	--
Ohio	0	--	--	0	--	--	0	--	--
Wisconsin	0	--	--	0	--	--	0	--	--
West North Central	6	3.06	9.3	0	--	--	0	--	--
Iowa	0	--	--	0	--	--	0	--	--
Kansas	0	--	--	0	--	--	0	--	--
Minnesota	0	--	--	0	--	--	0	--	--
Missouri	6	3.06	9.3	0	--	--	0	--	--
Nebraska	0	--	--	0	--	--	0	--	--
North Dakota	0	--	--	0	--	--	0	--	--
South Dakota	0	--	--	0	--	--	0	--	--
South Atlantic	0	--	--	0	--	--	0	--	--
Delaware	0	--	--	0	--	--	0	--	--
District of Columbia	0	--	--	0	--	--	0	--	--
Florida	0	--	--	0	--	--	0	--	--
Georgia	0	--	--	0	--	--	0	--	--
Maryland	0	--	--	0	--	--	0	--	--
North Carolina	0	--	--	0	--	--	0	--	--
South Carolina	0	--	--	0	--	--	0	--	--
Virginia	0	--	--	0	--	--	0	--	--
West Virginia	0	--	--	0	--	--	0	--	--
East South Central	0	--	--	0	--	--	0	--	--
Alabama	0	--	--	0	--	--	0	--	--
Kentucky	0	--	--	0	--	--	0	--	--
Mississippi	0	--	--	0	--	--	0	--	--
Tennessee	0	--	--	0	--	--	0	--	--
West South Central	0	--	--	0	--	--	0	--	--
Arkansas	0	--	--	0	--	--	0	--	--
Louisiana	0	--	--	0	--	--	0	--	--
Oklahoma	0	--	--	0	--	--	0	--	--
Texas	0	--	--	0	--	--	0	--	--
Mountain	0	--	--	0	--	--	0	--	--
Arizona	0	--	--	0	--	--	0	--	--
Colorado	0	--	--	0	--	--	0	--	--
Idaho	0	--	--	0	--	--	0	--	--
Montana	0	--	--	0	--	--	0	--	--
Nevada	0	--	--	0	--	--	0	--	--
New Mexico	0	--	--	0	--	--	0	--	--
Utah	0	--	--	0	--	--	0	--	--
Wyoming	0	--	--	0	--	--	0	--	--
Pacific Contiguous	0	--	--	0	--	--	0	--	--
California	0	--	--	0	--	--	0	--	--
Oregon	0	--	--	0	--	--	0	--	--
Washington	0	--	--	0	--	--	0	--	--
Pacific Noncontiguous	0	--	--	0	--	--	0	--	--
Alaska	0	--	--	0	--	--	0	--	--
Hawaii	0	--	--	0	--	--	0	--	--
U.S. Total	6	3.06	9.3	0	--	--	0	--	--

Displayed values of zero may represent small values that round to zero.
 NM = Not meaningful due to large relative standard error or excessive percentage change.
 W = Withheld to avoid disclosure of individual company data.

Notes:
 Bituminous coal includes anthracite coal and coal-derived synthesis gas.
 See Glossary for definitions. Values are final. See Technical Notes for a discussion of the sample design for the Form EIA-923.

Source: U.S. Energy Information Administration, Form EIA-923, "Power Plant Operations Report."

**Table 7.25. Receipts and Quality of Coal by Rank Delivered for Electricity Generation:
Industrial Sector by State, 2024**

Census Division and State	Bituminous			Subbituminous			Lignite		
	Receipts (Thousand Tons)	Average Sulfur Percent by Weight	Average Ash Percent by Weight	Receipts (Thousand Tons)	Average Sulfur Percent by Weight	Average Ash Percent by Weight	Receipts (Thousand Tons)	Average Sulfur Percent by Weight	Average Ash Percent by Weight
New England	0	--	--	0	--	--	0	--	--
Connecticut	0	--	--	0	--	--	0	--	--
Maine	0	--	--	0	--	--	0	--	--
Massachusetts	0	--	--	0	--	--	0	--	--
New Hampshire	0	--	--	0	--	--	0	--	--
Rhode Island	0	--	--	0	--	--	0	--	--
Vermont	0	--	--	0	--	--	0	--	--
Middle Atlantic	107	1.96	7.6	0	--	--	0	--	--
New Jersey	0	--	--	0	--	--	0	--	--
New York	0	--	--	0	--	--	0	--	--
Pennsylvania	107	1.96	7.6	0	--	--	0	--	--
East North Central	729	3.54	8.4	672	0.38	5.0	0	--	--
Illinois	729	3.54	8.4	672	0.38	5.0	0	--	--
Indiana	0	--	--	0	--	--	0	--	--
Michigan	0	--	--	0	--	--	0	--	--
Ohio	0	--	--	0	--	--	0	--	--
Wisconsin	0	--	--	0	--	--	0	--	--
West North Central	184	3.65	8.7	2,522	0.28	4.8	0	--	--
Iowa	184	3.65	8.7	1,955	0.28	4.8	0	--	--
Kansas	0	--	--	0	--	--	0	--	--
Minnesota	0	--	--	0	--	--	0	--	--
Missouri	0	--	--	0	--	--	0	--	--
Nebraska	0	--	--	567	0.28	4.8	0	--	--
North Dakota	0	--	--	0	--	--	0	--	--
South Dakota	0	--	--	0	--	--	0	--	--
South Atlantic	321	0.91	7.9	0	--	--	0	--	--
Delaware	0	--	--	0	--	--	0	--	--
District of Columbia	0	--	--	0	--	--	0	--	--
Florida	30	0.69	7.7	0	--	--	0	--	--
Georgia	113	0.77	8.3	0	--	--	0	--	--
Maryland	0	--	--	0	--	--	0	--	--
North Carolina	0	--	--	0	--	--	0	--	--
South Carolina	22	0.73	7.3	0	--	--	0	--	--
Virginia	156	1.07	7.8	0	--	--	0	--	--
West Virginia	0	--	--	0	--	--	0	--	--
East South Central	716	0.93	7.8	0	--	--	0	--	--
Alabama	0	--	--	0	--	--	0	--	--
Kentucky	0	--	--	0	--	--	0	--	--
Mississippi	0	--	--	0	--	--	0	--	--
Tennessee	716	0.93	7.8	0	--	--	0	--	--
West South Central	47	0.86	12.2	15	0.23	4.2	0	--	--
Arkansas	47	0.86	12.2	0	--	--	0	--	--
Louisiana	0	--	--	0	--	--	0	--	--
Oklahoma	0	--	--	15	0.23	4.2	0	--	--
Texas	0	--	--	0	--	--	0	--	--
Mountain	0	--	--	0	--	--	0	--	--
Arizona	0	--	--	0	--	--	0	--	--
Colorado	0	--	--	0	--	--	0	--	--
Idaho	0	--	--	0	--	--	0	--	--
Montana	0	--	--	0	--	--	0	--	--
Nevada	0	--	--	0	--	--	0	--	--
New Mexico	0	--	--	0	--	--	0	--	--
Utah	0	--	--	0	--	--	0	--	--
Wyoming	0	--	--	0	--	--	0	--	--
Pacific Contiguous	566	0.37	6.7	0	--	--	0	--	--
California	566	0.37	6.7	0	--	--	0	--	--
Oregon	0	--	--	0	--	--	0	--	--
Washington	0	--	--	0	--	--	0	--	--
Pacific Noncontiguous	0	--	--	0	--	--	0	--	--
Alaska	0	--	--	0	--	--	0	--	--
Hawaii	0	--	--	0	--	--	0	--	--
U.S. Total	2,671	1.70	7.9	3,210	0.30	4.8	0	--	--

Displayed values of zero may represent small values that round to zero.

NM = Not meaningful due to large relative standard error or excessive percentage change.

W = Withheld to avoid disclosure of individual company data.

Notes:

Bituminous coal includes anthracite coal and coal-derived synthesis gas.

See Glossary for definitions. Values are final. See Technical Notes for a discussion of the sample design for the Form EIA-923.

Source: U.S. Energy Information Administration, Form EIA-923, "Power Plant Operations Report."

Chapter 8

Electric Power System Characteristics and Performance

**Table 8.1. Average Operating Heat Rate for Selected Energy Sources,
2014 through 2024 (Btu per Kilowatthour)**

Year	Coal	Petroleum	Natural Gas	Nuclear
2014	10,428	10,814	7,907	10,459
2015	10,495	10,687	7,869	10,458
2016	10,493	10,811	7,863	10,459
2017	10,465	10,834	7,803	10,459
2018	10,481	11,095	7,811	10,455
2019	10,551	11,205	7,725	10,442
2020	10,655	11,259	7,725	10,446
2021	10,583	11,224	7,689	10,429
2022	10,689	11,166	7,740	10,448
2023	10,745	11,465	7,721	10,452
2024	10,777	11,200	7,754	10,443

Note:

Coal includes anthracite, bituminous, subbituminous, lignite, waste coal, refined coal; and coal-derived synthesis gas.

Petroleum 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:

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 Form EIA-860, "Annual Electric Generator Report."

Table 8.2. Average Tested Heat Rates by Prime Mover and Energy Source, 2014 - 2024
(Btu per Kilowatthour)

Prime Mover	Coal	Petroleum	Natural Gas	Nuclear
2014				
Steam Generator	10,080	10,156	10,408	10,459
Gas Turbine	--	13,457	11,378	--
Internal Combustion	--	10,403	9,375	--
Combined Cycle	W	9,924	7,658	--
2015				
Steam Generator	10,059	10,197	10,372	10,458
Gas Turbine	--	13,550	11,302	--
Internal Combustion	--	10,379	9,322	--
Combined Cycle	W	9,676	7,655	--
2016				
Steam Generator	10,045	10,189	10,382	10,459
Gas Turbine	--	13,535	11,214	--
Internal Combustion	--	10,331	9,179	--
Combined Cycle	W	9,860	7,652	--
2017				
Steam Generator	10,043	10,199	10,353	10,459
Gas Turbine	--	13,491	11,176	--
Internal Combustion	--	10,301	9,120	--
Combined Cycle	W	9,811	7,649	--
2018				
Steam Generator	10,015	10,270	10,334	10,455
Gas Turbine	--	13,352	11,138	--
Internal Combustion	--	10,326	9,009	--
Combined Cycle	W	9,663	7,627	--
2019				
Steam Generator	10,002	10,236	10,347	10,442
Gas Turbine	--	13,315	11,098	--
Internal Combustion	--	10,325	8,899	--
Combined Cycle	W	9,662	7,633	--
2020				
Steam Generator	9,997	10,339	10,368	10,446
Gas Turbine	--	13,223	11,069	--
Internal Combustion	--	10,334	8,832	--
Combined Cycle	W	9,208	7,604	--
2021				
Steam Generator	10,002	10,347	10,365	10,429
Gas Turbine	--	13,227	11,068	--
Internal Combustion	--	10,461	8,821	--
Combined Cycle	W	9,208	7,580	--
2022				
Steam Generator	10,026	10,263	10,295	10,448
Gas Turbine	--	13,217	11,030	--
Internal Combustion	--	10,475	8,894	--
Combined Cycle	W	9,204	7,596	--
2023				
Steam Generator	10,020	10,314	10,285	10,452
Gas Turbine	--	13,088	11,010	--
Internal Combustion	--	10,506	8,900	--
Combined Cycle	W	9,696	7,549	--
2024				
Steam Generator	10,018	10,331	10,337	10,443
Gas Turbine	--	13,083	10,999	--
Internal Combustion	--	10,512	8,924	--
Combined Cycle	W	9,702	7,548	--

Notes: W = Withheld to avoid disclosure of individual company data.

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.
Coal Combined Cycle represents integrated gasification units.

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

**Table 8.3. Revenue and Expense Statistics for Major U.S. Investor-Owned Electric Utilities,
2014 through 2024 (Million Dollars)**

Description	2014	2015	2016	2017	2018	2019
Utility Operating Revenues	298,430	282,695	282,499	286,501	293,868	293,000
.....Electric Utility	271,832	260,121	261,047	263,265	268,421	266,876
.....Other Utility	26,598	22,574	21,451	23,235	25,447	26,124
Utility Operating Expenses	258,936	242,728	239,037	240,041	253,944	250,136
.....Electric Utility	240,643	228,366	226,457	226,110	238,526	234,892
.....Operation	165,989	149,939	145,077	142,000	163,479	157,265
.....Production	123,366	107,201	100,852	98,859	104,185	99,518
.....Cost of Fuel	42,545	34,711	32,621	32,165	33,592	29,614
.....Purchased Power	62,066	52,970	49,962	49,030	53,060	50,378
.....Other	18,755	19,521	18,269	17,664	17,533	19,526
.....Transmission	8,902	9,624	10,447	10,804	11,387	11,941
.....Distribution	4,331	4,406	4,734	4,358	4,806	5,218
.....Customer Accounts	5,255	5,184	5,077	4,789	4,969	4,978
.....Customer Service	6,396	6,445	6,187	5,961	6,019	6,156
.....Sales	208	201	205	213	203	204
.....Administrative and General	17,532	16,878	17,575	17,016	31,911	29,248
.....Maintenance	16,801	16,392	16,982	17,996	17,786	19,898
.....Depreciation	25,919	26,847	30,097	30,323	32,125	34,883
.....Taxes and Other	31,934	35,188	34,301	35,791	25,136	22,846
.....Other Utility	18,293	14,362	12,579	13,931	15,418	15,245
Net Utility Operating Income	39,494	39,968	43,462	46,460	39,924	42,864

Description	2020	2021	2022	2023	2024
Utility Operating Revenues	294,756	329,138	381,129	378,230	384,741
.....Electric Utility	269,869	299,956	344,355	343,701	352,516
.....Other Utility	24,888	29,181	36,774	34,529	32,226
Utility Operating Expenses	240,802	271,078	315,491	307,839	306,372
.....Electric Utility	227,084	253,979	292,247	287,611	289,892
.....Operation	144,335	163,952	196,589	185,924	179,919
.....Production	93,505	110,775	140,287	126,857	120,333
.....Cost of Fuel	25,856	34,771	49,486	36,229	32,871
.....Purchased Power	50,407	61,627	80,032	67,897	63,763
.....Other	17,242	14,377	10,768	22,731	23,699
.....Transmission	12,949	15,310	15,872	15,746	17,863
.....Distribution	5,480	5,659	5,973	6,402	6,740
.....Customer Accounts	5,775	5,249	5,658	6,607	7,099
.....Customer Service	5,868	6,192	6,659	6,953	7,462
.....Sales	211	215	255	217	212
.....Administrative and General	20,546	20,553	21,886	23,142	20,211
.....Maintenance	20,030	20,875	21,834	21,570	23,128
.....Depreciation	38,208	39,666	42,104	44,693	47,887
.....Taxes and Other	24,510	29,485	31,720	35,424	38,958
.....Other Utility	13,718	17,100	23,244	20,228	16,480
Net Utility Operating Income	53,954	58,060	65,638	70,391	78,369

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

Total may not equal sum of components due to independent rounding.

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

Table 8.4. Average Power Plant Operating Expenses for Major U.S. Investor-Owned

Electric Utilities, 2014 through 2024 (Mills per Kilowatthour)

Year	Operation				Maintenance			
	Nuclear	Fossil Steam	Hydro-electric	Gas Turbine and Small Scale	Nuclear	Fossil Steam	Hydro-electric	Gas Turbine and Small Scale
2014	12.41	4.55	7.30	2.63	6.67	5.11	4.59	2.90
2015	11.17	5.16	8.37	2.34	7.06	5.41	5.06	2.68
2016	10.90	5.05	6.65	2.49	7.01	5.53	4.34	2.74
2017	10.27	5.01	6.33	2.45	6.63	5.13	3.96	2.83
2018	10.78	5.19	6.69	2.37	5.93	5.27	3.96	2.71
2019	10.63	5.52	6.86	2.58	6.29	6.85	3.94	2.64
2020	10.05	6.40	7.72	2.38	5.78	5.60	5.00	2.51
2021	10.55	5.70	7.98	2.12	5.88	5.32	4.33	2.28
2022	10.51	6.75	7.68	2.20	6.10	5.09	4.76	2.36
2023	9.52	6.48	9.18	2.16	6.36	5.61	5.53	2.12
2024	9.87	6.98	8.97	2.25	6.84	5.81	6.10	2.11

Year	Fuel				Total			
	Nuclear	Fossil Steam	Hydro-electric	Gas Turbine and Small Scale	Nuclear	Fossil Steam	Hydro-electric	Gas Turbine and Small Scale
2014	7.71	29.39	--	37.06	26.79	39.04	11.90	42.60
2015	7.48	26.70	--	28.22	25.71	37.26	13.42	33.24
2016	7.45	25.50	--	24.97	25.36	36.08	10.98	30.19
2017	7.47	25.27	--	26.48	24.38	35.41	10.29	31.76
2018	7.15	25.40	--	27.35	23.86	35.86	10.65	32.43
2019	6.81	24.28	--	23.11	23.73	36.66	10.80	28.33
2020	6.10	22.87	--	19.65	21.92	34.86	12.71	24.55
2021	6.31	24.64	--	25.78	22.74	35.66	12.30	30.18
2022	6.12	32.04	--	38.72	22.73	43.88	12.44	43.28
2023	6.12	30.58	--	22.19	22.00	42.67	14.71	26.47
2024	6.37	28.52	--	18.59	23.08	41.32	15.07	22.95

Hydroelectric category consists of both conventional hydroelectric and pumped storage.

Gas Turbine and Small Scale category consists of 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).

Total may not equal sum of components due to independent rounding.

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

Table 8.11.A. U.S. Transmission Circuit Outages by Type and NERC region, 2024

Outage Type	frcc	mro	npcc	rfc	serc	spp	tre	wecc	Contiguous U.S.
Circuit Outage Counts									
Automatic Outages (Sustained)	--	--	--	--	--	--	--	--	--
Non-Automatic Outages (Operational)	--	--	--	--	--	--	--	--	--
Circuit Outage Hours									
Automatic Outages (Sustained)	--	--	--	--	--	--	--	--	--
Non-Automatic Outages (Operational)	--	--	--	--	--	--	--	--	--
Circuit Outage Counts per 1,000 Circuit Miles									
Automatic Outages (Sustained)	--	--	--	--	--	--	--	--	--
Non-Automatic Outages (Operational)	--	--	--	--	--	--	--	--	--
Circuit Outage Hours per Outage Incident									
Automatic Outages (Sustained)	--	--	--	--	--	--	--	--	--
Non-Automatic Outages (Operational)	--	--	--	--	--	--	--	--	--

Notes:

Circuit Miles for each region is displayed in Table 8.10.A.

An Automatic Outage is an outage which results from the automatic operation of a switching device, causing an Element to change from an In-Service State to a not In-Service State.

A Sustained Outage is an automatic outage with an outage duration of a minute or greater.

A Non-Automatic Outage is an outage which results from the manual operation (including supervisory control) of a switching device, causing an element to change from an In-Service State to a not In-Service State.

An Operational Outage is a Non-Automatic Outage for the purpose of avoiding an emergency (i.e., risk to human life, damage to equipment, damage to property) or to maintain the system within operational limits and that cannot be deferred.

A Planned Outage is a Non-Automatic Outage with advance notice for the purpose of maintenance, construction, inspection, testing, or planned activities by third parties that may be deferred.

Detailed information on the Transmission Availability Data System outage definitions is available at:

<http://www.nerc.com/docs/pc/tadswg/Appendix%207%2020101202a%20clean.pdf>

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

Table 8.11.B. U.S. Transformer Outages by Type and NERC region, 2024

Outage Type	Eastern Interconnection	tre	wecc	Contiguous U.S.
Circuit Outage Counts				
Automatic Outages (Sustained)	--	--	--	--
Non-Automatic Outages (Operational)	--	--	--	--
Non-Automatic Outages (Planned)	--	--	--	--
Circuit Outage Hours				
Automatic Outages (Sustained)	--	--	--	--
Non-Automatic Outages (Operational)	--	--	--	--
Non-Automatic Outages (Planned)	--	--	--	--
Circuit Outage Hours per Outage Incident				
Automatic Outages (Sustained)	--	--	--	--
Non-Automatic Outages (Operational)	--	--	--	--
Non-Automatic Outages (Planned)	--	--	--	--

Notes:

An Automatic Outage is an outage which results from the automatic operation of a switching device, causing an Element to change from an In-Service State to a not In-Service State.

A Sustained Outage is an automatic outage with an outage duration of a minute or greater.

A Non-Automatic Outage is an outage which results from the manual operation (including supervisory control) of a switching device, causing an element to change from an In-Service State to a not In-Service State.

An Operational Outage is a Non-Automatic Outage for the purpose of avoiding an emergency (i.e., risk to human life, damage to equipment, damage to property) or to maintain the system within operational limits and that cannot be deferred.

A Planned Outage is a Non-Automatic Outage with advance notice for the purpose of maintenance, construction, inspection, testing, or planned activities by third parties that may be deferred.

Detailed information on the Transmission Availability Data System outage definitions is available at:

<http://www.nerc.com/docs/pc/tadswg/Appendix%207%2020101202a%20clean.pdf>

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

**Table 8.12.A. U.S. Transmission Circuit Sustained Automatic Outage Counts and Hours
by High-Voltage Size and NERC Region, 2024**

Sustained Automatic Outage Counts										
Voltage		Region								
Type	Operating (kV)	frcc	mro	npcc	rfc	serc	spp	tre	wecc	Contiguous U.S.
Grand Total		.	.	.	.	.	.	.	.	--

Total Outages per 1,000 Circuit Miles										
		Region								
		frcc	mro	npcc	rfc	serc	spp	tre	wecc	Contiguous U.S.
Rate		.	.	.	.	.	.	.	.	--

Sustained Automatic Outage Hours										
Voltage		Region								
Type	Operating (kV)	frcc	mro	npcc	rfc	serc	spp	tre	wecc	Contiguous U.S.
Grand Total		.	.	.	.	.	.	.	.	--

Outage Hours per Outage Incident										
		Region								
		frcc	mro	npcc	rfc	serc	spp	tre	wecc	Contiguous U.S.
Rate		.	.	.	.	.	.	.	.	--

Notes:

* = Value is less than half of the smallest unit of measure. (e.g., for values with no decimals, the smallest unit is 1 then values under 0.5 are shown as *.)

Circuit Miles for each region is displayed in Table 8.10.A.

An Automatic Outage is an outage which results from the automatic operation of a switching device, causing an Element to change from an In-Service State to a not In-Service State.

A Sustained Outage is an automatic outage with an outage duration of a minute or greater.

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

Table 8.12.B. U.S. Transformer Sustained Automatic Outage Counts
and Hours by High-Voltage Size and NERC Region, 2024

Sustained Automatic Outage Counts				
High-Side Voltage (kV)	Eastern Interconnection	tre	wecc	Contiguous U.S.
	--	--	--	--

Sustained Automatic Outage Hours				
High-Side Voltage (kV)	Eastern Interconnection	tre	wecc	Contiguous U.S.
	--	--	--	--

Table 8.13.A. U.S. Transmission Circuit Sustained Automatic Outage Counts and

Hours by Cause Code and by NERC Region, 2024 (Page 1)

	AC & DC Circuit Outage Counts								
Sustained Outage Causes	frcc	mro	npcc	rfc	serc	spp	tre	wecc	Contiguous U.S.
TOTAL	--	--	--	--	--	--	--	--	--

	Percentage of Total AC & DC Circuit Outage Counts								
Sustained Outage Causes	FRCC	MRO	NPCC	RFC	SERC	SPP	TRE	WECC	Contiguous U.S.
TOTAL	--	--	--	--	--	--	--	--	--

Notes:

Detailed information on the Transmission Availability Data System outage causes is available at:

<http://www.nerc.com/docs/pc/tadswg/Appendix%207%2020101202a%20clean.pdf>

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

Table 8.13.A. U.S. Transmission Circuit Sustained Automatic Outage Counts and

Hours by Cause Code and by NERC Region, 2024 (Page 2)

	AC & DC Circuit Outage Hours								
Sustained Outage Causes	frcc	mro	npcc	rfc	serc	spp	tre	wecc	Contiguous U.S.
TOTAL	--	--	--	--	--	--	--	--	--

	Percentage of Total AC & DC Circuit Outage Hours								
Sustained Outage Causes	FRCC	MRO	NPCC	RFC	SERC	SPP	TRE	WECC	Contiguous U.S.
TOTAL	--	--	--	--	--	--	--	--	--

Notes:

Detailed information on the Transmission Availability Data System outage causes is available at:

<http://www.nerc.com/docs/pc/tadswg/Appendix%207%2020101202a%20clean.pdf>

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

Table 8.13.B. U.S. Transformer Sustained Automatic Outage Counts and

Hours by Cause Code and by NERC Region, 2024 (Page 1)

	Transformer Outage Counts								
Sustained Outage Causes	frcc	mro	npcc	rfc	serc	spp	tre	wecc	Contiguous U.S.
TOTAL	--	--	--	--	--	--	--	--	--

	Percentage of Total Transformer Outage Counts								
Sustained Outage Causes	FRCC	MRO	NPCC	RFC	SERC	SPP	TRE	WECC	Contiguous U.S.
TOTAL	--	--	--	--	--	--	--	--	--

Notes:

Detailed information on the Transmission Availability Data System outage causes is available at:

<http://www.nerc.com/docs/pc/tadswg/Appendix%207%2020101202a%20clean.pdf>

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

Table 8.13.B. U.S. Transformer Sustained Automatic Outage Counts and

Hours by Cause Code and by NERC Region, 2024 (Page 2)

	Transformer Outage Hours								
Sustained Outage Causes	frcc	mro	npcc	rfc	serc	spp	tre	wecc	Contiguous U.S.
TOTAL	--	--	--	--	--	--	--	--	--

	Percentage of Total Transformer Outage Hours								
OUTAGE_CAUSE	FRCC	MRO	NPCC	RFC	SERC	SPP	TRE	WECC	Contiguous U.S.
TOTAL	--	--	--	--	--	--	--	--	--

Notes:

Detailed information on the Transmission Availability Data System outage causes is available at:

<http://www.nerc.com/docs/pc/tadswg/Appendix%207%2020101202a%20clean.pdf>

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

Chapter 9

Environmental Data

Table 9.1. Emissions from Energy Consumption at Conventional Power Plants and Combined-Heat-and-Power Plants 2014 through 2024 (Thousand Metric Tons)

Year	Carbon Dioxide (CO2)	Sulfur Dioxide (SO2)	Nitrogen Oxides (NOx)
2014	2,168,284	3,454	2,100
2015	2,031,452	2,548	1,824
2016	1,928,401	1,807	1,630
2017	1,849,750	1,599	1,493
2018	1,872,330	1,517	1,474
2019	1,724,873	1,267	1,342
2020	1,553,586	1,023	1,211
2021	1,651,911	1,168	1,253
2022	1,650,367	1,079	1,230
2023	1,531,554	848	1,117
2024	1,537,073	808	1,112

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.

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

Table 9.2. Quantity and Net Summer Capacity of Operable Environmental Equipment, 2014 - 2024

	Flue Gas Desulfurization Systems		Electrostatic Precipitators		Baghouses		Select Catalytic and Non-Catalytic Reduction Systems		Activated Carbon Injection Systems		Direct Sorbent Injection Systems	
Year	Quantity	Associated Net Summer Capacity (MW)	Quantity	Associated Net Summer Capacity (MW)	Quantity	Associated Net Summer Capacity (MW)	Quantity	Associated Net Summer Capacity (MW)	Quantity	Associated Net Summer Capacity (MW)	Quantity	Associated Net Summer Capacity (MW)
2014	703	223,850	1,173	284,303	621	105,990	1,485	361,548	280	69,287	105	16,913
2015	694	224,159	1,038	265,268	623	110,820	1,493	363,007	364	106,450	123	23,443
2016	698	228,598	944	253,267	614	112,824	1,497	365,644	482	153,800	126	26,815
2017	683	222,607	887	244,450	603	109,759	1,506	369,042	477	151,208	128	25,916
2018	664	214,176	842	229,774	584	105,546	1,503	369,625	455	143,471	121	26,415
2019	619	203,130	784	217,711	537	102,103	1,476	366,814	431	136,597	116	25,615
2020	595	193,216	749	207,516	514	98,754	1,455	363,480	410	130,761	112	23,917
2021	570	186,400	708	197,689	483	94,981	1,436	360,901	396	127,791	108	22,975
2022	552	178,539	665	183,139	467	91,660	1,410	354,352	364	117,573	103	22,308
2023	523	167,691	621	171,029	457	90,154	1,387	347,508	344	110,996	98	21,257
2024	500	163,094	596	165,540	437	89,328	1,364	344,431	332	107,481	97	21,035

Note:

'Associated Net Summer Capacity' is defined as the net summer capacity of the generators that are associated with the operation of this environmental equipment. In some cases respondents have reported equipment late. Counts and capacity may have changed from prior publications of this table because of late reporting.

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

Table 9.3. Quantity and Net Summer Capacity of Operable Cooling Systems, by Energy Source and

Cooling System Type, 2014 - 2024

Energy Source	Once-Through Cooling Systems		Recirculating Cooling Systems		Cooling Ponds		Dry Cooling Systems		Hybrid Wet and Dry Cooling Systems		Other Cooling System Types	
	Quantity	Associated Net Summer Capacity (MW)	Quantity	Associated Net Summer Capacity (MW)	Quantity	Associated Net Summer Capacity (MW)	Quantity	Associated Net Summer Capacity (MW)	Quantity	Associated Net Summer Capacity (MW)	Quantity	Associated Net Summer Capacity (MW)
2014												
Coal	328	115,930	340	160,534	74	38,906	4	1,422	1	750	22	8,322
Natural Gas	161	50,985	420	84,984	56	20,294	58	11,878	4	637	3	2,419
Nuclear	44	49,596	35	37,650	13	15,237	--	--	--	--	9	11,886
Petroleum	42	10,893	11	3,473	4	4,691	--	--	--	--	--	--
Solar Thermal	--	--	4	841	--	--	5	900	--	--	--	--
Other	16	1,332	31	2,756	1	66	1	72	--	--	1	128
2015												
Coal	259	93,180	313	153,917	77	45,026	4	1,422	1	750	25	9,883
Natural Gas	160	49,219	437	88,982	59	22,351	59	12,038	3	475	3	2,410
Nuclear	43	47,268	35	37,610	14	17,663	--	--	--	--	9	12,062
Petroleum	29	9,104	9	2,308	4	4,299	--	--	--	--	--	--
Solar Thermal	--	--	4	866	--	--	5	900	1	110	--	--
Other	18	1,676	26	2,104	1	66	1	72	--	--	1	128
2016												
Coal	210	82,047	294	149,187	79	44,702	4	1,422	1	750	22	10,148
Natural Gas	168	49,664	441	88,690	58	21,970	64	14,128	3	475	3	2,359
Nuclear	42	47,029	35	38,745	14	17,660	--	--	--	--	9	13,298
Petroleum	27	8,620	8	2,222	3	3,904	--	--	--	--	--	--
Solar Thermal	--	--	4	866	--	--	5	900	1	110	--	--
Other	18	1,689	24	2,035	1	66	1	72	--	--	1	128
2017												
Coal	197	76,492	281	142,578	75	44,341	4	1,422	1	750	19	9,581
Natural Gas	172	50,053	440	91,398	59	21,677	66	15,271	4	801	6	3,772
Nuclear	42	47,013	35	38,784	14	17,700	--	--	--	--	9	13,298
Petroleum	26	8,174	8	1,844	4	3,965	--	--	--	--	--	--
Solar Thermal	--	--	4	866	--	--	5	900	1	110	--	--
Other	17	1,582	26	2,464	2	97	2	245	--	--	1	128
2018												
Coal	180	70,659	273	138,632	67	39,593	4	1,422	1	750	16	8,089
Natural Gas	161	47,653	446	93,078	59	21,549	77	18,613	4	801	7	4,478
Nuclear	41	46,723	35	38,805	14	17,759	--	--	--	--	9	13,608
Petroleum	27	8,575	8	1,844	3	2,304	--	--	--	--	--	--
Solar Thermal	--	--	4	866	--	--	5	900	1	110	--	--
Other	17	1,931	25	2,161	1	31	1	72	--	--	1	128
2019												
Coal	163	67,142	246	129,998	63	37,807	4	1,432	1	750	14	7,629
Natural Gas	150	45,079	448	95,673	56	21,279	78	18,769	4	801	7	4,058
Nuclear	40	46,244	34	37,970	14	17,759	--	--	--	--	10	14,927
Petroleum	26	8,147	7	1,684	3	2,302	--	--	--	--	--	--
Solar Thermal	--	--	4	866	--	--	5	900	1	110	--	--
Other	18	1,962	25	2,161	--	--	1	72	--	--	1	128
2020												
Coal	143	61,538	232	123,410	58	35,832	5	1,536	1	750	13	6,703
Natural Gas	152	46,653	453	97,151	56	23,018	83	19,640	4	801	8	4,804
Nuclear	39	43,163	33	37,281	14	17,855	--	--	--	--	9	14,326
Petroleum	24	7,175	6	898	2	682	--	--	--	--	--	--
Solar Thermal	--	--	4	866	--	--	5	893	1	110	--	--
Other	18	1,955	25	2,158	--	--	1	72	--	--	1	128
2021												
Coal	130	59,230	221	119,928	58	35,856	5	1,536	1	750	14	7,992
Natural Gas	144	44,244	460	101,024	52	22,762	82	19,627	4	801	6	3,612
Nuclear	38	42,013	33	37,471	14	17,862	--	--	--	--	9	14,213
Petroleum	24	7,622	6	898	2	684	--	--	--	--	--	--
Solar Thermal	--	--	4	866	--	--	5	893	1	110	--	--
Other	18	1,955	22	2,045	--	--	1	72	--	--	1	128
2022												
Coal	105	46,596	207	112,393	57	35,718	4	1,432	1	750	11	6,581
Natural Gas	146	46,954	458	102,623	52	21,970	85	21,884	4	801	9	4,947
Nuclear	38	42,002	32	36,609	14	17,847	--	--	--	--	9	14,198
Petroleum	27	9,035	6	1,020	1	628	--	--	--	--	--	--
Solar Thermal	--	--	4	866	--	--	5	893	1	110	--	--
Other	15	1,760	19	1,773	--	--	1	72	--	--	1	128
2023												
Coal	94	41,649	198	107,601	54	34,183	4	1,432	1	750	10	5,581
Natural Gas	136	44,252	457	103,564	52	21,758	90	24,794	5	947	7	3,901
Nuclear	38	41,999	33	37,713	14	17,799	--	--	--	--	9	14,198
Petroleum	26	7,954	6	1,020	1	637	--	--	--	--	--	--
Solar Thermal	--	--	4	866	--	--	5	893	1	110	--	--
Other	16	1,806	20	1,826	--	--	1	72	--	--	1	128
2024												
Coal	86	38,413	194	106,748	53	34,044	4	1,432	1	750	10	5,581
Natural Gas	135	44,306	455	103,538	50	21,140	88	24,480	6	1,090	6	3,635
Nuclear	38	41,961	34	38,836	14	17,823	--	--	--	--	9	14,227
Petroleum	25	7,549	5	839	1	603	--	--	--	--	--	--
Solar Thermal	--	--	4	866	--	--	5	893	1	110	--	--
Other	15	1,645	20	1,823	--	--	1	72	--	--	1	128

Notes:

Associated Net Summer Capacity is defined as the net summer capacity of the generators that are associated with the operation of this environmental equipment.

In some cases respondents have reported equipment late. Counts and capacity may have changed from prior publications of this table because of late reporting.

Coal includes anthracite, bituminous, subbituminous, lignite, waste coal, refined coal, and coal-derived synthesis gas.

Petroleum Liquids includes distillate and residual fuel oils, jet fuel, kerosene, waste oil, and beginning in 2011, propane.

Petroleum Coke includes petroleum coke-derived synthesis gas.

Other Energy Sources consists of wood and wood waste products, biomass, blast furnace gas and Other Fossil Gas.

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

**Table 9.4. Average Costs of Existing Flue Gas Desulfurization Units
Operating in Electric Power Sector, 2014 - 2024**

Year	Average Operation and Maintenance Costs (Dollars per Megawatthour)	Average Installed Capital Costs (Dollars per Kilowatt)
2014	1.84	186.45
2015	2.03	154.73
2016	1.96	303.32
2017	2.15	242.88
2018	2.08	--
2019	2.11	452.20
2020	2.21	--
2021	2.14	--
2022	2.36	310.18
2023	2.54	--
2024	2.59	--

Notes:

Average Installed Capital Costs reflect units which began operating in the specified year.

Years in which no new Flue Gas Desulfurization units were installed a '--' is indicated in the Average Installed Capital Cost column.

Average Operation and Maintenance Costs are based on all units in operation during the specified year regardless of installation year.

Commercial and industrial facilities had significantly different costs than units used in the electric power sector. In order to give a more accurate reflection of the electric power sector, commercial and industrial facilities have been excluded from this publication table.

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

Table 9.5. Emissions from Energy Consumption at Conventional Power Plants and Combined-Heat-and-Power Plants, by State, 2023 and 2024 (Thousand Metric Tons)

Census Division and State	Carbon Dioxide (CO2)		Sulfur Dioxide (SO2)		Nitrogen Oxides (NOx)	
	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023
New England	28,989	27,434	7	7	21	21
Connecticut	11,002	10,653	0	0	4	5
Maine	3,245	2,434	4	4	4	4
Massachusetts	8,895	8,263	2	2	8	8
New Hampshire	2,159	2,060	0	0	2	2
Rhode Island	3,680	4,014	0	0	2	2
Vermont	8	9	0	0	1	1
Middle Atlantic	117,697	114,738	32	33	64	63
New Jersey	13,861	15,112	0	1	7	8
New York	31,513	29,418	6	6	25	25
Pennsylvania	72,323	70,207	27	26	32	31
East North Central	255,892	249,331	155	149	154	155
Illinois	42,894	42,186	28	29	18	18
Indiana	61,437	61,252	23	23	42	43
Michigan	54,012	50,018	31	31	42	43
Ohio	65,214	63,226	65	59	31	31
Wisconsin	32,335	32,649	7	7	21	20
West North Central	153,777	161,366	150	170	125	133
Iowa	22,400	24,593	10	18	17	19
Kansas	17,842	20,280	2	3	14	14
Minnesota	20,391	20,842	11	11	16	18
Missouri	44,270	45,916	59	66	32	34
Nebraska	18,303	19,770	34	38	16	18
North Dakota	27,555	27,040	33	33	27	27
South Dakota	3,016	2,926	1	1	3	3
South Atlantic	288,907	281,059	136	147	180	176
Delaware	2,456	2,374	0	0	1	1
District of Columbia	80	73	0	0	0	0
Florida	92,505	93,735	18	21	44	44
Georgia	42,718	43,044	40	42	35	35
Maryland	9,718	9,138	2	2	6	5
North Carolina	41,129	36,765	16	18	37	36
South Carolina	26,896	25,599	19	19	16	15
Virginia	29,439	24,587	10	10	16	15
West Virginia	43,967	45,743	30	36	25	26
East South Central	157,357	148,514	94	86	82	78
Alabama	48,517	46,082	27	25	24	23
Kentucky	53,086	50,039	39	34	31	29
Mississippi	27,914	27,096	11	11	13	14
Tennessee	27,840	25,297	18	16	14	11
West South Central	309,487	310,377	146	165	248	241
Arkansas	26,858	28,363	30	32	18	17
Louisiana	41,958	42,944	23	24	57	53
Oklahoma	28,769	26,301	10	9	27	21
Texas	211,902	212,769	84	101	146	150
Mountain	153,836	162,426	54	58	113	119
Arizona	33,418	34,788	5	6	21	22
Colorado	25,602	27,579	7	9	13	15
Idaho	3,482	3,002	3	3	4	4
Montana	11,839	13,774	7	8	12	12
Nevada	13,068	12,540	3	3	10	10
New Mexico	13,402	13,542	2	2	8	7
Utah	21,120	20,620	5	4	21	21
Wyoming	31,905	36,580	23	22	24	28
Pacific Contiguous	61,556	66,670	15	14	90	94
California	39,594	43,360	1	1	57	59
Oregon	10,351	9,636	4	4	22	22
Washington	11,610	13,674	10	10	11	13
Pacific Noncontiguous	9,574	9,639	19	19	35	37
Alaska	3,636	3,605	2	2	18	20
Hawaii	5,938	6,035	16	17	16	16
U.S. Total	1,537,073	1,531,554	808	848	1,112	1,117

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. Displayed values of zero may represent small values that round to zero. The Excel version of this table provides additional precision which may be accessed by selecting individual cells.

Source: Calculations made by the Office of Energy Production Conversion and Delivery, U.S. Energy Information Administration.

Chapter 10

Energy Efficiency, Demand Response and Advanced Meters

**Table 10.1. Energy Efficiency
Category, by Sector, 2013 through 2024**

Year	Residential	Commercial	Industrial	Transportation	Total
Incremental Annual Savings - Energy Savings (MWh)					
2015	11,012,627	12,285,000	2,818,448	13,414	26,129,489
2016	11,712,873	13,348,029	2,425,175	14,147	27,500,224
2017	13,199,995	14,095,101	2,592,155	11,776	29,899,028
2018	12,459,323	13,350,203	2,565,238	40,273	28,415,037
2019	13,283,024	12,706,234	2,538,169	35,103	28,562,529
2020	13,136,061	12,464,063	2,559,475	7,859	28,167,459
2021	12,444,823	11,459,062	1,853,577	3,195	25,760,657
2022	11,709,919	10,835,070	1,839,391	139	24,384,518
2023	11,243,272	11,048,142	1,929,875	--	24,221,289
2024	10,200,084	11,498,785	2,140,086	10	23,838,965
Incremental Annual Savings - Peak Demand Savings (MW)					
2015	2,654	2,891	407	--	5,952
2016	2,698	2,556	401	3	5,658
2017	2,790	2,739	540	1	6,071
2018	2,775	3,072	459	4	6,309
2019	3,402	3,116	614	4	7,135
2020	2,985	2,877	424	1	6,287
2021	2,753	2,712	336	1	5,801
2022	2,466	2,499	479	--	5,445
2023	2,204	3,191	366	--	5,761
2024	2,198	3,206	860	*	6,264
Incremental Costs - Customer Incentive (thousand dollars)					
2015	1,488,651	1,616,843	342,773	20	3,448,286
2016	1,541,458	1,733,170	296,321	--	3,570,950
2017	1,657,086	1,713,295	294,026	--	3,664,407
2018	1,602,723	1,608,369	273,676	--	3,484,767
2019	1,712,243	1,659,591	285,643	--	3,657,477
2020	1,358,512	1,557,663	236,198	--	3,152,372
2021	1,574,404	1,594,830	206,571	--	3,375,805
2022	1,644,822	1,531,745	197,812	--	3,374,379
2023	1,826,044	1,771,421	252,897	--	3,850,362
2024	1,917,829	2,015,664	274,988	--	4,208,481
Incremental Costs - All Other Costs (thousand dollars)					
2015	1,152,224	938,021	193,015	40	2,283,300
2016	1,387,122	959,160	176,560	12	2,522,854
2017	1,221,072	900,291	176,585	10	2,297,957
2018	1,127,692	874,427	163,783	78	2,165,981
2019	1,209,389	910,039	168,567	33	2,288,028
2020	1,108,027	844,860	159,365	9	2,112,261
2021	1,178,407	932,133	130,700	3	2,240,600
2022	1,110,656	964,655	141,385	--	2,216,696
2023	1,250,790	1,124,056	163,345	--	2,538,191
2024	1,285,513	1,249,059	158,031	4	2,692,606

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

**Table 10.2. Energy Efficiency - Life Cycle
Category, by Sector, 2013 through 2024**

Year	Residential	Commercial	Industrial	Transportation	Total
Life Cycle Savings - Energy Savings (MWh)					
2015	99,512,487	160,045,443	36,589,144	199,328	296,346,403
2016	134,003,597	186,654,713	33,477,182	212,200	354,347,692
2017	137,297,599	204,102,657	33,249,999	176,636	374,826,892
2018	129,572,460	195,288,558	33,981,062	604,095	359,446,175
2019	134,474,216	186,931,400	33,284,347	526,549	355,216,512
2020	144,098,659	190,336,319	33,276,349	117,879	367,829,206
2021	122,339,730	153,947,500	23,992,054	47,932	300,327,216
2022	113,782,935	137,420,139	22,384,375	2,085	273,589,534
2023	101,341,591	146,197,493	22,912,335		270,451,419
2024	106,666,954	149,150,238	25,569,385	149	281,386,727
Life Cycle Savings - Peak Demand Savings (MW)					
2015	3,492	3,104	500		7,096
2016	3,408	3,132	507	3	7,050
2017	2,668	2,698	584	1	5,951
2018	2,649	2,987	436	4	6,075
2019	3,322	2,993	613	4	6,931
2020	2,769	2,807	425	1	6,003
2021	2,628	2,651	351	1	5,631
2022	2,294	2,449	473		5,216
2023	2,069	3,214	372		5,655
2024	2,141	3,165	846		6,152
Life Cycle Costs - Customer Incentive (thousand dollars)					
2015	1,844,246	1,997,677	413,416	30	4,255,368
2016	1,704,458	2,079,373	342,927		4,126,758
2017	2,194,049	2,359,255	296,498		4,849,803
2018	1,808,354	2,093,170	276,381		4,177,905
2019	1,911,197	2,000,492	440,237		4,351,926
2020	1,414,886	1,650,928	495,334		3,561,148
2021	1,636,371	1,713,633	328,872	3	3,678,879
2022	1,920,560	1,885,652	213,120		4,019,332
2023	2,035,217	2,125,178	253,091		4,413,487
2024	2,128,317	2,340,496	275,298		4,744,110
Life Cycle Costs - All Other Costs (thousand dollars)					
2015	2,086,543	1,407,658	216,226	40	3,710,453
2016	1,964,832	1,265,765	202,112	12	3,432,717
2017	1,649,863	1,335,176	177,945	10	3,162,995
2018	2,605,135	1,409,483	164,623	78	4,179,320
2019	1,884,678	1,527,461	243,435	33	3,655,607
2020	1,773,693	1,346,643	228,973	9	3,349,318
2021	1,258,415	1,015,672	192,451	3	2,466,541
2022	1,314,337	1,205,465	147,051		2,666,853
2023	1,420,950	1,335,146	163,528		2,919,623
2024	1,427,688	1,444,307	168,060	4	3,040,059

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

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

**Table 10.3. Demand Response - Yearly Energy and Demand Savings
Category, by Sector, 2013 through 2024**

Year	Residential	Commercial	Industrial	Transportation	Total
Number of Customers Enrolled					
2015	8,140,688	890,284	63,163	3	9,094,138
2016	8,739,535	1,033,649	66,170	1	9,839,355
2017	8,287,913	1,084,392	68,630	3	9,440,938
2018	8,700,669	986,816	64,753	--	9,752,238
2019	10,447,335	432,669	52,841	--	10,932,845
2020	11,302,017	324,939	38,706	1	11,665,663
2021	10,196,668	255,355	40,560	1	10,492,584
2022	10,044,583	235,825	39,365	1	10,319,774
2023	10,282,113	245,332	39,808	1	10,567,254
2024	10,658,027	249,192	43,608	1	10,950,828
Energy Savings (MWh)					
2015	855,017	273,089	122,900	--	1,251,006
2016	1,005,144	225,174	105,818	--	1,336,136
2017	948,037	244,603	118,230	--	1,310,862
2018	1,099,179	221,502	105,536	--	1,426,211
2019	1,075,567	306,832	80,336	--	1,462,735
2020	1,186,421	251,719	70,984	--	1,509,124
2021	984,129	88,947	80,715	--	1,153,791
2022	1,004,031	126,867	162,081	--	1,292,980
2023	230,285	107,321	69,649	--	407,255
2024	247,973	88,063	73,367	--	409,404
Potential Peak Demand Savings (MW)					
2015	8,703	6,989	17,169	14	32,875
2016	10,518	11,053	14,339	14	35,924
2017	8,996	6,995	15,512	5	31,508
2018	8,539	7,021	15,335	--	30,895
2019	8,867	6,907	15,246	--	31,020
2020	8,535	5,837	15,098	--	29,470
2021	8,705	6,646	13,871	--	29,222
2022	9,039	6,545	14,864	--	30,448
2023	9,667	7,035	13,840	--	30,542
2024	9,706	7,346	14,439	--	31,491
Actual Peak Demand Savings (MW)					
2015	3,430	3,047	6,546	13	13,036
2016	3,608	3,598	4,632	4	11,841
2017	3,960	2,743	5,546	--	12,248
2018	3,788	2,694	6,040	--	12,522
2019	3,426	2,403	5,505	--	11,334
2020	3,504	2,115	4,768	--	10,387
2021	3,836	2,807	5,569	--	12,211
2022	4,606	2,608	6,613	--	13,827
2023	4,082	2,661	4,009	--	10,752
2024	4,785	2,457	5,080	--	12,322

Energy Savings dropped due to a reclassification in the 2023 annual filings.

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

Table 10.4. Demand Response - Program Costs
Category, by Sector, 2013 through 2024

Year	Residential	Commercial	Industrial	Transportation	Total
Customer Incentives (thousand dollars)					
2015	320,683	338,153	461,271	339	1,120,446
2016	306,635	448,332	284,584	339	1,039,890
2017	292,443	345,226	365,451	--	1,003,124
2018	310,892	347,235	531,157	--	1,189,284
2019	306,152	322,611	490,119	--	1,118,882
2020	274,021	281,304	432,328	--	987,653
2021	293,293	314,739	580,358	--	1,188,390
2022	265,186	287,785	596,309	--	1,149,280
2023	262,583	306,095	550,092	--	1,118,770
2024	273,346	348,692	602,656	--	1,224,694
All Other Costs (thousand dollars)					
2015	256,519	78,758	46,613	28	381,918
2016	253,180	66,084	60,443	--	379,707
2017	245,231	68,251	57,221	--	370,700
2018	235,159	66,024	59,534	--	360,718
2019	223,129	49,407	70,677	--	343,214
2020	213,592	59,905	53,365	10	326,872
2021	218,758	70,615	22,709	10	312,091
2022	244,430	62,832	21,782	10	329,053
2023	222,739	64,259	24,935	10	311,943
2024	262,017	68,914	31,132	10	362,073

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

Table 10.05. Advanced Metering Count by Technology Type, 2015 through 2024

Year	Residential	Commercial	Industrial	Transportation	Total
Automated Meter Reading (AMR)					
2015	42,326,302	5,049,978	226,908	1,023	47,604,211
2016	41,508,261	5,074,877	223,584	971	46,807,693
2017	39,325,014	4,813,029	230,099	707	44,368,849
2018	36,365,339	4,591,398	213,108	712	41,170,557
2019	32,750,506	4,160,628	207,286	861	37,119,281
2020	29,345,377	3,769,118	197,641	905	33,313,041
2021	26,098,336	3,550,517	184,358	920	29,834,131
2022	23,296,364	3,185,114	157,857	873	26,640,208
2023	19,591,318	2,982,169	156,330	571	22,730,388
2024	16,572,563	2,546,768	130,377	579	19,250,287
Advanced Metering Infrastructure (AMI)					
2015	57,107,785	7,324,345	310,889	813	64,743,832
2016	62,360,132	8,119,223	342,766	1,345	70,823,466
2017	69,474,626	9,060,128	365,447	1,389	78,901,590
2018	76,498,388	9,932,993	411,287	1,489	86,844,157
2019	83,539,594	10,850,886	446,871	1,504	94,838,855
2020	90,692,768	11,771,565	468,071	1,499	102,933,903
2021	97,708,824	12,930,423	535,725	1,786	111,176,758
2022	104,237,855	13,908,481	574,526	1,879	118,722,741
2023	112,175,762	14,830,952	755,067	2,584	127,764,365
2024	123,019,799	16,529,599	940,214	2,369	140,491,981
Standard (non-AMR/AMI) Meters					
2015	32,430,105	5,744,831	290,354	432	38,465,722
2016	28,491,094	4,929,344	280,406	416	33,701,260
2017	24,351,523	4,261,918	225,949	445	28,839,835
2018	21,982,727	3,884,695	186,001	414	26,053,837
2019	20,778,995	3,734,399	175,344	478	24,689,216
2020	18,941,774	3,572,152	140,087	510	22,654,523
2021	17,551,772	3,225,410	127,901	716	20,905,799
2022	15,675,775	2,953,060	106,426	691	18,735,952
2023	13,233,236	2,404,543	102,080	563	15,740,422
2024	6,958,631	1,284,234	100,308	558	8,343,731
Total Number of Meters					
2015	131,864,192	18,119,154	828,151	2,268	150,813,765
2016	132,359,487	18,123,444	846,756	2,732	151,332,419
2017	133,151,163	18,135,075	821,495	2,541	152,110,274
2018	134,846,454	18,409,086	810,396	2,615	154,068,551
2019	137,069,095	18,745,913	829,501	2,843	156,647,352
2020	138,979,919	19,112,835	805,799	2,914	158,901,467
2021	141,358,932	19,706,350	847,984	3,422	161,916,688
2022	143,209,994	20,046,655	838,809	3,443	164,098,901
2023	145,000,316	20,217,664	1,013,477	3,718	166,235,175
2024	146,550,993	20,360,601	1,170,899	3,506	168,085,999

Prior to 2010, the count was the number of customers, not number of meters.

Starting in 2013 Standard (Non-AMR/AMI) meter data was collected on the EIA-861.

This data is not collected on the EIA-861S.

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

Chapter 11

Distribution System Reliability

Table 11.1 Reliability Metrics of U.S. Distribution System

Year	IEEE									Any Method					
	All Events (With Major Event Days)			Without Major Event Days			Loss of Supply Removed			All Events (With Major Events)			Without Major Events		
	SAIDI (minutes per year)	SAIFI (times per year)	CAIDI (minutes per interruption)	SAIDI (minutes per year)	SAIFI (times per year)	CAIDI (minutes per interruption)	SAIDI (minutes per year)	SAIFI (times per year)	CAIDI (minutes per interruption)	SAIDI (minutes per year)	SAIFI (times per year)	CAIDI (minutes per interruption)	SAIDI (minutes per year)	SAIFI (times per year)	CAIDI (minutes per interruption)
2014	236.2	1.3	188.0	114.2	1.0	110.0	244.8	1.2	203.7	219.0	1.2	179.6	109.7	1.0	107.7
2015	209.0	1.3	163.9	117.0	1.1	109.1	198.2	1.2	170.4	205.0	1.2	164.5	113.1	1.0	108.1
2016	268.4	1.3	202.2	119.8	1.1	110.7	257.0	1.2	209.0	249.2	1.3	192.9	116.9	1.1	110.0
2017	505.9	1.4	356.2	117.0	1.0	114.3	489.6	1.3	390.6	473.1	1.4	339.3	114.4	1.0	113.6
2018	349.2	1.3	260.5	121.4	1.1	115.5	338.5	1.2	283.8	346.4	1.3	261.5	117.2	1.0	114.0
2019	295.5	1.3	221.8	122.2	1.0	117.5	289.1	1.2	243.0	284.6	1.3	214.8	118.6	1.0	116.6
2020	456.1	1.4	329.3	116.0	1.0	114.5	460.5	1.2	371.9	491.9	1.4	341.7	119.0	1.0	114.7
2021	475.8	1.4	331.2	125.7	1.0	120.9	404.5	1.3	312.6	440.0	1.4	308.8	121.5	1.0	118.5
2022	333.0	1.4	233.5	131.1	1.1	120.2	324.7	1.3	246.9	335.5	1.4	238.8	125.7	1.1	118.1
2023	366.6	1.3	271.8	123.9	1.0	121.3	357.7	1.2	288.0	342.0	1.3	256.6	118.4	1.0	118.5
2024	662.6	1.5	432.7	131.6	1.1	123.6	646.1	1.4	451.6	611.3	1.5	401.9	126.0	1.0	120.8

SAIDI = System Average Interruption Duration Index. It is the minutes of non-momentary electric interruptions, per year, the average customer experienced.

SAIFI = System Average Interruption Frequency Index. It is the number of non-momentary electric interruptions, per year, the average customer experienced.

CAIDI = Customer Average Interruption Duration Index. It is average number of minutes it takes to restore non-momentary electric interruptions.

IEEE refers to the IEEE 1366-2003 or the IEEE 1366-2012 standard. Any method combines data from utilities that use IEEE standard with data from utilities that do not.

For utilities using the IEEE method, a Major Event Day is any day that exceeds a daily SAIDI threshold called Tmed. Tmed is a duration statistic calculated from daily SAIDI values from the past five years. For utilities not using IEEE methods, Major Events are self-determined by the reporting utility.

Loss of Supply Removed excludes outages due to loss of supply from the high-voltage/bulk power system.

For a five minute video explanation of these metrics, go to <https://youtu.be/oVH9LOfCMTU>.

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

Table 11.2 Reliability Metrics Using IEEE of U.S. Distribution System by State, 2024 and 2023

Census Division and State	Percent of Customers Reported		All Events (With Major Event Days)						Without Major Event Days						Loss of Supply Removed					
			SAIDI (minutes per year)		SAIFI (times per year)		CAIDI (minutes per interruption)		SAIDI (minutes per year)		SAIFI (times per year)		CAIDI (minutes per interruption)		SAIDI (minutes per year)		SAIFI (times per year)		CAIDI (minutes per interruption)	
	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023
New England	89.7%	83.3%	389.8	489.3	1.3	1.4	299.6	357.7	101.4	103.4	0.9	0.9	111.9	112.5	387.1	481.2	1.2	1.3	311.8	370.7
Connecticut	99.8%	79.0%	152.8	193.4	0.9	0.9	174.3	212.4	73.6	77.7	0.6	0.7	113.3	114.0	152.3	188.2	0.9	0.9	177.4	214.9
Maine	100.3%	100.8%	1,748.6	1,863.0	3.6	3.3	480.9	562.2	274.0	247.4	2.1	2.0	128.1	125.0	1,701.0	1,781.4	3.3	3.0	511.5	590.9
Massachusetts	90.2%	86.0%	103.7	265.3	0.9	1.1	121.8	248.2	77.0	83.5	0.7	0.8	102.9	105.7	103.9	268.5	0.8	1.0	125.3	262.0
New Hampshire	88.1%	88.2%	735.5	590.6	1.6	1.5	455.2	397.7	84.2	89.3	0.8	0.8	108.5	116.6	733.0	587.7	1.6	1.5	459.0	397.2
Rhode Island	97.6%	98.3%	104.3	104.6	0.9	0.8	116.4	133.7	60.8	52.2	0.8	0.7	79.9	78.3	99.0	100.8	0.9	0.7	114.9	136.9
Vermont	10.5%	10.4%	895.8	486.3	3.3	2.3	268.2	216.1	231.8	204.3	1.4	1.4	165.6	148.1	884.6	480.1	2.1	2.0	429.4	235.3
Middle Atlantic	60.5%	58.8%	309.1	196.8	1.3	1.0	230.7	189.0	121.5	112.2	1.0	0.9	123.3	126.1	299.7	185.9	1.2	1.0	243.2	195.5
New Jersey	99.2%	99.3%	173.3	108.2	1.1	0.9	155.3	122.9	98.8	88.0	0.9	0.8	104.7	106.0	161.2	99.2	1.0	0.8	166.0	126.8
New York	23.8%	20.0%	477.3	204.8	1.7	1.1	286.1	181.7	142.8	130.1	1.1	1.0	134.4	135.1	483.6	207.5	1.7	1.1	291.1	182.0
Pennsylvania	84.4%	84.3%	353.1	265.1	1.4	1.1	253.5	232.0	131.5	125.9	1.0	0.9	133.0	137.7	340.9	248.3	1.3	1.0	266.7	242.3
East North Central	91.2%	91.0%	357.8	489.5	1.2	1.2	308.6	412.3	114.3	108.8	0.9	0.8	131.5	134.6	342.5	483.4	1.1	1.1	323.7	434.5
Illinois	96.6%	96.3%	158.0	210.4	0.8	0.8	186.3	252.4	59.1	56.2	0.6	0.6	92.7	93.0	154.7	209.9	0.8	0.8	189.9	256.4
Indiana	84.3%	83.4%	310.0	467.4	1.3	1.4	242.9	330.6	123.3	111.3	1.0	0.9	122.4	118.0	252.3	462.1	1.1	1.3	221.4	357.6
Michigan	94.3%	94.2%	481.7	1,127.7	1.4	1.5	353.0	730.9	161.3	164.8	1.0	0.9	164.0	177.1	456.2	1,131.2	1.3	1.5	364.5	738.0
Ohio	96.5%	96.4%	511.0	366.6	1.3	1.3	393.7	292.7	133.3	127.1	1.0	0.9	133.4	138.4	500.3	336.0	1.1	1.1	445.1	312.6
Wisconsin	74.2%	74.5%	296.8	203.8	1.0	0.9	285.2	223.3	97.5	76.8	0.7	0.6	134.3	121.4	294.8	200.9	1.0	0.9	288.8	228.0
West North Central	76.9%	76.2%	255.3	222.7	1.2	1.1	207.8	203.8	93.9	84.6	0.9	0.8	106.8	104.3	254.7	215.6	1.1	1.0	228.9	221.5
Iowa	52.9%	52.8%	200.3	83.9	1.2	0.9	165.1	97.7	84.1	60.7	0.8	0.6	103.6	94.1	187.0	75.5	1.0	0.7	179.3	101.9
Kansas	80.0%	80.1%	289.8	287.1	1.5	1.3	192.8	216.3	104.0	101.8	1.0	1.0	103.5	101.4	277.9	274.4	1.4	1.2	205.9	234.3
Minnesota	86.9%	86.7%	222.4	127.1	1.3	1.0	176.3	130.6	91.5	72.8	0.9	0.8	101.5	93.6	222.3	123.6	1.1	0.9	194.3	143.9
Missouri	82.7%	83.6%	212.6	379.0	1.2	1.3	180.8	286.1	106.6	104.4	0.9	0.9	115.4	118.9	206.0	391.2	1.1	1.3	192.5	309.8
Nebraska	66.2%	67.0%	697.8	69.4	1.2	0.6	560.8	125.2	69.8	55.6	0.6	0.5	116.3	116.2	696.7	66.4	1.2	0.5	564.0	121.8
North Dakota	83.6%	63.2%	102.7	262.3	0.9	1.2	109.0	227.9	87.0	93.9	0.9	0.9	98.7	99.7	82.2	259.0	0.7	0.8	120.7	307.2
South Dakota	70.8%	67.9%	85.6	78.1	0.8	1.0	105.0	76.8	61.5	63.9	0.7	0.9	85.4	71.4	67.5	62.2	0.6	0.7	116.0	90.1
South Atlantic	81.8%	81.7%	1,405.8	240.4	1.8	1.3	768.3	179.4	133.1	119.7	1.0	1.1	129.0	111.9	1,352.3	211.7	1.7	1.2	809.3	180.0
Delaware	87.5%	87.4%	117.9	109.7	0.9	0.8	138.0	130.4	66.8	61.2	0.7	0.7	91.9	87.2	118.9	112.1	0.9	0.9	138.7	130.6
District of Columbia	98.9%	98.9%	32.6	71.9	0.3	0.4	120.2	194.2	26.4	33.3	0.2	0.3	107.2	104.6	32.6	71.9	0.3	0.4	120.2	194.2
Florida	84.1%	84.4%	1,487.6	172.3	1.8	1.0	833.9	175.5	66.7	69.4	0.7	0.8	90.0	89.0	1,485.6	160.0	1.7	0.9	865.9	172.3
Georgia	87.0%	87.8%	1,208.1	342.7	2.1	1.9	574.3	184.5	211.4	133.4	1.2	1.3	170.0	99.9	768.0	300.3	1.9	1.8	403.2	170.1
Maryland	98.6%	98.7%	118.1	166.2	0.8	0.9	144.5	180.7	75.1	66.9	0.7	0.7	109.6	95.1	116.7	156.1	0.8	0.9	145.6	176.9
North Carolina	90.6%	88.5%	1,518.1	262.5	1.8	1.5	831.3	172.1	143.9	156.4	1.2	1.3	122.4	121.9	1,475.0	249.9	1.7	1.4	879.2	178.6
South Carolina	92.6%	92.2%	3,155.0	169.8	2.4	1.5	1,332.3	112.3	115.9	126.5	1.2	1.3	96.7	98.1	2,972.9	140.4	2.1	1.2	1,447.2	117.3
Virginia	30.6%	30.8%	962.1	292.8	2.2	1.7	429.9	176.9	245.1	239.9	1.6	1.5	149.4	157.6	911.2	280.6	2.0	1.6	447.0	179.8
West Virginia	97.3%	97.8%	1,165.5	751.5	2.8	2.4	411.5	319.4	486.1	385.7	2.3	1.9	212.6	206.2	1,067.4	700.4	2.5	2.1	427.0	333.5
East South Central	62.1%	61.5%	423.7	864.3	2.0	2.4	216.7	359.0	176.3	186.5	1.6	1.6	113.6	114.7	423.0	876.2	1.9	2.3	226.0	375.6
Alabama	15.5%	14.3%	197.7	400.2	1.7	2.3	113.0	175.4	120.8	189.5	1.3	1.5	93.6	128.0	189.6	380.2	1.7	2.0	114.6	192.8
Kentucky	93.8%	93.2%	537.7	861.5	1.8	1.9	301.6	463.4	145.7	140.6	1.2	1.1	119.8	124.5	520.1	841.1	1.6	1.7	329.2	507.5
Mississippi	69.3%	68.8%	607.3	877.8	2.5	2.6	244.7	334.1	279.0	266.6	1.9	2.1	148.3	126.2	693.8	991.9	2.7	2.9	255.7	338.3
Tennessee	73.5%	73.2%	289.3	926.9	1.9	2.8	149.2	330.7	169.9	192.7	1.8	1.9	97.0	101.9	283.3	933.4	1.9	2.8	149.4	336.5
West South Central	65.2%	64.8%	1,268.9	685.6	2.2	1.9	568.9	355.7	164.2	163.3	1.4	1.4	113.5	116.2	1,295.8	671.2	2.1	1.8	608.6	376.3
Arkansas	82.0%	82.0%	527.8	915.3	2.1	2.1	247.0	431.2	201.9	230.7	1.6	1.6	124.8	146.2	377.8	879.0	1.8	1.9	209.2	460.4
Louisiana	72.3%	72.3%	630.6	663.2	2.4	1.9	267.7	352.5	215.9	199.3	1.7	1.5	130.0	132.8	603.0	633.7	2.2	1.8	272.8	360.3
Oklahoma	46.2%	45.9%	220.7	1,339.4	1.6	2.1	139.3	644.3	121.3	123.8	1.3	1.1	95.9	109.2	188.1	1,012.7	1.3	1.7	150.4	591.2
Texas	64.9%	64.3%	1,614.3	583.1	2.3	1.9	704.2	308.7	153.4	150.3	1.4	1.4	109.7	108.1	1,724.6	604.3	2.3	1.8	759.9	340.0
Mountain	91.5%	90.2%	176.3	117.9	1.2	1.0	148.8	122.0	102.4	90.4	1.0	0.8	105.2	106.5	169.5	101.2	1.1	0.9	152.9	114.5
Arizona	95.7%	95.8%	83.6	103.8	1.0	1.0	86.8	109.2	69.8	66.9	0.9	0.8	79.4	84.9	75.8	88.7	0.9	0.9	81.1	96.8
Colorado	92.3%	88.8%	257.0	100.2	1.4	0.9	181.6	108.4	118.9	89.2	1.1	0.9	103.9	102.2	251.2	96.2	1.3	0.9	188.1	113.1
Idaho	93.2%	93.1%	204.4	134.4	1.3	1.1	155.5	125.5	152.5	121.8	1.1	1.0	134.2	123.6	150.5	95.9	1.0	0.8	157.1	126.7
Montana	72.3%	68.4%	341.7	113.9	1.6	1.1	209.8	108.3	152.3	113.9	1.2	1.1	130.9	108.3	298.1	93.9	1.4	0.9	219.2	110.2
Nevada	103.1%	102.7%	158.9	138.7	1.1	0.9	143.4	147.2	63.8	81.2	0.7	0.7	97.0	108.9	116.7	96.9	1.3	1.1	88.9	85.7
New Mexico	85.2%	85.1%	272.6	156.0	1.3	1.1	205.7	141.6	152.0	123.7	1.1	0.9	137.4	136.3	255.4	139.0	1.1	1.0	226.5	143.9
Utah	85.4%	85.5%	115.4	127.7	1.0	0.9	114.5	140.0	105.0	108.5	1.0	0.9	109.9	125.3						

Table 11.3 Reliability Metrics Using Any Method of U.S. Distribution System by State, 2024 and 2023

Census Division and State	Percent of Customers Reported		All Events (With Major Events)						Without Major Events					
			SAIDI (minutes per year)		SAIFI (times per year)		CAIDI (minutes per interruption)		SAIDI (minutes per year)		SAIFI (times per year)		CAIDI (minutes per interruption)	
	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023
New England	96.0%	94.2%	419.6	480.5	1.4	1.4	303.6	343.7	112.3	107.8	1.0	0.9	118.0	114.2
Connecticut	101.2%	100.6%	153.6	164.6	0.9	0.9	175.5	188.8	73.1	70.3	0.6	0.7	113.4	107.3
Maine	100.3%	100.8%	1,748.6	1,863.0	3.6	3.3	480.9	562.2	274.0	247.4	2.1	2.0	128.1	125.0
Massachusetts	92.3%	88.2%	102.0	259.4	0.8	1.1	120.9	245.4	76.1	82.2	0.7	0.8	102.3	105.4
New Hampshire	99.2%	99.3%	922.7	645.8	2.0	1.8	456.6	368.5	132.3	124.6	1.0	1.0	134.3	126.1
Rhode Island	97.6%	98.3%	104.3	104.6	0.9	0.8	116.4	133.7	60.8	52.2	0.8	0.7	79.9	78.3
Vermont	87.0%	87.0%	696.7	744.4	2.5	2.4	276.9	316.5	275.0	221.3	1.7	1.6	165.5	140.0
Middle Atlantic	97.6%	97.3%	246.2	159.5	1.1	0.9	224.0	180.7	97.2	89.9	0.8	0.7	120.9	122.2
New Jersey	100.9%	101.0%	174.2	108.3	1.1	0.9	155.7	123.0	99.7	88.5	0.9	0.8	105.2	106.5
New York	98.2%	97.7%	219.9	120.0	0.9	0.7	241.7	165.6	72.0	70.0	0.6	0.6	117.8	119.4
Pennsylvania	94.5%	94.4%	336.1	252.7	1.4	1.1	248.3	228.0	131.0	119.2	1.0	0.9	134.9	135.8
East North Central	95.9%	95.7%	349.2	472.8	1.2	1.2	302.2	401.6	112.8	107.1	0.9	0.8	130.0	133.3
Illinois	98.1%	97.8%	156.9	208.2	0.9	0.8	184.0	249.2	59.4	56.2	0.6	0.6	92.3	92.9
Indiana	92.0%	91.1%	312.4	455.4	1.3	1.4	243.5	314.8	121.4	110.3	1.0	0.9	121.8	116.6
Michigan	97.5%	97.4%	470.4	1,093.6	1.4	1.5	346.8	723.5	160.1	162.7	1.0	0.9	162.4	176.7
Ohio	96.6%	96.5%	510.5	366.2	1.3	1.3	393.4	292.5	133.2	127.0	1.0	0.9	133.4	138.4
Wisconsin	92.3%	92.5%	266.1	183.0	1.0	0.9	260.8	208.6	91.3	72.4	0.7	0.6	125.2	114.7
West North Central	84.8%	84.9%	246.9	213.8	1.2	1.1	202.9	198.1	94.3	85.5	0.9	0.8	106.8	105.5
Iowa	85.4%	85.2%	166.7	104.9	1.2	0.9	145.0	115.7	89.8	70.4	0.9	0.7	101.3	99.3
Kansas	82.4%	82.5%	285.6	283.1	1.5	1.3	189.7	214.9	103.6	101.7	1.0	1.0	103.3	101.9
Minnesota	89.0%	88.7%	219.6	126.4	1.3	1.0	175.6	129.9	92.2	73.4	0.9	0.8	102.3	93.5
Missouri	86.7%	87.6%	224.3	371.8	1.2	1.3	188.6	282.9	106.0	106.7	0.9	0.9	115.3	121.7
Nebraska	73.7%	73.6%	641.7	72.6	1.2	0.6	520.8	130.1	73.6	56.8	0.6	0.5	123.8	118.3
North Dakota	88.5%	89.0%	99.1	208.6	0.9	1.1	108.4	197.7	84.2	89.9	0.9	0.9	98.3	99.1
South Dakota	75.4%	74.3%	84.7	77.0	0.8	1.0	104.0	76.2	62.1	63.2	0.7	0.9	86.2	70.8
South Atlantic	96.6%	96.7%	1,247.3	227.4	1.8	1.3	698.7	169.3	129.3	117.5	1.0	1.1	124.0	108.6
Delaware	89.1%	89.0%	116.1	108.2	0.8	0.8	137.8	130.3	65.9	60.4	0.7	0.7	91.9	87.3
District of Columbia	98.9%	98.9%	32.6	71.9	0.3	0.4	120.2	194.2	26.4	33.3	0.2	0.3	107.2	104.6
Florida	100.4%	100.2%	1,321.5	160.1	1.8	1.0	746.6	157.7	66.4	69.2	0.8	0.8	87.1	84.1
Georgia	88.9%	89.5%	1,229.1	349.2	2.1	1.9	579.2	185.2	212.3	136.8	1.3	1.4	168.0	100.8
Maryland	98.6%	98.7%	118.1	166.2	0.8	0.9	144.5	180.7	75.1	66.9	0.7	0.7	109.6	95.1
North Carolina	96.0%	96.1%	1,441.0	252.0	1.8	1.5	795.0	167.4	141.4	153.5	1.2	1.3	120.6	120.5
South Carolina	96.5%	95.6%	3,136.5	167.2	2.4	1.5	1,326.3	110.9	117.8	126.1	1.2	1.3	97.6	97.7
Virginia	96.4%	96.8%	418.3	221.1	1.6	1.5	257.1	151.3	166.4	159.3	1.3	1.3	124.0	124.2
West Virginia	97.3%	97.8%	1,165.5	751.5	2.8	2.4	411.5	319.4	486.1	385.7	2.3	1.9	212.6	206.2
East South Central	86.5%	86.8%	415.7	715.5	2.0	2.3	204.7	317.2	162.8	168.7	1.5	1.5	109.1	111.7
Alabama	80.7%	80.0%	279.4	294.2	1.9	1.6	149.4	186.9	117.8	120.2	1.0	1.0	113.6	122.8
Kentucky	96.5%	96.6%	648.3	868.2	2.0	1.9	331.7	456.3	153.3	143.4	1.3	1.2	116.1	122.9
Mississippi	83.2%	83.6%	567.1	802.1	2.6	2.7	221.9	295.2	266.3	252.8	2.0	2.1	135.6	118.0
Tennessee	85.9%	87.0%	278.6	857.9	2.0	2.8	139.3	305.1	159.5	186.1	1.8	1.9	90.4	98.1
West South Central	96.1%	95.1%	1,050.4	579.1	2.1	1.8	489.0	314.2	142.3	142.0	1.3	1.3	109.3	113.0
Arkansas	89.2%	89.3%	509.1	911.2	2.1	2.1	239.3	433.4	194.6	221.7	1.6	1.5	122.7	144.0
Louisiana	93.5%	93.6%	727.5	584.2	2.7	2.1	267.2	275.1	206.0	195.0	1.8	1.6	117.6	118.8
Oklahoma	90.6%	90.0%	270.9	896.6	1.7	1.9	156.5	481.6	119.6	139.3	1.1	1.1	104.3	121.8
Texas	98.1%	96.9%	1,270.6	496.2	2.1	1.8	600.9	281.5	129.4	124.7	1.2	1.2	106.2	106.1
Mountain	93.3%	92.8%	181.3	120.2	1.2	1.0	152.1	121.6	105.8	91.7	1.0	0.9	108.1	106.3
Arizona	96.6%	96.7%	87.5	106.8	1.0	1.0	88.6	108.6	72.0	69.3	0.9	0.8	80.1	84.8
Colorado	93.7%	91.8%	255.1	99.2	1.4	0.9	181.0	108.3	119.0	88.4	1.1	0.9	104.3	102.2
Idaho	95.1%	94.9%	232.8	137.5	1.3	1.1	177.1	128.4	174.0	119.4	1.1	1.0	153.2	121.2
Montana	74.7%	75.0%	351.5	118.7	1.6	1.1	216.9	111.1	156.6	117.1	1.2	1.1	134.9	111.0
Nevada	103.1%	102.7%	158.9	138.7	1.1	0.9	143.4	147.2	63.8	81.2	0.7	0.7	97.0	108.9
New Mexico	90.1%	90.1%	278.8	168.9	1.3	1.2	211.1	136.0	156.5	132.3	1.1	1.0	141.1	132.7
Utah	88.3%	88.4%	119.8	127.1	1.0	0.9	116.3	138.7	106.7	109.8	1.0	0.9	110.4	124.9
Wyoming	76.0%	75.9%	137.8	127.0	1.0	1.0	138.0	127.8	109.1	96.0	0.9	0.8	125.6	124.7
Pacific Contiguous	98.5%	98.6%	365.4	294.2	1.4	1.3	258.7	229.2	155.8	144.6	1.1	1.0	139.5	140.8
California	100.0%	100.2%	279.6	346.6	1.3	1.4	208.0	248.1	158.2	152.0	1.2	1.1	137.1	140.0
Oregon	93.0%	92.9%	591.0	126.9	1.3	0.8	439.1	153.8	130.9	108.0	0.9	0.8	152.8	143.7
Washington	95.2%	95.1%	623.5	151.7	1.8	1.0	355.9	148.0	158.6	130.6	1.1	0.9	146.0	143.8
Pacific Noncontiguous	93.4%	93.6%	323.0	448.4	2.6	2.1	123.9	210.8	213.7	184.6	2.1	1.6	103.4	115.8
Alaska	84.2%	84.5%	327.1	374.8	2.6	2.7	126.3	138.8	192.4	325.7	1.9	2.4	103.3	137.6
Hawaii	99.9%	99.9%	320.6	491.8	2.6	1.8	122.6	275.1	225.6	148.6	2.2	1.4	103.5	106.3
U.S. Total	95.0%	94.8%	611.3	342.0	1.5	1.3	401.9	256.6	126.0	118.4	1.0	1.0	120.8	118.5

SAIFI = System Average Interruption Frequency Index. It is the number of non-momentary electric interruptions, per year, the average customer experienced.

CAIDI = Customer Average Interruption Duration Index. It is average number of minutes it takes to restore non-momentary electric interruptions.

Any method combines data from utilities that use IEEE standard with data from utilities that do not.

For utilities using the IEEE method, a Major Event Day is any day that exceeds a daily SAIDI threshold called Tmed. Tmed is a duration statistic calculated from daily SAIDI values from the past five years. For utilities not using IEEE methods, Major Events are self-determined by the reporting utility.

Percent of Customers Reported is an estimate of the percentage of total customers covered by these metrics. The numerator is reported number of meters used on the reliability schedule, while the denominator is the number of customers reported on the sales to ultimate customers schedule. It is possible, in some instances, for this metric to exceed 100%.

For a five minute video explanation of these metrics, go to <https://youtu.be/oVH9l0fCMTU>.

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

Table 11.5 SAIFI Values (Times Per Year) of U.S. Distribution System by State, 2014 - 2024

[illegible]

U.S. Total	23	23	18	18	18	23	23	18	23	23	23

IEEE refers to the IEEE 1366-2003 or the IEEE 1366-2002 standard. Any method combines data from utilities that use IEEE standard with data from utilities that do not.

For utilities using the IEEE method, a Major Event Day is any day that exceeds a daily SAIDI threshold called *Timed*. *Timed* is a duration statistic calculated from daily SAIDI values from the past five years. For utilities not using IEEE methods, Major Events are self-determined by the reporting utility.

Loss of Supply Removed excludes outages due to loss of supply from the high-voltage/bulk power system.

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

Chapter 12

U.S. Territories

**Table 12.1 Puerto Rico- Number of Ultimate Customers Served:
by Sector, 2014 through 2024**

Period	Residential	Commercial	Industrial	Transportation	All Sectors
Annual Totals					
2014	1,328,546	129,122	662	--	1,458,330
2015	1,326,631	127,365	647	--	1,454,643
2016	1,332,152	127,179	633	--	1,459,964
2017	1,337,756	127,065	618	--	1,465,439
2018	1,346,102	126,527	602	--	1,473,231
2019	1,341,424	124,912	588	--	1,466,924
2020	1,351,190	125,391	587	--	1,477,168
2021	1,358,513	126,159	591	--	1,485,263
2022	1,370,811	127,741	589	--	1,499,141
2023	1,379,341	127,792	582	--	1,507,715
2024	1,383,774	127,491	583	--	1,511,848
Year 2022					
January	1,366,102	127,193	590	--	1,493,885
February	1,365,877	127,084	590	--	1,493,551
March	1,366,362	127,176	589	--	1,494,127
April	1,368,406	127,392	587	--	1,496,385
May	1,369,833	127,589	585	--	1,498,007
June	1,372,587	127,921	588	--	1,501,096
July	1,372,079	127,976	588	--	1,500,643
August	1,372,668	127,954	589	--	1,501,211
September	1,373,141	128,077	590	--	1,501,808
October	1,374,149	128,107	590	--	1,502,846
November	1,374,192	128,189	589	--	1,502,970
December	1,374,331	128,237	590	--	1,503,158
Year 2023					
January	1,374,717	128,302	589	--	1,503,608
February	1,375,176	128,312	588	--	1,504,076
March	1,376,298	128,040	580	--	1,504,918
April	1,377,070	127,611	580	--	1,505,261
May	1,378,115	127,668	579	--	1,506,362
June	1,379,369	127,598	580	--	1,507,547
July	1,380,020	127,637	581	--	1,508,238
August	1,380,809	127,612	580	--	1,509,001
September	1,381,572	127,766	581	--	1,509,919
October	1,382,416	127,596	582	--	1,510,594
November	1,383,057	127,673	583	--	1,511,313
December	1,383,477	127,690	585	--	1,511,752
Year 2024					
January	1,383,758	126,967	584	--	1,511,309
February	1,382,595	126,777	584	--	1,509,956
March	1,383,053	126,808	584	--	1,510,445
April	1,383,157	126,802	584	--	1,510,543
May	1,383,293	127,693	585	--	1,511,571
June	1,382,822	127,663	585	--	1,511,070
July	1,383,420	127,965	585	--	1,511,970
August	1,384,098	128,003	585	--	1,512,686
September	1,383,799	127,930	582	--	1,512,311
October	1,384,566	127,787	582	--	1,512,935
November	1,385,486	127,813	580	--	1,513,879
December	1,385,241	127,685	579	--	1,513,505

Sources: U.S. Energy Information Administration, Form EIA-861M (formerly EIA-826), Monthly Electric Industry Power Report.
Form EIA-826, Monthly Electric Sales and Revenue Report with State Distributions Report;
Form EIA-861, Annual Electric Power Industry Report

**Table 12.2 Puerto Rico- Sales of Electricity to Ultimate Customers:
by Sector, 2014 through 2024 (Megawatthours)**

Period	Residential	Commercial	Industrial	Transportation	All Sectors
Annual Totals					
2014	6,218,352	8,761,182	2,376,022	--	17,355,556
2015	6,313,615	8,586,457	2,355,385	--	17,255,457
2016	6,524,304	8,568,874	2,251,095	--	17,344,273
2017	5,045,346	6,819,591	1,746,554	--	13,611,491
2018	6,102,980	8,202,893	2,128,354	--	16,434,227
2019	6,205,152	7,905,084	2,048,192	--	16,158,428
2020	6,908,138	7,320,018	1,909,660	--	16,137,816
2021	7,119,383	7,484,529	1,853,200	--	16,457,112
2022	6,723,199	7,511,478	1,768,396	--	16,003,073
2023	7,402,045	8,083,092	1,684,002	--	17,169,139
2024	7,853,014	8,369,293	1,558,835	--	17,781,142
Year 2022					
January	529,162	572,918	163,052	--	1,265,132
February	447,525	578,680	141,256	--	1,167,461
March	504,302	569,385	146,676	--	1,220,362
April	509,408	552,580	128,935	--	1,190,924
May	558,688	724,155	178,453	--	1,461,296
June	691,409	696,464	137,232	--	1,525,105
July	677,481	707,421	160,056	--	1,544,958
August	641,604	644,816	159,043	--	1,445,462
September	614,175	676,030	144,496	--	1,434,702
October	426,129	525,960	116,067	--	1,068,155
November	587,283	624,719	149,591	--	1,361,593
December	536,033	638,350	143,540	--	1,317,923
Year 2023					
January	476,437	585,902	125,879	--	1,188,218
February	428,728	547,881	123,762	--	1,100,372
March	497,284	606,624	142,910	--	1,246,818
April	522,925	621,366	143,333	--	1,287,624
May	630,969	689,494	125,636	--	1,446,100
June	695,670	698,032	145,894	--	1,539,596
July	765,237	722,232	146,190	--	1,633,660
August	743,125	723,022	163,155	--	1,629,302
September	725,204	747,147	146,118	--	1,618,469
October	742,232	768,617	149,438	--	1,660,286
November	598,657	688,244	133,467	--	1,420,367
December	575,576	684,531	138,220	--	1,398,327
Year 2024					
January	512,524	632,826	108,457	--	1,253,808
February	493,736	612,821	132,288	--	1,238,845
March	646,496	698,774	131,864	--	1,477,135
April	639,471	656,801	145,230	--	1,441,502
May	629,170	771,788	103,158	--	1,504,116
June	751,556	697,964	143,444	--	1,592,964
July	796,135	733,371	130,559	--	1,660,065
August	748,382	733,371	136,500	--	1,618,253
September	697,473	696,856	112,124	--	1,506,453
October	740,475	756,853	152,639	--	1,649,966
November	615,724	685,972	122,842	--	1,424,538
December	581,873	691,895	139,728	--	1,413,497

Sources: U.S. Energy Information Administration, Form EIA-861M (formerly EIA-826), Monthly Electric Industry Power Report.
Form EIA-826, Monthly Electric Sales and Revenue Report with State Distributions Report;
Form EIA-861, Annual Electric Power Industry Report

**Table 12.3 Puerto Rico- Revenue from Sales of Electricity to Ultimate Customers:
by Sector, 2014 through 2024 (Thousand Dollars)**

Period	Residential	Commercial	Industrial	Transportation	All Sectors
Annual Totals					
2014	1,636,166	2,394,155	550,673	--	4,580,994
2015	1,282,008	1,850,101	417,158	--	3,549,267
2016	1,169,715	1,677,209	356,310	--	3,203,233
2017	1,123,005	1,549,337	344,034	--	3,016,376
2018	1,265,179	1,893,330	405,173	--	3,563,682
2019	1,329,706	1,810,611	420,178	--	3,560,495
2020	1,329,048	1,568,470	360,707	--	3,258,225
2021	1,506,288	1,799,862	380,303	--	3,686,454
2022	1,901,871	2,334,964	505,081	--	4,741,916
2023	1,685,843	1,978,615	390,129	--	4,054,587
2024	1,859,196	2,056,541	368,709	--	4,284,446
Year 2022					
January	136,075	154,251	40,378	--	330,704
February	116,007	168,487	36,286	--	320,780
March	138,639	188,166	40,864	--	367,669
April	135,982	182,484	34,936	--	353,402
May	151,008	225,891	47,947	--	424,846
June	190,133	204,465	40,191	--	434,788
July	237,463	238,282	56,584	--	532,329
August	190,956	212,419	48,442	--	451,816
September	170,168	202,916	40,893	--	413,977
October	140,294	194,981	40,032	--	375,307
November	157,125	187,145	40,552	--	384,822
December	138,021	175,478	37,978	--	351,476
Year 2023					
January	107,600	147,132	28,698	--	283,431
February	101,169	144,459	29,577	--	275,205
March	123,536	167,523	37,382	--	328,442
April	127,840	167,604	36,386	--	331,829
May	152,487	187,613	31,346	--	371,446
June	153,899	145,348	32,048	--	331,294
July	184,185	198,081	38,885	--	421,151
August	173,819	180,163	36,641	--	390,624
September	142,739	158,096	28,399	--	329,233
October	178,311	193,748	37,359	--	409,418
November	128,361	150,841	26,953	--	306,156
December	111,895	138,007	26,455	--	276,358
Year 2024					
January	112,384	143,417	23,649	--	279,450
February	114,038	149,219	29,746	--	293,004
March	150,972	170,528	30,735	--	352,234
April	148,863	160,347	33,277	--	342,486
May	168,442	217,368	29,129	--	414,939
June	186,227	180,266	34,775	--	401,267
July	200,221	201,775	35,455	--	437,451
August	192,232	180,702	33,555	--	406,489
September	172,212	176,112	29,813	--	378,137
October	157,810	172,526	33,275	--	363,611
November	123,826	140,027	23,802	--	287,654
December	131,968	164,255	31,500	--	327,723

Sources: U.S. Energy Information Administration, Form EIA-861M (formerly EIA-826), Monthly Electric Industry Power Report.
Form EIA-826, Monthly Electric Sales and Revenue Report with State Distributions Report;
Form EIA-861, Annual Electric Power Industry Report

**Table 12.4 Puerto Rico- Average Price of Electricity to Ultimate Customers:
by Sector, 2014 through 2024 (Cents per Kilowatthour)**

Period	Residential	Commercial	Industrial	Transportation	All Sectors
Annual Totals					
2014	26.31	27.33	23.18	--	26.39
2015	20.31	21.55	17.71	--	20.57
2016	17.93	19.57	15.83	--	18.47
2017	22.26	22.72	19.70	--	22.16
2018	20.73	23.08	19.04	--	21.68
2019	21.43	22.90	20.51	--	22.03
2020	19.24	21.43	18.89	--	20.19
2021	21.16	24.05	20.52	--	22.40
2022	28.29	31.09	28.56	--	29.63
2023	22.78	24.48	23.17	--	23.62
2024	23.67	24.57	23.65	--	24.10
Year 2022					
January	25.72	26.92	24.76	--	26.14
February	25.92	29.12	25.69	--	27.48
March	27.49	33.05	27.86	--	30.13
April	26.69	33.02	27.10	--	29.67
May	27.03	31.19	26.87	--	29.07
June	27.50	29.36	29.29	--	28.51
July	35.05	33.68	35.35	--	34.46
August	29.76	32.94	30.46	--	31.26
September	27.71	30.02	28.30	--	28.85
October	32.92	37.07	34.49	--	35.14
November	26.75	29.96	27.11	--	28.26
December	25.75	27.49	26.46	--	26.67
Year 2023					
January	22.58	25.11	22.80	--	23.85
February	23.60	26.37	23.90	--	25.01
March	24.84	27.62	26.16	--	26.34
April	24.45	26.97	25.39	--	25.77
May	24.17	27.21	24.95	--	25.69
June	22.12	20.82	21.97	--	21.52
July	24.07	27.43	26.60	--	25.78
August	23.39	24.92	22.46	--	23.97
September	19.68	21.16	19.44	--	20.34
October	24.02	25.21	25.00	--	24.66
November	21.44	21.92	20.19	--	21.55
December	19.44	20.16	19.14	--	19.76
Year 2024					
January	21.93	22.66	21.80	--	22.29
February	23.10	24.35	22.49	--	23.65
March	23.35	24.40	23.31	--	23.85
April	23.28	24.41	22.91	--	23.76
May	26.77	28.16	28.24	--	27.59
June	24.78	25.83	24.24	--	25.19
July	25.15	27.51	27.16	--	26.35
August	25.69	24.64	24.58	--	25.12
September	24.69	25.27	26.59	--	25.10
October	21.31	22.80	21.80	--	22.04
November	20.11	20.41	19.38	--	20.19
December	22.68	23.74	22.54	--	23.19

Sources: U.S. Energy Information Administration, Form EIA-861M (formerly EIA-826), Monthly Electric Industry Power Report.
Form EIA-826, Monthly Electric Sales and Revenue Report with State Distributions Report;
Form EIA-861, Annual Electric Power Industry Report

**Table 12.5. American Samoa
By Sector, 2014 through 2024**

Year	Residential	Commercial	Industrial	Transportation	Total
Number of Ultimate Customers					
2014	11,561	1,386	4	--	12,951
2015	11,023	1,356	4	--	12,383
2016	10,916	1,363	6	--	12,285
2017	10,930	1,386	4	--	12,320
2018	10,866	1,395	4	--	12,265
2019	10,762	1,450	4	--	12,216
2020	10,720	1,452	4	--	12,176
2021	10,802	1,522	4	--	12,328
2022	10,893	1,575	4	--	12,472
2023	10,903	1,581	12	--	12,496
2024	10,998	1,674	12	--	12,684
Sales of Electricity to Ultimate Customers (megawatthours)					
2014	41,029	70,598	23,142	--	134,769
2015	43,306	72,007	25,974	--	141,287
2016	46,493	69,617	32,232	--	148,342
2017	49,538	71,173	26,699	--	147,410
2018	45,621	72,185	24,546	--	142,352
2019	47,127	75,151	25,415	--	147,693
2020	50,304	74,463	25,714	--	150,481
2021	55,625	72,814	24,867	--	153,306
2022	56,424	70,418	24,745	--	151,587
2023	57,015	70,466	28,750	--	156,231
2024	62,505	74,799	30,763	--	168,067
Revenue from Sales of Electricity to Ultimate Customers (thousand dollars)					
2014	17,286	27,553	8,076	--	52,915
2015	15,035	22,981	7,695	--	45,710
2016	13,184	18,402	7,962	--	39,548
2017	15,020	20,626	7,294	--	42,940
2018	15,434	23,557	7,668	--	46,659
2019	16,617	25,328	8,211	--	50,155
2020	16,513	23,480	7,680	--	47,672
2021	17,640	22,745	7,335	--	47,720
2022	25,373	31,668	10,835	--	67,875
2023	25,286	30,386	12,115	--	67,787
2024	26,519	30,482	12,099	--	69,100
Average Price of Electricity to Ultimate Customers (cents per kilowatthour)					
2014	42.13	39.03	34.90	--	39.26
2015	34.72	31.91	29.63	--	32.35
2016	28.36	26.43	24.70	--	26.66
2017	30.32	28.98	27.32	--	29.13
2018	33.83	32.63	31.24	--	32.78
2019	35.26	33.70	32.31	--	33.96
2020	32.83	31.53	29.87	--	31.68
2021	31.71	31.24	29.50	--	31.13
2022	44.97	44.97	43.79	--	44.78
2023	44.35	43.12	42.14	--	43.39
2024	42.43	40.75	39.33	--	41.11

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

Table 12.6. Guam
By Sector, 2014 through 2024

Year	Residential	Commercial	Industrial	Transportation	Total
Number of Ultimate Customers					
2014	41,999	6,925	--	--	48,924
2015	42,752	6,940	--	--	49,692
2016	43,943	6,956	--	--	50,899
2017	43,756	7,087	--	--	50,843
2018	44,006	7,366	--	--	51,372
2019	44,226	7,517	--	--	51,743
2020	44,420	7,518	--	--	51,938
2021	44,748	7,516	--	--	52,264
2022	45,271	7,602	--	--	52,873
2023	45,302	7,708	--	--	53,010
2024	45,808	7,751	--	--	53,559
Sales of Electricity to Ultimate Customers (megawatthours)					
2014	457,835	1,075,511	--	--	1,533,346
2015	463,990	1,078,018	--	--	1,542,008
2016	494,842	1,087,317	--	--	1,582,159
2017	516,682	1,103,757	--	--	1,620,439
2018	510,725	1,071,705	--	--	1,582,430
2019	514,829	1,071,513	--	--	1,586,342
2020	552,083	991,159	--	--	1,543,242
2021	603,924	970,623	--	--	1,574,547
2022	574,292	984,602	--	--	1,558,894
2023	495,407	952,195	--	--	1,447,602
2024	549,816	1,018,473	--	--	1,568,289
Revenue from Sales of Electricity to Ultimate Customers (thousand dollars)					
2014	125,028	309,439	--	--	434,467
2015	106,057	260,652	--	--	366,709
2016	93,568	214,840	--	--	308,408
2017	103,327	230,472	--	--	333,799
2018	121,331	260,506	--	--	381,837
2019	128,641	275,267	--	--	403,908
2020	116,537	221,583	--	--	338,121
2021	121,239	207,645	--	--	328,883
2022	172,623	305,997	--	--	478,620
2023	188,415	360,267	--	--	548,681
2024	192,509	355,416	--	--	547,925
Average Price of Electricity to Ultimate Customers (cents per kilowatthour)					
2014	27.31	28.77	--	--	28.33
2015	22.86	24.18	--	--	23.78
2016	18.91	19.76	--	--	19.49
2017	20.00	20.88	--	--	20.60
2018	23.76	24.31	--	--	24.13
2019	24.99	25.69	--	--	25.46
2020	21.11	22.36	--	--	21.91
2021	20.08	21.39	--	--	20.89
2022	30.06	31.08	--	--	30.70
2023	38.03	37.84	--	--	37.90
2024	35.01	34.90	--	--	34.94

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

**Table 12.7. Northern Mariana Islands
By Sector, 2011 through 2024**

Year	Residential	Commercial	Industrial	Transportation	Total
Number of Ultimate Customers					
2014	11,045	3,651	--	--	14,696
2015	11,318	3,612	--	--	14,930
2016	11,869	3,952	--	--	15,821
2017	12,106	3,952	--	--	16,058
2018	12,323	4,243	--	--	16,566
2019	11,525	3,983	--	--	15,508
2020	12,329	3,212	--	--	15,541
2021	12,394	4,381	--	--	16,775
2022	12,770	4,195	--	--	16,965
2023	13,027	4,256	--	--	17,283
2024	13,052	4,503	--	--	17,555
Sales of Electricity to Ultimate Customers (megawatthours)					
2014	57,532	153,959	--	--	211,491
2015	52,928	145,170	--	--	198,098
2016	70,404	177,766	--	--	248,170
2017	80,502	193,399	--	--	273,901
2018	75,128	182,533	--	--	257,661
2019	76,795	180,421	--	--	257,216
2020	86,601	121,698	--	--	208,299
2021	98,119	106,158	--	--	204,277
2022	94,566	163,706	--	--	258,272
2023	92,078	169,896	--	--	261,974
2024	95,199	180,702	--	--	275,901
Revenue from Sales of Electricity to Ultimate Customers (thousand dollars)					
2014	20,714	66,034	--	--	86,749
2015	12,197	43,521	--	--	55,718
2016	12,657	42,870	--	--	55,527
2017	18,653	52,614	--	--	71,268
2018	20,530	58,788	--	--	79,318
2019	19,410	55,434	--	--	74,844
2020	18,655	32,784	--	--	51,439
2021	24,881	30,748	--	--	55,629
2022	25,079	37,702	--	--	62,781
2023	33,050	68,374	--	--	101,424
2024	27,592	31,062	--	--	58,653
Average Price of Electricity to Ultimate Customers (cents per kilowatthour)					
2014	36.01	42.89	--	--	41.02
2015	23.04	29.98	--	--	28.13
2016	17.98	24.12	--	--	22.37
2017	23.17	27.21	--	--	26.02
2018	27.33	32.21	--	--	30.78
2019	25.28	30.72	--	--	29.10
2020	21.54	26.94	--	--	24.69
2021	25.36	28.96	--	--	27.23
2022	26.52	23.03	--	--	24.31
2023	35.89	40.24	--	--	38.72
2024	28.98	17.19	--	--	21.26

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

**Table 12.8. Virgin Islands
By Sector, 2014 through 2024**

Year	Residential	Commercial	Industrial	Transportation	Total
Number of Ultimate Customers					
2014	45,066	8,808	1,043	--	54,917
2015	45,090	8,747	1,044	--	54,881
2016	49,559	9,951	1,089	--	60,599
2017	49,559	9,951	1,089	--	60,599
2018	46,721	7,491	2,238	--	56,450
2019	46,283	7,526	2,324	--	56,133
2020	46,283	7,526	2,324	--	56,133
2021	46,386	7,535	2,386	--	56,307
2022	45,850	7,524	2,292	--	55,666
2023	44,216	7,924	2,292	--	54,432
2024	44,319	7,915	2,286	--	54,520
Sales of Electricity to Ultimate Customers (megawatthours)					
2014	219,402	113,517	308,119	--	641,038
2015	211,753	109,530	299,598	--	620,881
2016	224,268	115,464	298,959	--	638,691
2017	174,208	85,273	201,822	--	461,303
2018	191,200	75,000	256,100	--	522,300
2019	217,003	87,000	257,313	--	561,316
2020	244,849	86,350	256,827	--	588,026
2021	253,666	100,239	263,702	--	617,607
2022	258,812	101,485	261,772	--	622,069
2023	266,288	148,402	234,226	--	648,916
2024	267,063	148,381	209,582	--	625,026
Revenue from Sales of Electricity to Ultimate Customers (thousand dollars)					
2014	108,204	58,361	153,232	--	319,797
2015	90,567	43,840	134,197	--	268,603
2016	76,907	45,969	101,434	--	224,310
2017	72,035	38,703	93,206	--	203,944
2018	66,093	36,220	83,192	--	185,505
2019	84,090	43,842	95,311	--	223,243
2020	84,094	43,816	95,297	--	223,207
2021	85,613	43,653	95,974	--	225,240
2022	87,199	43,788	95,359	--	226,347
2023	88,316	64,490	96,543	--	249,349
2024	88,624	64,489	87,197	--	240,311
Average Price of Electricity to Ultimate Customers (cents per kilowatthour)					
2014	49.32	51.41	49.73	--	49.89
2015	42.77	40.03	44.79	--	43.26
2016	34.29	39.81	33.93	--	35.12
2017	41.35	45.39	46.18	--	44.21
2018	34.57	48.29	32.48	--	35.52
2019	38.75	50.39	37.04	--	39.77
2020	34.35	50.74	37.11	--	37.96
2021	33.75	43.55	36.39	--	36.47
2022	33.69	43.15	36.43	--	36.39
2023	33.17	43.46	41.22	--	38.43
2024	33.18	43.46	41.61	--	38.45

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

Appendix

Table A.1. Sulfur Dioxide Uncontrolled Emission Factors

Fuel, Code, Source and Emission Units				Combustion System Type / Firing Configuration						
Fuel	EIA Fuel Code	Source and Tables (As Appropriate)	Emissions Units Lbs = Pounds MMCF = Million Cubic Feet MG = Thousand Gallons	Cyclone Firing Boiler	Fluidized Bed Firing Boiler	Stoker Boiler	Tangential Firing Boiler	All Other Boiler Types	Combustion Turbine	Internal Combustion Engine
Distillate Fuel Oil*	DFO	Source: 2, Table 3.1-2a, 3.4-1 & 1.3-1	Lbs per MG	142.00	14.20	142.00	142.00	142.00	140.00	140.00
Jet Fuel*	JF	Assumed to have emissions similar to DFO.	Lbs per MG	142.00	14.20	142.00	142.00	142.00	140.00	140.00
Kerosene*	KER	Assumed to have emissions similar to DFO.	Lbs per MG	142.00	14.20	142.00	142.00	142.00	140.00	140.00
Other Biomass Liquids*	OBL	Source: 1 (including footnotes 3 and 16 within source)	Lbs per MG	142.00	14.20	142.00	142.00	142.00	140.00	140.00
Residual Fuel Oil*	RFO	Source: 2, Table 1.3-1; Combustion turbines and internal combustion engines assumed to have emissions similar to DFO.	Lbs per MG	157.00	15.70	157.00	157.00	157.00	140.00	140.00
Wood Waste Liquids*	WDL	Source: 1 (including footnotes 3 and 16 within source)	Lbs per MG	142.00	14.20	142.00	142.00	142.00	140.00	140.00
Waste Oil*	WO	Source: 2, Table 1.11-2; Combustion turbines and internal combustion engines assumed to have emissions similar to DFO.	Lbs per MG	147.00	14.70	147.00	147.00	147.00	140.00	140.00
Blast Furnace Gas	BFG	Sources: 1 (including footnote 7 within source); 2, Table 1.4-2 (including footnote d within source)	Lbs per MMCF	0.60	0.06	0.60	0.60	0.60	0.60	0.60
Landfill Gas	LFG	Sources: 1 (including footnote 7 within source); 2, Table 1.4-2 (including footnote d within source)	Lbs per MMCF	0.60	0.06	0.60	0.60	0.60	0.60	0.60
Natural Gas	NG	Sources: 1 (including footnote 7 within source); 2, Table 1.4-2 (including footnote d within source)	Lbs per MMCF	0.60	0.06	0.60	0.60	0.60	0.60	0.60
Other Biomass Gas	OBG	Sources: 1 (including footnote 7 within source); 2, Table 1.4-2 (including footnote d within source)	Lbs per MMCF	0.60	0.06	0.60	0.60	0.60	0.60	0.60
Other Gases	OG	Source: 1 (including footnote 7 within source)	Lbs per MMCF	0.60	0.06	0.60	0.60	0.60	0.60	0.60
Other	OTH	Assumed to have emissions similar to Natural Gas.	Lbs per MMCF	0.60	0.06	0.60	0.60	0.60	0.60	0.60
Propane Gas	PG	Sources: 1 (including footnote 7 within source); 2, Table 1.4-2 (including footnote d within source)	Lbs per MMCF	0.60	0.06	0.60	0.60	0.60	0.60	0.60
Coal-Derived Synthesis Gas	SGC	Assumed to have emissions similar to Natural Gas	Lbs per MMCF	0.60	0.06	0.60	0.60	0.60	0.60	0.60
Synthesis Gas from Petroleum Coke	SGP	Assumed to have emissions similar to Natural Gas	Lbs per MMCF	0.60	0.06	0.60	0.60	0.60	0.60	0.60
Agricultural Byproducts	AB	Source: 1	Lbs per ton	0.08	0.01	0.08	0.08	0.08	N/A	N/A
Bituminous Coal*	BIT	Source: 2, Table 1.1-3	Lbs per ton	38.00	3.80	38.00	38.00	38.00	N/A	N/A
Lignite Coal*	LIG	Source: 2, Table 1.7-1	Lbs per ton	30.00	3.00	30.00	30.00	30.00	N/A	N/A
Municipal Solid Waste	MSW	Source: 1	Lbs per ton	1.70	0.17	1.70	1.70	1.70	N/A	N/A
Other Biomass Solids	OBS	Source: 1 (including footnote 11 within source)	Lbs per ton	0.23	0.02	0.23	0.23	0.23	N/A	N/A
Petroleum Coke*	PC	Source: 1	Lbs per ton	39.00	3.90	39.00	39.00	39.00	N/A	N/A
Refined Coal*	RC	Assumed to have the emissions similar to Bituminous Coal.	Lbs per ton	38.00	3.80	38.00	38.00	38.00	N/A	N/A
Subbituminous Coal*	SUB	Source: 2, Table 1.1-3	Lbs per ton	35.00	3.50	35.00	35.00	35.00	N/A	N/A
Tire-Derived Fuel*	TDF	Source: 1 (including footnote 13 within source)	Lbs per ton	38.00	3.80	38.00	38.00	38.00	N/A	N/A
Waste Coal*	WC	Source: 1 (including footnote 20 within source)	Lbs per ton	30.00	3.00	30.00	30.00	30.00	N/A	N/A
Wood Waste Solids	WDS	Source: 1	Lbs per ton	0.29	0.08	0.08	0.29	0.29	N/A	N/A
Black Liquor	BLQ	Source: 1	Lbs per ton **	7.00	0.70	7.00	7.00	7.00	N/A	N/A
Sludge Waste	SLW	Source: 1 (including footnote 11 within source)	Lbs per ton **	2.80	0.28	2.80	2.80	2.80	N/A	N/A

Notes:

* 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.

** 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

Table A.2. Nitrogen Oxides Uncontrolled Emission Factors

Fuel, Code, Source and Emission Units				Combustion System Type / Firing Configuration								
Fuel	EIA Fuel Code	Source and Tables (As Appropriate)	Emissions Units Lbs = Pounds MMCF = Million Cubic Feet MG = Thousand Gallons				Tangential Boiler		All Other Boiler Types		Combustion Turbine	Internal Combustion Engine
				Cyclone Firing Boiler	Fluidized Bed Firing Boiler	Stoker Boiler	Dry-Bottom Boilers	Wet-Bottom Boilers	Dry-Bottom Boilers	Wet-Bottom Boilers		
Distillate Fuel Oil	DFO	Source: 2, Tables 1.3-1, 3.1-1, & 3.4-1	Lbs per MG	24.00	24.00	24.00	24.00	24.00	24.00	24.00	122.00	443.80
Jet Fuel	JF	Source: 2, Tables 1.3-1, 3.1-1, & 3.4-1	Lbs per MG	24.00	24.00	24.00	24.00	24.00	24.00	24.00	118.80	432.00
Kerosene	KER	Source: 2, Tables 1.3-1, 3.1-1, & 3.4-1	Lbs per MG	24.00	24.00	24.00	24.00	24.00	24.00	24.00	118.80	432.00
Other Biomass Liquids	OBL	Source: 1 (including footnote 3 within source); EIA estimates	Lbs per MG	19.00	19.00	19.00	19.00	19.00	19.00	19.00	112.30	408.30
Residual Fuel Oil	RFO	Source: 2, Table 1.3-1; EIA estimates	Lbs per MG	47.00	47.00	47.00	32.00	32.00	47.00	47.00	131.70	479.00
Wood Waste Liquids	WDL	Source: 1 (including footnote 16 within source); EIA estimates	Lbs per MG	5.43	5.43	5.43	5.43	5.43	5.43	5.43	230.50	838.10
Waste Oil	WO	Source: 2, Table 1.11-2; EIA estimates	Lbs per MG	19.00	19.00	19.00	19.00	19.00	19.00	19.00	92.20	335.20
Blast Furnace Gas	BFG	Sources: 1 (including footnote 7 within source); EIA estimates	Lbs per MMCF	15.40	15.40	15.40	15.40	15.40	15.40	15.40	30.40	256.55
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	72.44	144.00	1,215.22
Natural Gas	NG	Source: 2, Tables 1.4-1, 3.1-1, and 3.4-1	Lbs per MMCF	280.00	280.00	280.00	170.00	170.00	280.00	280.00	328.00	2,768.00
Other Biomass Gas	OBG	Sources: 1 (including footnote 7 within source); EIA estimates	Lbs per MMCF	112.83	112.83	112.83	112.83	112.83	112.83	112.83	313.60	2,646.48
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	152.82	263.82	2,226.41
Other	OTH	Assumed to have emissions similar to Natural Gas.	Lbs per MMCF	280.00	280.00	280.00	170.00	170.00	280.00	280.00	328.00	2,768.00
Propane Gas	PG	Sources: 3; EIA estimates	Lbs per MMCF	522.26	522.26	522.26	522.26	522.26	522.26	522.26	803.36	6,779.57
Synthesis Gas from Petroleum Coke	SGC	Assumed to have emissions similar to Natural Gas	Lbs per MMCF	280.00	280.00	280.00	170.00	170.00	280.00	280.00	328.00	2,768.00
Coal-Derived Synthesis Gas	SGP	Assumed to have emissions similar to Natural Gas	Lbs per MMCF	280.00	280.00	280.00	170.00	170.00	280.00	280.00	328.00	2,768.00
Agricultural Byproducts	AB	Source: 1	Lbs per ton	1.20	1.20	1.20	1.20	1.20	1.20	1.20	N/A	N/A
Bituminous Coal	BIT	Source: 2, Table 1.1-3	Lbs per ton	33.00	5.00	11.00	10.00	14.00	12.00	31.00	N/A	N/A
Lignite Coal	LIG	Source: 2, Table 1.7-1	Lbs per ton	15.00	3.60	5.80	7.10	7.10	6.30	6.30	N/A	N/A
Municipal Solid Waste	MSW	Source: 1	Lbs per ton	5.00	5.00	5.00	5.00	5.00	5.00	5.00	N/A	N/A
Other Biomass Solids	OBS	Source: 1 (including footnote 11 within source)	Lbs per ton	2.00	2.00	2.00	2.00	2.00	2.00	2.00	N/A	N/A
Petroleum Coke	PC	Source: 1 (including footnote 8 within source)	Lbs per ton	21.00	5.00	21.00	21.00	21.00	21.00	21.00	N/A	N/A
Refined Coal	RC	Assumed to have the emissions similar to Bituminous Coal.	Lbs per ton	33.00	5.00	11.00	10.00	14.00	12.00	31.00	N/A	N/A
Subbituminous Coal	SUB	Source: 2, Table 1.1-3	Lbs per ton	17.00	5.00	8.80	7.20	7.20	7.40	24.00	N/A	N/A
Tire-Derived Fuel	TDF	Source: 1 (including footnote 13 within source)	Lbs per ton	33.00	5.00	11.00	10.00	14.00	12.00	31.00	N/A	N/A
Waste Coal	WC	Source: 1 (including footnote 20 within source)	Lbs per ton	15.00	3.60	5.80	7.10	7.10	6.30	6.30	N/A	N/A
Wood Waste Solids	WDS	Source: 1	Lbs per ton	2.51	2.00	1.50	2.51	2.51	2.51	2.51	N/A	N/A
Black Liquor	BLQ	Source: 1	Lbs per ton **	1.50	1.50	1.50	1.50	1.50	1.50	1.50	N/A	N/A
Sludge Waste	SLW	Source: 1 (including footnote 11 within source)	Lbs per ton **	5.00	5.00	5.00	5.00	5.00	5.00	5.00	N/A	N/A

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).

3. U.S. Environmental Protection Agency, Factor Information Retrieval (FIRE) Database, Version 6.25.

Table A.3. Carbon Dioxide Uncontrolled Emission Factors

Fuel	EIA Fuel Code	Factor (Kilograms of CO2 Per Million Btu)**	Notes
Bituminous Coal	BIT	93.24	
Distillate Fuel Oil	DFO	74.14	
Geothermal (Steam)	GEO	11.81	
Geothermal (Binary Cycle)	GEO	0.00	
Jet Fuel	JF	72.23	
Kerosene	KER	73.19	
Lignite Coal	LIG	98.27	
Municipal Solid Waste	MSW	49.89	
Natural Gas	NG	52.91	
Petroleum Coke	PC	102.12	
Propane Gas	PG	62.88	
Refined Coal	RC	93.24	Assumed to have emissions similar to Bituminous Coal.
Residual Fuel Oil	RFO	75.09	
Synthesis Gas Derived from Coal	SGC		* Factor is based on the fuel source used to produce the synthesis gas
Synthesis Gas Derived from Petroleum Coke	SGP		* Factor is based on the fuel source used to produce the synthesis gas
Subbituminous Coal	SUB	97.13	
Tire-Derived Fuel	TDF	85.97	
Waste Coal	WC	93.24	Assumed to have emissions similar to Bituminous Coal.
Waste Oil	WO	74.00	

Notes:

* Factors for synthesis gas derived from coal and synthesis gas derived from petroleum coke are based on the fuel source used to produce the synthesis gas.

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

Source: Energy Information Administration estimates:

http://www.eia.gov/environment/emissions/co2_vol_mass.cfm

Table A.4. Nitrogen Oxides Control Technology Emissions Reduction Factors

Nitrogen Oxides Control Technology	EIA Code	Reduction Factor							
		Coal	Residual Fuel Oil and Distillate Fuel Oil	Natural Gas	Wood	Other Solids	Other Liquids	Other Fossil Gas	Other Fuels
Burner Out of Service	BO	15.00%	15.00%	15.00%	15.00%	15.00%	15.00%	15.00%	15.00%
Low Excess Air	LA	15.00%	15.00%	15.00%	15.00%	15.00%	15.00%	15.00%	15.00%
Biased Firing (Alternative Burners)	BF	15.00%	15.00%	15.00%	15.00%	15.00%	15.00%	15.00%	15.00%
Overfire Air	OV	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%
Advanced Overfire Air	AA	30.00%	30.00%	30.00%	30.00%	30.00%	30.00%	30.00%	30.00%
Low NOx Burners	LN	45.00%	45.00%	50.00%	45.00%	45.00%	45.00%	50.00%	45.00%
Fuel Reburning	FU	55.00%	55.00%	55.00%	55.00%	55.00%	55.00%	55.00%	55.00%
Selective Noncatalytic Reduction	SN	45.00%	32.50%	32.50%	55.00%	45.00%	32.50%	32.50%	45.00%
Selective Catalytic Reduction	SR	80.00%	80.00%	85.00%	80.00%	80.00%	80.00%	85.00%	80.00%
Ammonia Injection	NH3	62.50%	56.25%	58.75%	67.50%	62.50%	56.25%	58.75%	62.50%
Flue Gas Recirculation	FR	45.00%	45.00%	45.00%	45.00%	45.00%	45.00%	45.00%	45.00%
Water Injection	H2O	15.00%	15.00%	15.00%	15.00%	15.00%	15.00%	15.00%	15.00%
Steam Injection	STM	15.00%	15.00%	15.00%	15.00%	15.00%	15.00%	15.00%	15.00%
Other	OT	15.00%	15.00%	15.00%	15.00%	15.00%	15.00%	15.00%	15.00%

Nitrogen Oxides Control Technology	EIA Code	Source of Selected Reduction Factor							
		Coal	Residual Fuel Oil and Distillate Fuel Oil	Natural Gas	Wood	Other Solids	Other Liquids	Other Fossil Gas	Other Fuels
Burner Out of Service	BO	Source: 1	Source: 2	Source: 9	Source: 9	Source: 9	Source: 10	Source: 11	Source: 9
Low Excess Air	LA	Source: 1	Source: 2	Source: 9	Source: 9	Source: 9	Source: 10	Source: 11	Source: 9
Biased Firing (Alternative Burners)	BF	Source: 1	Source: 2	Source: 9	Source: 9	Source: 9	Source: 10	Source: 11	Source: 9
Overfire Air	OV	Source: 1	Source: 9	Source: 9	Source: 9	Source: 9	Source: 10	Source: 11	Source: 9
Advanced Overfire Air	AA	Source: 1	Source: 9	Source: 9	Source: 9	Source: 9	Source: 10	Source: 11	Source: 9
Low NOx Burners	LN	Source: 1	Source: 2	Source: 3	Source: 9	Source: 9	Source: 10	Source: 11	Source: 9
Fuel Reburning	FU	Source: 1	Source: 9	Source: 9	Source: 9	Source: 9	Source: 10	Source: 11	Source: 9
Selective Noncatalytic Reduction	SN	Source: 1	Source: 2	Source: 4	Source: 5	Source: 9	Source: 10	Source: 11	Source: 9
Selective Catalytic Reduction	SR	Source: 1	Source: 2	Source: 4	Source: 9	Source: 9	Source: 10	Source: 11	Source: 9
Ammonia Injection	NH3	Source: 6	Source: 6	Source: 6	Source: 6	Source: 9	Source: 10	Source: 11	Source: 9
Flue Gas Recirculation	FR	Source: 10	Source: 2	Source: 10	Source: 10	Source: 9	Source: 10	Source: 11	Source: 9
Water Injection	H2O	Source: 8	Source: 8	Source: 8	Source: 8	Source: 9	Source: 10	Source: 11	Source: 9
Steam Injection	STM	Source: 8	Source: 8	Source: 8	Source: 8	Source: 9	Source: 10	Source: 11	Source: 9
Other	OT	Source: 7	Source: 7	Source: 7	Source: 7	Source: 9	Source: 10	Source: 11	Source: 9

Source: 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/>

Source 1: AP-42, Table 1.1-2

Source 2: AP-42, Section 1.3.4.3 Text

Source 3: AP-42, Table 1.4-1

Source 4: AP-42, Section 1.4.4 Text

Source 5: AP-42, Section 1.6.4 Text

Source 6: Average of Selective Catalytic Reduction and Selective Noncatalytic Reduction

Source 7: Minimum of other technologies for fuel group

Source 8: Matches Other selection

Source 9: Assumed to have reduction similar to coal

Source 10: Assumed to have reduction similar to Residual Fuel Oil and Distillate Fuel Oil

Source 11: Assumed to have reduction similar to natural gas

Notes:

Coal reduction factors are applied to Bituminous Coal, Subbituminous Coal, Lignite Coal, and Waste Coal.

Wood reduction factors are applied to Wood Waste Solids, Black Liquor, and Wood Waste Liquids.

Other Solids reduction factors are applied to Petroleum Coke, Municipal Solid Waste, Tire-Derived Fuels, Sludge Waste, Agricultural Byproducts, and Other Biomass Solids.

Other Liquids reduction factors are applied to Jet Fuel, Kerosene, Waste Oil, and Other Biomass Liquids.

Other Fossil Gas reduction factors are applied to Blast Furnace Gas, Landfill Gas, Propane Gas, Coal-Derived Synthesis Gas, Synthesis Gas from Petroleum Coke, Other Biomass Gas, and Other Fossil Gas.

Table A.5. Unit of Measure Equivalents

Unit	Equivalent
Kilowatt (kW)	1,000 (One Thousand) Watts
Megawatt (MW)	1,000,000 (One Million) Watts
Gigawatt (GW)	1,000,000,000 (One Billion) Watts
Terawatt (TW)	1,000,000,000,000 (One Trillion) Watts
Gigawatt	1,000,000 (One Million) Kilowatts
Thousand Gigawatts	1,000,000,000 (One Billion) Kilowatts
Kilowatthours (kWh)	1,000 (One Thousand) Watthours
Megawatthours (MWh)	1,000,000 (One Million) Watthours
Gigawatthours (GWh)	1,000,000,000 (One Billion) Watthours
Terawatthours (TWh)	1,000,000,000,000 (One Trillion) Watthours
Gigawatthours	1,000,000 (One Million) Kilowatthours
Thousand Gigawatthours	1,000,000,000 (One Billion) Kilowatthours
U.S. Dollar	1,000 (One Thousand) Mills
U.S. Cent	10 (Ten) Mills
Barrel of Oil	42 Gallons

Source: U.S. Energy Information Administration

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 Energy Production, Conversion, and Delivery (EPCD), U.S. Energy Information Administration (EIA), U.S. Department of Energy (DOE). EPCD 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 EIA's Internet Data Collection (IDC) system. A small number of hard copy forms are keyed into the system by EIA personnel. All data are subject to review via interactive edits built into the IDC system, internal quality assurance reports, and review by 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, because 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 after 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 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 n th digit if the $(n+1)$ digit is 5 or larger and keep the n th digit unchanged if the $(n+1)$ digit is less than 5.

Percent Change: The following formula is used to calculate percent changes:

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

where $x(t_1)$ and $x(t_2)$ denote the quantity at 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-111, "Quarterly Electricity Imports and Exports Report;"
- Form EIA-860, "Annual Electric Generator Report;"
- Form EIA-861, "Annual Electric Power Industry Report;"
- Form EIA-861M, "Monthly Electric Power Industry Report;"
- Form EIA-861S, "Annual Electric Power Industry Report (Short Form);"
- Form EIA-923, "Power Plant Operations Report."

These forms can be found on the EIA Internet website at: <https://www.eia.gov/survey/>

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

- FERC Form 1, "Annual Report of Major Electric Utilities, Licensees, and Others;"

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

Form EIA-111

The Form EIA-111 is a mandatory census that collects import/export data from importers and exporters of electricity, border balancing authorities, and entities authorized to export electric energy and to construct, connect, operate, or maintain facilities for the transmission of electric energy at an international boundary. Respondents report monthly data quarterly. These data are used by EIA to track electricity being imported into and exported from the United States. There are currently 173 respondents to the EIA-111. These data were first collected for the 2016 data year.

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 collected at the boiler level. These data include environmental equipment design parameters and boiler air emission standards and boiler emission controls. There are approximately 6,700 respondents on the EIA-860 data collection.

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: No imputation is required for EIA-860 data.

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 after 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.

Prime Movers: The Form EIA-860 sometimes represents a generator's prime mover by using the abbreviations in the table below.

Prime Mover Code	Prime Mover Description
BA	Energy Storage, Battery
BT	Turbines Used in a Binary Cycle. Including those used for geothermal applications
CA	Combined-Cycle -- Steam Part
CE	Energy Storage, Compressed Air
CP	Energy Storage, Concentrated Solar Power
CS	Combined-Cycle Single-Shaft Combustion Turbine and Steam Turbine share of single generator
CT	Combined-Cycle Combustion Turbine Part
ES	Energy Storage, Other (Specify on Schedule 9, Comments)
FC	Fuel Cell
FW	Energy Storage, Flywheel
GT	Combustion (Gas) Turbine. Including Jet Engine design
HA	Hydrokinetic, Axial Flow Turbine
HB	Hydrokinetic, Wave Buoy
HK	Hydrokinetic, Other
HY	Hydraulic Turbine. Including turbines associated with delivery of water by pipeline.
IC	Internal Combustion (diesel, piston, reciprocating) Engine
PS	Energy Storage, Reversible Hydraulic Turbine (Pumped Storage)
OT	Other
ST	Steam Turbine. Including Nuclear, Geothermal, and Solar Steam (does not include Combined Cycle).
PV	Photovoltaic
WT	Wind Turbine, Onshore
WS	Wind Turbine, Offshore

Energy Sources: The Form EIA-860 sometimes represents the energy sources associated with generators by using the abbreviations and/or groupings in the table below.

Energy Source Grouping	Energy Source Code	Energy Source Description
Fossil Fuels		
Coal	ANT	Anthracite Coal
	BIT	Bituminous Coal
	LIG	Lignite Coal
	RC	Refined Coal (A coal product that is created when impurities and/or moisture are removed to improve heat content and reduce emissions. Includes any coal which meets the IRS definition of refined coal [Notice 2010-54 or any superseding IRS notices]. Does not include coal processed by coal preparation plants.)
	SGC	Coal-Derived Synthesis Gas
	SUB	Subbituminous Coal
	WC	Waste/Other Coal (including anthracite culm, bituminous gob, fine coal, lignite waste, waste coal)
Petroleum Products	DFO	Distillate Fuel Oil (including diesel, No. 1, No. 2, and No. 4 fuel oils)
	JF	Jet Fuel
	KER	Kerosene
	PC	Petroleum Coke
	PG	Propane, gaseous
	RFO	Residual Fuel Oil (including No. 5 and No. 6 fuel oils, and bunker C fuel oil)
	SGP	Petroleum Coke Derived Synthesis Gas
	WO	Waste/Other Oil (including crude oil, liquid butane, liquid propane, naphtha, oil waste, re-refined motor oil, sludge oil, tar oil, or other petroleum-based liquid wastes)
Natural Gas and Other Fossil Gas	BFG	Blast Furnace Gas
	NG	Natural Gas
	OG	Other Gas (Specify the fuel in the text box in the applicable schedule.)
Renewable Fuels		
Solid Renewable Fuels	AB	Agricultural By-products
	MSW	Municipal Solid Waste
	OBS	Other Biomass Solids

Energy Source Grouping	Energy Source Code	Energy Source Description
Liquid Renewable (Biomass) Fuels	WDS	Wood/Wood Waste Solids (including paper pellets, railroad ties, utility poles, wood chips, bark, and wood waste solids)
	BLQ	Black Liquor
	OBL	Other Biomass Liquids
	SLW	Sludge Waste
	WDL	Wood Waste Liquids excluding Black Liquor (includes red liquor, sludge wood, spent sulfite liquor, and other wood-based liquids)
Gaseous Renewable (Biomass) Fuels	LFG	Landfill Gas
	OBG	Other Biomass Gas (includes digester gas, methane, and other biomass gasses)
All Other Renewable Fuels	GEO	Geothermal
	SUN	Solar
	WAT	Water at a Conventional Hydroelectric Turbine, and water used in Wave Buoy Hydrokinetic Technology, Current Hydrokinetic Technology, and Tidal Hydrokinetic Technology.
	WND	Wind
	All Other Fuels	
	H2	Hydrogen
	MWH	Electricity used for energy storage
	NUC	Nuclear Uranium, Plutonium, Thorium
	PUR	Purchased Steam
	TDF	Tire-derived Fuels
	WAT	Pumping Energy for Reversible (Pumped Storage) Hydroelectric Turbine
	WH	Waste heat not directly attributed to a fuel source
	OTH	Other

Sensitive Data: The tested heat rate and generator cost 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. Prior to data year 2012, the survey was used to collect information on power sales and revenue data from approximately 3,300 respondents. About 3,100 are electric utilities, and the remainders are nontraditional entities such as energy service providers or the unregulated subsidiaries of electric utilities and power marketers. The current frame has since expanded to about 3,400 respondents, with about 3,000 of those respondents being electric utilities and about 400 nontraditional entities.

For data year 2012 and forward, EIA modified the frame of the Form EIA-861, “Annual Electric Power Industry Report,” from a census to a sample, and EIA is using model-based methods to estimate the sales, revenues, and customer counts by sector and state for those respondents that have been removed from the frame. EIA created a new Form EIA-861S, “Annual Electric Power Industry Report (Short Form),” for the respondents that have been removed from the Form EIA-861 frame. Respondents removed from the EIA-861 frame and placed on the EIA-861S are smaller utilities with annual sales volumes. Form EIA-861S with fewer data elements compared to the EIA-861, collects limited data on total sales, revenues, and customer counts by state. Every eighth data year, EIA-861S respondents are required to fill out the full EIA-861 form. For data year 2019, EIA-861S respondents were required to complete the full EIA-861 form. There are about 1,700 respondents on the EIA-861S data collection.

Transportation Sector: Prior to 2003, sales of electric power for transportation (e.g., city subway systems) were included in a sector labeled other, along with sales to customers for public buildings, traffic signals and public street lighting. Beginning with the 2003 data collection, sales to the other sector was removed and the transportation was created. Non transportation that was previously reported in the sector other was reclassified as commercial.

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.

Data Reconciliation: The Electric Power Annual reports total sales volumes (megawatthours) of electricity to ultimate consumers and customer counts in states with deregulated markets as the sum of bundled sales reported by full-service providers and delivery reported by transmission and distribution

utilities. EIA has concluded that the sales of electricity to ultimate consumers 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 average 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 several 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.

Net-Metering: This section was expanded in 2011. Previously, customer count by sector was the only data collected and published. In 2010, the EIA-861 started collecting the capacity of the net-metered installations by sector and technology. The technology types are photovoltaic (PV), wind, and other. Starting with the 2016 data collection year, storage and virtual net metering were added to the PV section.

Demand-Side Management (DSM): Prior to 2011, DSM data was separated into two categories, large and small utilities. Some tables contained data for just large utilities and others contained both

categories, published separately. Starting in 2011, there is no longer a division in the data. All tables now include all DSM data from utilities; this change is also reflected in the historical data.

Starting in 2011, a new category of respondents was added to the EIA-861, non-utility DSM administrators: Efficiency Maine Trust, Energy trust of Oregon, Focus on Energy, NYSERDA, and Vermont Energy Investment Corporation.

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 the potential peak load reduction that may occur if all demand response is called and/or participates.

Advanced Metering: New in 2011, Automated Meter Reading (AMR) and Advanced Metering Infrastructure (AMI), including historical data back to 2007. From 2007-2009, the count by sector is for number of customers, for 2010-2011, the count is the actual number of meters. For example, if an industrial customer had 12 meters, in 2007-2009 the count would have been 1, in 2010-2011, the count would be 12.

In 2013, the number of standard meters (non-AMR/AMI) was added to this schedule. Starting in 2020, EIA imputes the number of standard meters for the short form (EIA-861S) by estimating the number of total meters based on the revenue, sales, and customer count schedule and subtracting the number of advanced meters.

Reliability: New in 2021, reliability metrics SAIDI (System Average Interruption Duration Index), SAIFI (System Average Interruption Frequency Index), and CAIDI (Customer Average Interruption Duration Index) are reported in aggregate by the state, census, and U.S. level dating back to 2013. Data are weighted by customers reported on the schedule and divided by all customers who reported by that metric. For example,

$$SAIDI_{All\ Events} = \frac{\sum(SAIDI_{All\ Events} * customers\ reported_{All\ Events})}{\sum customers\ reported_{All\ Events}}$$

Some respondents may report SAIDI for all events, but not with major events removed. In this case their values would be included in the calculations for SAIDI_{All Events} but their values (and customers reported) would not be included in the SAIDI_{w/o Major Events}.

CAIDI is not collected on the form and is a derived value of SAIDI/SAIFI. If a utility reports only one of these values (such as SAIDI) and not the other (SAIFI), it would be included in the regional CAIDI value. The final metric of percent reporting in some of the tables is a sum of customers who reported at least one reliability metric divided by the total number of customers on the revenue, sales, and customer counts schedule.

Form EIA-861M (formerly the EIA-826)

The Form EIA 861M, “Monthly Electric Power Industry Report,” is a monthly collection of data from a sample of approximately 650 of the largest electric utilities (primarily investor and publicly owned) as well as a census of energy service providers with sales to ultimate consumers in deregulated States. Form EIA-861 (see below), with approximately 3,400 respondents, serves as a frame from which the Form EIA-861M sample is drawn. Based on this sample, a model is used to estimate for the entire universe of U.S. electric utilities monthly.

Instrument and design history: The collection of electric power sales data and related information began in the early 1940’s and was established as FPC Form 5 by FPC Order 141 in 1947. In 1980, the report was revised with only selected income items remaining and became the FERC Form 5. The survey has gone by various other names, such as “Electric Utility Company Monthly Statement,” “Monthly Electric Utility Sales and Revenue Report with State Distributions,” and “Monthly Electric Utility Sales and Revenues with State Distributions Report.”

In 1993, EIA for the first time used a model sample for the Form EIA-861M. A stratified random sample, employing auxiliary data, was used for each of the four previous years. The sample for the Form EIA-861M was designed to obtain estimates of electricity sales and average retail price of electricity at the state level by end use sector.

Starting with data for January 2001, the restructuring of the electric power industry was considered by forming different schedules on the Form EIA-861M. These schedules group customers based on services provided by the utility: full service (or bundled) providers), electric service providers (energy) only, distribution service (delivery) only, and energy service providers that also provide the customers’ bill. -

With the revised definitions for the commercial and industrial sectors to include all data previously reported as ‘other’ data except transportation, and a separate transportation sector, all responses that would formerly have been reported under the “other” sector are now to be reported under one of the sectors that currently exist. This means there is probably a lower correlation between commercial and industrial data 2003 and after with data prior.

Average retail price of electricity 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 utility. Operating revenue includes energy charges, demand charges, consumer service charges, environmental surcharges, fuel adjustments, and other miscellaneous charges. Electric utility operating revenues also include State and Federal income taxes and taxes other than income taxes paid by the utility.

The average retail price of electricity reported in this publication by sector represents a weighted average of consumer revenue and sales within sectors and across sectors for all consumers and does not reflect the per kWh rate charged by the electric utility to the individual consumers. Electric utilities typically employ several rate schedules within a single sector. These alternative rate schedules reflect the varying consumption levels and patterns of consumers and their associated impact on the costs to the electric utility for providing electrical service.

Adjusting monthly data to annual data: As a final adjustment based on our most complete data, use is made of final Form EIA-861 data, when available. The annual totals for Form EIA-861M data by state and end-use sector are compared to the corresponding Form EIA-861 values for sales and revenue. The ratio of these two values in each case is then used to adjust each corresponding monthly value.

Form EIA-861S (Short Form)

The Form EIA 861S, “Annual Electric Power Industry Report (Short Form),” which started in year 2012. EIA-861S was created to lower the burden for bundled-service utilities with small annual sales that model-based estimation methods can be used to estimate the remaining parts of the survey. Starting in data year 2020, EIA raised the thresholds of utilities that could report on the short form and still ensure acceptable quality of statistical estimates. Respondents report on the long form (EIA-861) once every eight years. The most recent year all respondents were required to complete the full EIA-861 form was 2019. There are currently about 1,700 respondents on the Form EIA-861S.

Short form respondents report data on total sales, revenues, and customer counts by state. They answer a yes/no questions about demand side management (DSM) programs and the number of water heaters added to DSM programs. For time-based rate programs they provide the number of customers enrolled by state. Number of advanced meters are also provided by state, as well as a yes/no question about having any net-metering programs.

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, nonutility source and disposition of electricity, combustion by-product collection and disposal, and cooling systems, as well as operational data for flue gas desulfurization, particulates, and nitrous oxide controls. Data are collected from a monthly sample of approximately 3,300 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, at combined heat and power (CHP) plants, useful thermal output. At the end of the year, the monthly respondents report their annual source and disposition of electric power (nonutilities only), operational data for air emissions controls and cooling systems, and the collection and disposal of combustion by-products on the Form EIA-923 Supplemental Form (Schedules 6, 7, and 8A to 8F). Approximately 10,200 plants, representing all generators not included in the monthly sample and with a nameplate capacity of 1 MW or more, report applicable 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 total generator nameplate capacity of 50 megawatts or greater where coal is the primary fuel; or the total generator nameplate capacity is 200 megawatts or greater where the primary fuel is any combination of natural gas, petroleum coke, distillate fuel oil, or residual fuel oil. 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. Operational data for air emissions equipment are collected annually from facilities that have a steam turbine capacity of at least 10 megawatts, and operational data on cooling systems and data on the collection and disposal of combustion by-products are collected from facilities that have a steam turbine capacity of at least 100 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). Approximately 0.12 percent of the national total generation for is imputed, although this will vary by State and energy source.

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

Net Generation = (Factor) x Gross Generation
<u>Prime Movers:</u>
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
<u>Environmental Equipment:</u>
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. Power plants include independent power producers, electric utilities, and commercial and industrial CHP facilities. Power plants required to report receipts data are plants with 50 megawatts of capacity that has coal as its primary fuel, as well as plants with a combined capacity of 200 megawatts with its primary fuel being any combination of natural gas, petroleum coke, distillate fuel oil, or residual fuel oil. The data on cost and quality of fuel shipments are 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, thousand cubic feet (Mcf) and million Btu per thousand cubic feet.

Net and Gross Generation and Fuel Consumption and Stocks: Generation data are collected in megawatthours from all power plants with a sum of nameplate capacity at least 1 MW. The fuels consumed are collected in tons (solids), barrels (liquids) and thousand cubic feet (gases). Fuels are grouped into coal, petroleum liquids, petroleum coke, natural gas, other gases, and other miscellaneous fuels. Energy consumption is not collected for nuclear, wind, solar, geothermal, or other plants that do not burn fuels. For information on fuel groupings, see the instructions to the Form EIA-923 at http://www.eia.gov/survey/form/eia_923/instructions.pdf.

Combustion By-Product Collection and Disposal: Data are collected in thousand tons. Associated financial data for by-products (O&M and capital expenses and revenue) are collected in thousand dollars.

Air Emissions Equipment: Operational efficiencies and emission rates are collected for flue gas desulfurization, particulate matter, and nitrous oxide control equipment for steam-electric units with at least 10 MW nameplate capacity.

Cooling Systems: Operational data on water use is collected from steam-electric plants, including nuclear plants, with at least 100 MW nameplate capacity.

Methodology to Estimate Biogenic and Non-biogenic Municipal Solid Waste:² Municipal solid waste (MSW) consumption for generation of electric power is split into its biogenic and non-biogenic components beginning with the 2001 data year.

The tonnage of MSW consumed is reported on the Form EIA-923. The composition of MSW and categorization of the components were obtained from the U.S. Environmental Protection Agency (USEPA). For data years 2001 through 2009, the MSW composition was based on the USEPA annual publication, *Municipal Solid Waste in the United States: Facts and Figures*. The compositions developed for the 2009 data year were carried forward for the 2010 through 2018 data years. The most updated composition and categorization of MSW (for the 2019 data year) were also derived from a USEPA publication: *Advancing Sustainable Materials Management: Facts and Figures Report: 2015 Data Tables*. The updated composition values were applied in the October EPM 2019 on the preliminary 2019 values and will be applied going forward in future data years until EIA revises the MSW composition ratios again. The Btu contents of the components of MSW were obtained from various sources.

The numbers in Tables 1 and 2 illustrate two interrelated trends in the composition of the MSW stream. First, the heat content (per unit weight) of the waste stream has been steadily increasing overtime due to higher concentrations of non-biogenic materials. Second, the shares of energy contributed to the waste stream by biogenic and non-biogenic components have been changing over time with the percentage of biogenic materials falling and the share of non-biogenic materials rising.

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 was attributed to non-biogenic components (see Tables 1 and 2, below). Note, biogenic components include newsprint, paper, containers and packaging, leather, textiles, yard trimmings, food wastes, and wood. Non-biogenic components include plastics, rubber, and other miscellaneous non-biogenic waste.

These values are used to allocate net generation published in the Electric Power Monthly generation tables. The tons of biogenic and non-biogenic components were estimated with the assumption that

glass and metals were removed prior to combustion. The average Btu/ton for the biogenic and non-biogenic components is estimated by dividing the total Btu consumption by the total tons. Published net generation attributed to biogenic MSW and non-biogenic MSW is classified under Other Renewables and Other, respectively.

Table 1. Btu consumption for biogenic and non-biogenic municipal solid waste (percent)

	2001	2002	2003	2004	2005	2006	2007	2008	2009	...	2018	2019
Biogenic	57	56	55	55	56	57	55	54	51	51	51	45
Non-biogenic	43	44	45	45	44	43	46	46	49	49	49	55

Table 2. Tonnage consumption for biogenic and non-biogenic municipal solid waste (percent)

	2001	2002	2003	2004	2005	2006	2007	2008	2009	...	2018	2019
Biogenic	77	77	76	76	75	67	65	65	64	64	64	61
Non-biogenic	23	23	24	24	25	34	35	35	36	36	36	39

Useful Thermal Output (UTO): With the implementation of the Form EIA-923, “Power Plant Operations Report,” in 2008, combined heat and power (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.

Beginning with 2016 Form EIA-923 data, reported efficiency factors by survey respondents replaced the previously EIA estimated efficiency factors used in the fuel allocation process. For the processing of 2016 CHP data, EIA used for each plant an average of the efficiency factors reported by the CHP plants on the 2013, 2014, and 2015 Form EIA-923, “Power Plant Operations Report” surveys. An average was used to smooth out variations in any one year’s data. Once efficiency of each plant was established, the value was input into the above methodology to allocate the consumption of fuel between electric power and UTO. This update applies to the 2016 data and going forward but was not retroactively applied to previous years.

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 Electric Power Annual (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.

Capacity Factors and Usage Factors

This section describes the methodology for calculating capacity factors and usages factors by fuel and technology type for operating electric power plants. Capacity factor is a measure (expressed as a percent) of how often an electric generator operates over a specific period, using a ratio of the actual output to the maximum possible output over that period.

The monthly capacity factor calculation includes all operating electric generators which operated for the entire month using the net generation reported on the Form EIA-923 and the net summer capacity reported on the Form EIA-860. The capacity factor for a particular fuel/technology type is given by:

$$capacity\ factor = \frac{\sum_{x,m} net\ generation_{x,m}}{\sum_{x,m} capacity_{x,m} * hours\ in\ month_m}$$

where x represents generators of that fuel/technology combination and m represents individual months. Net generation and capacity are specific to a generator, and the generator is categorized by its primary fuel type as reported on the EIA-860. All generation from that generator is included, regardless of other fuels consumed. Net generation and capacity for a generator is excluded from the summations during the month that the generator initially began operation and if applicable during the month that the generator retired. Therefore, these published capacity factors will differ from a simple calculation using annual generation and capacity totals from the appropriate tables in this publication.

Usage factors are calculated for energy storage technologies using gross generation instead of net generation:

$$usage\ factor = \frac{\sum_{x,m} gross\ generation_{x,m}}{\sum_{x,m} capacity_{x,m} * hours\ in\ month_m}$$

Air Emissions

This section describes the methodology for calculating estimated emissions of carbon dioxide (CO₂) from electric generating plants for 1989 through the present, as well as the estimated emissions of sulfur dioxide (SO₂) and nitrogen oxides (NO_x) from electric generating plants for 2001 through the present. For a description of the methodology used for other years, see the technical notes to the EPA 2003.

Methodology Overview: Initial estimates of uncontrolled SO₂ 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:

$$\text{Emissions} = \text{Quantity of Fuel Consumed} \times \text{Emission Factor}$$

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 SO₂ emissions. As discussed below, physical quantities are converted to millions of Btus for calculating CO₂ emissions.

For some fuels, the calculation of SO₂ 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:

$$\text{Emissions} = \text{Quantity of Fuel Consumed} \times \text{Emission Factor} \times \text{Sulfur Content}$$

The fuels that require the percent sulfur as part of the emissions calculation are indicated in Table A.1., which lists the SO₂ emission factors used for this report.

In the case of SO₂ 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 the boiler is a wet-bottom or dry-bottom design.³ These distinctions are shown in Tables A.1. and A.2.

For SO₂ 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 SO₂ is the fluidized bed boiler, in which the sulfur removal process is integral with the operation of the boiler. The SO₂ emission factors shown in Table A.1. for fluidized bed boilers already account for 90 percent removal of SO₂ since, in effect, the plant has no uncontrolled emissions of this pollutant.

Although SO₂ 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 CO₂ are incomplete and are not used in this report.) The CEMS data account for the bulk of SO₂ and NO_x emissions from the electric power industry. For those plants for which CEMS data are available, the EIA estimates of SO₂ 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 several 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 Electric Power Annual 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.

CO₂ Emissions: CO₂ 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 CO₂ emissions, the fuel-specific emission factor from Table A.3. is multiplied by the fuel consumption in MMBtu.

The estimation procedure calculates uncontrolled CO₂ emissions. CO₂ control technologies are currently in the early stages of research and there are no commercial systems installed. Therefore, no estimates of controlled CO₂ emissions are made.

SO₂ and NO_x Emissions: To comply with environmental regulations controlling SO₂ 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 A.4.). 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 fuels⁴ 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 SO₂ and NO_x emissions:

- For steam electric plants, uncontrolled emissions are estimated using the emission factors shown in Tables A.1. and A.2. 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 SO₂, 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 A.4. 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 A.1. and Table A.2. 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 A.1.⁵

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 SO₂ 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 Factors for Propane, Petroleum Coke, and Synthesis Gases.

The quantity conversion for petroleum coke is 5 barrels (of 42 U.S. gallons each) per short ton (2,000 pounds), propane is 1.53 thousand cubic feet per barrel, coal-derived synthesis gas is 98.06 thousand cubic feet per ton, and petroleum coke-derived synthesis gas is 107.31 thousand cubic feet per ton.

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 Electric Power Annual and other data products, classifies nonutility power producers into the following categories:

- **Electric Utility (Sector 1):** All regulated plants with a primary purpose of selling electricity in the public markets (NAICS = 22).
- **Independent Power Producers (Sector 2):** All non-regulated plants with a primary purpose of electric power generation and a primary purpose of selling electricity in the public markets (NAICS = 22) with no ability to cogenerate heat and power.
- **Electric Power, Combined Heat and Power (Sector 3):** All non-regulated plants with a primary purpose of electric power generation and a primary purpose of selling electricity in the public markets (NAICS = 22) with the ability to cogenerate heat and power.
- **Commercial, Non-Combined Heat and Power (Sector 4):** All plants with a commercial primary purpose with no ability to cogenerate heat and power.
- **Commercial, Combined Heat and Power (Sector 5):** All plants with a commercial primary purpose with the ability to cogenerate heat and power.
- **Industrial, Non-Combined Heat and Power (Sector 6):** All plants with an industrial primary purpose with no ability to cogenerate heat and power.
- **Industrial, Combined Heat and Power (Sector 7):** All plants with an industrial primary purpose with the ability to cogenerate heat and power.

The following is a list of the North American Industry Classification System (NAICS) classifications used by EIA.

	Agriculture, Forestry, Fishing and Hunting
111	Crop Production
112	Animal Production
113	Forestry and Logging
114	Fishing, Hunting and Trapping
115	Support Activities for Agriculture and Forestry
	Mining, Quarrying, and Oil and Gas Extraction
211	Oil and Gas Extraction
2121	Coal Mining
2122	Metal Ore Mining
2123	Nonmetallic Mineral Mining and Quarrying
	Utilities
22	Electric Power Generation, Transmission and Distribution (other than 2212, 2213, 22131, 22132 or 22133)
2212	Natural Gas Distribution
22131	Water Supply and Irrigation Systems
22132	Sewage Treatment Facilities

22133	Steam and Air-Conditioning Supply
	Manufacturing
311	Food Manufacturing
312	Beverage and Tobacco Product Manufacturing
313	Textile Mills (Fiber, Yarn, Thread, Fabric, and Textiles)
314	Textile Product Mills
315	Apparel Manufacturing
316	Leather and Allied Product Manufacturing
321	Wood Product Manufacturing
322	Paper Manufacturing (other than 322122 or 32213)
322122	Newsprint Mills
32213	Paperboard Mills
323	Printing and Related Support Activities
324	Petroleum and Coal Products Manufacturing (other than 32411)
32411	Petroleum Refineries
325	Chemical Manufacturing (other than 32511, 32512, 325193, 325188, 3252 325211, 3253 or 325311)
32511	Petrochemical Manufacturing
32512	Industrial Gas Manufacturing
325193	Ethyl Alcohol Manufacturing (including Ethanol)
325188	Industrial Inorganic Chemicals
3252	Resin, Synthetic Rubber, and Artificial Synthetic Fibers and Filaments Manufacturing (other than 325211)
325211	Plastics Material and Resin Manufacturing
3253	Pesticide, Fertilizer, and Other Agricultural Chemical Manufacturing (other than 325311)
325311	Nitrogenous Fertilizer Manufacturing
326	Plastics and Rubber Products Manufacturing
327	Nonmetallic Mineral Product Manufacturing (other than 32731)
32731	Cement Manufacturing
331	Primary Metal Manufacturing (other than 331111 or 331312)
331111	Iron and Steel Mills
331312	Primary Aluminum Production
332	Fabricated Metal Product Manufacturing
333	Machinery Manufacturing
334	Computer and Electronic Product Manufacturing
335	Electrical Equipment, Appliance, and Component Manufacturing
336	Transportation Equipment Manufacturing
337	Furniture and Related Product Manufacturing
339	Miscellaneous Manufacturing
421	Wholesale Trade
441	Retail Trade
	Transportation and Warehousing
481	Air Transportation
482	Rail Transportation
483	Water Transportation
484	Truck Transportation
485	Transit and Ground Passenger Transportation
486	Pipeline Transportation
487	Scenic and Sightseeing Transportation

488	Support Activities for Transportation (other than 4881, 4882, 4883 or 4884)
4881	Support Activities for Air Transportation (including Airports)
4882	Support Activities for Rail Transportation (including Rail Stations)
4883	Support Activities for Water Transportation (including Marinas)
4884	Support Activities for Road Transportation
491	Postal Service
492	Couriers and Messengers
493	Warehousing and Storage
	Information
511	Publishing Industries (except Internet)
512	Motion Picture and Sound Recording Industries
515	Broadcasting (except Internet)
517	Telecommunications
518	Data Processing, Hosting, and Related Services
519	Other Information Services
521	Finance and Insurance
53	Real Estate and Rental and Leasing (including Convention Centers and Office Buildings)
541	Professional, Scientific, and Technical Services
55	Management of Companies and Enterprises
	Administrative and Support and Waste Management and Remediation Services
561	Administrative and Support Services
562	Waste Management and Remediation Services (other than 562212 or 562213)
562212	Solid Waste Landfill
562213	Solid Waste Combustors and Incinerators
611	Educational Services
	Health Care and Social Assistance
621	Ambulatory Health Care Services
622	Hospitals
623	Nursing and Residential Care Facilities
624	Social Assistance
	Arts, Entertainment, and Recreation
711	Performing Arts, Spectator Sports, and Related Industries
712	Museums, Historical Sites, and Similar Institutions
713	Amusement, Gambling, and Recreation Industries
	Accommodation and Food Services
721	Accommodation
722	Food Services and Drinking Places
	Other Services (except Public Administration)
811	Repair and Maintenance
812	Personal and Laundry Services
813	Religious, Grantmaking, Civic, Professional, and Similar Organizations
814	Private Households

92	Public Administration (other than 921, 922, 92214 or 928)
921	Executive, Legislative, and Other General Government Services
922	Justice, Public Order and Safety Activities (other than 92214)
92214	Correctional Facilities
928	National Security and International Affairs (including Military Bases)

Multiple Survey Programs- Small Scale PV Solar Estimation of Generation

Monthly generation from small scale PV solar resources is an estimation of the generation produced from PV solar resources and not the results of a data collection effort for generation directly, except for “Third Party Owned” or (TPO) solar installations which has direct data collection. TPO data however is not comprehensive. TPOs do not operate in every state, TPO collected data is not a large portion of the estimated amount, and the data has been collected for limited period. The generation estimate is based on data collected for PV solar capacity.

Capacity of PV solar resources is collected directly from respondents. These data are collected on several EIA forms and from several types of respondents. Monthly data for net-metered PV solar capacity is reported on the Form EIA-861M. Form EIA-61M is a cutoff sample drawn from the annual survey Form EIA-861 which collects this data from all respondents. Using data from both surveys we have a regression model to impute for the non-sampled monthly capacity.

The survey instruments collect solar net metering capacity from reporting utilities by state and customer class. There are four customer classes: residential, commercial, industrial and transportation. However, the estimation process included only the residential, commercial, and industrial customers.¹ Data for these customer classes were further classified by U.S. Census Regions, to ensure adequate number of customer observations in for each estimation group.

Estimation Model: The total PV capacity reported by utilities in the annual EIA-861 survey is the single primary input (regressor) to the monthly estimation of PV capacity by state. The model tested for each census region was of the form:

$$y_{i_{2015,m}} = \beta_1 x_{i_{2013}} + w_i^{-1/2} e_i, \text{ where}$$

$x_{i_{2013}}$ is the i^{th} utility’s 2013 (or the last published year) solar PV capacity

$y_{i_{2015,m}}$ is the i^{th} utility’s month m , 2015 (or the current year) reported solar PV capacity

w_i is the weight factor, which is the inverse of $x_{i_{2013}}$

β_1 is effectively the growth rate of reported month m solar PV capacity

ϵ_i is the error term

The model checks for outliers and removes them from the regression equation inputs. The model calculates RSEs by sector, state, census region, and U.S. total. Once we have imputed for all the monthly net-metered PV solar capacity we add to total net metered capacity, the PV solar capacity collected for the non net-metered capacity.

We use a second model to estimate the generation using this capacity as an input. The original methodology was developed for the “Annual Energy Outlook” based on our “NEMS” modelled projections several years ago. The original method underwent a calibration project designed to develop PV production levels for the NEMS projections consistent with simulations of a National Renewable Energy Laboratory model called PVWatts, which is itself embedded in PC software under the umbrella of the NREL’s System Advisor Model (SAM).

The PVWatts simulations require, panel azimuth orientations and tilts, something that the NEMS projections do not include. Call the combinations of azimuths and tilts “orientations.” The orientation and solar insolation (specific to a location) have a direct effect on the PV production level. The calibration project selected the 100 largest population Metropolitan Statistical Areas (MSAs) and relied on weights derived from orientation data from California Solar Initiative dataset to develop typical outputs for each of the 100 MSAs. It then was expanded from an annual estimate to a monthly estimate. A further description of this model is located here. A listing of the MSAs is included in Appendix 1.

Using Form EIA-861 data for service territories, which lists the counties that each electric distribution company (EDC) provides service, and NREL solar insolation data by county a simple average of insolation values by EDC is calculated.

Using the estimation model, we produce by utility, by state and by sector an estimate of generation. All the utilities’ capacity and generation estimates are summed by state and sector and a KWh/KW rate by state and sector is calculated.

Capacity from the Form EIA-860 that is net metered is subtracted from the total capacity by state and sector as well as the capacity reported on the EIA-861M from TPOs, resulting in a new “net” capacity amount. This capacity amount is multiplied by the KWh/KW rate to produce the non-TPO generation estimate and then it is added to the TPO reported sales to ultimate customers from the EIA-861 to obtain a final estimate for generation and a blended KWh/KW rate is calculated. The estimate for generation is aggregated by US census regions and US totals. The RSEs for capacity are checked for level of error and if they pass, the summary data by state, US census region and US total are reported in the EPM.

Appendix 2 contains a flow diagram of the data inputs, data quality control checks and data analysis required to perform this estimation.

Appendix 1- MSAs

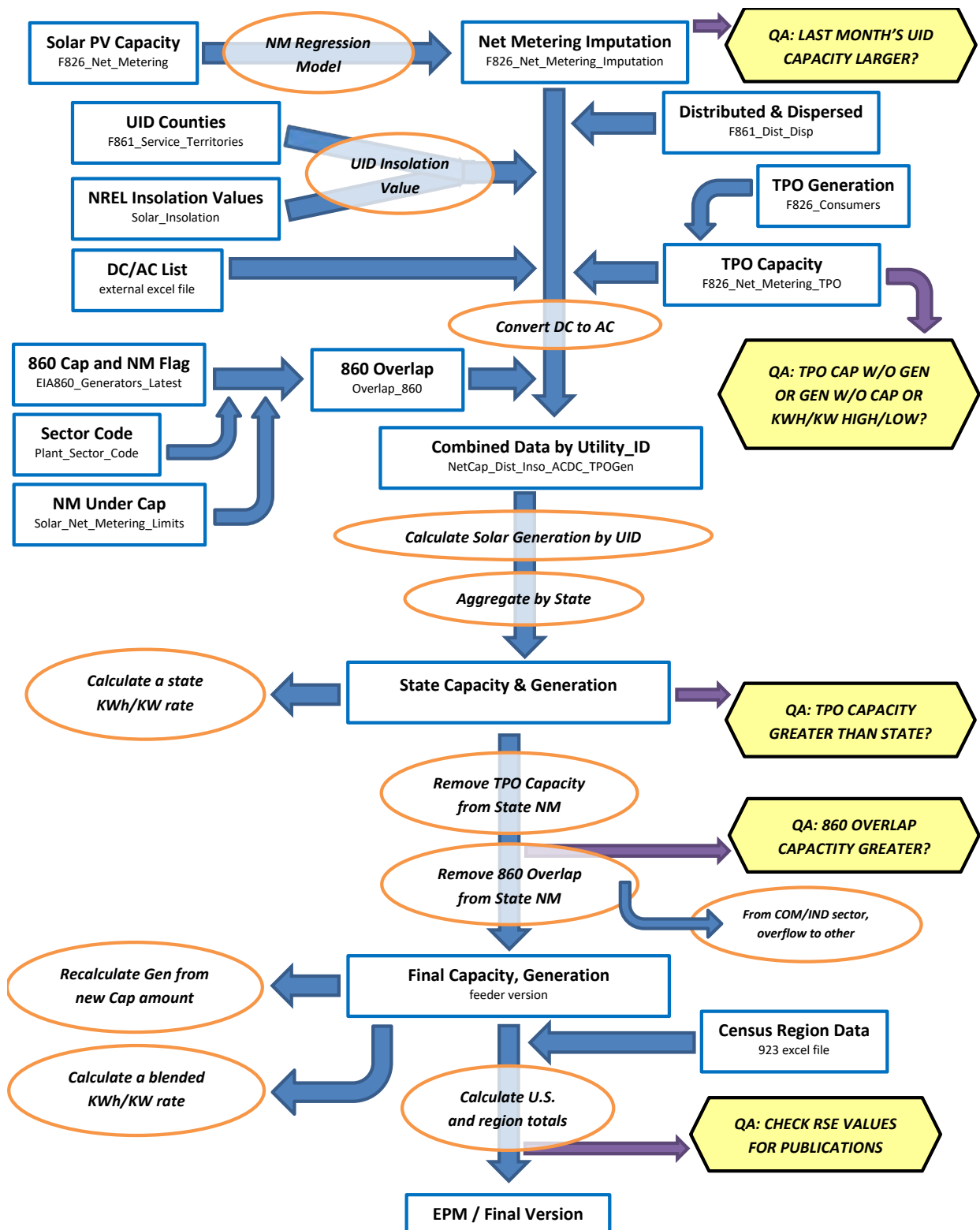
TMY3 (1991-2005) Weather Stations by MSA

Site	Weather Location	MSA
1	USA NY New York Central Park Obs.	New York-Newark-Jersey City, NY-NJ-PA MSA
2	USA CA Los Angeles Intl Airport	Los Angeles-Long Beach-Anaheim, CA MSA
3	USA IL Chicago Midway Airport	Chicago-Naperville-Elgin, IL-IN-WI MSA
4	USA TX Dallas-Fort Worth Intl Airport	Dallas-Fort Worth-Arlington, TX MSA
5	USA TX Houston Bush Intercontinental	Houston-The Woodlands-Sugar Land, TX MSA
6	USA PA Philadelphia Int'l Airport	Philadelphia-Camden-Wilmington, PA-NJ-DE-MD MSA
7	USA VA Washington Dc Reagan Airport	Washington-Arlington-Alexandria, DC-VA-MD-WV MSA
8	USA FL Miami Intl Airport	Miami-Fort Lauderdale-West Palm Beach, FL MSA
9	USA GA Atlanta Hartsfield Intl Airport	Atlanta-Sandy Springs-Roswell, GA MSA
10	USA MA Boston Logan Int'l Airport	Boston-Cambridge-Newton, MA-NH MSA
11	USA CA San Francisco Intl Airport	San Francisco-Oakland-Hayward, CA MSA
12	USA AZ Phoenix Sky Harbor Intl Airport	Phoenix-Mesa-Scottsdale, AZ MSA
13	USA CA Riverside Municipal Airport	Riverside-San Bernardino-Ontario, CA MSA
14	USA MI Detroit City Airport	Detroit-Warren-Dearborn, MI MSA
15	USA WA Seattle Seattle-Tacoma Intl Airport	Seattle-Tacoma-Bellevue, WA MSA
16	USA MN Minneapolis-St. Paul Int'l Arp	Minneapolis-St. Paul-Bloomington, MN-WI MSA
17	USA CA San Diego Lindbergh Field	San Diego-Carlsbad, CA MSA
18	USA FL Tampa Int'l Airport	Tampa-St. Petersburg-Clearwater, FL MSA
19	USA MO St Louis Lambert Int'l Airport	St. Louis, MO-IL MSA
20	USA MD Baltimore-Washington Int'l Airport	Baltimore-Columbia-Towson, MD MSA
21	USA CO Denver Centennial [Golden - NREL]	Denver-Aurora-Lakewood, CO MSA
22	USA PA Pittsburgh Allegheny Co Airport	Pittsburgh, PA MSA
23	USA NC Charlotte Douglas Intl Airport	Charlotte-Concord-Gastonia, NC-SC MSA
24	USA OR Portland Hillsboro	Portland-Vancouver-Hillsboro, OR-WA MSA
25	USA TX San Antonio Intl Airport	San Antonio-New Braunfels, TX MSA
26	USA FL Orlando Intl Airport	Orlando-Kissimmee-Sanford, FL MSA
27	USA CA Sacramento Executive Airport	Sacramento-Roseville-Arden-Arcade, CA MSA
28	USA OH Cincinnati Municipal Airport	Cincinnati, OH-KY-IN MSA
29	USA OH Cleveland Hopkins Intl Airport	Cleveland-Elyria, OH MSA
30	USA MO Kansas City Int'l Airport	Kansas City, MO-KS MSA
31	USA NV Las Vegas McCarran Intl Airport	Las Vegas-Henderson-Paradise, NV MSA
32	USA OH Columbus Port Columbus Intl A	Columbus, OH MSA
33	USA IN Indianapolis Intl Airport	Indianapolis-Carmel-Anderson, IN MSA
34	USA CA San Jose Intl Airport	San Jose-Sunnyvale-Santa Clara, CA MSA
35	USA TX Austin Mueller Municipal Airport	Austin-Round Rock, TX MSA

36	USA TN Nashville Int'l Airport	Nashville-Davidson–Murfreesboro–Franklin, TN MSA
37	USA VA Norfolk Int'l Airport	Virginia Beach-Norfolk-Newport News, VA-NC MSA
38	USA RI Providence T F Green State	Providence-Warwick, RI-MA MSA
39	USA WI Milwaukee Mitchell Intl Airport	Milwaukee-Waukesha-West Allis, WI MSA
40	USA FL Jacksonville Craig	Jacksonville, FL MSA
41	USA TN Memphis Int'l Airport	Memphis, TN-MS-AR MSA
42	USA OK Oklahoma City Will Rogers	Oklahoma City, OK MSA
43	USA KY Louisville Bowman Field	Louisville/Jefferson County, KY-IN MSA
44	USA VA Richmond Int'l Airport	Richmond, VA MSA
45	USA LA New Orleans Alvin Callender	New Orleans-Metairie, LA MSA
46	USA CT Hartford Bradley Intl Airport	Hartford-West Hartford-East Hartford, CT MSA
47	USA NC Raleigh Durham Int'l	Raleigh, NC MSA
48	USA UT Salt Lake City Int'l Airport	Salt Lake City, UT MSA
49	USA AL Birmingham Municipal Airport	Birmingham-Hoover, AL MSA
50	USA NY Buffalo Niagara Intl Airport	Buffalo-Cheektowaga-Niagara Falls, NY MSA
51	USA NY Rochester Greater Rochester	Rochester, NY MSA
52	USA MI Grand Rapids Kent County Int'l Airport	Grand Rapids-Wyoming, MI MSA
53	USA AZ Tucson Int'l Airport	Tucson, AZ MSA
54	USA HI Honolulu Intl Airport	Urban Honolulu, HI MSA
55	USA OK Tulsa Int'l Airport	Tulsa, OK MSA
56	USA CA Fresno Yosemite Intl Airport	Fresno, CA MSA
57	USA CT Bridgeport Sikorsky Memorial	Bridgeport-Stamford-Norwalk, CT MSA
58	USA MA Worcester Regional Airport	Worcester, MA-CT MSA
59	USA NM Albuquerque Intl Airport	Albuquerque, NM MSA
60	USA NE Omaha Eppley Airfield	Omaha-Council Bluffs, NE-IA MSA
61	USA NY Albany County Airport	Albany-Schenectady-Troy, NY MSA
62	USA CA Bakersfield Meadows Field	Bakersfield, CA MSA
63	USA CT New Haven Tweed Airport	New Haven-Milford, CT MSA
64	USA TN Knoxville McGhee Tyson Airport	Knoxville, TN MSA
65	USA SC Greenville Downtown Airport	Greenville-Anderson-Mauldin, SC MSA
66	USA CA Oxnard Airport	Oxnard-Thousand Oaks-Ventura, CA MSA
67	USA TX El Paso Int'l Airport	El Paso, TX MSA
68	USA PA Allentown Lehigh Valley Intl	Allentown-Bethlehem-Easton, PA-NJ MSA
69	USA LA Baton Rouge Ryan Airport	Baton Rouge, LA MSA
70	USA TX McCallen Miller Intl Airport	McAllen-Edinburg-Mission, TX MSA
71	USA OH Dayton Int'l Airport	Dayton, OH MSA
72	USA SC Columbia Metro Airport	Columbia, SC MSA
73	USA NC Greensboro Piedmont Triad Int'l Airport	Greensboro-High Point, NC MSA
74	USA FL Sarasota Bradenton	North Port-Sarasota-Bradenton, FL MSA
75	USA AR Little Rock Adams Field	Little Rock-North Little Rock-Conway, AR MSA
76	USA SC Charleston Intl Airport	Charleston-North Charleston, SC MSA

77	USA OH Akron Akron-canton Reg. Airport	Akron, OH MSA
78	USA CA Stockton Metropolitan Airport	Stockton-Lodi, CA MSA
79	USA CO Colorado Springs Muni Airport	Colorado Springs, CO MSA
80	USA NY Syracuse Hancock Int'l Airport	Syracuse, NY MSA
81	USA FL Fort Myers Page Field	Cape Coral-Fort Myers, FL MSA
82	USA NC Winston-Salem Reynolds Airport	Winston-Salem, NC MSA
83	USA ID Boise Air Terminal	Boise City, ID MSA
84	USA KS Wichita Mid-continent Airport	Wichita, KS MSA
85	USA WI Madison Dane Co Regional Airport	Madison, WI MSA
86	USA MA Worcester Regional Airport	Springfield, MA MSA
87	USA FL Lakeland Linder Regional Airport	Lakeland-Winter Haven, FL MSA
88	USA UT Ogden Hinkley Airport	Ogden-Clearfield, UT MSA
89	USA OH Toledo Express Airport	Toledo, OH MSA
90	USA FL Daytona Beach Intl Airport	Deltona-Daytona Beach-Ormond Beach, FL MSA
91	USA IA Des Moines Intl Airport	Des Moines-West Des Moines, IA MSA
92	USA GA Augusta Bush Field	Augusta-Richmond County, GA-SC MSA
93	USA MS Jackson Int'l Airport	Jackson, MS MSA
94	USA UT Provo Muni	Provo-Orem, UT MSA
95	USA PA Wilkes-Barre Scranton Intl Airport	Scranton-Wilkes-Barre-Hazleton, PA MSA
96	USA PA Harrisburg Capital City Airport	Harrisburg-Carlisle, PA MSA
97	USA OH Youngstown Regional Airport	Youngstown-Warren-Boardman, OH-PA MSA
98	USA FL Melbourne Regional Airport	Palm Bay-Melbourne-Titusville, FL MSA
99	USA TN Chattanooga Lovell Field Airport	Chattanooga, TN-GA MSA
100	USA WA Spokane Int'l Airport	Spokane Spokane Valley, WA MSA

Appendix 2 – Flow diagram of data sources and analysis



Endnotes

- 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 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
- ³ 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.
- ⁴ 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.
- ⁵ 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/survey/form/eia_767/instructions_form.pdf.

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c))
Emergency Order: Tri-State)
Generation and Transmission)
Association, Platte River Power)
Authority, Salt River Project,)
PacifiCorp, and Xcel Energy)

Order No. 202-25-14

Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
Public Interest Organizations

Filed January 28, 2026

Exhibit 1-107:
EIA Annual 2019



Independent Statistics & Analysis

U.S. Energy Information
Administration

Electric Power Annual 2019

February 2021

Electric Power Annual 2019 Revision Notice – February 19, 2021

Due to several plant-level data corrections in 2019 net generation and fossil fuel consumption, EIA has revised tables 1.1; 1.2; 1.3; 3.1.A; 3.1.B; 3.2.A; 3.2.B; 3.3.A; 3.3.B; 3.7; 3.8; 3.9; 3.11; 3.15; 3.17; 3.18; 3.23; 3.26; 4.8.B; 5.1.A; 5.1.C; 5.1.D; 5.1.E; 5.1.F; 5.4.A; 5.4.C; 5.4.D; 5.4.F; 5.9; 5.12; 6.1; 6.2; 6.3; 6.4; 7.6; and 8.1.

This report was prepared by the U.S. Energy Information Administration (EIA), the statistical and analytical agency within the U.S. Department of Energy. By law, EIA's data, analyses, and forecasts are independent of approval by any other officer or employee of the United States Government.



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EIA Electric Industry Data Collection

Chapter 1

National Summary Data

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Net Generation and Consumption of Fuels for January through December														
		Total (All Sectors)			Electric Power Sector				Commercial		Industrial		Residential	
					Electric Utilities		Independent Power Producers							
Fuel	Facility Type	Year 2019	Year 2018	Percentage Change	Year 2019	Year 2018	Year 2019	Year 2018	Year 2019	Year 2018	Year 2019	Year 2018	Year 2019	Year 2018
Net Generation (Thousand Megawatthours)														
Coal	Utility Scale Facilities	964,957	1,149,487	-16.1%	722,885	863,505	235,847	278,668	268	303	5,957	7,011	0	0
Petroleum Liquids	Utility Scale Facilities	11,522	16,245	-29.1%	8,313	10,108	2,669	5,487	116	132	424	517	0	0
Petroleum Coke	Utility Scale Facilities	6,819	8,981	-24.1%	5,112	6,817	1,125	1,516	5	7	576	640	0	0
Natural Gas	Utility Scale Facilities	1,585,814	1,469,133	7.9%	785,026	720,206	692,113	645,616	8,610	8,419	100,065	94,892	0	0
Other Gas	Utility Scale Facilities	12,591	13,463	-6.5%	154	151	3,883	3,935	0	0	8,554	9,377	0	0
Nuclear	Utility Scale Facilities	809,409	807,084	0.3%	430,672	424,251	378,738	382,833	0	0	0	0	0	0
Hydroelectric Conventional	Utility Scale Facilities	287,874	292,524	-1.6%	262,364	267,336	24,288	23,812	188	227	1,033	1,149	0	0
Renewable Sources Excluding Hydroelectric	Utility Scale Facilities	440,799	414,292	6.4%	55,188	49,100	354,823	333,491	3,426	3,214	27,361	28,487	0	0
... Wind	Utility Scale Facilities	295,882	272,667	8.5%	43,636	38,466	251,968	233,931	179	174	100	97	0	0
... Solar Thermal and Photovoltaic	Utility Scale Facilities	71,937	63,825	12.7%	6,785	4,916	64,480	58,337	587	525	85	47	0	0
... Wood and Wood-Derived Fuels	Utility Scale Facilities	38,543	40,936	-5.8%	2,784	3,364	9,237	10,021	90	77	26,433	27,475	0	0
... Other Biomass	Utility Scale Facilities	18,964	20,896	-9.2%	1,213	1,344	14,878	16,279	2,129	2,404	743	868	0	0
... Geothermal	Utility Scale Facilities	15,473	15,967	-3.1%	771	1,009	14,260	14,924	442	33	0	0	0	0
Hydroelectric Pumped Storage	Utility Scale Facilities	-5,261	-5,905	-10.9%	-4,261	-4,785	-1,000	-1,119	0	0	0	0	0	0
Other Energy Sources	Utility Scale Facilities	13,331	12,973	2.8%	551	561	7,138	6,677	1,076	1,010	4,567	4,725	0	0
All Energy Sources	Utility Scale Facilities	4,127,855	4,178,277	-1.2%	2,266,004	2,337,250	1,699,625	1,680,917	13,689	13,312	148,537	146,798	0	0
Estimated Small Scale Solar Photovoltaic	Small Scale Facilities	34,957	29,539	18.3%	0	0	0	0	11,002	9,798	3,041	2,636	20,914	17,105
Estimated Total Solar Photovoltaic	All Facilities	103,676	89,773	15.5%	6,757	4,865	61,290	54,796	11,588	10,324	3,127	2,683	20,914	17,105
Estimated Total Solar	All Facilities	106,894	93,365	14.5%	6,785	4,916	64,480	58,337	11,588	10,324	3,127	2,683	20,914	17,105
Consumption of Fossil Fuels for Electricity Generation														
Coal (1000 tons)	Utility Scale Facilities	537,620	636,213	-15.5%	399,545	473,617	135,838	159,976	76	87	2,161	2,534	0	0
Petroleum Liquids (1000 barrels)	Utility Scale Facilities	20,836	28,614	-27.2%	15,677	18,345	4,464	9,467	251	269	444	534	0	0
Petroleum Coke (1000 tons)	Utility Scale Facilities	2,724	3,623	-24.8%	2,067	2,740	478	704	1	2	177	177	0	0
Natural Gas (1000 Mcf)	Utility Scale Facilities	11,601,600	10,833,043	7.1%	5,969,422	5,551,181	4,958,798	4,663,935	55,575	52,650	617,805	565,276	0	0
Consumption of Fossil Fuels for Useful Thermal Output														
Coal (1000 tons)	Utility Scale Facilities	12,397	13,813	-10.3%	2,062	2,268	1,161	1,356	443	490	8,731	9,700	0	0
Petroleum Liquids (1000 barrels)	Utility Scale Facilities	2,162	2,614	-17.3%	71	103	226	354	419	350	1,446	1,807	0	0
Petroleum Coke (1000 tons)	Utility Scale Facilities	839	929	-9.7%	17	12	93	93	6	10	724	814	0	0
Natural Gas (1000 Mcf)	Utility Scale Facilities	1,196,025	1,205,962	-0.8%	42,645	43,156	317,231	331,952	79,734	81,856	756,415	748,997	0	0
Consumption of Fossil Fuels for Electricity Generation and Useful Thermal Output														
Coal (1000 tons)	Utility Scale Facilities	550,017	650,027	-15.4%	401,607	475,885	136,998	161,332	519	577	10,892	12,233	0	0
Petroleum Liquids (1000 barrels)	Utility Scale Facilities	22,998	31,228	-26.4%	15,748	18,448	4,690	9,820	670	619	1,890	2,341	0	0
Petroleum Coke (1000 tons)	Utility Scale Facilities	3,563	4,552	-21.7%	2,083	2,752	571	797	7	12	900	991	0	0
Natural Gas (1000 Mcf)	Utility Scale Facilities	12,797,626	12,039,005	6.3%	6,012,067	5,594,338	5,276,029	4,995,888	135,310	134,507	1,374,220	1,314,273	0	0

Sales, Revenue, and Average Price of Electricity to Ultimate Customers for January through December									
Total U.S. Electric Power Industry									
	Sales of Electricity to Ultimate Customers (million kWh)			Revenue from Sales of Electricity to Ultimate Customers (million dollars)			Average Price of Electricity to Ultimate Customers (cents/kWh)		
Sector	Year 2019	Year 2018	Percentage Change	Year 2019	Year 2018	Percentage Change	Year 2019	Year 2018	Percentage Change
Residential	1,440,289	1,469,093	-2.0%	187,436	189,033	-0.8%	13.01	12.87	1.1%
Commercial	1,360,877	1,381,755	-1.5%	145,280	147,425	-1.5%	10.68	10.67	0.1%
Industrial	1,002,353	1,000,673	0.2%	68,285	69,218	-1.3%	6.81	6.92	-1.6%
Transportation	7,632	7,665	-0.4%	737	744	-0.8%	9.66	9.70	-0.4%
All Sectors	3,811,150	3,859,185	-1.2%	401,738	406,420	-1.2%	10.54	10.53	0.1%

NM = Not meaningful due to large relative standard error.
W = Withheld to avoid disclosure of individual company data.
Displayed values of zero may represent small values that round to zero. The Excel version of this table provides additional precision which may be accessed by selecting individual cells.
Coal generation and consumption includes anthracite, bituminous, subbituminous, lignite, waste coal, refined coal, synthetic coal, and coal-derived synthesis gas.
Petroleum Liquids includes distillate fuel oil, residual fuel oil, jet fuel, kerosene, propane, and waste oil.
Petroleum Coke includes petroleum coke and synthesis gas derived from petroleum coke.
Natural gas includes a small amount of supplemental gaseous fuels that cannot be identified separately.
Other Gases includes blast furnace gas and other manufactured and waste gases derived from fossil fuels.
Wood and Wood-Derived Fuels include wood, black liquor, and other wood waste.
Other Biomass includes biogenic municipal solid waste, landfill gas, sludge waste, agricultural byproducts, and other biomass.
Coal stocks include anthracite, bituminous, subbituminous, lignite, refined coal, and synthetic coal; waste coal is excluded.
Sales of electricity to ultimate customers and net generation may not correspond exactly for a particular month for a variety of reasons (e.g., sales data may include imported electricity).
Net generation is presented for the calendar month while sales of electricity to ultimate customers and associated revenue accumulate from bills collected for periods of time that vary depending

Table 1.2. Summary Statistics for the United States, 2009 - 2019

(From Table 2.1.) Number of Ultimate Customers

Year	Residential	Commer- cial	Industrial	Transpor- tation	Other	Total
2009	125,208,829	17,562,235	757,537	704	N/A	143,529,305
2010	125,717,935	17,674,338	747,747	239	N/A	144,140,259
2011	126,143,072	17,638,062	727,920	92	N/A	144,509,146
2012	126,832,343	17,729,029	732,385	83	N/A	145,293,840
2013	127,777,153	17,679,562	831,790	75	N/A	146,288,580
2014	128,680,416	17,853,995	839,212	79	N/A	147,373,702
2015	129,811,718	17,985,690	835,536	78	N/A	148,633,022
2016	131,068,760	18,148,353	838,059	86	N/A	150,055,258
2017	132,579,747	18,359,427	840,329	86	N/A	151,779,589
2018	133,893,321	18,605,393	840,321	83	N/A	153,339,118
2019	135,249,616	18,694,240	954,222	83	N/A	154,898,161

(From Table 2.2.) Sales to Ultimate Customers

(Thousand Megawatthours)

Year	Residential	Commer- cial	Industrial	Transpor- tation	Other	Total
2009	1,364,758	1,306,853	917,416	7,768	N/A	3,596,795
2010	1,445,708	1,330,199	971,221	7,712	N/A	3,754,841
2011	1,422,801	1,328,057	991,316	7,672	N/A	3,749,846
2012	1,374,515	1,327,101	985,714	7,320	N/A	3,694,650
2013	1,394,812	1,337,079	985,352	7,625	N/A	3,724,868
2014	1,407,208	1,352,158	997,576	7,758	N/A	3,764,700
2015	1,404,096	1,360,752	986,508	7,637	N/A	3,758,992
2016	1,411,058	1,367,191	976,715	7,497	N/A	3,762,462
2017	1,378,648	1,352,888	984,298	7,523	N/A	3,723,356
2018	1,469,093	1,381,755	1,000,673	7,665	N/A	3,859,185
2019	1,440,289	1,360,877	1,002,353	7,632	N/A	3,811,150

(From Table 2.3.) Revenue From Ultimate Customers

(Million Dollars)

Year	Residential	Commer- cial	Industrial	Transpor- tation	Other	Total
2009	157,044	132,747	62,670	828	N/A	353,289
2010	166,778	135,554	65,772	814	N/A	368,918
2011	166,714	135,927	67,606	803	N/A	371,049
2012	163,280	133,898	65,761	747	N/A	363,687
2013	169,131	137,188	67,934	805	N/A	375,058
2014	176,178	145,253	70,855	810	N/A	393,096
2015	177,624	144,781	68,166	771	N/A	391,341
2016	177,077	142,643	66,068	722	N/A	386,509
2017	177,661	144,242	67,691	728	N/A	390,322
2018	189,033	147,425	69,218	744	N/A	406,420
2019	187,436	145,280	68,285	737	N/A	401,738

Table 1.2. Summary Statistics for the United States, 2009 - 2019

(From Table 2.4.) Average Price

(Cents per Kilowatthour)

Year	Residential	Commer- cial	Industrial	Transpor- tation	Other	Total
2009	11.51	10.16	6.83	10.66	N/A	9.82
2010	11.54	10.19	6.77	10.56	N/A	9.83
2011	11.72	10.24	6.82	10.46	N/A	9.90
2012	11.88	10.09	6.67	10.21	N/A	9.84
2013	12.13	10.26	6.89	10.55	N/A	10.07
2014	12.52	10.74	7.10	10.45	N/A	10.44
2015	12.65	10.64	6.91	10.09	N/A	10.41
2016	12.55	10.43	6.76	9.63	N/A	10.27
2017	12.89	10.66	6.88	9.68	N/A	10.48
2018	12.87	10.67	6.92	9.70	N/A	10.53
2019	13.01	10.68	6.81	9.66	N/A	10.54

(From Tables 2.12. - 2.14.) Trade

(Thousand Megawatthours)

Year	Purchases	Sales for Resale	Imports	Exports
2009	5,028,647	5,065,031	52,191	18,138
2010	5,770,134	5,929,211	45,083	19,106
2011	5,024,621	5,143,121	52,300	15,049
2012	4,984,933	5,013,765	59,257	11,996
2013	4,684,977	4,842,508	68,947	11,373
2014	4,802,227	4,908,839	66,510	13,298
2015	4,761,523	4,797,395	75,770	9,100
2016	4,723,571	4,746,967	72,716	6,214
2017	4,861,257	4,889,947	65,685	9,371
2018	5,168,874	5,127,276	58,261	13,804
2019	5,371,635	5,172,430	59,052	20,008

(From Tables 3.1.A. and 3.1.B.) Net Generation (Thousand Megawatthours)

Generation at Utility Scale Facilities									
Year	Coal	Petroleum	Natural Gas	Other Gas	Nuclear	Hydro Conven- tional	Hydro Pumped Storage	Geothermal	Wind
2009	1,755,904	38,937	920,979	10,632	798,855	273,445	-4,627	15,009	73,886
2010	1,847,290	37,061	987,697	11,313	806,968	260,203	-5,501	15,219	94,652
2011	1,733,430	30,182	1,013,689	11,566	790,204	319,355	-6,421	15,316	120,177
2012	1,514,043	23,190	1,225,894	11,898	769,331	276,240	-4,950	15,562	140,822
2013	1,581,115	27,164	1,124,836	12,853	789,016	268,565	-4,681	15,775	167,840
2014	1,581,710	30,232	1,126,609	12,022	797,166	259,367	-6,174	15,877	181,655
2015	1,352,398	28,249	1,333,482	13,117	797,178	249,080	-5,091	15,918	190,719
2016	1,239,149	24,205	1,378,307	12,807	805,694	267,812	-6,686	15,826	226,993
2017	1,205,835	21,390	1,296,442	12,469	804,950	300,333	-6,495	15,927	254,303
2018	1,149,487	25,226	1,469,133	13,463	807,084	292,524	-5,905	15,967	272,667
2019	964,957	18,341	1,585,814	12,591	809,409	287,874	-5,261	15,473	295,882

Table 1.2. Summary Statistics for the United States, 2009 - 2019

Generation at Utility Scale Facilities							Small Scale Generation	Utility and Small Scale Generation	
Year	Solar Photo-voltaic	Solar Thermal	Wood and Wood-Derived Fuels	Other Biomass	Other Energy Sources	Total Utility Scale Generation	Estimated Photo-voltaic	Total Photo-voltaic	Total Solar
2009	157	735	36,050	18,443	11,928	3,950,331	--	157	891
2010	423	789	37,172	18,917	12,855	4,125,060	--	423	1,212
2011	1,012	806	37,449	19,222	14,154	4,100,141	--	1,012	1,818
2012	3,451	876	37,799	19,823	13,787	4,047,765	--	3,451	4,327
2013	8,121	915	40,028	20,830	13,588	4,065,964	--	8,121	9,036
2014	15,250	2,441	42,340	21,650	13,461	4,093,606	11,233	26,482	28,924
2015	21,666	3,227	41,929	21,703	14,028	4,077,601	14,139	35,805	39,032
2016	32,670	3,384	40,947	21,813	13,754	4,076,675	18,812	51,483	54,866
2017	50,018	3,269	41,124	21,610	13,096	4,034,271	23,990	74,008	77,277
2018	60,234	3,592	40,936	20,896	12,973	4,178,277	29,539	89,773	93,365
2019	68,719	3,218	38,543	18,964	13,331	4,127,855	34,957	103,676	106,894

(From Tables 4.2.A. and 4.2.B.) Net Summer Generating Capacity (Megawatts)

Utility Scale Capacity									
Year	Coal	Petroleum	Natural Gas	Other Gas	Nuclear	Hydro Conventional	Hydro Pumped Storage	Geothermal	Wind
2009	314,294.1	56,780.5	401,271.8	1,932.4	101,003.7	78,517.7	22,160.4	2,381.9	34,295.8
2010	316,800.1	55,646.9	407,028.4	2,700.3	101,167.4	78,824.7	22,198.9	2,404.6	39,134.5
2011	317,640.3	51,481.6	415,191.3	1,934.2	101,418.8	78,651.6	22,292.6	2,409.2	45,675.9
2012	309,680.4	47,167.2	422,364.4	1,945.6	101,885.0	78,738.0	22,368.3	2,592.1	59,074.8
2013	303,306.3	43,523.0	425,389.7	2,107.8	99,240.3	79,200.0	22,389.3	2,607.0	59,973.4
2014	299,094.2	41,135.4	432,150.3	1,914.3	98,569.3	79,677.3	22,485.1	2,514.3	64,231.5
2015	279,719.9	36,830.3	439,425.4	2,500.4	98,672.0	79,664.2	22,575.1	2,541.5	72,573.4
2016	266,619.9	34,382.4	446,823.2	2,456.9	99,564.8	79,912.9	22,778.7	2,516.6	81,286.6
2017	256,547.3	33,306.7	456,011.6	2,375.8	99,628.9	79,794.5	22,810.4	2,483.3	87,597.5
2018	242,785.6	32,218.2	470,236.9	2,543.9	99,432.9	79,871.8	22,830.2	2,444.3	94,417.7
2019	228,657.4	31,400.3	476,567.4	2,499.2	98,119.0	79,773.1	22,778.3	2,555.4	103,571.2

Utility Scale Capacity							Small Scale Capacity	Utility and Small Scale Capacity	
Year	Solar Photo-voltaic	Solar Thermal	Wood and Wood-Derived Fuels	Other Biomass	Other Energy Sources	Total Utility Scale Capacity	Estimated Photo-voltaic	Total Photo-voltaic	Total Solar
2009	145.5	473.0	6,939.3	4,316.5	887.8	1,025,400.4	--	145.5	618.5
2010	393.4	473.0	7,037.3	4,368.5	883.8	1,039,061.8	--	393.4	866.4
2011	1,052.0	471.5	7,076.5	4,535.9	1,419.6	1,051,251.0	--	1,052.0	1,523.5
2012	2,694.1	476.0	7,507.6	4,810.6	1,728.9	1,063,033.0	--	2,694.1	3,170.1
2013	5,336.1	1,286.4	8,354.2	5,043.0	2,307.0	1,060,063.5	--	5,336.1	6,622.5
2014	8,656.6	1,666.7	8,368.1	5,166.5	2,792.6	1,068,422.2	7,326.6	15,983.2	17,649.9
2015	11,905.4	1,757.9	8,968.9	5,124.5	1,795.6	1,064,054.5	9,778.5	21,683.9	23,441.8
2016	20,192.9	1,757.9	8,936.1	5,088.8	2,015.1	1,074,332.8	12,765.1	32,958.0	34,715.9

Table 1.2. Summary Statistics for the United States, 2009 - 2019

2017	25,209.0	1,757.9	8,830.9	5,129.5	2,886.3	1,084,369.6	16,147.8	41,356.8	43,114.7
2018	30,120.5	1,757.9	8,694.6	5,038.6	2,346.7	1,094,739.8	19,547.1	49,667.6	51,425.5
2019	35,710.2	1,758.1	8,374.5	4,738.8	2,606.4	1,099,109.3	23,213.6	58,923.8	60,681.9

(From Chapter 5.) Consumption of Fossil Fuels

	For Electricity Generation				For Useful Thermal Output			
Year	Coal (Thousand Tons)	Petroleum (Thousand Barrels)	Natural Gas (Millions of Cubic Feet)	Other Gas (Millions of BTU)	Coal (Thousand Tons)	Petroleum (Thousand Barrels)	Natural Gas (Millions of Cubic Feet)	Other Gas (Millions of BTU)
2009	934,683	67,668	7,121,069	83,593	20,507	13,161	816,787	175,671
2010	979,684	65,071	7,680,185	90,058	21,727	10,161	821,775	172,081
2011	934,938	52,387	7,883,865	91,290	21,532	9,223	839,681	191,138
2012	825,734	40,977	9,484,710	103,353	19,333	9,828	886,103	199,121
2013	860,729	47,492	8,596,299	115,303	18,350	10,886	882,385	189,902
2014	853,634	53,593	8,544,387	110,010	18,107	9,513	865,146	194,088
2015	739,594	49,145	10,016,576	105,997	16,632	8,864	935,098	183,596
2016	677,371	43,671	10,170,110	73,785	16,586	7,770	1,151,866	221,835
2017	663,911	39,144	9,508,062	70,721	14,667	6,899	1,168,544	227,981
2018	636,213	46,727	10,833,043	78,757	13,813	7,261	1,205,962	274,612
2019	537,620	34,454	11,601,600	71,854	12,397	6,357	1,196,025	209,000

	Total			
Year	Coal (Thousand Tons)	Petroleum (Thousand Barrels)	Natural Gas (Millions of Cubic Feet)	Other Gas (Millions of BTU)
2009	955,190	80,830	7,937,856	259,265
2010	1,001,411	75,231	8,501,960	262,138
2011	956,470	61,610	8,723,546	282,428
2012	845,066	50,805	10,370,812	302,475
2013	879,078	58,378	9,478,685	305,205
2014	871,741	63,106	9,409,532	304,098
2015	756,226	58,009	10,951,674	289,593
2016	693,958	51,441	11,321,975	295,619
2017	678,578	46,043	10,676,606	298,702
2018	650,027	53,988	12,039,005	353,369
2019	550,017	40,811	12,797,626	280,854

(From Tables 6.1. and 7.1)

Year End Stocks, Annual Receipts and Average Costs

	Electric Power Sector Year End Stocks		Annual Receipts at All Electricity Generators			Average Cost of Fuel at All Electricity Generators		
Year	Coal (Thousand Tons)	Petroleum (Thousand Barrels)	Coal (Thousand Tons)	Petroleum (Thousand Barrels)	Natural Gas (Millions of Cubic Feet)	Coal (Dollars per MMBtu)	Petroleum (Dollars per MMBtu)	Natural Gas (Dollars per MMBtu)
2009	189,467	45,575	981,477	88,951	8,118,550	2.21	7.02	4.74
2010	174,917	39,936	979,918	75,285	8,673,070	2.27	9.54	5.09
2011	172,387	36,282	956,538	66,058	9,056,164	2.39	12.48	4.72
2012	185,116	33,336	841,183	40,364	9,531,389	2.38	12.48	3.42

Table 1.2. Summary Statistics for the United States, 2009 - 2019

2013	147,884	32,336	823,222	43,714	8,503,424	2.34	11.57	4.33
2014	151,548	36,459	854,560	54,488	8,431,423	2.37	11.60	5.00
2015	195,548	38,396	782,929	48,804	9,842,581	2.22	6.74	3.23
2016	162,009	34,818	650,770	37,637	10,271,180	2.11	5.24	2.87
2017	137,687	32,407	642,364	32,672	9,628,733	2.06	7.10	3.37
2018	102,793	28,674	596,215	37,341	10,885,764	2.06	9.68	3.55
2019	128,176	28,317	560,153	24,556	11,693,486	2.02	9.07	2.89

(From Table 9.1.) Emissions

(Thousand Metric Tons)

Year	Carbon Dioxide (CO ₂)	Sulfur Dioxide (SO ₂)	Nitrogen Oxides (NO _x)
2009	2,269,508	5,970	2,395
2010	2,388,596	5,400	2,491
2011	2,287,071	4,845	2,406
2012	2,156,875	3,704	2,148
2013	2,173,806	3,609	2,163
2014	2,168,284	3,454	2,100
2015	2,031,452	2,548	1,824
2016	1,928,401	1,807	1,630
2017	1,849,750	1,657	1,506
2018	1,874,346	1,571	1,485
2019	1,724,396	1,267	1,342

(From Tables 10.6. and 10.7.) Energy Efficiency

Year	Savings		Incremental Costs		Life Cycle Savings		Life Cycle Costs	
	Energy (MWh)	Peak Demand (MW)	Incentives (thousand dollars)	Other (thousand dollars)	Energy (MWh)	Peak Demand (MW)	Incentives (thousand dollars)	Other (thousand dollars)
2013	24,653,124	11,078	2,871,654	1,944,597	249,940,645	10,956	6,028,810	3,994,889
2014	26,466,020	6,453	3,410,854	2,209,098	301,956,123	8,040	4,007,452	3,120,898
2015	26,129,489	5,952	3,448,286	2,283,300	296,346,403	7,096	4,255,368	3,710,453
2016	27,500,224	5,658	3,570,950	2,522,854	354,347,692	7,050	4,126,758	3,432,717
2017	29,899,028	6,071	3,664,407	2,297,957	374,826,892	5,951	4,849,803	3,162,995
2018	28,415,037	6,309	3,484,767	2,165,981	359,446,175	6,075	4,177,905	4,179,320
2019	28,562,529	7,135	3,657,477	2,288,028	355,216,512	6,931	4,351,926	3,655,607

(From Tables 10.8. and 10.9.) Demand Response

Year	Yearly Energy and Demand Savings				Program Costs	
	Customers	Energy (MWh)	Potential Peak Demand (MW)	Actual Peak Demand (MW)	Incentives (thousand dollars)	Other (thousand dollars)
2013	9,187,350	1,401,987	27,095	11,883	1,112,782	485,133
2014	9,265,629	1,436,449	31,191	12,683	1,217,796	447,659
2015	9,094,138	1,251,006	32,875	13,036	1,120,446	381,918
2016	9,839,355	1,336,136	35,924	11,841	1,039,890	379,707
2017	9,440,938	1,310,862	31,508	12,248	1,003,124	370,700
2018	9,752,238	1,426,211	30,895	12,522	1,189,284	360,718
2019	10,932,845	1,462,735	31,020	11,334	1,118,882	343,214

Table 1.2. Summary Statistics for the United States, 2009 - 2019

Coal includes anthracite, bituminous, subbituminous and lignite coal. Starting in 2002 waste coal is included in all coal metrics except for year-end stocks. Starting in 2002 Synthetic coal is included in all coal metrics. Starting in 2011 Coal-derived synthesis gas is included in all coal metrics. Prior to 2011 coal-derived synthesis gas was included in Other Gases.

Petroleum includes 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. Prior to 2011 propane was in the Other Gas category. Beginning in 2004 small quantities of waste oil were excluded from petroleum stocks.

Natural gas includes a small number of generators for which waste heat is the primary energy source. Natural gas also includes a small amount of supplemental gaseous fuels that cannot be identified separately.

Prior to 2011, synthesis gas derived from petroleum coke was in the Other Gas category. Other Gas includes blast furnace gas, propane gas, and other manufactured and waste gases derived from fossil fuels.

Conventional hydroelectric power excludes pumped storage facilities.

Wood and wood derived fuels include 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.

Other biomass includes 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). The reported summer capacity for other biomass also includes non-biogenic municipal solid waste.

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.

Other energy sources include batteries, hydrogen, purchased steam, sulfur, tire-derived fuels and other miscellaneous energy sources, and for generation values, non-biogenic municipal solid waste.

Costs of fuels for 2002 through 2007 include data from the Form EIA-423 for independent power producers, commercial power-producing facilities, and industrial power-producing facilities. Beginning in 2008, data are collected on the Form EIA-923 for utilities, independent power producers, commercial power-producing facilities, and industrial power-producing facilities. Receipts, 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 receipts beginning with 2008 data. Receipts of coal include imported coal.

N/A = Not available.

Notes: See Glossary reference for definitions. See Technical Notes Appendix 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.

In 2013, EIA revised its approach to estimating imports from Mexico.

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: National Energy Board of Canada; FERC 714, Annual Electric Balancing Authority Area and Planning Report; California Energy Commission; and EIA estimates

Table 1.3. Supply and Disposition of Electricity, 2009 through 2019

(From Chapter 3.) Supply (Thousand Megawatthours)

	Generation						
Year	Electric Utilities	IPP (Non-CHP)	IPP (CHP)	Commercial Sector	Industrial Sector	Total Imports	Total Supply
2009	2,372,776	1,277,916	159,146	8,165	132,329	52,191	4,002,522
2010	2,471,632	1,338,712	162,042	8,592	144,082	45,083	4,170,143
2011	2,460,851	1,331,303	156,032	10,080	141,875	52,300	4,152,441
2012	2,339,172	1,386,991	164,194	11,301	146,107	59,257	4,107,022
2013	2,388,058	1,368,038	147,619	12,234	150,015	68,947	4,134,911
2014	2,382,473	1,404,324	150,205	12,520	144,083	66,510	4,160,116
2015	2,315,323	1,448,799	155,173	12,595	145,712	75,770	4,153,371
2016	2,304,923	1,459,624	153,532	12,706	145,890	72,716	4,149,391
2017	2,274,279	1,464,590	138,584	13,060	143,758	65,685	4,099,955
2018	2,337,250	1,538,235	142,682	13,312	146,798	58,261	4,236,538
2019	2,266,004	1,559,801	139,824	13,689	148,537	59,052	4,186,908

(From Chapter 2.) Disposition (Thousand Megawatthours)

	Retail Sales						
Year	Full-Service Providers	Energy-Only Providers	Facility Direct	Direct Use	Total Exports	Losses and Unaccounted For	Total Disposition
2009	3,289,877	294,229	12,689	126,938	18,138	260,650	4,002,522
2010	3,365,338	379,277	10,226	131,910	19,106	264,285	4,170,143
2011	3,272,622	466,964	10,259	132,754	15,049	254,792	4,152,441
2012	3,172,096	514,290	8,263	137,657	11,996	262,720	4,107,022
2013	3,147,192	559,211	18,465	143,462	11,373	255,208	4,134,911
2014	3,184,841	563,441	16,418	138,574	13,298	243,544	4,160,116
2015	3,191,425	554,944	12,624	141,168	9,100	244,112	4,153,371
2016	3,189,541	560,015	12,905	139,844	6,214	240,871	4,149,391
2017	3,149,973	559,727	13,656	141,114	9,371	226,114	4,099,955
2018	3,260,944	584,077	14,164	144,114	13,804	219,434	4,236,538
2019	3,213,129	583,431	14,591	143,458	20,008	212,291	4,186,908

N/A = Not Available.

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).

Chapter 2

Electricity Sales

Table 2.1. Number of Ultimate Customers Served by Sector, by Provider, 2009 through 2019

Year	Residential	Commercial	Industrial	Transportation	Total
Total Electric Industry					
2009	125,208,829	17,562,235	757,537	704	143,529,305
2010	125,717,935	17,674,338	747,747	239	144,140,259
2011	126,143,072	17,638,062	727,920	92	144,509,146
2012	126,832,343	17,729,029	732,385	83	145,293,840
2013	127,777,153	17,679,562	831,790	75	146,288,580
2014	128,680,416	17,853,995	839,212	79	147,373,702
2015	129,811,718	17,985,690	835,536	78	148,633,022
2016	131,068,760	18,148,353	838,059	86	150,055,258
2017	132,579,747	18,359,427	840,329	86	151,779,589
2018	133,893,321	18,605,393	840,321	83	153,339,118
2019	135,249,616	18,694,240	954,222	83	154,898,161
Full-Service Providers					
2009	122,560,533	16,852,697	736,326	666	140,150,222
2010	121,555,089	16,675,341	718,652	198	138,949,280
2011	120,306,190	16,321,174	682,906	56	137,310,326
2012	118,650,233	16,111,883	681,074	48	135,443,238
2013	116,624,884	15,817,442	780,759	48	133,223,133
2014	117,230,661	15,942,158	789,803	50	133,962,672
2015	119,477,949	16,108,931	787,466	48	136,374,394
2016	120,875,548	16,197,174	788,641	53	137,861,416
2017	121,964,414	16,329,808	789,732	52	139,084,006
2018	122,767,933	16,415,207	794,548	49	139,977,737
2019	122,422,722	16,367,082	904,443	50	139,694,297
Energy-Only Providers					
2009	2,648,296	709,538	21,211	38	3,379,083
2010	4,162,846	998,997	29,095	41	5,190,979
2011	5,836,882	1,316,888	45,014	36	7,198,820
2012	8,182,110	1,617,146	51,311	35	9,850,602
2013	11,152,269	1,862,120	51,031	27	13,065,447
2014	11,449,755	1,911,837	49,409	29	13,411,030
2015	10,333,769	1,876,759	48,070	30	12,258,628
2016	10,193,212	1,951,179	49,418	33	12,193,842
2017	10,615,333	2,029,619	50,597	34	12,695,583
2018	11,125,388	2,190,186	45,773	34	13,361,381
2019	12,826,894	2,327,158	49,779	33	15,203,864

N/A = Not Available.

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

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." and Form EIA-861S, "Annual Electric Power Industry Report (Short Form)."

Table 2.2. Sales and Direct Use of Electricity to Ultimate Customers by Sector, by Provider, 2009 through 2019 (Megawatthours)

Year	Residential	Commercial	Industrial	Transportation	Total	Direct Use	Total End Use
Total Electric Industry							
2009	1,364,758,153	1,306,852,524	917,416,468	7,767,989	3,596,795,134	126,937,958	3,723,733,092
2010	1,445,708,403	1,330,199,364	971,221,189	7,712,412	3,754,841,368	131,910,249	3,886,751,617
2011	1,422,801,093	1,328,057,439	991,315,564	7,672,084	3,749,846,180	132,754,037	3,882,600,217
2012	1,374,514,708	1,327,101,196	985,713,854	7,320,028	3,694,649,786	137,656,510	3,832,306,296
2013	1,394,812,129	1,337,078,777	985,351,874	7,625,041	3,724,867,821	143,461,937	3,868,329,758
2014	1,407,208,311	1,352,158,263	997,576,138	7,757,555	3,764,700,267	138,573,884	3,903,274,151
2015	1,404,096,499	1,360,751,527	986,507,732	7,636,632	3,758,992,390	141,167,519	3,900,159,909
2016	1,411,058,153	1,367,191,386	976,715,181	7,496,910	3,762,461,630	139,844,397	3,902,306,027
2017	1,378,647,742	1,352,887,694	984,297,945	7,522,593	3,723,355,974	141,114,442	3,864,470,416
2018	1,469,093,059	1,381,754,845	1,000,672,553	7,664,804	3,859,185,261	144,113,808	4,003,299,069
2019	1,440,288,909	1,360,876,555	1,002,352,849	7,632,150	3,811,150,463	143,458,489	3,954,608,952
Full-Service Providers							
2009	1,345,314,362	1,143,473,246	811,314,045	2,464,259	3,302,565,912	N/A	3,302,565,912
2010	1,409,355,244	1,123,328,313	840,439,791	2,440,567	3,375,563,915	N/A	3,375,563,915
2011	1,368,453,770	1,090,292,969	822,404,124	1,730,820	3,282,881,683	N/A	3,282,881,683
2012	1,297,818,441	1,073,346,766	807,805,140	1,389,340	3,180,359,687	N/A	3,180,359,687
2013	1,291,368,071	1,074,915,884	797,769,849	1,603,318	3,165,657,122	N/A	3,165,657,122
2014	1,301,458,851	1,083,806,639	814,206,541	1,787,408	3,201,259,439	N/A	3,201,259,439
2015	1,307,918,081	1,089,268,864	805,111,979	1,749,450	3,204,048,374	N/A	3,204,048,374
2016	1,316,113,416	1,091,957,177	792,712,354	1,663,475	3,202,446,422	N/A	3,202,446,422
2017	1,285,787,376	1,078,679,288	797,505,332	1,656,960	3,163,628,956	N/A	3,163,628,956
2018	1,368,032,531	1,096,773,561	808,613,290	1,688,442	3,275,107,824	N/A	3,275,107,824
2019	1,335,937,347	1,078,046,650	811,871,096	1,864,134	3,227,719,227	N/A	3,227,719,227
Energy-Only Providers							
2009	19,443,791	163,379,278	106,102,423	5,303,730	294,229,222	N/A	294,229,222
2010	36,353,159	206,871,051	130,781,398	5,271,845	379,277,453	N/A	379,277,453
2011	54,347,323	237,764,470	168,911,440	5,941,264	466,964,497	N/A	466,964,497
2012	76,696,267	253,754,430	177,908,714	5,930,688	514,290,099	N/A	514,290,099
2013	103,444,058	262,162,893	187,582,025	6,021,723	559,210,699	N/A	559,210,699
2014	105,749,460	268,351,624	183,369,597	5,970,147	563,440,828	N/A	563,440,828
2015	96,178,418	271,482,663	181,395,753	5,887,182	554,944,016	N/A	554,944,016
2016	94,944,737	275,234,209	184,002,827	5,833,435	560,015,208	N/A	560,015,208
2017	92,860,366	274,208,406	186,792,613	5,865,633	559,727,018	N/A	559,727,018
2018	101,060,528	284,981,284	192,059,263	5,976,362	584,077,437	N/A	584,077,437
2019	104,351,562	282,829,905	190,481,753	5,768,016	583,431,236	N/A	583,431,236

N/A = Not Available.

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.

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

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.", Form EIA-861S, "Annual Electric Power Industry Report (Short Form)" and Form EIA-923, "Power Plant Operations Report"

Table 2.3. Revenue from Sales of Electricity to Ultimate Customers by Sector, by Provider, 2009 through 2019 (Million Dollars)

Year	Residential	Commercial	Industrial	Transportation	Total
Total Electric Industry					
2009	157,044	132,747	62,670	828	353,289
2010	166,778	135,554	65,772	814	368,918
2011	166,714	135,927	67,606	803	371,049
2012	163,280	133,898	65,761	747	363,687
2013	169,131	137,188	67,934	805	375,058
2014	176,178	145,253	70,855	810	393,096
2015	177,624	144,781	68,166	771	391,341
2016	177,077	142,643	66,068	722	386,509
2017	177,661	144,242	67,691	728	390,322
2018	189,033	147,425	69,218	744	406,420
2019	187,436	145,280	68,285	737	401,738
Full-Service Providers					
2009	153,741	112,254	53,284	226	319,506
2010	161,221	110,298	54,582	233	326,334
2011	158,788	108,318	54,285	162	321,552
2012	152,817	106,012	52,667	132	311,628
2013	155,203	108,460	54,309	167	318,138
2014	160,637	113,880	57,140	187	331,845
2015	162,857	113,225	54,787	170	331,038
2016	162,395	111,218	52,958	164	326,735
2017	162,762	112,576	54,412	171	329,921
2018	172,556	114,007	55,058	176	341,797
2019	169,867	112,036	54,782	190	336,876
Competitive Service Providers					
2009	3,302	20,493	9,386	602	33,783
2010	5,557	25,256	11,190	581	42,584
2011	7,926	27,609	13,321	641	49,497
2012	10,464	27,886	13,094	615	52,059
2013	13,928	28,729	13,625	638	56,919
2014	15,541	31,373	13,715	623	61,251
2015	14,767	31,557	13,379	601	60,303
2016	14,682	31,425	13,110	557	59,774
2017	14,899	31,666	13,279	557	60,402
2018	16,477	33,418	14,161	567	64,623
2019	17,569	33,244	13,502	547	64,863
Energy-Only Providers					
2009	1,889	14,045	7,369	460	23,763
2010	3,226	16,994	8,664	424	29,308
2011	4,578	18,086	10,392	463	33,519
2012	5,776	17,397	9,895	432	33,500
2013	7,755	17,876	10,330	451	36,412
2014	9,079	19,948	10,813	436	40,277
2015	8,428	19,657	10,298	407	38,791
2016	7,947	18,850	9,896	360	37,053
2017	7,666	18,368	9,829	363	36,227
2018	8,438	19,279	10,424	378	38,518
2019	8,718	18,436	9,738	360	37,253
Delivery-Only Providers					
2009	1,413	6,448	2,017	143	10,021
2010	2,330	8,262	2,526	157	13,276
2011	3,348	9,523	2,929	178	15,978
2012	4,687	10,489	3,199	183	18,559
2013	6,172	10,853	3,295	187	20,507
2014	6,462	11,425	2,901	187	20,975
2015	6,339	11,900	3,081	193	21,512
2016	6,735	12,575	3,213	197	22,720
2017	7,232	13,298	3,450	194	24,174
2018	8,039	14,139	3,737	190	26,105
2019	8,850	14,809	3,764	187	27,610

N/A = Not Available.

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

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 Competitive Service Providers represent the sum of Energy-Only and Delivery-Only Services."

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." Form EIA-861S, "Annual Electric Power Industry Report (Short Form)."

Table 2.4. Average Price of Electricity to Ultimate Customers

by End-Use Sectors 2009 through 2019 (Cents per kilowatthour)

Year	Residential	Commercial	Industrial	Transportation	Total
Total Electric Industry					
2009	11.51	10.16	6.83	10.66	9.82
2010	11.54	10.19	6.77	10.56	9.83
2011	11.72	10.24	6.82	10.46	9.90
2012	11.88	10.09	6.67	10.21	9.84
2013	12.13	10.26	6.89	10.55	10.07
2014	12.52	10.74	7.10	10.45	10.44
2015	12.65	10.64	6.91	10.09	10.41
2016	12.55	10.43	6.76	9.63	10.27
2017	12.89	10.66	6.88	9.68	10.48
2018	12.87	10.67	6.92	9.70	10.53
2019	13.01	10.68	6.81	9.66	10.54
Full-Service Providers					
2009	11.43	9.82	6.57	9.17	9.67
2010	11.44	9.82	6.49	9.55	9.67
2011	11.60	9.93	6.60	9.35	9.79
2012	11.77	9.88	6.52	9.50	9.80
2013	12.02	10.09	6.81	10.40	10.05
2014	12.34	10.51	7.02	10.49	10.37
2015	12.45	10.39	6.80	9.71	10.33
2016	12.34	10.19	6.68	9.87	10.20
2017	12.66	10.44	6.82	10.32	10.43
2018	12.61	10.39	6.81	10.44	10.44
2019	12.72	10.39	6.75	10.20	10.44
Competitive Service Providers					
2009	16.98	12.54	8.85	11.36	11.48
2010	15.29	12.21	8.56	11.03	11.23
2011	14.58	11.61	7.89	10.79	10.60
2012	13.64	10.99	7.36	10.38	10.12
2013	13.46	10.96	7.26	10.60	10.18
2014	14.70	11.69	7.48	10.44	10.87
2015	15.35	11.62	7.38	10.20	10.87
2016	15.46	11.42	7.12	9.56	10.67
2017	16.04	11.55	7.11	9.50	10.79
2018	16.30	11.73	7.37	9.49	11.06
2019	16.84	11.75	7.09	9.49	11.12
Energy-Only Providers					
2009	9.72	8.60	6.94	8.67	8.08
2010	8.88	8.21	6.62	8.05	7.73
2011	8.42	7.61	6.15	7.80	7.18
2012	7.53	6.86	5.56	7.29	6.51
2013	7.50	6.82	5.51	7.49	6.51
2014	8.59	7.43	5.90	7.31	7.15
2015	8.76	7.24	5.68	6.92	6.99
2016	8.37	6.85	5.38	6.17	6.62
2017	8.26	6.70	5.26	6.19	6.47
2018	8.35	6.77	5.43	6.32	6.59
2019	8.35	6.52	5.11	6.25	6.39
Delivery-Only Providers					
2009	7.27	3.95	1.90	2.69	3.41
2010	6.41	3.99	1.93	2.98	3.50
2011	6.16	4.01	1.73	2.99	3.42
2012	6.11	4.13	1.80	3.09	3.61
2013	5.97	4.14	1.76	3.11	3.67
2014	6.11	4.26	1.58	3.12	3.72
2015	6.59	4.38	1.70	3.28	3.88
2016	7.09	4.57	1.75	3.38	4.06
2017	7.79	4.85	1.85	3.31	4.32
2018	7.95	4.96	1.95	3.17	4.47
2019	8.48	5.24	1.98	3.24	4.73

N/A = Not Available.

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

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 Competitive Service Providers represent the sum of Energy-Only and Delivery-Only Services."

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." Form EIA-861S, "Annual Electric Power Industry Report (Short Form)."

**Table 2.5. Sales of Electricity to Ultimate Customers:
Total by End-Use Sector, 2009 - December 2019 (Thousand Megawatthours)**

Period	Residential	Commercial	Industrial	Transportation	All Sectors
Annual Totals					
2009	1,364,758	1,306,853	917,416	7,768	3,596,795
2010	1,445,708	1,330,199	971,221	7,712	3,754,841
2011	1,422,801	1,328,057	991,316	7,672	3,749,846
2012	1,374,515	1,327,101	985,714	7,320	3,694,650
2013	1,394,812	1,337,079	985,352	7,625	3,724,868
2014	1,407,208	1,352,158	997,576	7,758	3,764,700
2015	1,404,096	1,360,752	986,508	7,637	3,758,992
2016	1,411,058	1,367,191	976,715	7,497	3,762,462
2017	1,378,648	1,352,888	984,298	7,523	3,723,356
2018	1,469,093	1,381,755	1,000,673	7,665	3,859,185
2019	1,440,289	1,360,877	1,002,353	7,632	3,811,150
Year 2017					
January	129,212	109,488	78,809	667	318,177
February	100,968	99,640	74,534	635	275,777
March	103,096	107,173	80,530	645	291,444
April	90,725	102,589	78,899	589	272,801
May	98,281	109,872	83,134	583	291,871
June	122,543	120,013	85,399	628	328,583
July	149,900	129,277	87,806	630	367,613
August	142,007	128,481	89,134	640	360,263
September	118,779	118,789	83,540	618	321,726
October	102,811	113,287	82,815	626	299,539
November	98,321	104,973	79,456	598	283,347
December	122,005	109,306	80,242	664	312,216
Year 2018					
January	148,917	114,925	79,890	745	344,478
February	113,751	102,685	75,661	634	292,732
March	107,218	108,108	81,053	620	296,999
April	95,454	103,331	79,083	599	278,468
May	103,848	113,175	85,638	587	303,248
June	129,913	122,011	85,536	623	338,083
July	153,566	131,522	89,301	634	375,023
August	153,496	134,848	92,106	680	381,131
September	128,910	122,033	85,679	640	337,263
October	107,049	116,133	85,301	631	309,114
November	103,790	104,983	81,118	616	290,507
December	123,180	107,998	80,306	655	312,140
Year 2019					
January	133,318	112,012	82,610	670	328,609
February	116,608	102,071	76,447	672	295,798
March	112,605	107,468	81,093	686	301,853
April	90,384	102,446	80,460	610	273,900
May	100,331	111,201	84,661	608	296,802
June	120,116	115,745	84,992	608	321,462
July	153,749	130,951	90,752	642	376,095
August	150,083	130,776	91,062	653	372,574
September	131,567	122,059	86,160	677	340,463
October	107,997	115,305	84,396	543	308,241
November	102,453	102,840	79,625	614	285,532
December	121,078	108,001	80,095	648	309,823

See Technical notes for additional information on the Commercial, Industrial, and Transportation sectors. NA = Not available. See Glossary for definitions.

Geographic coverage is the 50 States and the District of Columbia. Values include energy service provider (power marketer) data.

Values are final. See Technical Notes for a discussion of the sample design for the Form EIA-826. 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. 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. Sales and net generation may not correspond exactly for a particular month for a variety of reasons (i.e., sales data may include purchases of electricity from nonutilities or imported electricity). Net generation is for the calendar month while sales and associated revenue accumulate from bills collected for periods of time (28 to 35 days) that vary dependent upon customer class and consumption occurring in and outside the calendar month.

Sources: U.S. Energy Information Administration, Form EIA-861M (formerly EIA-826), Monthly Electric Industry Power Report.

Form EIA-826, Monthly Electric Sales and Revenue Report with State Distributions Report;

Form EIA-861, Annual Electric Power Industry Report; and Form EIA-861S, Annual Electric Power Industry Report (Short Form).

**Table 2.6. Revenue from Sales of Electricity to Ultimate Customers:
Total by End-Use Sector, 2009 - December 2019 (Million Dollars)**

Period	Residential	Commercial	Industrial	Transportation	All Sectors
Annual Totals					
2009	157,044	132,747	62,670	828	353,289
2010	166,778	135,554	65,772	814	368,918
2011	166,714	135,927	67,606	803	371,049
2012	163,280	133,898	65,761	747	363,687
2013	169,131	137,188	67,934	805	375,058
2014	176,178	145,253	70,855	810	393,096
2015	177,624	144,781	68,166	771	391,341
2016	177,077	142,643	66,068	722	386,509
2017	177,661	144,242	67,691	728	390,322
2018	189,033	147,425	69,218	744	406,420
2019	187,436	145,280	68,285	737	401,738
Year 2017					
January	15,781	11,183	5,190	63	32,216
February	12,911	10,442	4,941	60	28,354
March	13,289	11,208	5,407	61	29,965
April	11,536	10,669	5,209	56	27,470
May	12,843	11,638	5,639	56	30,176
June	16,171	13,209	6,141	64	35,585
July	19,606	14,184	6,416	64	40,269
August	18,679	14,141	6,435	64	39,320
September	15,772	13,104	5,992	62	34,930
October	13,164	12,208	5,725	60	31,157
November	12,721	11,016	5,345	57	29,139
December	15,189	11,239	5,249	62	31,739
Year 2018					
January	18,193	12,053	5,543	70	35,859
February	14,364	10,936	5,128	62	30,490
March	13,905	11,365	5,373	58	30,701
April	12,290	10,806	5,194	57	28,347
May	13,625	11,890	5,819	55	31,388
June	16,922	13,223	6,136	64	36,344
July	20,156	14,466	6,540	64	41,226
August	20,351	14,874	6,673	65	41,963
September	16,775	13,085	6,038	64	35,962
October	13,751	12,506	5,864	62	32,182
November	13,389	11,069	5,557	60	30,074
December	15,311	11,155	5,353	64	31,883
Year 2019					
January	16,620	11,541	5,433	66	33,660
February	14,831	10,761	5,116	67	30,775
March	14,457	11,238	5,454	63	31,212
April	11,976	10,777	5,239	58	28,050
May	13,356	11,725	5,667	58	30,805
June	16,005	12,618	5,843	61	34,526
July	20,382	14,433	6,476	63	41,354
August	19,955	14,407	6,739	63	41,164
September	17,317	13,379	6,085	66	36,847
October	13,837	12,380	5,770	53	32,039
November	13,346	10,874	5,350	58	29,629
December	15,354	11,146	5,112	61	31,674

See Technical notes for additional information on the Commercial, Industrial, and Transportation sectors. NA = Not available. See Glossary for definitions.

Geographic coverage is the 50 States and the District of Columbia. Values include energy service provider (power marketer) data.

Values are final. See Technical Notes for a discussion of the sample design for the Form EIA-826. 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. 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. Sales and net generation may not correspond exactly for a particular month for a variety of reasons (i.e., sales data may include purchases of electricity from nonutilities or imported electricity). Net generation is for the calendar month while sales and associated revenue accumulate from bills collected for periods of time (28 to 35 days) that vary dependent upon customer class and consumption occurring in and outside the calendar month.

Sources: U.S. Energy Information Administration, Form EIA-861M (formerly EIA-826), Monthly Electric Industry Power Report.

Form EIA-826, Monthly Electric Sales and Revenue Report with State Distributions Report;

Form EIA-861, Annual Electric Power Industry Report; and Form EIA-861S, Annual Electric Power Industry Report (Short Form).

**Table 2.7. Average Price of Electricity to Ultimate Customers:
Total by End-Use Sector, 2009 - December 2019 (Cents per Kilowatthour)**

Period	Residential	Commercial	Industrial	Transportation	All Sectors
Annual Totals					
2009	11.51	10.16	6.83	10.66	9.82
2010	11.54	10.19	6.77	10.56	9.83
2011	11.72	10.24	6.82	10.46	9.90
2012	11.88	10.09	6.67	10.21	9.84
2013	12.13	10.26	6.89	10.55	10.07
2014	12.52	10.74	7.10	10.45	10.44
2015	12.65	10.64	6.91	10.09	10.41
2016	12.55	10.43	6.76	9.63	10.27
2017	12.89	10.66	6.88	9.68	10.48
2018	12.87	10.67	6.92	9.70	10.53
2019	13.01	10.68	6.81	9.66	10.54
Year 2017					
January	12.21	10.21	6.59	9.39	10.13
February	12.79	10.48	6.63	9.50	10.28
March	12.89	10.46	6.71	9.49	10.28
April	12.72	10.40	6.60	9.46	10.07
May	13.07	10.59	6.78	9.61	10.34
June	13.20	11.01	7.19	10.18	10.83
July	13.08	10.97	7.31	10.12	10.95
August	13.15	11.01	7.22	10.06	10.91
September	13.28	11.03	7.17	9.99	10.86
October	12.80	10.78	6.91	9.57	10.40
November	12.94	10.49	6.73	9.50	10.28
December	12.45	10.28	6.54	9.35	10.17
Year 2018					
January	12.22	10.49	6.94	9.39	10.41
February	12.63	10.65	6.78	9.78	10.42
March	12.97	10.51	6.63	9.40	10.34
April	12.88	10.46	6.57	9.47	10.18
May	13.12	10.51	6.79	9.39	10.35
June	13.03	10.84	7.17	10.23	10.75
July	13.13	11.00	7.32	10.05	10.99
August	13.26	11.03	7.25	9.50	11.01
September	13.01	10.72	7.05	10.05	10.66
October	12.85	10.77	6.87	9.79	10.41
November	12.90	10.54	6.85	9.70	10.35
December	12.43	10.33	6.67	9.71	10.21
Year 2019					
January	12.47	10.30	6.58	9.83	10.24
February	12.72	10.54	6.69	10.02	10.40
March	12.84	10.46	6.73	9.25	10.34
April	13.25	10.52	6.51	9.45	10.24
May	13.31	10.54	6.69	9.46	10.38
June	13.32	10.90	6.87	10.01	10.74
July	13.26	11.02	7.14	9.82	11.00
August	13.30	11.02	7.40	9.65	11.05
September	13.16	10.96	7.06	9.78	10.82
October	12.81	10.74	6.84	9.72	10.39
November	13.03	10.57	6.72	9.52	10.38
December	12.68	10.32	6.38	9.46	10.22

See Technical notes for additional information on the Commercial, Industrial, and Transportation sectors. NA = Not available. See Glossary for definitions.

Geographic coverage is the 50 States and the District of Columbia. Values include energy service provider (power marketer) data.

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Sources: U.S. Energy Information Administration, Form EIA-861M (formerly EIA-826), Monthly Electric Industry Power Report.

Form EIA-826, Monthly Electric Sales and Revenue Report with State Distributions Report;

Form EIA-861, Annual Electric Power Industry Report; and Form EIA-861S, Annual Electric Power Industry Report (Short Form).

Table 2.8. Sales of Electricity to Ultimate Customers by End-Use Sector, by State, 2019 and 2018 (Thousand Megawatthours)

Census Division and State	Residential		Commercial		Industrial		Transportation		All Sectors	
	Year 2019	Year 2018	Year 2019	Year 2018	Year 2019	Year 2018	Year 2019	Year 2018	Year 2019	Year 2018
New England	46,173	48,099	51,503	52,924	16,234	17,054	547	557	114,458	118,634
Connecticut	12,494	13,061	12,158	12,381	3,072	3,210	177	181	27,900	28,834
Maine	4,794	4,872	4,148	4,447	2,790	3,036	0	0	11,732	12,355
Massachusetts	19,315	20,285	25,337	25,952	6,342	6,699	343	349	51,337	53,285
New Hampshire	4,507	4,641	4,281	4,443	1,924	1,963	0	0	10,712	11,046
Rhode Island	2,983	3,124	3,644	3,698	695	735	27	27	7,350	7,583
Vermont	2,082	2,116	1,934	2,004	1,412	1,411	0	0	5,428	5,531
Middle Atlantic	133,150	137,580	153,246	158,774	74,961	74,601	3,740	3,968	365,097	374,923
New Jersey	28,613	29,531	38,013	38,807	6,990	7,369	301	310	73,917	76,017
New York	50,141	52,153	75,091	76,745	17,548	18,077	2,820	2,954	145,600	149,930
Pennsylvania	54,396	55,896	40,143	43,222	50,423	49,155	619	703	145,580	148,977
East North Central	186,187	193,825	180,212	185,278	192,318	195,875	636	615	559,352	575,593
Illinois	45,220	47,226	49,279	50,763	43,250	44,115	570	551	138,319	142,655
Indiana	33,249	34,575	23,518	24,305	45,317	45,293	21	21	102,104	104,194
Michigan	33,496	35,131	37,861	38,925	29,886	30,806	6	7	101,249	104,869
Ohio	52,226	54,452	46,009	47,192	50,249	51,236	38	36	148,522	152,915
Wisconsin	21,995	22,441	23,546	24,093	23,615	24,425	1	0	69,158	70,960
West North Central	106,595	109,892	102,643	104,457	93,550	94,080	49	49	302,838	308,478
Iowa	14,495	14,840	12,310	12,418	24,239	23,953	0	0	51,043	51,211
Kansas	13,631	14,187	15,916	16,169	11,613	11,681	0	0	41,160	42,037
Minnesota	22,288	22,837	22,904	23,399	21,748	22,447	25	26	66,966	68,708
Missouri	35,691	37,463	30,133	31,179	13,010	13,390	24	24	78,858	82,056
Nebraska	10,308	10,412	9,457	9,553	10,619	10,974	0	0	30,383	30,939
North Dakota	5,125	5,133	7,035	6,836	9,399	8,700	0	0	21,559	20,670
South Dakota	5,057	5,018	4,888	4,903	2,924	2,935	0	0	12,869	12,857
South Atlantic	370,430	374,135	318,135	317,277	141,243	142,648	1,383	1,331	831,191	835,391
Delaware	5,004	5,070	4,421	4,342	2,044	2,361	0	0	11,469	11,773
District of Columbia	2,547	2,592	7,952	8,236	180	193	350	337	11,028	11,358
Florida	127,182	125,528	96,567	96,265	16,514	16,689	85	83	240,348	238,565
Georgia	59,331	59,689	47,412	47,312	32,393	32,696	164	170	139,301	139,866
Maryland	27,534	28,138	28,893	29,548	3,718	3,870	575	530	60,721	62,086
North Carolina	59,853	61,622	49,173	49,298	27,391	27,354	19	13	136,436	138,287
South Carolina	31,160	31,852	22,168	22,233	26,877	27,556	0	0	80,206	81,641
Virginia	46,666	47,963	53,981	52,268	17,598	17,737	190	199	118,435	118,166
West Virginia	11,153	11,679	7,567	7,774	14,527	14,193	0	0	33,247	33,647
East South Central	120,280	124,486	93,078	94,924	98,863	100,783	0	0	312,221	320,192
Alabama	32,416	33,080	23,076	23,483	32,603	33,717	0	0	88,095	90,280
Kentucky	26,573	27,713	19,612	19,980	29,161	28,917	0	0	75,345	76,611
Mississippi	18,718	19,311	14,239	14,530	15,994	16,549	0	0	48,951	50,390
Tennessee	42,573	44,382	36,151	36,930	21,105	21,599	0	0	99,829	102,911
West South Central	229,006	232,709	198,321	201,723	207,836	198,150	199	201	635,361	632,783
Arkansas	18,732	19,259	11,949	12,278	17,412	18,065	0	0	48,093	49,603
Louisiana	30,986	32,066	24,284	24,691	37,846	37,417	12	13	93,129	94,186
Oklahoma	23,806	24,117	20,086	21,229	20,904	19,229	0	0	64,796	64,575
Texas	155,481	157,268	142,002	143,525	131,674	123,439	187	187	429,343	424,419
Mountain	100,458	100,312	98,070	99,065	84,813	83,788	185	161	283,525	283,325
Arizona	34,720	34,660	29,415	29,684	13,783	13,994	11	8	77,929	78,346
Colorado	19,405	19,287	21,111	21,023	15,891	16,047	114	93	56,521	56,450
Idaho	8,697	8,428	6,441	6,437	8,847	8,889	0	0	23,985	23,754
Montana	5,308	5,198	4,956	4,921	5,057	4,720	0	0	15,321	14,839
Nevada	12,868	13,450	11,681	12,124	12,426	12,198	8	8	36,982	37,780
New Mexico	6,872	6,826	9,029	9,035	8,980	8,187	0	0	24,880	24,049
Utah	9,740	9,715	11,860	12,084	9,491	9,393	52	51	31,143	31,242
Wyoming	2,849	2,748	3,575	3,757	10,339	10,359	0	0	16,763	16,865
Pacific Contiguous	143,323	143,370	159,972	161,653	87,648	88,750	893	783	391,836	394,556
California	87,524	89,100	114,279	115,786	47,808	49,588	768	750	250,379	255,224
Oregon	19,286	18,931	16,423	16,470	14,668	13,899	27	26	50,404	49,326
Washington	36,512	35,339	29,270	29,396	25,172	25,263	99	7	91,053	90,006
Pacific Noncontiguous	4,688	4,686	5,697	5,679	4,887	4,945	0	0	15,272	15,310
Alaska	1,928	1,975	2,639	2,646	1,252	1,352	0	0	5,819	5,972
Hawaii	2,760	2,711	3,058	3,033	3,635	3,593	0	0	9,453	9,337
U.S. Total	1,440,289	1,469,093	1,360,877	1,381,755	1,002,353	1,000,673	7,632	7,665	3,811,150	3,859,185

See Technical notes for additional information on the Commercial, Industrial, and Transportation sectors.

Displayed values of zero may represent small values that round to zero. The Excel version of this table provides additional precision which may be accessed by selecting individual cells.

Notes: - See Glossary for definitions. - Values are final.

See Technical Notes for a discussion of the sample design for the Form EIA-826.

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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.

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 2.9. Revenue from Sales of Electricity to Ultimate Customers by End-Use Sector, by State, 2019 and 2018 (Million Dollars)

Census Division and State	Residential		Commercial		Industrial		Transportation		All Sectors	
	Year 2019	Year 2018	Year 2019	Year 2018	Year 2019	Year 2018	Year 2019	Year 2018	Year 2019	Year 2018
New England	9,744	9,910	8,412	8,709	2,122	2,249	50	50	20,328	20,918
Connecticut	2,733	2,769	2,036	2,075	413	442	24	23	5,206	5,309
Maine	858	821	532	556	257	283	0	0	1,647	1,660
Massachusetts	4,233	4,383	4,255	4,457	936	998	21	22	9,445	9,860
New Hampshire	904	914	682	703	252	263	0	0	1,838	1,880
Rhode Island	648	642	597	613	108	113	5	5	1,359	1,373
Vermont	369	381	309	305	156	150	0	0	834	837
Middle Atlantic	21,039	21,974	18,705	19,729	4,925	5,191	418	441	45,088	47,336
New Jersey	4,535	4,550	4,651	4,737	710	742	27	28	9,922	10,057
New York	8,995	9,659	10,557	11,128	985	1,088	346	359	20,884	22,233
Pennsylvania	7,509	7,765	3,498	3,864	3,230	3,362	45	55	14,282	15,045
East North Central	24,929	25,681	18,378	18,887	13,290	13,912	45	43	56,642	58,523
Illinois	5,891	6,029	4,476	4,631	2,822	2,999	39	37	13,228	13,696
Indiana	4,183	4,240	2,594	2,576	3,335	3,343	2	2	10,114	10,161
Michigan	5,273	5,427	4,313	4,339	2,114	2,187	1	1	11,701	11,954
Ohio	6,464	6,840	4,470	4,769	3,292	3,592	3	3	14,229	15,203
Wisconsin	3,118	3,146	2,525	2,571	1,727	1,791	0	0	7,370	7,508
West North Central	12,643	13,184	9,911	10,223	6,802	6,845	4	4	29,360	30,256
Iowa	1,806	1,817	1,230	1,203	1,600	1,546	0	0	4,636	4,566
Kansas	1,733	1,894	1,638	1,723	853	887	0	0	4,224	4,505
Minnesota	2,907	3,001	2,369	2,429	1,637	1,689	2	2	6,915	7,122
Missouri	3,976	4,249	2,734	2,931	925	966	2	2	7,636	8,148
Nebraska	1,110	1,114	837	843	813	834	0	0	2,759	2,792
North Dakota	528	526	634	622	747	694	0	0	1,908	1,842
South Dakota	584	582	469	472	228	228	0	0	1,281	1,282
South Atlantic	44,201	43,771	29,764	29,507	9,175	9,299	109	105	83,250	82,683
Delaware	628	635	421	419	157	188	0	0	1,207	1,242
District of Columbia	331	333	975	986	15	16	33	32	1,354	1,367
Florida	14,883	14,485	8,950	8,845	1,263	1,276	7	7	25,103	24,614
Georgia	6,979	6,847	4,752	4,633	1,999	1,963	10	9	13,740	13,453
Maryland	3,611	3,742	2,880	3,083	290	318	42	39	6,823	7,182
North Carolina	6,834	6,835	4,331	4,229	1,727	1,732	2	1	12,893	12,797
South Carolina	4,048	3,963	2,345	2,248	1,643	1,681	0	0	8,036	7,891
Virginia	5,632	5,624	4,417	4,347	1,206	1,217	16	16	11,271	11,204
West Virginia	1,255	1,306	693	719	875	908	0	0	2,823	2,933
East South Central	13,668	13,862	9,997	9,983	5,699	5,891	0	0	29,364	29,736
Alabama	4,061	4,028	2,658	2,639	1,940	2,028	0	0	8,659	8,694
Kentucky	2,869	2,936	1,991	1,946	1,624	1,643	0	0	6,484	6,525
Mississippi	2,109	2,147	1,498	1,516	936	993	0	0	4,543	4,655
Tennessee	4,629	4,752	3,851	3,882	1,198	1,228	0	0	9,678	9,861
West South Central	25,587	25,056	16,257	16,564	11,277	10,703	13	16	53,134	52,340
Arkansas	1,835	1,889	1,050	951	1,068	1,019	0	0	3,952	3,859
Louisiana	3,035	3,074	2,164	2,185	1,979	2,003	1	1	7,179	7,263
Oklahoma	2,430	2,484	1,603	1,713	1,059	1,027	0	0	5,092	5,224
Texas	18,287	17,610	11,440	11,715	7,171	6,654	12	15	36,910	35,994
Mountain	11,866	11,974	9,373	9,470	5,372	5,407	17	15	26,629	26,866
Arizona	4,317	4,425	3,014	3,158	865	916	1	1	8,197	8,501
Colorado	2,363	2,343	2,203	2,106	1,175	1,199	10	8	5,750	5,655
Idaho	860	855	494	511	538	575	0	0	1,892	1,941
Montana	591	570	516	497	276	245	0	0	1,382	1,312
Nevada	1,545	1,593	939	939	763	744	1	1	3,247	3,277
New Mexico	860	866	884	905	492	478	0	0	2,236	2,250
Utah	1,013	1,011	979	994	567	554	5	5	2,565	2,565
Wyoming	318	310	345	360	695	695	0	0	1,358	1,365
Pacific Contiguous	22,432	22,308	23,067	22,954	8,474	8,552	80	68	54,053	53,882
California	16,764	16,782	19,052	18,924	6,406	6,546	68	65	42,290	42,318
Oregon	2,124	2,079	1,453	1,468	859	814	2	2	4,438	4,364
Washington	3,545	3,446	2,561	2,562	1,209	1,191	9	1	7,325	7,200
Pacific Noncontiguous	1,327	1,313	1,416	1,398	1,148	1,169	0	0	3,891	3,881
Alaska	442	433	522	492	212	231	0	0	1,176	1,156
Hawaii	885	880	894	907	936	938	0	0	2,715	2,725
U.S. Total	187,436	189,033	145,280	147,425	68,285	69,218	737	744	401,738	406,420

See Technical notes for additional information on the Commercial, Industrial, and Transportation sectors.

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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 2.10. Average Price of Electricity to Ultimate Customers by End-Use Sector, by State, 2019 and 2018 (Cents per Kilowatthour)

Census Division and State	Residential		Commercial		Industrial		Transportation		All Sectors	
	Year 2019	Year 2018	Year 2019	Year 2018	Year 2019	Year 2018	Year 2019	Year 2018	Year 2019	Year 2018
New England	21.10	20.60	16.33	16.46	13.07	13.19	9.20	9.00	17.76	17.63
Connecticut	21.87	21.20	16.75	16.76	13.44	13.77	13.69	12.84	18.66	18.41
Maine	17.89	16.84	12.83	12.51	9.22	9.32	--	--	14.04	13.44
Massachusetts	21.92	21.61	16.80	17.17	14.76	14.89	6.15	6.38	18.40	18.50
New Hampshire	20.05	19.69	15.93	15.81	13.09	13.42	--	--	17.15	17.01
Rhode Island	21.73	20.55	16.38	16.58	15.59	15.39	18.49	17.00	18.49	18.10
Vermont	17.71	18.02	15.98	15.24	11.05	10.66	--	--	15.36	15.13
Middle Atlantic	15.80	15.97	12.21	12.43	6.57	6.96	11.17	11.13	12.35	12.63
New Jersey	15.85	15.41	12.23	12.21	10.16	10.07	8.80	9.07	13.42	13.23
New York	17.94	18.52	14.06	14.50	5.61	6.02	12.28	12.14	14.34	14.83
Pennsylvania	13.80	13.89	8.71	8.94	6.41	6.84	7.26	7.78	9.81	10.10
East North Central	13.39	13.25	10.20	10.19	6.91	7.10	7.08	6.96	10.13	10.17
Illinois	13.03	12.77	9.08	9.12	6.52	6.80	6.91	6.75	9.56	9.60
Indiana	12.58	12.26	11.03	10.60	7.36	7.38	10.76	10.44	9.91	9.75
Michigan	15.74	15.45	11.39	11.15	7.07	7.10	10.56	10.76	11.56	11.40
Ohio	12.38	12.56	9.72	10.11	6.55	7.01	6.83	7.33	9.58	9.94
Wisconsin	14.18	14.02	10.72	10.67	7.31	7.33	13.85	13.85	10.66	10.58
West North Central	11.86	12.00	9.66	9.79	7.27	7.28	8.72	9.07	9.69	9.81
Iowa	12.46	12.24	9.99	9.68	6.60	6.45	--	--	9.08	8.92
Kansas	12.71	13.35	10.29	10.66	7.35	7.60	--	--	10.26	10.72
Minnesota	13.04	13.14	10.34	10.38	7.53	7.52	9.49	9.58	10.33	10.37
Missouri	11.14	11.34	9.07	9.40	7.11	7.22	7.89	8.52	9.68	9.93
Nebraska	10.77	10.70	8.85	8.83	7.65	7.60	--	--	9.08	9.02
North Dakota	10.30	10.25	9.01	9.10	7.94	7.98	--	--	8.85	8.91
South Dakota	11.55	11.59	9.59	9.62	7.81	7.77	--	--	9.96	9.97
South Atlantic	11.93	11.70	9.36	9.30	6.50	6.52	7.92	7.91	10.02	9.90
Delaware	12.55	12.53	9.53	9.65	7.70	7.95	--	--	10.52	10.55
District of Columbia	12.98	12.84	12.26	11.97	8.22	8.30	9.50	9.54	12.27	12.03
Florida	11.70	11.54	9.27	9.19	7.65	7.65	8.32	8.26	10.44	10.32
Georgia	11.76	11.47	10.02	9.79	6.17	6.00	5.85	5.52	9.86	9.62
Maryland	13.12	13.30	9.97	10.43	7.80	8.23	7.37	7.44	11.24	11.57
North Carolina	11.42	11.09	8.81	8.58	6.30	6.33	8.20	8.02	9.45	9.25
South Carolina	12.99	12.44	10.58	10.11	6.11	6.10	--	--	10.02	9.67
Virginia	12.07	11.73	8.18	8.32	6.85	6.86	8.27	8.28	9.52	9.48
West Virginia	11.25	11.18	9.16	9.24	6.02	6.40	--	--	8.49	8.72
East South Central	11.36	11.14	10.74	10.52	5.76	5.85	--	--	9.40	9.29
Alabama	12.53	12.18	11.52	11.24	5.95	6.01	--	--	9.83	9.63
Kentucky	10.80	10.60	10.15	9.74	5.57	5.68	--	--	8.61	8.52
Mississippi	11.27	11.12	10.52	10.43	5.85	6.00	--	--	9.28	9.24
Tennessee	10.87	10.71	10.65	10.51	5.68	5.68	--	--	9.69	9.58
West South Central	11.17	10.77	8.20	8.21	5.43	5.40	6.61	8.16	8.36	8.27
Arkansas	9.80	9.81	8.78	7.75	6.13	5.64	11.73	11.35	8.22	7.78
Louisiana	9.80	9.59	8.91	8.85	5.23	5.35	9.08	9.21	7.71	7.71
Oklahoma	10.21	10.30	7.98	8.07	5.07	5.34	--	--	7.86	8.09
Texas	11.76	11.20	8.06	8.16	5.45	5.39	6.44	8.08	8.60	8.48
Mountain	11.81	11.94	9.56	9.56	6.33	6.45	9.29	9.53	9.39	9.48
Arizona	12.43	12.77	10.25	10.64	6.28	6.55	9.68	10.02	10.52	10.85
Colorado	12.18	12.15	10.43	10.02	7.40	7.47	8.70	9.00	10.17	10.02
Idaho	9.89	10.15	7.67	7.93	6.08	6.47	--	--	7.89	8.17
Montana	11.13	10.96	10.41	10.11	5.45	5.19	--	--	9.02	8.84
Nevada	12.00	11.85	8.04	7.74	6.14	6.10	8.51	8.31	8.78	8.67
New Mexico	12.51	12.68	9.79	10.02	5.48	5.84	--	--	8.99	9.35
Utah	10.40	10.41	8.26	8.23	5.98	5.90	10.62	10.59	8.24	8.21
Wyoming	11.18	11.29	9.64	9.58	6.73	6.71	--	--	8.10	8.09
Pacific Contiguous	15.65	15.56	14.42	14.20	9.67	9.64	8.98	8.67	13.79	13.66
California	19.15	18.84	16.67	16.34	13.40	13.20	8.91	8.64	16.89	16.58
Oregon	11.01	10.98	8.85	8.91	5.86	5.86	9.14	9.16	8.81	8.85
Washington	9.71	9.75	8.75	8.72	4.80	4.71	9.45	9.38	8.04	8.00
Pacific Noncontiguous	28.30	28.03	24.86	24.62	23.50	23.64	--	--	25.48	25.35
Alaska	22.92	21.94	19.80	18.58	16.94	17.10	--	--	20.22	19.36
Hawaii	32.06	32.47	29.23	29.90	25.76	26.10	--	--	28.72	29.18
U.S. Total	13.01	12.87	10.68	10.67	6.81	6.92	9.66	9.70	10.54	10.53

See Technical notes for additional information on the Commercial, Industrial, and Transportation sectors.

Displayed values of zero may represent small values that round to zero. The Excel version of this table provides additional precision which may be accessed by selecting individual cells.

Notes: - See Glossary for definitions. - Values are final.

See Technical Notes for a discussion of the sample design for the Form EIA-826.

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.

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.

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 2.11. Number of Ultimate Customers by Sector by State, 2018 and 2019

Census Division and State	Residential		Commercial		Industrial		Transportation		All Sectors	
	Year 2019	Year 2018	Year 2019	Year 2018	Year 2019	Year 2018	Year 2019	Year 2018	Year 2019	Year 2018
New England	6,411,587	6,377,606	889,951	883,832	23,310	23,028	6	7	7,324,854	7,284,473
Connecticut	1,510,966	1,503,701	151,979	153,824	4,204	4,308	3	4	1,667,152	1,661,837
Maine	710,869	709,848	99,738	96,066	2,893	3,064	--	--	813,500	808,978
Massachusetts	2,802,099	2,784,243	410,995	408,972	11,020	10,503	2	2	3,224,116	3,203,720
New Hampshire	627,257	622,671	108,247	107,805	3,193	3,176	--	--	738,697	733,652
Rhode Island	444,216	442,005	60,672	60,128	1,758	1,773	1	1	506,647	503,907
Vermont	316,180	315,138	58,320	57,037	242	204	--	--	374,742	372,379
Middle Atlantic	16,251,104	16,149,378	2,361,895	2,345,015	33,176	30,504	21	20	18,646,196	18,524,917
New Jersey	3,596,834	3,568,044	523,796	521,429	11,781	11,877	7	6	4,132,418	4,101,356
New York	7,235,400	7,190,906	1,121,107	1,106,650	7,607	6,884	8	8	8,364,122	8,304,448
Pennsylvania	5,418,870	5,390,428	716,992	716,936	13,788	11,743	6	6	6,149,656	6,119,113
East North Central	20,287,076	20,183,560	2,515,638	2,498,950	55,588	53,956	10	9	22,858,312	22,736,475
Illinois	5,314,522	5,289,573	622,802	616,192	5,737	5,717	3	3	5,943,064	5,911,485
Indiana	2,887,031	2,863,358	358,791	354,730	18,805	17,763	1	1	3,264,628	3,235,852
Michigan	4,384,305	4,365,529	544,690	543,261	5,726	5,972	2	2	4,934,723	4,914,764
Ohio	4,980,931	4,964,855	632,794	630,210	19,798	18,715	2	2	5,633,525	5,613,782
Wisconsin	2,720,287	2,700,245	356,561	354,557	5,522	5,789	2	1	3,082,372	3,060,592
West North Central	9,570,282	9,497,228	1,465,470	1,455,145	126,985	124,102	3	3	11,162,740	11,076,478
Iowa	1,392,979	1,385,756	241,734	239,703	8,565	7,890	--	--	1,643,278	1,633,349
Kansas	1,274,955	1,266,044	235,236	234,091	24,230	24,185	--	--	1,534,421	1,524,320
Minnesota	2,446,111	2,420,325	299,995	295,855	8,998	9,066	1	1	2,755,105	2,725,247
Missouri	2,811,863	2,792,459	384,787	384,493	10,096	8,085	2	2	3,206,748	3,185,039
Nebraska	855,619	849,898	153,814	153,749	62,204	61,968	--	--	1,071,637	1,065,615
North Dakota	385,038	382,596	76,355	75,148	8,803	8,985	--	--	470,196	466,729
South Dakota	403,717	400,150	73,549	72,106	4,089	3,923	--	--	481,355	476,179
South Atlantic	28,325,448	27,947,855	3,835,185	3,788,481	85,778	83,599	13	13	32,246,424	31,819,948
Delaware	439,167	432,449	55,802	54,904	865	837	--	--	495,834	488,190
District of Columbia	282,277	274,613	26,471	26,336	1	1	3	3	308,752	300,953
Florida	9,565,846	9,423,022	1,240,902	1,229,559	23,579	21,327	2	2	10,830,329	10,673,910
Georgia	4,411,521	4,354,021	585,573	579,468	23,539	23,065	1	1	5,020,634	4,956,555
Maryland	2,352,535	2,332,517	256,165	254,163	8,935	8,801	5	5	2,617,640	2,595,486
North Carolina	4,620,856	4,550,420	705,587	691,673	9,871	10,025	1	1	5,336,315	5,252,119
South Carolina	2,330,903	2,290,200	385,285	376,842	3,703	4,324	--	--	2,719,891	2,671,366
Virginia	3,464,677	3,431,574	434,175	431,058	3,723	3,704	1	1	3,902,576	3,866,337
West Virginia	857,666	859,039	145,225	144,478	11,562	11,515	--	--	1,014,453	1,015,032
East South Central	8,448,897	8,382,954	1,414,750	1,404,952	24,787	26,090	--	--	9,888,434	9,813,996
Alabama	2,249,425	2,229,472	369,798	371,097	7,245	7,342	--	--	2,626,468	2,607,911
Kentucky	1,991,137	1,980,209	309,830	305,417	6,147	6,750	--	--	2,307,114	2,292,376
Mississippi	1,293,419	1,290,281	237,625	236,871	10,379	10,988	--	--	1,541,423	1,538,140
Tennessee	2,914,916	2,882,992	497,497	491,567	1,016	1,010	--	--	3,413,429	3,375,569
West South Central	16,636,131	16,387,177	2,316,766	2,363,259	306,569	200,568	6	6	19,259,472	18,951,010
Arkansas	1,396,870	1,388,358	198,861	196,482	34,864	36,596	2	2	1,630,597	1,621,438
Louisiana	2,095,466	2,085,055	295,153	292,752	19,373	19,558	1	1	2,409,993	2,397,366
Oklahoma	1,777,156	1,764,980	285,641	282,875	19,905	18,700	--	--	2,082,702	2,066,555
Texas	11,366,639	11,148,784	1,537,111	1,591,150	232,427	125,714	3	3	13,136,180	12,865,651
Mountain	9,994,348	9,825,511	1,431,391	1,414,958	96,422	95,524	5	5	11,522,166	11,335,998
Arizona	2,853,183	2,808,352	326,191	322,135	7,899	7,794	2	2	3,187,275	3,138,283
Colorado	2,370,164	2,326,976	380,609	376,104	14,386	15,985	1	1	2,765,160	2,719,066
Idaho	763,841	743,567	112,137	110,797	28,493	28,418	--	--	904,471	882,782
Montana	516,052	509,526	109,459	108,695	11,286	9,915	--	--	636,797	628,136
Nevada	1,204,996	1,183,660	167,628	164,982	3,265	3,446	1	1	1,375,890	1,352,089
New Mexico	895,086	889,841	144,960	143,874	9,456	9,360	--	--	1,049,502	1,043,075
Utah	1,116,145	1,091,162	132,082	130,053	10,343	9,666	1	1	1,258,571	1,230,882
Wyoming	274,881	272,427	58,325	58,318	11,294	10,940	--	--	344,500	341,685
Pacific Contiguous	18,597,101	18,418,260	2,348,236	2,337,183	199,658	200,749	19	20	21,145,014	20,956,212
California	13,707,126	13,591,152	1,718,601	1,714,875	147,660	148,644	12	12	15,573,399	15,454,683
Oregon	1,763,783	1,750,240	240,488	237,942	25,169	24,821	2	2	2,029,442	2,013,005
Washington	3,126,192	3,076,868	389,147	384,366	26,829	27,284	5	6	3,542,173	3,488,524
Pacific Noncontiguous	727,642	723,792	114,958	113,618	1,949	2,201	--	--	844,549	839,611
Alaska	289,290	287,526	55,080	53,957	1,126	1,387	--	--	345,496	342,870
Hawaii	438,352	436,266	59,878	59,661	823	814	--	--	499,053	496,741
U.S. Total	135,249,616	133,893,321	18,694,240	18,605,393	954,222	840,321	83	83	154,898,161	153,339,118

**Table 2.12. Electric Power Industry - Electricity Purchases,
2009 through 2019 (Thousand Megawatthours)**

Year	Electric Utilities	Energy-Only Providers	Independent Power Producers	Combined Heat and Power	U.S. Total
2010	2,353,086	3,319,211	23,976	73,861	5,770,134
2011	2,245,381	2,679,803	21,844	77,593	5,024,621
2012	2,148,346	2,740,043	17,726	78,818	4,984,933
2013	2,099,528	2,482,928	16,101	86,420	4,684,977
2014	2,145,378	2,559,875	17,000	79,975	4,802,227
2015	2,101,788	2,506,185	54,046	99,505	4,761,523
2016	2,089,540	2,438,204	8,520	187,307	4,723,571
2017	2,102,971	2,552,146	9,372	196,768	4,861,257
2018	2,187,615	2,713,174	8,730	259,354	5,168,874
2019	2,231,042	2,778,349	9,391	352,854	5,371,635

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" and Form EIA-923, "Power Plant Operations Report"

Table 2.13. Electric Power Industry - Electricity Sales for Resale, 2009 through 2019 (Thousand Megawatthours)

Year	Electric Utilities	Energy-Only Providers	Independent Power Producers	Combined Heat and Power	U.S. Total
2009	1,495,636	2,240,399	1,295,857	33,139	5,065,031
2010	1,541,554	2,946,452	1,404,137	37,068	5,929,211
2011	1,529,434	2,206,981	1,372,306	34,400	5,143,121
2012	1,456,774	2,135,819	1,384,155	37,017	5,013,765
2013	1,472,124	2,036,460	1,298,528	35,396	4,842,508
2014	1,485,964	2,081,235	1,301,724	39,916	4,908,839
2015	1,393,396	2,033,705	1,331,181	39,113	4,797,395
2016	1,391,873	1,947,036	1,372,928	35,131	4,746,967
2017	1,396,838	2,066,455	1,389,083	37,571	4,889,947
2018	1,431,952	2,193,414	1,463,236	38,674	5,127,276
2019	1,402,200	2,259,028	1,466,561	44,641	5,172,430

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" and Form EIA-923, "Power Plant Operations Report"

Table 2.14. Electric Power Industry - U.S. Electricity Imports from and Electricity Exports to Canada and Mexico, 2009-2019 (Megawatthours)

Year	Canada		Mexico		U.S. Total	
	Imports from	Exports to	Imports from	Exports to	Imports	Exports
2009	50,870,451	17,517,112	1,320,144	620,872	52,190,595	18,137,984
2010	43,763,091	18,481,678	1,320,095	624,502	45,083,186	19,106,180
2011	51,075,952	14,398,470	1,223,758	650,082	52,299,710	15,048,552
2012	57,971,110	11,392,267	1,285,959	603,382	59,257,069	11,995,649
2013	62,739,038	10,694,907	6,207,597	678,300	68,946,635	11,373,207
2014	59,369,660	12,860,889	7,140,624	437,364	66,510,284	13,298,253
2015	68,462,277	8,707,873	7,308,192	392,016	75,770,469	9,099,889
2016	65,173,818	2,682,381	7,542,445	3,531,636	72,716,263	6,214,017
2017	59,909,320	3,312,798	5,775,597	6,058,005	65,684,917	9,370,803
2018	51,494,627	7,290,070	6,765,975	6,514,422	58,260,602	13,804,492
2019	52,309,254	13,532,067	6,743,207	6,475,965	59,052,461	20,008,032

Notes: As of November 2017, the data for 2016 and going forward will be published using data from the Form EIA-111, "Quarterly Electricity Imports and Exports Report." During 2013-2015, EIA revised its approach to estimating imports from Mexico.

Sources: 2016-2019, U.S. Energy Information Administration, Form EIA-111, "Quarterly Electricity Imports and Exports Report"; 2006-2015 data, National Energy Board of Canada; FERC 714, Annual Electric Balancing Authority Area and Planning Report; California Energy Commission; and EIA estimates.

Chapter 3

Net Generation

Table 3.1.A. Net Generation by Energy Source: Total (All Sectors), 2009 - 2019
(Thousand Megawatthours)

Period	Generation at Utility Scale Facilities												Small Scale Generation	Net Generation From Utility and Small Scale Facilities	
	Coal	Petroleum Liquids	Petroleum Coke	Natural Gas	Other Gas	Nuclear	Hydroelectric Conventional	Solar	Renewable Sources Excluding Hydroelectric and Solar	Hydroelectric Pumped Storage	Other	Total Generation at Utility Scale Facilities	Estimated Solar Photovoltaic	Estimated Total Solar Photovoltaic	Estimated Total Solar
Annual Totals															
2009	1,755,904	25,972	12,964	920,979	10,632	798,855	273,445	891	143,388	-4,627	11,928	3,950,331	N/A	N/A	N/A
2010	1,847,290	23,337	13,724	987,697	11,313	806,968	260,203	1,212	165,961	-5,501	12,855	4,125,060	N/A	N/A	N/A
2011	1,733,430	16,086	14,096	1,013,689	11,566	790,204	319,355	1,818	192,163	-6,421	14,154	4,100,141	N/A	N/A	N/A
2012	1,514,043	13,403	9,787	1,225,894	11,898	769,331	276,240	4,327	214,006	-4,950	13,787	4,047,765	N/A	N/A	N/A
2013	1,581,115	13,820	13,344	1,124,836	12,853	789,016	268,565	9,036	244,472	-4,681	13,588	4,065,964	N/A	N/A	N/A
2014	1,581,710	18,276	11,955	1,126,609	12,022	797,166	259,367	17,691	261,522	-6,174	13,461	4,093,606	11,233	26,482	28,924
2015	1,352,398	17,372	10,877	1,333,482	13,117	797,178	249,080	24,893	270,268	-5,091	14,028	4,077,601	14,139	35,805	39,032
2016	1,239,149	13,008	11,197	1,378,307	12,807	805,694	267,812	36,054	305,579	-6,686	13,754	4,076,675	18,812	51,483	54,866
2017	1,205,835	12,414	8,976	1,296,442	12,469	804,950	300,333	53,287	332,963	-6,495	13,096	4,034,271	23,990	74,008	77,277
2018	1,149,487	16,245	8,981	1,469,133	13,463	807,084	292,524	63,825	350,467	-5,905	12,973	4,178,277	29,539	89,773	93,365
2019	964,957	11,522	6,819	1,585,814	12,591	809,409	287,874	71,937	368,862	-5,261	13,331	4,127,855	34,957	103,676	106,894
Year 2017															
January	115,333	1,102	944	95,572	1,047	73,121	26,628	2,324	27,605	-435	1,092	344,332	1,246	3,480	3,570
February	86,822	869	723	82,768	978	63,560	23,882	2,751	23,882	-508	992	291,050	1,384	4,000	4,135
March	89,365	956	699	95,074	1,060	65,093	29,613	4,514	32,421	-521	1,061	319,336	1,972	6,190	6,487
April	81,335	860	431	88,455	1,001	56,743	29,409	4,907	31,607	-439	1,050	295,361	2,195	6,791	7,102
May	92,777	970	847	98,019	1,056	61,313	32,607	5,785	29,408	-423	1,089	323,447	2,423	7,806	8,208
June	107,508	991	901	117,236	993	67,011	30,575	6,115	26,659	-568	1,099	358,522	2,487	8,137	8,602
July	127,698	920	889	146,929	1,047	71,314	26,598	5,569	23,019	-759	1,207	404,432	2,555	7,812	8,124
August	119,488	968	765	141,201	1,133	72,384	22,034	5,369	20,817	-638	1,217	384,739	2,480	7,507	7,848
September	98,202	931	712	118,036	1,059	68,098	19,152	5,059	24,238	-606	1,034	335,915	2,225	6,935	7,285
October	89,776	973	572	106,826	998	65,995	17,698	4,650	30,614	-463	1,031	318,670	1,990	6,325	6,640
November	90,986	915	755	94,928	1,001	66,618	19,888	3,209	29,150	-478	1,079	308,052	1,561	4,639	4,770
December	106,545	1,958	737	111,398	1,095	73,700	22,248	3,035	29,211	-656	1,145	350,416	1,472	4,384	4,507
Year 2018															
January	119,284	5,555	965	110,293	1,097	74,649	25,064	3,319	32,443	-547	1,109	373,230	1,619	4,810	4,938
February	82,050	804	754	98,512	1,092	64,790	24,902	3,896	29,415	-315	994	306,894	1,766	5,472	5,663
March	80,626	830	642	106,524	1,158	67,033	25,861	5,056	33,200	-490	1,108	321,547	2,434	7,233	7,490
April	73,346	872	666	98,371	1,099	59,133	28,115	6,057	32,446	-377	1,028	300,756	2,740	8,482	8,796
May	85,227	1,040	517	115,284	1,167	67,320	30,444	6,849	30,419	-390	1,070	338,948	3,011	9,430	9,860
June	101,503	1,066	834	130,826	1,091	69,688	27,597	7,415	31,193	-433	1,104	371,886	3,059	9,957	10,474
July	115,376	988	913	164,749	1,172	72,456	25,100	6,755	23,316	-644	1,111	411,290	3,146	9,521	9,901
August	115,129	1,047	879	161,676	1,301	72,282	22,017	6,695	26,601	-747	1,146	408,028	3,017	9,303	9,712
September	96,544	1,055	799	141,786	1,104	64,725	19,166	5,961	24,718	-603	1,004	356,258	2,674	8,205	8,635
October	87,264	1,015	562	123,142	1,016	59,397	19,548	4,970	27,426	-492	1,084	324,932	2,392	7,087	7,361
November	92,819	1,006	656	108,168	1,045	63,954	21,913	3,743	28,334	-343	1,075	322,369	1,905	5,480	5,648
December	100,319	966	795	109,802	1,120	71,657	22,797	3,110	30,956	-522	1,139	342,139	1,775	4,792	4,885
Year 2019															
January	100,905	1,413	800	121,589	1,025	73,701	24,798	3,580	30,829	-323	1,194	359,509	1,903	5,373	5,483
February	79,929	815	692	112,142	948	64,715	22,881	3,836	28,455	-389	1,003	315,026	2,059	5,763	5,895
March	78,352	816	574	115,813	1,086	65,080	26,334	5,899	32,036	-409	1,077	326,657	2,914	8,553	8,813
April	59,922	782	401	104,059	948	60,581	27,820	6,752	34,486	-103	1,015	296,663	3,245	9,672	9,997
May	71,885	937	737	117,059	1,054	67,124	31,982	7,162	31,736	-368	1,117	330,423	3,549	10,375	10,711
June	78,540	957	563	137,836	1,009	68,805	28,078	7,971	28,514	-385	1,101	352,988	3,604	11,136	11,575
July	100,771	1,004	791	171,955	1,185	72,199	24,875	8,133	28,591	-622	1,157	410,038	3,760	11,493	11,893
August	94,040	1,047	684	174,968	1,147	71,911	22,579	7,877	26,546	-579	1,211	401,430	3,611	11,075	11,488
September	85,707	923	581	149,697	1,112	66,064	18,526	6,817	30,622	-671	1,142	360,518	3,205	9,728	10,022
October	66,777	942	200	130,948	924	62,033	18,306	6,093	33,402	-373	1,100	320,352	2,833	8,628	8,926
November	75,549	899	333	117,910	1,047	64,125	20,218	4,364	30,830	-509	1,082	315,849	2,228	6,450	6,592
December	72,581	988	463	131,839	1,107	73,074	21,478	3,453	32,815	-529	1,133	338,402	2,047	5,430	5,500

Coal includes anthracite, bituminous, subbituminous, lignite, and waste coal; synthetic coal and refined coal; and beginning in 2011, coal-derived synthesis gas. Prior to 2011 coal-derived synthesis gas was included in Other Gases.

Petroleum Liquids includes distillate and residual fuel oils, jet fuel, kerosene, waste oil, and beginning in 2011, propane. Prior to 2011 propane was included in Other Gases.

Petroleum Coke includes petroleum coke-derived synthesis gas. Prior to 2011, petroleum coke-derived synthesis gas was included in Other Gases.

Other Gas includes blast furnace gas and other manufactured and waste gases derived from fossil fuels. Prior to 2011, Other Gas included propane and synthesis gases.

See the Technical Notes for fuel conversion factors.

Renewable Sources include wood, black liquor, other wood waste, biogenic municipal solid waste, landfill gas, sludge waste, agriculture byproducts, other biomass, geothermal, solar thermal, photovoltaic energy, and wind.

Other includes non-biogenic municipal solid waste, batteries, hydrogen, purchased steam, sulfur, tire-derived fuel, and other miscellaneous energy sources.

Notes: Beginning with 2001 data, non-biogenic municipal solid waste and tire-derived fuels are reclassified as non-renewable energy sources and included in Other. Biogenic municipal solid waste is included in Other Renewable Sources.

See Glossary for definitions. Values are final. See Technical Notes for a discussion of the sample design for the Form EIA-923 and predecessor forms.

Totals may not equal sum of components because of independent rounding. NM=Not meaningful due to large standard error. W=Withheld to avoid disclosure of individual company data.

Displayed values of zero may represent small values that round to zero. The Excel version of this table provides additional precision which may be accessed by selecting individual cells.

Sources: U.S. Energy Information Administration, Form EIA-923, Power Plant Operations Report; U.S. Energy Information Administration, Form EIA-906, Power Plant Report; U.S. Energy Information Administration, Form EIA-920 Combined Heat and Power Plant Report; and predecessor forms.

Beginning with 2008 data, the Form EIA-923, Power Plant Operations Report, replaced the following: 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 Federal Energy Regulatory Commission, FERC Form 423, Monthly Report of Cost and Quality of Fuels for Electric Plants.

Estimated small scale solar photovoltaic generation and small scale solar photovoltaic capacity are based on data from Form EIA-861M, Form EIA-861 and from estimation methods described in the technical notes.

Table 3.1.B. Net Generation from Renewable Sources: Total (All Sectors), 2009 - 2019
(Thousand Megawatthours)

		Generation at Utility Scale Facilities										Small Scale Generation	Generation From Utility and Small Scale Facilities	
Period		Wind	Solar Photovoltaic	Solar Thermal	Wood and Wood-Derived Fuels	Landfill Gas	Biogenic Municipal Solid Waste	Other Waste Biomass	Geothermal	Conventional Hydroelectric	Total Renewable Generation at Utility Scale Facilities	Estimated Solar Photovoltaic	Estimated Total Solar Photovoltaic	Estimated Total Solar
Annual Totals														
	2009	73,886	157	735	36,050	7,924	8,058	2,461	15,009	273,445	417,724	N/A	N/A	N/A
	2010	94,652	423	789	37,172	8,377	7,927	2,613	15,219	260,203	427,376	N/A	N/A	N/A
	2011	120,177	1,012	806	37,449	9,044	7,354	2,824	15,316	319,355	513,336	N/A	N/A	N/A
	2012	140,822	3,451	876	37,799	9,803	7,320	2,700	15,562	276,240	494,573	N/A	N/A	N/A
	2013	167,840	8,121	915	40,028	10,658	7,186	2,986	15,775	268,565	522,073	N/A	N/A	N/A
	2014	181,655	15,250	2,441	42,340	11,220	7,228	3,202	15,877	259,367	538,579	11,233	26,482	28,924
	2015	190,719	21,666	3,227	41,929	11,291	7,211	3,201	15,918	249,080	544,241	14,139	35,805	39,032
	2016	226,993	32,670	3,384	40,947	11,218	7,265	3,331	15,826	267,812	609,445	18,812	51,483	54,866
	2017	254,303	50,018	3,269	41,124	11,543	6,951	3,115	15,927	300,333	686,583	23,990	74,008	77,277
	2018	272,667	60,234	3,592	40,936	11,036	7,136	2,724	15,967	292,524	706,816	29,539	89,773	93,365
	2019	295,882	68,719	3,218	38,543	10,468	6,093	2,402	15,473	287,874	728,673	34,957	103,676	106,894
Year 2017														
	January	20,799	2,234	90	3,502	999	617	281	1,407	26,628	56,557	1,246	3,480	3,570
	February	22,091	2,616	136	3,186	912	528	257	1,239	23,882	54,846	1,384	4,000	4,135
	March	25,731	4,217	297	3,456	1,000	557	291	1,387	29,613	66,548	1,972	6,190	6,487
	April	25,378	4,596	310	3,146	943	544	255	1,341	29,409	65,923	2,195	6,791	7,102
	May	23,068	5,383	402	3,188	980	604	266	1,302	32,607	67,800	2,423	7,806	8,208
	June	20,142	5,651	465	3,437	957	588	252	1,284	30,575	63,350	2,487	8,137	8,602
	July	16,120	5,258	311	3,703	960	604	260	1,373	26,598	55,187	2,555	7,812	8,124
	August	13,879	5,028	341	3,751	963	617	245	1,363	22,034	48,220	2,480	7,507	7,848
	September	17,912	4,710	349	3,292	922	558	224	1,332	19,152	48,449	2,225	6,935	7,285
	October	24,369	4,335	314	3,303	933	558	237	1,214	17,698	52,962	1,990	6,325	6,640
	November	22,615	3,078	131	3,426	963	571	271	1,305	19,888	52,248	1,561	4,639	4,770
	December	22,201	2,912	123	3,734	1,014	606	276	1,381	22,248	54,494	1,472	4,384	4,507
Year 2018														
	January	25,599	3,191	128	3,686	964	588	265	1,341	25,064	60,826	1,619	4,810	4,938
	February	23,189	3,705	191	3,235	906	559	251	1,274	24,902	58,213	1,766	5,472	5,663
	March	26,464	4,799	258	3,547	972	597	253	1,367	25,861	64,117	2,434	7,233	7,490
	April	26,431	5,743	314	3,102	920	566	239	1,188	28,115	66,618	2,740	8,482	8,796
	May	23,953	6,419	430	3,352	930	573	228	1,383	30,444	67,712	3,011	9,430	9,860
	June	24,703	6,898	517	3,471	889	629	202	1,300	27,597	66,206	3,059	9,957	10,474
	July	16,447	6,374	380	3,749	909	638	202	1,370	25,100	55,170	3,146	9,521	9,901
	August	19,846	6,286	409	3,630	919	630	208	1,367	22,017	55,313	3,017	9,303	9,712
	September	18,520	5,531	430	3,281	836	562	192	1,328	19,166	49,844	2,674	8,205	8,635
	October	21,194	4,695	275	3,216	918	594	231	1,273	19,548	51,944	2,392	7,087	7,361
	November	22,016	3,575	168	3,264	920	584	220	1,331	21,913	53,990	1,905	5,480	5,648
	December	24,306	3,018	92	3,404	951	616	233	1,446	22,797	56,863	1,775	4,792	4,885
Year 2019														
	January	24,301	3,470	111	3,465	930	528	214	1,390	24,798	59,207	1,903	5,373	5,483
	February	22,623	3,704	131	3,042	843	464	191	1,293	22,881	55,172	2,059	5,763	5,895
	March	25,773	5,639	260	3,217	908	490	227	1,422	26,334	64,269	2,914	8,553	8,813
	April	28,915	6,427	325	2,807	833	468	208	1,254	27,820	69,059	3,245	9,672	9,997
	May	25,779	6,826	336	3,051	859	526	179	1,342	31,982	70,880	3,549	10,375	10,711
	June	22,446	7,532	439	3,159	868	523	191	1,328	28,078	64,563	3,604	11,136	11,575
	July	22,101	7,733	400	3,498	884	538	194	1,375	24,875	61,599	3,760	11,493	11,893
	August	19,978	7,464	413	3,539	886	546	204	1,393	22,579	57,001	3,611	11,075	11,488
	September	24,513	6,523	294	3,211	838	512	179	1,368	18,526	55,965	3,205	9,728	10,022
	October	27,625	5,796	298	3,063	868	500	206	1,141	18,306	57,801	2,833	8,628	8,926
	November	25,184	4,223	141	3,137	844	484	198	984	20,218	55,412	2,228	6,450	6,592
	December	26,644	3,383	70	3,355	908	513	213	1,183	21,478	57,746	2,047	5,430	5,500

Wood and Wood-derived fuels include 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.

Other Waste Biomass includes sludge waste, agricultural byproducts, other biomass solids, other biomass liquids, and other biomass gases (including digester gases, methane, and other biomass gases).

Notes: Beginning with 2001 data, non-biogenic municipal solid waste and tire-derived fuels are reclassified as non-renewable energy sources and included in Other. Biogenic municipal solid waste is included in Other Renewable Sources.

See Glossary for definitions. Values are final. See Technical Notes for a discussion of the sample design for the Form EIA-923 and predecessor forms.

Totals may not equal sum of components because of independent rounding. NM=Not meaningful due to large standard error. W=Withheld to avoid disclosure of individual company data.

Displayed values of zero may represent small values that round to zero. The Excel version of this table provides additional precision which may be accessed by selecting individual cells.

Sources: U.S. Energy Information Administration, Form EIA-923, Power Plant Operations Report; U.S. Energy Information Administration, Form EIA-906, Power Plant Report; U.S. Energy Information Administration, Form EIA-920 Combined Heat and Power Plant Report; and predecessor forms.

Beginning with 2008 data, the Form EIA-923, Power Plant Operations Report, replaced the following: 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 Federal Energy Regulatory Commission, FERC Form 423, Monthly Report of Cost and Quality of Fuels for Electric Plants.

Estimated small scale solar photovoltaic generation and small scale solar photovoltaic capacity are based on data from Form EIA-861M, Form EIA-861 and from estimation methods described in the technical notes.

Table 3.2.A. Net Generation by Energy Source: Electric Utilities, 2009 - 2019
(Thousand Megawatthours)

	Generation at Utility Scale Facilities											
									Renewable Sources Excluding Hydroelectric and Solar	Hydroelectric Pumped Storage		
Period	Coal	Petroleum Liquids	Petroleum Coke	Natural Gas	Other Gas	Nuclear	Hydroelectric Conventional	Solar			Other	Total
Annual Totals												
2009	1,322,092	18,035	7,182	349,166	96	417,275	247,198	28	14,589	-3,369	483	2,372,776
2010	1,378,028	17,258	8,807	392,616	52	424,843	236,104	101	17,826	-4,466	462	2,471,632
2011	1,301,107	11,688	9,428	414,843	29	415,298	291,413	216	21,717	-5,492	604	2,460,851
2012	1,146,480	9,892	5,664	504,958	0	394,823	252,936	639	27,378	-4,202	603	2,339,172
2013	1,188,452	9,446	9,522	501,427	798	406,114	243,040	943	31,474	-3,773	615	2,388,058
2014	1,173,073	10,696	9,147	501,414	112	419,871	238,185	1,218	33,278	-5,144	622	2,382,473
2015	998,385	10,386	8,278	617,817	199	416,680	229,640	1,494	35,992	-4,105	558	2,315,323
2016	922,399	9,069	8,881	654,780	154	424,400	247,787	1,995	40,666	-5,629	421	2,304,923
2017	893,639	8,567	6,711	623,834	149	424,485	275,677	3,348	42,763	-5,448	553	2,274,279
2018	863,505	10,108	6,817	720,206	151	424,251	267,336	4,916	44,184	-4,785	561	2,337,250
2019	722,885	8,313	5,112	785,026	154	430,672	262,364	6,785	48,403	-4,261	551	2,266,004
Year 2017												
January	85,985	796	743	45,737	13	38,425	24,538	158	3,381	-346	43	199,474
February	64,844	627	540	39,552	17	33,911	21,937	194	3,796	-418	37	165,037
March	65,992	752	535	46,425	16	34,693	27,285	279	4,428	-455	42	179,993
April	58,913	641	260	43,439	18	30,217	26,825	307	4,178	-368	45	164,476
May	69,099	708	654	48,492	5	31,728	29,918	347	3,665	-350	42	184,308
June	81,297	707	698	56,422	10	35,022	28,240	344	3,407	-474	45	205,719
July	96,782	651	673	71,139	19	37,874	24,415	322	2,692	-646	50	233,972
August	90,517	696	540	67,676	2	38,667	20,221	322	2,358	-531	54	220,522
September	71,859	665	523	56,361	0	35,496	17,664	308	2,943	-522	48	185,345
October	66,498	734	405	50,125	9	35,038	16,270	283	4,185	-388	48	173,207
November	64,983	639	583	45,119	15	34,541	17,894	237	3,870	-394	49	167,537
December	76,870	950	556	53,347	24	38,871	20,469	246	3,859	-557	50	194,686
Year 2018												
January	88,718	2,491	770	55,797	26	39,366	23,106	288	4,399	-475	41	214,525
February	61,138	617	575	48,715	17	33,941	22,864	314	3,853	-226	38	171,847
March	58,606	595	491	52,161	16	35,262	23,638	446	4,276	-408	48	175,132
April	55,281	632	477	48,151	28	30,580	25,598	480	4,120	-295	39	165,093
May	64,034	745	336	58,251	11	34,479	28,055	463	3,427	-309	45	189,538
June	77,899	756	670	66,774	13	36,437	25,778	503	3,691	-339	50	212,232
July	88,102	668	716	81,297	15	38,293	23,303	477	2,824	-522	55	235,229
August	87,359	711	686	78,025	24	38,885	20,050	476	3,122	-626	56	228,767
September	73,021	781	639	68,655	3	34,377	17,368	436	3,288	-500	47	198,116
October	64,902	751	378	59,071	0	31,364	17,571	418	3,447	-405	43	177,541
November	68,864	703	477	51,796	0	33,043	19,630	325	3,631	-254	50	178,265
December	75,578	657	601	51,512	0	38,223	20,373	290	4,105	-426	49	190,963
Year 2019												
January	74,950	884	634	59,221	12	39,806	22,391	379	3,980	-247	42	202,052
February	59,507	580	564	55,553	22	34,243	20,610	403	3,431	-310	30	174,633
March	56,482	616	464	57,144	31	34,213	23,839	598	4,349	-309	31	177,458
April	44,228	545	276	51,616	0	32,063	25,266	667	4,820	-26	35	159,490
May	55,130	685	552	59,603	0	35,416	29,266	689	4,057	-305	41	185,133
June	60,199	723	398	70,460	23	36,847	25,767	662	3,649	-299	39	198,468
July	77,085	713	551	85,011	18	39,023	22,846	673	3,631	-505	36	229,082
August	72,032	802	501	87,745	16	39,218	20,913	640	3,139	-470	66	224,601
September	64,955	694	460	74,912	10	34,770	17,045	641	4,185	-583	59	197,147
October	49,301	701	146	64,537	0	32,289	16,625	574	4,600	-316	58	168,516
November	55,455	638	251	56,508	19	32,923	18,467	464	4,237	-424	56	168,594
December	53,561	730	315	62,718	2	39,861	19,330	395	4,325	-465	57	180,830

Coal includes anthracite, bituminous, subbituminous, lignite, and waste coal; synthetic coal and refined coal; and beginning in 2011, coal-derived synthesis gas. Prior to 2011 coal-derived synthesis gas was included in Other Gases.

Petroleum Liquids includes distillate and residual fuel oils, jet fuel, kerosene, waste oil, and beginning in 2011, propane. Prior to 2011 propane was included in Other Gases.

Petroleum Coke includes petroleum coke-derived synthesis gas. Prior to 2011, petroleum coke-derived synthesis gas was included in Other Gases.

Other Gas includes blast furnace gas and other manufactured and waste gases derived from fossil fuels. Prior to 2011, Other Gas included propane and synthesis gases.

See the Technical Notes for fuel conversion factors.

Renewable Sources include wood, black liquor, other wood waste, biogenic municipal solid waste, landfill gas, sludge waste, agriculture byproducts, other biomass, geothermal, solar thermal, photovoltaic energy, and wind.

Other includes non-biogenic municipal solid waste, batteries, hydrogen, purchased steam, sulfur, tire-derived fuel, and other miscellaneous energy sources.

Notes: Beginning with 2001 data, non-biogenic municipal solid waste and tire-derived fuels are reclassified as non-renewable energy sources and included in Other. Biogenic municipal solid waste is included in Other Renewable Sources.

See Glossary for definitions. Values are final. See Technical Notes for a discussion of the sample design for the Form EIA-923 and predecessor forms.

Totals may not equal sum of components because of independent rounding. NM=Not meaningful due to large standard error. W=Withheld to avoid disclosure of individual company data.

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Sources: U.S. Energy Information Administration, Form EIA-923, Power Plant Operations Report; U.S. Energy Information Administration, Form EIA-906, Power Plant Report; U.S. Energy Information Administration, Form EIA-920 Combined Heat and Power Plant Report; and predecessor forms.

Beginning with 2008 data, the Form EIA-923, Power Plant Operations Report, replaced the following: Form EIA-906, Power Plant Report; Form EIA-920, Combined Heat and Power Plant Report;

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Table 3.2.B. Net Generation from Renewable Sources: Electric Utilities, 2009 - 2019
(Thousand Megawatthours)

		Generation at Utility Scale Facilities									Small Scale Generation	Generation From Utility and Small Scale Facilities	
Period	Wind	Solar Photovoltaic	Solar Thermal	Wood and Wood-Derived Fuels	Landfill Gas	Biogenic Municipal Solid Waste	Other Waste Biomass	Geothermal	Conventional Hydroelectric	Total Renewable Generation at Utility Scale Facilities	Estimated Solar Photovoltaic	Estimated Total Solar Photovoltaic	Estimated Total Solar
Annual Totals													
2009	10,348	28	1	1,748	866	184	261	1,182	247,198	261,815	N/A	N/A	N/A
2010	13,089	101	0	2,328	879	154	259	1,118	236,104	254,031	N/A	N/A	N/A
2011	17,140	187	29	2,023	957	165	295	1,137	291,413	313,346	N/A	N/A	N/A
2012	22,926	551	89	1,836	1,022	184	265	1,143	252,936	280,953	N/A	N/A	N/A
2013	26,436	841	102	2,534	1,114	197	188	1,005	243,040	275,457	N/A	N/A	N/A
2014	27,671	1,094	124	3,050	1,068	191	182	1,116	238,185	272,681	0	1,094	1,218
2015	30,412	1,388	106	3,018	1,061	195	218	1,089	229,640	267,125	0	1,388	1,494
2016	35,070	1,920	75	3,038	1,040	201	237	1,080	247,787	290,448	0	1,920	1,995
2017	37,068	3,326	22	3,226	1,103	184	161	1,022	275,677	321,788	0	3,326	3,348
2018	38,466	4,865	51	3,364	1,004	203	138	1,009	267,336	316,436	0	4,865	4,916
2019	43,636	6,757	28	2,784	964	122	126	771	262,364	317,552	0	6,757	6,785
Year 2017													
January	2,836	158	0	329	96	14	13	94	24,538	28,078	0	158	158
February	3,338	194	0	265	90	9	15	80	21,937	25,927	0	194	194
March	3,907	279	0	311	98	15	19	78	27,285	31,992	0	279	279
April	3,721	307	0	246	95	16	11	90	26,825	31,311	0	307	307
May	3,239	346	1	213	99	15	13	88	29,918	33,930	0	346	347
June	2,960	343	1	245	86	17	14	86	28,240	31,991	0	343	344
July	2,203	321	1	282	88	17	13	89	24,415	27,429	0	321	322
August	1,865	318	4	280	90	19	15	89	20,221	22,901	0	318	322
September	2,575	302	7	166	83	18	13	87	17,664	20,915	0	302	308
October	3,742	282	1	252	89	14	11	77	16,270	20,739	0	282	283
November	3,376	235	2	288	93	15	10	88	17,894	22,001	0	235	237
December	3,306	241	6	350	98	14	15	75	20,469	24,574	0	241	246
Year 2018													
January	3,832	286	1	364	102	11	17	73	23,106	27,793	0	286	288
February	3,363	311	3	291	92	12	12	82	22,864	27,031	0	311	314
March	3,717	437	9	343	100	17	10	89	23,638	28,361	0	437	446
April	3,707	472	9	221	94	16	10	73	25,598	30,199	0	472	480
May	2,990	460	3	228	93	20	6	90	28,055	31,945	0	460	463
June	3,227	498	5	278	75	18	7	85	25,778	29,972	0	498	503
July	2,297	472	6	327	77	21	14	88	23,303	26,604	0	472	477
August	2,612	470	6	317	73	21	11	88	20,050	23,647	0	470	476
September	2,875	432	4	234	68	15	11	85	17,368	21,092	0	432	436
October	3,007	413	5	251	76	18	14	81	17,571	21,437	0	413	418
November	3,164	324	1	277	76	17	14	84	19,630	23,586	0	324	325
December	3,676	290	1	233	77	17	12	90	20,373	24,769	0	290	290
Year 2019													
January	3,505	377	2	284	86	13	14	78	22,391	26,750	0	377	379
February	3,034	400	3	229	77	8	15	70	20,610	24,444	0	400	403
March	3,957	594	4	206	86	8	16	76	23,839	28,786	0	594	598
April	4,495	661	6	165	81	12	12	56	25,266	30,753	0	661	667
May	3,659	686	3	234	83	11	10	60	29,266	34,012	0	686	689
June	3,284	661	1	194	79	11	10	72	25,767	30,078	0	661	662
July	3,142	672	1	316	79	10	11	73	22,846	27,150	0	672	673
August	2,630	636	4	329	80	12	14	74	20,913	24,691	0	636	640
September	3,777	639	2	241	76	8	8	74	17,045	21,871	0	639	641
October	4,255	573	2	198	78	12	5	51	16,625	21,800	0	573	574
November	3,965	464	0	142	76	10	3	40	18,467	23,168	0	464	464
December	3,932	395	1	246	82	8	9	48	19,330	24,051	0	395	395

Wood and Wood-derived fuels include 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.

Other Waste Biomass includes sludge waste, agricultural byproducts, other biomass solids, other biomass liquids, and other biomass gases (including digester gases, methane, and other biomass gases).

Notes: Beginning with 2001 data, non-biogenic municipal solid waste and tire-derived fuels are reclassified as non-renewable energy sources and included in Other. Biogenic municipal solid waste is included in Other Renewable Sources.

See Glossary for definitions. Values are final. See Technical Notes for a discussion of the sample design for the Form EIA-923 and predecessor forms.

Totals may not equal sum of components because of independent rounding. NM=Not meaningful due to large standard error. W=Withheld to avoid disclosure of individual company data.

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Beginning with 2008 data, the Form EIA-923, Power Plant Operations Report, replaced the following: 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 Federal Energy Regulatory Commission, FERC Form 423, Monthly Report of Cost and Quality of Fuels for Electric Plants.

Estimated small scale solar photovoltaic generation and small scale solar photovoltaic capacity are based on data from Form EIA-861M, Form EIA-861 and from estimation methods described in the technical notes.

Table 3.3.A. Net Generation by Energy Source: Independent Power Producers, 2009 - 2019
(Thousand Megawatthours)

	Generation at Utility Scale Facilities												
										Renewable Sources Excluding Hydroelectric and Solar	Hydroelectric Pumped Storage		
Period	Coal	Petroleum Liquids	Petroleum Coke	Natural Gas	Other Gas	Nuclear	Hydroelectric Conventional	Solar				Other	Total
Annual Totals													
2009	419,031	6,306	4,288	491,839	2,962	381,579	24,308	863	100,997	-1,259		6,146	1,437,061
2010	449,709	5,117	3,497	508,774	2,915	382,126	22,351	1,105	119,851	-1,035		6,345	1,500,754
2011	416,783	3,655	3,431	511,447	2,911	374,906	26,117	1,511	140,442	-928		7,059	1,487,335
2012	354,076	2,757	1,758	627,833	2,984	374,509	20,923	3,525	156,539	-748		7,030	1,551,186
2013	379,270	3,761	1,780	527,522	3,524	382,902	22,018	7,782	181,263	-908		6,742	1,515,657
2014	395,701	6,789	1,410	531,758	3,246	377,295	19,861	16,086	196,723	-1,030		6,690	1,554,530
2015	342,608	6,240	1,601	619,839	3,517	380,498	17,996	22,962	202,858	-987		6,838	1,603,971
2016	307,263	3,360	1,401	624,600	3,758	381,294	18,539	33,502	233,553	-1,057		6,941	1,613,156
2017	304,198	3,281	1,480	572,919	3,978	380,465	23,034	49,376	258,962	-1,047		6,527	1,603,174
2018	278,668	5,487	1,516	645,616	3,935	382,833	23,812	58,337	275,154	-1,119		6,677	1,680,917
2019	235,847	2,669	1,125	692,113	3,883	378,738	24,288	64,480	290,343	-1,000		7,138	1,699,625
Year 2017													
January	28,587	251	139	41,210	336	34,695	1,941	2,140	21,591	-90		583	131,384
February	21,314	198	123	35,536	291	29,650	1,809	2,523	22,000	-90		514	113,867
March	22,696	157	81	40,477	343	30,400	2,175	4,185	25,419	-66		523	126,389
April	21,829	178	113	37,158	282	26,526	2,410	4,546	24,944	-71		507	118,422
May	23,043	221	136	41,502	346	29,585	2,503	5,378	23,207	-73		548	126,395
June	25,528	245	132	52,358	314	31,988	2,182	5,708	20,610	-93		549	139,521
July	30,237	228	138	66,687	350	33,440	2,045	5,188	17,552	-114		572	156,322
August	28,293	232	140	64,699	358	33,717	1,703	4,989	15,669	-107		580	150,272
September	25,701	226	136	53,795	346	32,602	1,399	4,698	18,801	-84		509	138,127
October	22,616	195	110	48,675	318	30,957	1,336	4,323	23,905	-75		518	132,878
November	25,364	221	111	41,715	337	32,077	1,864	2,937	22,697	-84		539	127,777
December	28,990	930	122	49,108	358	34,828	1,667	2,760	22,569	-99		586	141,819
Year 2018													
January	29,839	2,951	137	45,672	318	35,283	1,856	3,000	25,364	-72		575	144,924
February	20,261	133	126	41,986	320	30,849	1,929	3,549	23,179	-89		543	122,786
March	21,377	186	96	46,436	331	31,770	2,114	4,563	26,260	-82		564	133,615
April	17,506	199	137	42,464	326	28,553	2,392	5,522	25,872	-82		527	123,416
May	20,600	248	124	48,762	379	32,841	2,264	6,325	24,380	-81		526	136,366
June	22,994	268	100	55,398	303	33,251	1,724	6,845	24,920	-95		582	146,291
July	26,647	260	139	73,967	344	34,163	1,700	6,214	17,729	-123		586	161,625
August	27,157	292	139	74,126	369	33,398	1,858	6,158	20,775	-121		579	164,730
September	22,941	233	108	64,337	328	30,348	1,692	5,475	18,927	-103		515	144,800
October	21,834	218	126	55,462	255	28,033	1,855	4,508	21,450	-87		556	134,209
November	23,393	245	140	47,623	311	30,911	2,150	3,386	22,175	-88		551	130,797
December	24,120	254	144	49,384	350	33,434	2,277	2,792	24,124	-96		574	137,357
Year 2019													
January	25,344	462	125	52,923	348	33,895	2,266	3,167	24,193	-76		625	143,272
February	19,875	185	91	48,397	329	30,472	2,162	3,395	22,632	-79		544	128,002
March	21,337	155	71	49,981	352	30,867	2,368	5,243	25,078	-100		573	135,927
April	15,198	189	79	44,245	329	28,518	2,429	6,023	27,340	-78		546	124,819
May	16,258	215	145	48,842	325	31,708	2,591	6,406	25,316	-63		623	132,365
June	17,844	196	117	58,469	306	31,958	2,198	7,236	22,392	-86		610	141,240
July	23,140	254	135	77,238	354	33,176	1,942	7,380	22,329	-118		634	166,465
August	21,485	200	134	77,396	361	32,693	1,592	7,163	20,752	-109		638	162,304
September	20,261	186	77	65,571	332	31,294	1,416	6,112	23,996	-88		590	149,747
October	17,011	200	9	57,397	189	29,744	1,607	5,466	26,335	-56		582	138,483
November	19,591	215	41	52,175	307	31,202	1,672	3,859	24,109	-84		572	133,658
December	18,504	213	102	59,480	352	33,212	2,044	3,028	25,871	-64		601	143,343

Coal includes anthracite, bituminous, subbituminous, lignite, and waste coal; synthetic coal and refined coal; and beginning in 2011, coal-derived synthesis gas. Prior to 2011 coal-derived synthesis gas was included in Other Gases.

Petroleum Liquids includes distillate and residual fuel oils, jet fuel, kerosene, waste oil, and beginning in 2011, propane. Prior to 2011 propane was included in Other Gases.

Petroleum Coke includes petroleum coke-derived synthesis gas. Prior to 2011, petroleum coke-derived synthesis gas was included in Other Gases.

Other Gas includes blast furnace gas and other manufactured and waste gases derived from fossil fuels. Prior to 2011, Other Gas included propane and synthesis gases.

See the Technical Notes for fuel conversion factors.

Renewable Sources include wood, black liquor, other wood waste, biogenic municipal solid waste, landfill gas, sludge waste, agriculture byproducts, other biomass, geothermal, solar thermal, photovoltaic energy, and wind.

Other includes non-biogenic municipal solid waste, batteries, hydrogen, purchased steam, sulfur, tire-derived fuel, and other miscellaneous energy sources.

Notes: Beginning with 2001 data, non-biogenic municipal solid waste and tire-derived fuels are reclassified as non-renewable energy sources and included in Other. Biogenic municipal solid waste is included in Other Renewable Sources.

See Glossary for definitions. Values are final. See Technical Notes for a discussion of the sample design for the Form EIA-923 and predecessor forms.

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Table 3.3.B. Net Generation from Renewable Sources: Independent Power Producers, 2009 - 2019
(Thousand Megawatthours)

		Generation at Utility Scale Facilities										Small Scale Generation	Generation From Utility and Small Scale Facilities	
Period		Wind	Solar Photovoltaic	Solar Thermal	Wood and Wood-Derived Fuels	Landfill Gas	Biogenic Municipal Solid Waste	Other Waste Biomass	Geothermal	Conventional Hydroelectric	Total Renewable Generation at Utility Scale Facilities	Estimated Solar Photovoltaic	Estimated Total Solar Photovoltaic	Estimated Total Solar
Annual Totals														
	2009	63,538	129	734	8,990	6,718	6,829	1,095	13,826	24,308	126,168	N/A	N/A	N/A
	2010	81,547	316	789	9,118	7,227	6,742	1,116	14,101	22,351	143,306	N/A	N/A	N/A
	2011	102,981	734	777	8,709	7,120	6,217	1,237	14,180	26,117	168,071	N/A	N/A	N/A
	2012	117,822	2,737	787	9,214	7,852	6,056	1,176	14,419	20,923	180,987	N/A	N/A	N/A
	2013	141,306	6,969	813	9,768	8,442	5,838	1,139	14,770	22,018	211,063	N/A	N/A	N/A
	2014	153,825	13,769	2,317	11,977	9,062	5,838	1,261	14,761	19,861	232,670	0	13,769	16,086
	2015	160,135	19,841	3,121	11,545	9,202	5,806	1,342	14,829	17,996	243,816	0	19,841	22,962
	2016	191,720	30,194	3,308	10,382	9,255	5,965	1,486	14,746	18,539	285,594	0	30,194	33,502
	2017	217,006	46,128	3,248	10,416	9,505	5,652	1,479	14,905	23,034	331,372	0	46,128	49,376
	2018	233,931	54,796	3,540	10,021	9,162	5,891	1,226	14,924	23,812	357,303	0	54,796	58,337
	2019	251,968	61,290	3,190	9,237	8,739	5,096	1,043	14,260	24,288	379,111	0	61,290	64,480
Year 2017														
	January	17,944	2,051	90	860	819	518	136	1,313	1,941	25,672	0	2,051	2,140
	February	18,734	2,387	136	796	747	440	124	1,158	1,809	26,332	0	2,387	2,523
	March	21,798	3,888	297	905	819	454	134	1,309	2,175	31,779	0	3,888	4,185
	April	21,634	4,236	310	728	774	440	116	1,251	2,410	31,899	0	4,236	4,546
	May	19,808	4,977	402	765	804	484	132	1,214	2,503	31,089	0	4,977	5,378
	June	17,164	5,245	464	848	792	479	129	1,198	2,182	28,501	0	5,245	5,708
	July	13,905	4,877	311	958	796	484	126	1,284	2,045	24,784	0	4,877	5,188
	August	12,004	4,652	337	991	795	494	111	1,274	1,703	22,361	0	4,652	4,989
	September	15,321	4,355	343	922	763	447	104	1,244	1,399	24,898	0	4,355	4,698
	October	20,604	4,009	313	831	773	447	113	1,137	1,336	29,564	0	4,009	4,323
	November	19,217	2,808	130	875	791	466	132	1,216	1,864	27,498	0	2,808	2,937
	December	18,873	2,643	117	936	833	499	123	1,305	1,667	26,996	0	2,643	2,760
Year 2018														
	January	21,738	2,873	127	956	786	492	124	1,268	1,856	30,221	0	2,873	3,000
	February	19,802	3,361	188	846	741	472	125	1,192	1,929	28,657	0	3,361	3,549
	March	22,718	4,314	248	857	794	494	120	1,278	2,114	32,936	0	4,314	4,563
	April	22,700	5,216	306	727	751	466	114	1,115	2,392	33,786	0	5,216	5,522
	May	20,941	5,898	427	810	765	461	110	1,293	2,264	32,969	0	5,898	6,325
	June	21,456	6,333	512	890	745	516	98	1,214	1,724	33,489	0	6,333	6,845
	July	14,135	5,839	374	944	761	524	83	1,281	1,700	25,642	0	5,839	6,214
	August	17,218	5,754	403	900	774	517	87	1,279	1,858	28,792	0	5,754	6,158
	September	15,627	5,049	425	810	700	465	82	1,243	1,692	26,094	0	5,049	5,475
	October	18,162	4,238	270	738	770	489	98	1,192	1,855	27,812	0	4,238	4,508
	November	18,827	3,219	167	753	774	487	86	1,247	2,150	27,712	0	3,219	3,386
	December	20,606	2,701	91	789	802	508	98	1,322	2,277	29,194	0	2,701	2,792
Year 2019														
	January	20,768	3,059	109	857	770	438	91	1,270	2,266	29,627	0	3,059	3,167
	February	19,565	3,266	128	718	700	390	76	1,182	2,162	28,189	0	3,266	3,395
	March	21,789	4,987	256	733	749	409	97	1,302	2,368	32,690	0	4,987	5,243
	April	24,392	5,704	319	604	699	384	90	1,171	2,429	35,793	0	5,704	6,023
	May	22,097	6,073	333	731	729	441	72	1,245	2,591	34,313	0	6,073	6,406
	June	19,142	6,798	439	780	727	437	84	1,223	2,198	31,827	0	6,798	7,236
	July	18,942	6,982	398	836	740	454	88	1,269	1,942	31,651	0	6,982	7,380
	August	17,333	6,754	409	843	739	459	91	1,288	1,592	29,507	0	6,754	7,163
	September	20,717	5,821	292	804	696	431	83	1,264	1,416	31,525	0	5,821	6,112
	October	23,344	5,170	296	701	725	419	95	1,052	1,607	33,407	0	5,170	5,466
	November	21,194	3,718	141	815	705	406	87	901	1,672	29,640	0	3,718	3,859
	December	22,684	2,959	70	815	762	430	88	1,093	2,044	30,943	0	2,959	3,028

Wood and Wood-derived fuels include 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.

Other Waste Biomass includes sludge waste, agricultural byproducts, other biomass solids, other biomass liquids, and other biomass gases (including digester gases, methane, and other biomass gases).

Notes: Beginning with 2001 data, non-biogenic municipal solid waste and tire-derived fuels are reclassified as non-renewable energy sources and included in Other. Biogenic municipal solid waste is included in Other Renewable Sources.

See Glossary for definitions. Values are final. See Technical Notes for a discussion of the sample design for the Form EIA-923 and predecessor forms.

Totals may not equal sum of components because of independent rounding. NM=Not meaningful due to large standard error. W=Withheld to avoid disclosure of individual company data.

Displayed values of zero may represent small values that round to zero. The Excel version of this table provides additional precision which may be accessed by selecting individual cells.

Sources: U.S. Energy Information Administration, Form EIA-923, Power Plant Operations Report; U.S. Energy Information Administration, Form EIA-906, Power Plant Report; U.S. Energy Information Administration, Form EIA-920 Combined Heat and Power Plant Report; and predecessor forms.

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Estimated small scale solar photovoltaic generation and small scale solar photovoltaic capacity are based on data from Form EIA-861M, Form EIA-861 and from estimation methods described in the technical notes.

Table 3.4.A. Net Generation by Energy Source: Commercial Sector, 2009 - 2019
(Thousand Megawatthours)

Period	Generation at Utility Scale Facilities												Small Scale Generation	Net Generation From Utility and Small Scale Facilities	
	Coal	Petroleum Liquids	Petroleum Coke	Natural Gas	Other Gas	Nuclear	Hydroelectric Conventional	Solar	Renewable Sources Excluding Hydroelectric and Solar	Hydroelectric Pumped Storage	Other	Total Generation at Utility Scale Facilities	Estimated Solar Photovoltaic	Estimated Total Solar Photovoltaic	Estimated Total Solar
Annual Totals															
2009	1,096	157	5	4,225	0	0	71	0	1,769	0	842	8,165	N/A	N/A	N/A
2010	1,111	117	7	4,725	3	0	80	5	1,709	0	834	8,592	N/A	N/A	N/A
2011	1,049	86	3	5,487	3	0	26	84	2,392	0	950	10,080	N/A	N/A	N/A
2012	883	191	6	6,603	0	0	28	148	2,397	0	1,046	11,301	N/A	N/A	N/A
2013	839	118	5	7,154	0	0	44	294	2,662	0	1,118	12,234	N/A	N/A	N/A
2014	595	247	9	7,227	0	0	38	371	2,862	0	1,171	12,520	5,146	5,516	5,516
2015	509	183	8	7,471	0	0	35	416	2,803	0	1,170	12,595	5,689	6,106	6,106
2016	383	77	6	7,730	0	0	217	529	2,697	0	1,068	12,706	6,158	6,687	6,687
2017	329	103	8	8,042	0	0	240	521	2,729	0	1,088	13,060	7,685	8,206	8,206
2018	303	132	7	8,419	0	0	227	525	2,688	0	1,010	13,312	9,798	10,324	10,324
2019	268	116	5	8,610	0	0	188	587	2,840	0	1,076	13,689	11,002	11,588	11,588
Year 2017															
January	41	13	1	686	0	0	21	24	232	0	84	1,103	420	445	445
February	32	7	1	603	0	0	20	32	209	0	78	980	458	490	490
March	33	9	1	655	0	0	24	47	232	0	86	1,087	629	676	676
April	20	5	0	577	0	0	25	50	222	0	87	986	699	748	748
May	19	6	0	621	0	0	27	56	243	0	101	1,074	770	826	826
June	21	5	0	715	0	0	24	58	225	0	89	1,138	777	835	835
July	25	7	0	782	0	0	21	55	237	0	99	1,227	808	863	863
August	23	7	1	766	0	0	18	53	233	0	100	1,201	788	841	841
September	27	6	1	694	0	0	15	49	216	0	90	1,098	709	758	758
October	24	6	1	659	0	0	13	40	216	0	94	1,054	632	673	673
November	29	7	1	609	0	0	14	32	226	0	88	1,006	502	534	534
December	35	23	1	674	0	0	16	26	238	0	91	1,105	492	519	519
Year 2018															
January	40	41	1	671	0	0	19	29	229	0	84	1,114	552	581	581
February	32	7	1	626	0	0	19	31	206	0	72	995	605	636	636
March	27	7	1	647	0	0	21	43	227	0	83	1,058	820	863	863
April	24	8	0	585	0	0	24	50	217	0	81	989	907	957	957
May	21	7	0	656	0	0	24	57	221	0	90	1,076	992	1,048	1,048
June	20	7	0	737	0	0	21	62	224	0	92	1,163	1,003	1,065	1,065
July	21	11	0	875	0	0	19	59	223	0	90	1,298	1,036	1,094	1,094
August	23	9	0	892	0	0	17	56	230	0	90	1,318	993	1,049	1,049
September	24	7	1	771	0	0	16	46	213	0	80	1,156	893	938	938
October	20	7	1	668	0	0	14	39	223	0	83	1,055	786	826	826
November	25	12	1	622	0	0	16	29	212	0	77	993	623	652	652
December	24	9	1	669	0	0	17	25	262	0	88	1,095	589	614	614
Year 2019															
January	29	19	1	706	0	0	16	30	263	0	95	1,160	629	659	659
February	27	9	1	654	0	0	15	34	236	0	81	1,057	676	710	710
March	33	8	1	711	0	0	19	50	262	0	90	1,173	933	983	983
April	22	7	1	646	0	0	19	54	216	0	88	1,053	1,032	1,086	1,086
May	18	7	0	663	0	0	22	58	213	0	91	1,072	1,110	1,168	1,168
June	13	6	0	711	0	0	18	63	229	0	93	1,133	1,118	1,181	1,181
July	18	9	0	869	0	0	16	69	240	0	92	1,313	1,171	1,241	1,241
August	17	12	0	852	0	0	15	64	235	0	94	1,290	1,116	1,181	1,181
September	21	10	0	731	0	0	12	55	230	0	91	1,150	994	1,049	1,049
October	21	9	0	666	0	0	11	46	235	0	84	1,072	881	927	927
November	23	9	0	667	0	0	12	36	235	0	84	1,066	683	719	719
December	27	10	1	735	0	0	14	26	246	0	93	1,151	657	684	684

Coal includes anthracite, bituminous, subbituminous, lignite, and waste coal; synthetic coal and refined coal; and beginning in 2011, coal-derived synthesis gas. Prior to 2011 coal-derived synthesis gas was included in Other Gases.

Petroleum Liquids includes distillate and residual fuel oils, jet fuel, kerosene, waste oil, and beginning in 2011, propane. Prior to 2011 propane was included in Other Gases.

Petroleum Coke includes petroleum coke-derived synthesis gas. Prior to 2011, petroleum coke-derived synthesis gas was included in Other Gases.

Other Gas includes blast furnace gas and other manufactured and waste gases derived from fossil fuels. Prior to 2011, Other Gas included propane and synthesis gases.

See the Technical Notes for fuel conversion factors.

Renewable Sources include wood, black liquor, other wood waste, biogenic municipal solid waste, landfill gas, sludge waste, agriculture byproducts, other biomass, geothermal, solar thermal, photovoltaic energy, and wind.

Other includes non-biogenic municipal solid waste, batteries, hydrogen, purchased steam, sulfur, tire-derived fuel, and other miscellaneous energy sources.

Notes: Beginning with 2001 data, non-biogenic municipal solid waste and tire-derived fuels are reclassified as non-renewable energy sources and included in Other. Biogenic municipal solid waste is included in Other Renewable Sources.

See Glossary for definitions. Values are final. See Technical Notes for a discussion of the sample design for the Form EIA-923 and predecessor forms.

Totals may not equal sum of components because of independent rounding. NM=Not meaningful due to large standard error. W=Withheld to avoid disclosure of individual company data.

Displayed values of zero may represent small values that round to zero. The Excel version of this table provides additional precision which may be accessed by selecting individual cells.

Sources: U.S. Energy Information Administration, Form EIA-923, Power Plant Operations Report; U.S. Energy Information Administration, Form EIA-906, Power Plant Report; U.S. Energy Information Administration, Form EIA-920 Combined Heat and Power Plant Report; and predecessor forms.

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

Estimated small scale solar photovoltaic generation and small scale solar photovoltaic capacity are based on data from Form EIA-861M, Form EIA-861 and from estimation methods described in the technical notes.

Table 3.4.B. Net Generation from Renewable Sources: Commercial Sector, 2009 - 2019
(Thousand Megawatthours)

		Generation at Utility Scale Facilities										Small Scale Generation	Generation From Utility and Small Scale Facilities	
Period	Wind	Solar Photovoltaic	Solar Thermal	Wood and Wood-Derived Fuels	Landfill Gas	Biogenic Municipal Solid Waste	Other Waste Biomass	Geothermal	Conventional Hydroelectric	Total Renewable Generation at Utility Scale Facilities	Estimated Solar Photovoltaic	Estimated Total Solar Photovoltaic	Estimated Total Solar	
Annual Totals														
2009	0	0	0	20	318	1,045	386	0	71	1,839	N/A	N/A	N/A	
2010	16	5	0	21	256	1,031	386	0	80	1,794	N/A	N/A	N/A	
2011	51	84	0	26	952	971	393	0	26	2,502	N/A	N/A	N/A	
2012	54	148	0	24	848	1,070	402	0	28	2,573	N/A	N/A	N/A	
2013	61	294	0	34	925	1,149	493	0	44	3,000	N/A	N/A	N/A	
2014	107	371	0	74	905	1,202	575	0	38	3,271	5,146	5,516	5,516	
2015	118	416	0	48	847	1,199	592	0	35	3,255	5,689	6,106	6,106	
2016	131	529	0	69	753	1,093	649	0	217	3,443	6,158	6,687	6,687	
2017	144	521	0	70	753	1,114	648	0	240	3,490	7,685	8,206	8,206	
2018	174	525	0	77	703	1,038	664	33	227	3,441	9,798	10,324	10,324	
2019	179	587	0	90	626	869	634	442	188	3,615	11,002	11,588	11,588	
Year 2017														
January	11	24	0	8	68	86	59	0	21	277	420	445	445	
February	11	32	0	7	60	79	51	0	20	260	458	490	490	
March	17	47	0	3	67	88	58	0	24	303	629	676	676	
April	15	50	0	5	59	89	54	0	25	297	699	748	748	
May	13	56	0	7	64	103	56	0	27	326	770	826	826	
June	11	58	0	6	63	91	54	0	24	307	777	835	835	
July	8	55	0	7	64	102	57	0	21	313	808	863	863	
August	6	53	0	7	63	102	54	0	18	303	788	841	841	
September	11	49	0	2	62	92	49	0	15	280	709	758	758	
October	15	40	0	5	55	97	45	0	13	269	632	673	673	
November	14	32	0	6	63	90	54	0	14	273	502	534	534	
December	13	26	0	6	67	93	59	0	16	281	492	519	519	
Year 2018														
January	18	29	0	9	61	86	56	0	19	277	552	581	581	
February	15	31	0	6	57	74	53	0	19	256	605	636	636	
March	18	43	0	5	63	85	56	0	21	292	820	863	863	
April	16	50	0	2	60	84	55	0	24	291	907	957	957	
May	14	57	0	4	57	92	54	0	24	302	992	1,048	1,048	
June	14	62	0	8	55	94	54	0	21	308	1,003	1,065	1,065	
July	10	59	0	9	58	92	55	0	19	301	1,036	1,094	1,094	
August	11	56	0	11	59	92	57	0	17	304	993	1,049	1,049	
September	12	46	0	8	57	81	54	0	16	274	893	938	938	
October	15	39	0	4	60	86	58	0	14	276	786	826	826	
November	16	29	0	2	57	81	56	0	16	256	623	652	652	
December	15	25	0	8	59	91	55	33	17	304	589	614	614	
Year 2019														
January	17	30	0	8	62	78	55	42	16	310	629	659	659	
February	15	34	0	9	55	66	50	41	15	284	676	710	710	
March	17	50	0	11	61	73	55	44	19	330	933	983	983	
April	17	54	0	4	42	72	53	27	19	289	1,032	1,086	1,086	
May	14	58	0	2	35	74	51	37	22	292	1,110	1,168	1,168	
June	12	63	0	4	52	75	52	34	18	310	1,118	1,181	1,181	
July	11	69	0	16	54	73	52	33	16	325	1,171	1,241	1,241	
August	9	64	0	9	56	75	54	31	15	315	1,116	1,181	1,181	
September	14	55	0	8	55	73	51	30	12	297	994	1,049	1,049	
October	17	46	0	7	53	67	52	38	11	292	881	927	927	
November	17	36	0	6	51	67	53	42	12	283	683	719	719	
December	17	26	0	5	50	75	56	43	14	286	657	684	684	

Wood and Wood-derived fuels include 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.

Other Waste Biomass includes sludge waste, agricultural byproducts, other biomass solids, other biomass liquids, and other biomass gases (including digester gases, methane, and other biomass gases).

Notes: Beginning with 2001 data, non-biogenic municipal solid waste and tire-derived fuels are reclassified as non-renewable energy sources and included in Other. Biogenic municipal solid waste is included in Other Renewable Sources.

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Sources: U.S. Energy Information Administration, Form EIA-923, Power Plant Operations Report; U.S. Energy Information Administration, Form EIA-906, Power Plant Report; U.S. Energy Information Administration, Form EIA-920 Combined Heat and Power Plant Report; and predecessor forms.

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Estimated small scale solar photovoltaic generation and small scale solar photovoltaic capacity are based on data from Form EIA-861M, Form EIA-861 and from estimation methods described in the technical notes.

Table 3.5.A. Net Generation by Energy Source: Industrial Sector, 2009 - 2019
(Thousand Megawatthours)

Period	Generation at Utility Scale Facilities												Small Scale Generation	Net Generation From Utility and Small Scale Facilities	
	Coal	Petroleum Liquids	Petroleum Coke	Natural Gas	Other Gas	Nuclear	Hydroelectric Conventional	Solar	Renewable Sources Excluding Hydroelectric and Solar	Hydroelectric Pumped Storage	Other	Total Generation at Utility Scale Facilities	Estimated Solar Photovoltaic	Estimated Total Solar Photovoltaic	Estimated Total Solar
Annual Totals															
2009	13,686	1,474	1,489	75,748	7,574	0	1,868	0	26,033	0	4,457	132,329	N/A	N/A	N/A
2010	18,441	844	1,414	81,583	8,343	0	1,668	2	26,574	0	5,214	144,082	N/A	N/A	N/A
2011	14,490	657	1,234	81,911	8,624	0	1,799	7	27,612	0	5,541	141,875	N/A	N/A	N/A
2012	12,603	563	2,359	86,500	8,913	0	2,353	14	27,693	0	5,108	146,107	N/A	N/A	N/A
2013	12,554	495	2,036	88,733	8,531	0	3,463	17	29,074	0	5,113	150,015	N/A	N/A	N/A
2014	12,341	544	1,389	86,209	8,664	0	1,282	16	28,659	0	4,978	144,083	1,139	1,156	1,156
2015	10,896	563	990	88,355	9,401	0	1,410	21	28,614	0	5,462	145,712	1,451	1,472	1,472
2016	9,103	503	909	91,197	8,895	0	1,269	27	28,663	0	5,324	145,890	2,060	2,087	2,087
2017	7,669	463	776	91,647	8,343	0	1,382	42	28,508	0	4,928	143,758	2,364	2,406	2,406
2018	7,011	517	640	94,892	9,377	0	1,149	47	28,440	0	4,725	146,798	2,636	2,683	2,683
2019	5,957	424	576	100,065	8,554	0	1,033	85	27,276	0	4,567	148,537	3,041	3,127	3,127
Year 2017															
January	720	42	61	7,939	697	0	127	2	2,401	0	382	12,370	123	124	124
February	633	37	60	7,077	669	0	116	2	2,208	0	364	11,165	137	139	139
March	644	38	82	7,517	702	0	129	3	2,342	0	410	11,867	197	200	200
April	573	36	58	7,281	701	0	149	4	2,264	0	411	11,476	213	217	217
May	616	35	57	7,405	705	0	158	4	2,292	0	398	11,670	239	243	243
June	662	33	71	7,741	669	0	129	5	2,417	0	416	12,143	241	246	246
July	654	34	78	8,322	679	0	117	5	2,539	0	485	12,912	252	257	257
August	655	33	83	8,059	774	0	93	5	2,557	0	483	12,743	246	251	251
September	615	35	52	7,185	714	0	74	4	2,278	0	388	11,345	223	227	227
October	637	39	56	7,367	672	0	79	3	2,308	0	370	11,531	201	204	204
November	610	47	61	7,485	649	0	116	3	2,357	0	404	11,731	156	158	158
December	650	55	58	8,269	712	0	96	2	2,545	0	418	12,806	138	141	141
Year 2018															
January	687	73	57	8,153	752	0	83	2	2,450	0	410	12,668	146	149	149
February	619	47	52	7,184	755	0	89	3	2,177	0	340	11,265	155	158	158
March	616	41	54	7,280	811	0	87	4	2,437	0	413	11,742	221	225	225
April	535	33	51	7,172	744	0	102	4	2,237	0	380	11,258	241	245	245
May	572	41	56	7,614	778	0	101	5	2,390	0	409	11,967	267	271	271
June	590	34	64	7,918	775	0	74	5	2,358	0	381	12,199	268	273	273
July	606	49	57	8,609	813	0	78	5	2,540	0	381	13,138	277	282	282
August	590	35	54	8,634	909	0	91	5	2,474	0	421	13,212	268	273	273
September	558	34	51	8,022	773	0	90	4	2,290	0	363	12,185	242	247	247
October	507	39	58	7,941	762	0	108	4	2,307	0	402	12,127	220	224	224
November	536	46	38	8,127	734	0	116	3	2,318	0	396	12,313	174	177	177
December	596	46	49	8,237	771	0	130	2	2,464	0	429	12,724	157	160	160
Year 2019															
January	581	48	40	8,739	664	0	124	4	2,393	0	432	13,025	168	172	172
February	521	40	36	7,538	597	0	94	5	2,156	0	348	11,335	178	182	182
March	500	37	37	7,978	702	0	108	7	2,348	0	384	12,099	254	261	261
April	475	40	45	7,552	619	0	106	8	2,110	0	346	11,301	278	286	286
May	479	30	41	7,951	730	0	104	9	2,150	0	361	11,854	309	317	317
June	484	31	47	8,196	680	0	95	10	2,244	0	360	12,147	311	320	320
July	528	28	105	8,837	813	0	71	10	2,391	0	394	13,178	321	331	331
August	506	33	50	8,976	770	0	59	9	2,419	0	413	13,236	311	320	320
September	470	34	44	8,483	770	0	52	8	2,211	0	402	12,474	281	289	289
October	445	32	44	8,348	735	0	63	7	2,233	0	375	12,281	255	262	262
November	480	36	41	8,561	721	0	67	5	2,249	0	371	12,531	198	204	204
December	489	35	45	8,906	753	0	91	4	2,372	0	382	13,077	179	183	183

Coal includes anthracite, bituminous, subbituminous, lignite, and waste coal; synthetic coal and refined coal; and beginning in 2011, coal-derived synthesis gas. Prior to 2011 coal-derived synthesis gas was included in Other Gases.

Petroleum Liquids includes distillate and residual fuel oils, jet fuel, kerosene, waste oil, and beginning in 2011, propane. Prior to 2011 propane was included in Other Gases.

Petroleum Coke includes petroleum coke-derived synthesis gas. Prior to 2011, petroleum coke-derived synthesis gas was included in Other Gases.

Other Gas includes blast furnace gas and other manufactured and waste gases derived from fossil fuels. Prior to 2011, Other Gas included propane and synthesis gases.

See the Technical Notes for fuel conversion factors.

Renewable Sources include wood, black liquor, other wood waste, biogenic municipal solid waste, landfill gas, sludge waste, agriculture byproducts, other biomass, geothermal, solar thermal, photovoltaic energy, and wind.

Other includes non-biogenic municipal solid waste, batteries, hydrogen, purchased steam, sulfur, tire-derived fuel, and other miscellaneous energy sources.

Notes: Beginning with 2001 data, non-biogenic municipal solid waste and tire-derived fuels are reclassified as non-renewable energy sources and included in Other. Biogenic municipal solid waste is included in Other Renewable Sources.

See Glossary for definitions. Values are final. See Technical Notes for a discussion of the sample design for the Form EIA-923 and predecessor forms.

Totals may not equal sum of components because of independent rounding. NM=Not meaningful due to large standard error. W=Withheld to avoid disclosure of individual company data.

Displayed values of zero may represent small values that round to zero. The Excel version of this table provides additional precision which may be accessed by selecting individual cells.

Sources: U.S. Energy Information Administration, Form EIA-923, Power Plant Operations Report; U.S. Energy Information Administration, Form EIA-906, Power Plant Report; U.S. Energy Information Administration, Form EIA-920 Combined Heat and Power Plant Report; and predecessor forms.

Beginning with 2008 data, the Form EIA-923, Power Plant Operations Report, replaced the following: 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 Federal Energy Regulatory Commission, FERC Form 423, Monthly Report of Cost and Quality of Fuels for Electric Plants.

Estimated small scale solar photovoltaic generation and small scale solar photovoltaic capacity are based on data from Form EIA-861M, Form EIA-861 and from estimation methods described in the technical notes.

Table 3.5.B. Net Generation from Renewable Sources: Industrial Sector, 2009 - 2019
(Thousand Megawatthours)

		Generation at Utility Scale Facilities										Small Scale Generation	Generation From Utility and Small Scale Facilities	
Period		Wind	Solar Photovoltaic	Solar Thermal	Wood and Wood-Derived Fuels	Landfill Gas	Biogenic Municipal Solid Waste	Other Waste Biomass	Geothermal	Conventional Hydroelectric	Total Renewable Generation at Utility Scale Facilities	Estimated Solar Photovoltaic	Estimated Total Solar Photovoltaic	Estimated Total Solar
Annual Totals														
	2009	0	0	0	25,292	22	0	718	0	1,868	27,901	N/A	N/A	N/A
	2010	0	2	0	25,706	15	0	853	0	1,668	28,244	N/A	N/A	N/A
	2011	5	7	0	26,691	15	2	900	0	1,799	29,418	N/A	N/A	N/A
	2012	19	14	0	26,725	81	10	857	0	2,353	30,060	N/A	N/A	N/A
	2013	37	17	0	27,691	178	2	1,166	0	3,463	32,554	N/A	N/A	N/A
	2014	53	16	0	27,239	185	-2	1,185	0	1,282	29,957	1,139	1,156	1,156
	2015	53	21	0	27,318	182	12	1,049	0	1,410	30,045	1,451	1,472	1,472
	2016	71	27	0	27,458	170	6	959	0	1,269	29,960	2,060	2,087	2,087
	2017	84	42	0	27,412	183	1	827	0	1,382	29,932	2,364	2,406	2,406
	2018	97	47	0	27,475	168	4	697	0	1,149	29,636	2,636	2,683	2,683
	2019	100	85	0	26,433	139	5	598	0	1,033	28,395	3,041	3,127	3,127
Year 2017														
	January	7	2	0	2,305	16	-1	74	0	127	2,530	123	124	124
	February	8	2	0	2,117	16	-1	68	0	116	2,326	137	139	139
	March	9	3	0	2,237	17	-1	80	0	129	2,474	197	200	200
	April	8	4	0	2,167	15	-1	74	0	149	2,417	213	217	217
	May	8	4	0	2,204	14	1	66	0	158	2,454	239	243	243
	June	7	5	0	2,337	16	0	56	0	129	2,551	241	246	246
	July	4	5	0	2,457	13	1	64	0	117	2,661	252	257	257
	August	4	5	0	2,472	15	1	65	0	93	2,655	246	251	251
	September	4	4	0	2,202	14	1	57	0	74	2,356	223	227	227
	October	8	3	0	2,215	15	1	69	0	79	2,390	201	204	204
	November	9	3	0	2,257	16	0	75	0	116	2,476	156	158	158
	December	8	2	0	2,442	17	0	79	0	96	2,643	138	141	141
Year 2018														
	January	11	2	0	2,357	15	0	67	0	83	2,535	146	149	149
	February	9	3	0	2,091	15	0	61	0	89	2,269	155	158	158
	March	10	4	0	2,342	16	1	68	0	87	2,528	221	225	225
	April	9	4	0	2,151	16	0	60	0	102	2,343	241	245	245
	May	8	5	0	2,310	14	0	58	0	101	2,496	267	271	271
	June	6	5	0	2,294	14	1	43	0	74	2,437	268	273	273
	July	5	5	0	2,470	14	1	51	0	78	2,623	277	282	282
	August	5	5	0	2,402	13	1	53	0	91	2,570	268	273	273
	September	6	4	0	2,228	12	0	44	0	90	2,385	242	247	247
	October	9	4	0	2,223	13	0	62	0	108	2,418	220	224	224
	November	9	3	0	2,231	13	0	65	0	116	2,436	174	177	177
	December	9	2	0	2,374	13	0	67	0	130	2,596	157	160	160
Year 2019														
	January	11	4	0	2,317	12	0	53	0	124	2,520	168	172	172
	February	9	5	0	2,086	11	0	50	0	94	2,255	178	182	182
	March	10	7	0	2,267	12	0	59	0	108	2,462	254	261	261
	April	10	8	0	2,034	12	1	53	0	106	2,224	278	286	286
	May	8	9	0	2,084	12	0	46	0	104	2,263	309	317	317
	June	8	10	0	2,179	11	0	46	0	95	2,349	311	320	320
	July	6	10	0	2,331	11	1	43	0	71	2,473	321	331	331
	August	5	9	0	2,357	11	0	45	0	59	2,488	311	320	320
	September	5	8	0	2,157	11	0	37	0	52	2,271	281	289	289
	October	9	7	0	2,157	12	1	53	0	63	2,302	255	262	262
	November	8	5	0	2,174	12	0	55	0	67	2,321	198	204	204
	December	11	4	0	2,289	13	1	59	0	91	2,466	179	183	183

Wood and Wood-derived fuels include 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.

Other Waste Biomass includes sludge waste, agricultural byproducts, other biomass solids, other biomass liquids, and other biomass gases (including digester gases, methane, and other biomass gases).

Notes: Beginning with 2001 data, non-biogenic municipal solid waste and tire-derived fuels are reclassified as non-renewable energy sources and included in Other. Biogenic municipal solid waste is included in Other Renewable Sources.

See Glossary for definitions. Values are final. See Technical Notes for a discussion of the sample design for the Form EIA-923 and predecessor forms.

Totals may not equal sum of components because of independent rounding. NM=Not meaningful due to large standard error. W=Withheld to avoid disclosure of individual company data.

Displayed values of zero may represent small values that round to zero. The Excel version of this table provides additional precision which may be accessed by selecting individual cells.

Sources: U.S. Energy Information Administration, Form EIA-923, Power Plant Operations Report; U.S. Energy Information Administration, Form EIA-906, Power Plant Report; U.S. Energy Information Administration, Form EIA-920 Combined Heat and Power Plant Report; and predecessor forms.

Beginning with 2008 data, the Form EIA-923, Power Plant Operations Report, replaced the following: 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 Federal Energy Regulatory Commission, FERC Form 423, Monthly Report of Cost and Quality of Fuels for Electric Plants.

Estimated small scale solar photovoltaic generation and small scale solar photovoltaic capacity are based on data from Form EIA-861M, Form EIA-861 and from estimation methods described in the technical notes.

Table 3.6. Net Generation by Energy Source: Residential Sector, 2014 - 2019
(Thousand Megawatthours)

Thousand Megawatts)

	Small Scale Generation
Period	Estimated Small Scale Solar Photovoltaic Generation
Annual Totals	
2014	4,947
2015	6,999
2016	10,595
2017	13,942
2018	17,105
2019	20,914
Year 2017	
January	703
February	789
March	1,147
April	1,283
May	1,415
June	1,469
July	1,495
August	1,446
September	1,293
October	1,157
November	904
December	841
Year 2018	
January	921
February	1,007
March	1,393
April	1,592
May	1,753
June	1,788
July	1,834
August	1,756
September	1,539
October	1,385
November	1,108
December	1,029
Year 2019	
January	1,107
February	1,205
March	1,727
April	1,935
May	2,130
June	2,175
July	2,268
August	2,184
September	1,930
October	1,697
November	1,346
December	1,210

See Glossary for definitions. Values are final.

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Displayed values of zero may represent small values that round to zero. The Excel version of this table provides additional precision which may be accessed by selecting individual cells.

Sources:

Estimated small scale solar photovoltaic generation and small scale solar photovoltaic capacity are based on data from Form EIA-861M, Form EIA-861 and from estimation methods described in the technical notes.

Table 3.7. Utility Scale Facility Net Generation
by State, by Sector, 2019 and 2018 (Thousand Megawatthours)

	All Sectors			Electric Power Sector				Commercial Sector		Industrial Sector	
				Electric Utilities		Independent Power Producers					
	Generation at Utility Scale Facilities			Generation at Utility Scale Facilities		Generation at Utility Scale Facilities		Generation at Utility Scale Facilities		Generation at Utility Scale Facilities	
Census Division and State	Year 2019	Year 2018	Percentage Change	Year 2019	Year 2018	Year 2019	Year 2018	Year 2019	Year 2018	Year 2019	Year 2018
New England	99,997	105,548	-5.3%	2,414	2,968	93,277	98,313	1,307	1,371	2,998	2,897
Connecticut	40,050	39,454	1.5%	99	109	38,846	38,267	445	433	661	644
Maine	10,491	11,281	-7.0%	4	0	8,457	9,308	132	165	1,898	1,807
Massachusetts	21,516	27,173	-20.8%	407	587	20,239	25,676	606	642	264	269
New Hampshire	18,027	17,087	5.5%	935	1,417	16,997	15,571	64	69	30	31
Rhode Island	7,624	8,375	-9.0%	0	0	7,421	8,170	57	59	146	146
Vermont	2,290	2,179	5.1%	970	856	1,316	1,320	3	3	0	0
Middle Atlantic	431,617	422,940	2.1%	35,171	35,936	389,911	380,377	2,381	2,286	4,155	4,340
New Jersey	71,019	75,034	-5.4%	145	125	69,390	73,602	704	602	780	704
New York	131,603	132,521	-0.7%	34,926	35,660	94,557	94,641	1,278	1,312	843	908
Pennsylvania	228,995	215,386	6.3%	100	151	225,964	212,134	399	373	2,532	2,728
East North Central	586,452	609,422	-3.8%	215,936	240,648	357,937	356,005	1,751	1,924	10,829	10,845
Illinois	184,470	188,003	-1.9%	5,192	5,450	176,335	179,341	363	405	2,580	2,807
Indiana	102,505	113,460	-9.7%	70,437	84,830	27,387	24,138	292	250	4,390	4,242
Michigan	116,701	115,837	0.7%	78,882	81,450	35,687	32,195	729	867	1,403	1,324
Ohio	120,001	126,185	-4.9%	13,064	17,624	106,004	107,628	230	256	704	676
Wisconsin	62,774	65,937	-4.8%	48,361	51,294	12,524	12,702	137	145	1,752	1,796
West North Central	344,147	353,902	-2.8%	272,591	290,130	66,980	59,134	648	631	3,928	4,006
Iowa	62,650	63,381	-1.2%	47,135	49,513	13,035	11,531	231	227	2,248	2,110
Kansas	50,888	51,710	-1.6%	31,468	34,518	19,305	17,091	17	16	98	86
Minnesota	59,379	61,517	-3.5%	44,812	48,577	13,249	11,416	191	193	1,127	1,331
Missouri	78,279	85,095	-8.0%	72,581	79,780	5,472	5,098	192	175	34	43
Nebraska	37,298	36,966	0.9%	30,018	31,167	6,914	5,407	18	18	348	374
North Dakota	41,147	42,615	-3.4%	34,191	35,946	6,896	6,604	0	NM	60	62
South Dakota	14,507	12,616	15.0%	12,385	10,628	2,109	1,988	0	0	12	0
South Atlantic	811,088	819,993	-1.1%	669,612	674,016	120,785	125,574	2,004	1,728	18,687	18,675
Delaware	5,259	6,241	-15.7%	35	37	3,886	5,124	6	6	1,332	1,073
District of Columbia	174	79	119.4%	0	0	9	0	165	79	0	0
Florida	245,603	244,252	0.6%	229,438	227,284	10,989	11,808	70	80	5,107	5,079
Georgia	128,692	129,239	-0.4%	107,079	109,171	16,421	14,824	7	7	5,184	5,238
Maryland	39,326	43,810	-10.2%	3,359	3,797	34,782	38,930	1,039	840	146	244
North Carolina	131,174	134,249	-2.3%	111,312	117,492	17,822	14,636	347	332	1,692	1,790
South Carolina	100,108	99,364	0.7%	95,689	94,058	2,838	3,602	3	3	1,577	1,702
Virginia	96,828	95,509	1.4%	74,386	72,379	19,670	20,264	368	382	2,404	2,484
West Virginia	63,926	67,249	-4.9%	48,312	49,799	14,367	16,385	0	0	1,246	1,065
East South Central	362,770	368,891	-1.7%	313,578	312,387	39,144	47,022	213	229	9,836	9,253
Alabama	142,679	145,058	-1.6%	102,180	102,665	35,596	37,771	0	0	4,903	4,622
Kentucky	71,804	78,804	-8.9%	70,897	77,557	396	715	0	0	512	533
Mississippi	65,959	63,474	3.9%	61,366	53,311	2,702	8,248	0	0	1,891	1,915
Tennessee	82,327	81,555	0.9%	79,135	78,854	449	289	213	229	2,531	2,183
West South Central	733,035	733,704	-0.1%	244,261	256,469	409,475	398,531	975	957	78,324	77,747
Arkansas	64,443	67,999	-5.2%	57,343	59,485	5,451	6,829	56	44	1,592	1,642
Louisiana	100,175	102,128	-1.9%	59,912	62,152	7,912	9,167	164	170	32,187	30,639
Oklahoma	85,217	86,224	-1.2%	41,188	41,868	43,198	43,469	0	0	830	887
Texas	483,201	477,352	1.2%	85,818	92,965	352,914	339,066	755	743	43,714	44,579
Mountain	372,421	371,498	0.2%	286,297	289,926	82,251	77,889	1,011	576	2,862	3,107
Arizona	113,552	111,925	1.5%	96,645	98,448	16,754	13,323	152	154	0	0
Colorado	56,338	55,386	1.7%	43,713	42,037	12,514	13,248	36	27	75	76
Idaho	18,408	18,172	1.3%	11,986	11,904	5,777	5,695	65	50	580	523
Montana	27,797	28,213	-1.5%	10,708	12,087	17,057	16,090	0	0	32	36
Nevada	39,890	39,640	0.6%	27,293	27,482	11,715	11,667	569	159	312	332
New Mexico	35,175	32,674	7.7%	23,575	21,112	11,486	11,431	109	107	4	24
Utah	39,117	39,375	-0.7%	34,770	34,901	3,747	3,803	80	79	520	592
Wyoming	42,146	46,112	-8.6%	37,607	41,955	3,201	2,633	0	0	1,338	1,525
Pacific Contiguous	370,506	376,336	-1.5%	215,445	223,897	135,809	134,016	2,721	2,885	16,531	15,538
California	201,784	195,466	3.2%	82,940	75,239	102,455	103,882	2,627	2,779	13,762	13,566
Oregon	62,258	64,114	-2.9%	44,038	47,020	17,578	16,410	71	74	570	609
Washington	106,464	116,757	-8.8%	88,467	101,638	15,776	13,724	22	32	2,199	1,363
Pacific Noncontiguous	15,821	16,044	-1.4%	10,699	10,871	4,056	4,057	678	726	388	391
Alaska	6,071	6,247	-2.8%	5,447	5,575	243	234	265	328	116	110
Hawaii	9,750	9,797	-0.5%	5,252	5,296	3,813	3,822	413	398	272	281
U.S. Total	4,127,855	4,178,277	-1.2%	2,266,004	2,337,250	1,699,625	1,680,917	13,689	13,312	148,537	146,798

Displayed values of zero may represent small values that round to zero. The Excel version of this table provides additional precision which may be accessed by selecting individual cells.

NM = Not meaningful due to large relative standard error or excessive percentage change.

Notes: See Glossary for definitions. Values are final. See Technical Notes for a discussion of the sample design for the Form EIA-923.

Negative generation denotes that electric power consumed for plant use exceeds gross generation.

Totals may not equal sum of components because of independent rounding. Percentage change is calculated before rounding.

Source: U.S. Energy Information Administration, Form EIA-923, Power Plant Operations Report.

Table 3.8. Utility Scale Facility Net Generation from Coal
by State, by Sector, 2019 and 2018 (Thousand Megawatthours)

	All Sectors			Electric Power Sector				Commercial Sector		Industrial Sector	
				Electric Utilities		Independent Power Producers					
	Generation at Utility Scale Facilities			Generation at Utility Scale Facilities		Generation at Utility Scale Facilities		Generation at Utility Scale Facilities		Generation at Utility Scale Facilities	
Census Division and State	Year 2019	Year 2018	Percentage Change	Year 2019	Year 2018	Year 2019	Year 2018	Year 2019	Year 2018	Year 2019	Year 2018
New England	467	1,061	-56.0%	343	660	114	386	0	0	11	15
Connecticut	53	330	-83.9%	0	0	53	330	0	0	0	0
Maine	71	71	0.3%	0	0	61	56	0	0	11	15
Massachusetts	0	0	--	0	0	0	0	0	0	0	0
New Hampshire	343	660	-48.1%	343	660	0	0	0	0	0	0
Rhode Island	0	0	--	0	0	0	0	0	0	0	0
Vermont	0	0	--	0	0	0	0	0	0	0	0
Middle Atlantic	39,392	45,970	-14.3%	0	0	39,304	45,843	0	0	88	127
New Jersey	1,042	1,193	-12.7%	0	0	1,042	1,193	0	0	0	0
New York	422	690	-38.9%	0	0	422	679	0	0	0	11
Pennsylvania	37,929	44,086	-14.0%	0	0	37,841	43,970	0	0	88	116
East North Central	219,992	271,477	-19.0%	128,525	161,313	89,534	107,879	58	69	1,875	2,217
Illinois	48,788	59,642	-18.2%	3,482	4,052	43,772	53,810	13	31	1,522	1,748
Indiana	60,762	77,455	-21.6%	56,524	73,105	4,193	4,312	45	38	0	0
Michigan	37,341	42,331	-11.8%	36,942	41,830	381	427	0	0	18	73
Ohio	46,765	58,727	-20.4%	5,575	9,391	41,187	49,330	0	0	3	6
Wisconsin	26,335	33,322	-21.0%	26,003	32,933	0	0	0	0	333	389
West North Central	161,119	189,023	-14.8%	158,954	186,667	0	0	79	85	2,086	2,270
Iowa	22,159	28,553	-22.4%	20,551	26,969	0	0	68	74	1,541	1,509
Kansas	17,315	20,474	-15.4%	17,315	20,474	0	0	0	0	0	0
Minnesota	17,805	23,455	-24.1%	17,605	23,068	0	0	2	1	197	387
Missouri	55,686	63,355	-12.1%	55,678	63,345	0	0	9	10	0	0
Nebraska	20,385	23,305	-12.5%	20,038	22,931	0	0	0	0	348	374
North Dakota	25,151	27,541	-8.7%	25,151	27,541	0	0	0	0	0	0
South Dakota	2,617	2,339	11.9%	2,617	2,339	0	0	0	0	0	0
South Atlantic	159,468	195,286	-18.3%	141,570	170,331	17,280	24,215	40	45	577	695
Delaware	119	273	-56.4%	0	0	119	273	0	0	0	0
District of Columbia	0	0	--	0	0	0	0	0	0	0	0
Florida	21,248	30,272	-29.8%	21,197	30,175	0	0	0	0	51	98
Georgia	25,245	32,181	-21.6%	25,065	31,983	0	0	0	0	181	198
Maryland	5,722	10,067	-43.2%	0	0	5,690	10,007	0	0	32	60
North Carolina	30,672	31,690	-3.2%	30,413	31,412	86	98	36	39	137	142
South Carolina	14,861	19,497	-23.8%	14,640	19,481	212	0	0	0	10	16
Virginia	3,418	9,266	-63.1%	3,176	8,453	71	625	4	6	167	182
West Virginia	58,182	62,039	-6.2%	47,080	48,827	11,101	13,211	0	0	0	0
East South Central	101,476	117,192	-13.4%	98,613	113,670	2,363	2,831	0	0	500	691
Alabama	26,655	31,778	-16.1%	26,638	31,734	0	0	0	0	17	44
Kentucky	51,714	59,168	-12.6%	51,714	59,168	0	0	0	0	0	0
Mississippi	4,414	5,280	-16.4%	2,052	2,449	2,363	2,831	0	0	0	0
Tennessee	18,692	20,967	-10.8%	18,209	20,320	0	0	0	0	483	647
West South Central	130,375	168,412	-22.6%	67,575	92,704	62,639	75,458	0	0	161	250
Arkansas	23,313	29,996	-22.3%	19,338	24,754	3,933	5,197	0	0	43	46
Louisiana	7,419	11,787	-37.1%	5,633	7,780	1,786	4,007	0	0	0	0
Oklahoma	7,826	14,907	-47.5%	7,708	12,868	0	1,834	0	0	119	205
Texas	91,817	111,723	-17.8%	34,897	47,302	56,920	64,420	0	0	0	0
Mountain	140,704	151,985	-7.4%	124,330	136,335	15,979	15,208	0	0	395	442
Arizona	23,218	30,745	-24.5%	23,218	30,745	0	0	0	0	0	0
Colorado	25,321	26,382	-4.0%	25,316	26,370	0	0	0	0	5	12
Idaho	21	20	3.3%	0	0	0	0	0	0	21	20
Montana	14,101	13,360	5.5%	261	234	13,831	13,116	0	0	9	10
Nevada	2,735	2,485	10.1%	1,689	1,443	1,047	1,042	0	0	0	0
New Mexico	14,692	13,402	9.6%	14,692	13,402	0	0	0	0	0	0
Utah	25,241	25,912	-2.6%	24,842	25,501	400	412	0	0	0	0
Wyoming	35,376	39,679	-10.8%	34,314	38,642	702	638	0	0	360	400
Pacific Contiguous	9,980	7,141	39.8%	2,569	1,476	7,146	5,359	0	0	264	305
California	240	281	-14.5%	0	0	0	0	0	0	240	281
Oregon	2,569	1,476	74.0%	2,569	1,476	0	0	0	0	0	0
Washington	7,170	5,383	33.2%	0	0	7,146	5,359	0	0	24	24
Pacific Noncontiguous	1,985	1,940	2.3%	406	347	1,489	1,489	91	103	0	0
Alaska	683	629	8.7%	406	347	187	178	91	103	0	0
Hawaii	1,302	1,311	-0.7%	0	0	1,302	1,311	0	0	0	0
U.S. Total	964,957	1,149,487	-16.1%	722,885	863,505	235,847	278,668	268	303	5,957	7,011

Displayed values of zero may represent small values that round to zero. The Excel version of this table provides additional precision which may be accessed by selecting individual cells.

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Notes: See Glossary for definitions. Values are final. See Technical Notes for a discussion of the sample design for the Form EIA-923.

Negative generation denotes that electric power consumed for plant use exceeds gross generation.

Totals may not equal sum of components because of independent rounding. Percentage change is calculated before rounding.

Source: U.S. Energy Information Administration, Form EIA-923, Power Plant Operations Report.

Table 3.9. Utility Scale Facility Net Generation from Petroleum Liquids
by State, by Sector, 2019 and 2018 (Thousand Megawatthours)

Census Division and State	All Sectors			Electric Power Sector				Commercial Sector		Industrial Sector	
				Electric Utilities		Independent Power Producers					
				Generation at Utility Scale Facilities		Generation at Utility Scale Facilities		Generation at Utility Scale Facilities		Generation at Utility Scale Facilities	
	Year 2019	Year 2018	Percentage Change	Year 2019	Year 2018	Year 2019	Year 2018	Year 2019	Year 2018	Year 2019	Year 2018
New England	193	1,246	-84.5%	23	184	116	1,006	37	36	17	20
Connecticut	12	339	-96.4%	5	5	1	329	3	3	3	1
Maine	35	189	-81.6%	0	0	20	171	2	2	12	17
Massachusetts	104	461	-77.5%	7	75	79	371	16	13	1	2
New Hampshire	30	178	-83.1%	9	101	7	61	13	16	0	0
Rhode Island	11	76	-85.4%	0	0	9	74	2	2	0	0
Vermont	1	3	-67.1%	1	3	0	0	0	0	0	0
Middle Atlantic	740	2,452	-69.8%	244	621	457	1,767	15	23	24	41
New Jersey	71	302	-76.3%	1	3	67	293	2	5	1	1
New York	512	1,591	-67.8%	242	616	245	926	9	13	16	35
Pennsylvania	157	559	-72.0%	0	2	145	548	4	4	7	5
East North Central	481	556	-13.4%	291	299	175	226	2	6	14	25
Illinois	44	53	-18.0%	8	8	36	45	0	0	0	0
Indiana	127	131	-3.0%	119	110	0	0	NM	1	7	19
Michigan	94	117	-20.3%	90	112	0	0	1	4	2	2
Ohio	164	219	-24.7%	30	34	130	180	0	1	3	3
Wisconsin	53	36	47.3%	43	35	9	1	0	0	1	1
West North Central	353	323	9.3%	339	300	10	19	2	2	1	1
Iowa	63	67	-5.4%	60	63	4	4	0	0	0	0
Kansas	78	52	50.2%	78	52	0	0	0	0	0	0
Minnesota	51	47	8.7%	40	28	7	16	2	2	1	1
Missouri	97	100	-2.6%	97	100	0	0	0	0	0	0
Nebraska	16	12	29.6%	16	12	0	0	0	0	0	0
North Dakota	34	38	-12.4%	34	38	0	0	0	0	0	0
South Dakota	14	6	113.2%	14	6	0	0	0	0	0	0
South Atlantic	1,175	3,398	-65.4%	899	2,386	157	819	45	55	74	138
Delaware	19	201	-90.7%	0	6	18	195	0	0	0	0
District of Columbia	0	0	--	0	0	0	0	0	0	0	0
Florida	324	572	-43.3%	301	537	7	12	0	0	17	23
Georgia	107	279	-61.5%	61	105	5	92	4	5	38	77
Maryland	67	260	-74.1%	-1	3	66	253	1	1	1	3
North Carolina	192	633	-69.7%	177	570	5	41	1	2	9	19
South Carolina	79	344	-77.2%	69	327	3	5	0	0	7	11
Virginia	258	950	-72.9%	164	692	52	207	40	47	2	4
West Virginia	128	159	-19.2%	127	145	1	14	0	0	0	0
East South Central	224	293	-23.6%	209	250	4	30	0	0	11	13
Alabama	20	66	-69.7%	10	29	3	29	0	0	6	7
Kentucky	50	70	-28.3%	50	70	0	0	0	0	0	0
Mississippi	14	27	-49.8%	12	23	0	0	0	0	2	4
Tennessee	140	130	7.8%	137	127	0	0	0	0	2	2
West South Central	147	136	8.1%	101	104	35	24	1	1	10	8
Arkansas	47	36	32.7%	33	27	12	6	0	0	3	3
Louisiana	28	21	33.0%	18	21	11	0	0	0	0	0
Oklahoma	18	18	-2.6%	16	17	0	0	0	0	1	1
Texas	54	61	-11.7%	34	39	13	18	1	1	6	4
Mountain	367	186	97.1%	349	165	18	21	0	0	0	0
Arizona	64	50	27.6%	64	50	0	0	0	0	0	0
Colorado	8	12	-33.0%	8	11	0	0	0	0	0	0
Idaho	0	0	304.3%	0	0	0	0	0	0	0	0
Montana	16	17	-6.2%	2	0	14	16	0	0	0	0
Nevada	12	10	20.5%	10	7	2	3	0	0	0	0
New Mexico	184	21	785.4%	184	21	0	0	0	0	0	0
Utah	40	37	8.8%	38	35	2	1	0	0	0	0
Wyoming	44	40	9.0%	44	40	0	0	0	0	0	0
Pacific Contiguous	77	97	-20.5%	43	43	15	16	1	1	19	38
California	51	69	-26.0%	35	34	6	5	1	1	9	29
Oregon	7	5	36.4%	7	5	0	0	0	0	0	0
Washington	20	24	-16.0%	1	4	9	10	0	0	10	9
Pacific Noncontiguous	7,765	7,558	2.7%	5,817	5,756	1,682	1,560	13	9	254	233
Alaska	901	809	11.4%	845	761	3	0	7	6	47	43
Hawaii	6,864	6,749	1.7%	4,972	4,995	1,679	1,560	6	3	207	191
U.S. Total	11,522	16,245	-29.1%	8,313	10,108	2,669	5,487	116	132	424	517

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Source: U.S. Energy Information Administration, Form EIA-923, Power Plant Operations Report.

Table 3.10. Utility Scale Facility Net Generation from Petroleum Coke
by State, by Sector, 2019 and 2018 (Thousand Megawatthours)

Census Division and State	All Sectors			Electric Power Sector				Commercial Sector		Industrial Sector	
				Electric Utilities		Independent Power Producers					
	Generation at Utility Scale Facilities			Generation at Utility Scale Facilities		Generation at Utility Scale Facilities		Generation at Utility Scale Facilities		Generation at Utility Scale Facilities	
	Year 2019	Year 2018	Percentage Change	Year 2019	Year 2018	Year 2019	Year 2018	Year 2019	Year 2018	Year 2019	Year 2018
New England	0	0	--	0	0	0	0	0	0	0	0
Connecticut	0	0	--	0	0	0	0	0	0	0	0
Maine	0	0	--	0	0	0	0	0	0	0	0
Massachusetts	0	0	--	0	0	0	0	0	0	0	0
New Hampshire	0	0	--	0	0	0	0	0	0	0	0
Rhode Island	0	0	--	0	0	0	0	0	0	0	0
Vermont	0	0	--	0	0	0	0	0	0	0	0
Middle Atlantic	99	127	-21.5%	0	0	0	0	0	0	99	127
New Jersey	71	60	17.7%	0	0	0	0	0	0	71	60
New York	0	0	--	0	0	0	0	0	0	0	0
Pennsylvania	28	66	-57.1%	0	0	0	0	0	0	28	66
East North Central	1,591	2,295	-30.7%	762	1,085	676	1,087	0	0	153	123
Illinois	0	0	--	0	0	0	0	0	0	0	0
Indiana	0	0	--	0	0	0	0	0	0	0	0
Michigan	822	1,096	-25.0%	673	984	0	0	0	0	149	112
Ohio	680	1,097	-38.0%	0	0	676	1,087	0	0	4	10
Wisconsin	90	101	-11.6%	90	101	0	0	0	0	0	0
West North Central	77	44	77.6%	0	0	0	0	5	7	73	36
Iowa	77	44	77.6%	0	0	0	0	5	7	73	36
Kansas	0	0	--	0	0	0	0	0	0	0	0
Minnesota	0	0	--	0	0	0	0	0	0	0	0
Missouri	0	0	--	0	0	0	0	0	0	0	0
Nebraska	0	0	--	0	0	0	0	0	0	0	0
North Dakota	0	0	--	0	0	0	0	0	0	0	0
South Dakota	0	0	--	0	0	0	0	0	0	0	0
South Atlantic	1,341	1,662	-19.3%	1,201	1,506	0	0	0	0	140	156
Delaware	0	0	--	0	0	0	0	0	0	0	0
District of Columbia	0	0	--	0	0	0	0	0	0	0	0
Florida	1,201	1,506	-20.2%	1,201	1,506	0	0	0	0	0	0
Georgia	140	156	-10.6%	0	0	0	0	0	0	140	156
Maryland	0	0	--	0	0	0	0	0	0	0	0
North Carolina	0	0	--	0	0	0	0	0	0	0	0
South Carolina	0	0	--	0	0	0	0	0	0	0	0
Virginia	0	0	--	0	0	0	0	0	0	0	0
West Virginia	0	0	--	0	0	0	0	0	0	0	0
East South Central	0	0	-100.0%	0	0	0	0	0	0	0	0
Alabama	0	0	--	0	0	0	0	0	0	0	0
Kentucky	0	0	-100.0%	0	0	0	0	0	0	0	0
Mississippi	0	0	--	0	0	0	0	0	0	0	0
Tennessee	0	0	--	0	0	0	0	0	0	0	0
West South Central	3,261	4,425	-26.3%	3,149	4,227	0	0	0	0	111	198
Arkansas	0	0	--	0	0	0	0	0	0	0	0
Louisiana	3,160	4,356	-27.5%	3,149	4,227	0	0	0	0	11	130
Oklahoma	0	0	--	0	0	0	0	0	0	0	0
Texas	100	68	47.4%	0	0	0	0	0	0	100	68
Mountain	449	429	4.6%	0	0	449	429	0	0	0	0
Arizona	0	0	--	0	0	0	0	0	0	0	0
Colorado	0	0	--	0	0	0	0	0	0	0	0
Idaho	0	0	--	0	0	0	0	0	0	0	0
Montana	449	429	4.6%	0	0	449	429	0	0	0	0
Nevada	0	0	--	0	0	0	0	0	0	0	0
New Mexico	0	0	--	0	0	0	0	0	0	0	0
Utah	0	0	--	0	0	0	0	0	0	0	0
Wyoming	0	0	--	0	0	0	0	0	0	0	0
Pacific Contiguous	0	0	--	0	0	0	0	0	0	0	0
California	0	0	--	0	0	0	0	0	0	0	0
Oregon	0	0	--	0	0	0	0	0	0	0	0
Washington	0	0	--	0	0	0	0	0	0	0	0
Pacific Noncontiguous	0	0	--	0	0	0	0	0	0	0	0
Alaska	0	0	--	0	0	0	0	0	0	0	0
Hawaii	0	0	--	0	0	0	0	0	0	0	0
U.S. Total	6,819	8,981	-24.1%	5,112	6,817	1,125	1,516	5	7	576	640

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Negative generation denotes that electric power consumed for plant use exceeds gross generation.

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Source: U.S. Energy Information Administration, Form EIA-923, Power Plant Operations Report.

Table 3.11. Utility Scale Facility Net Generation from Natural Gas
by State, by Sector, 2019 and 2018 (Thousand Megawatthours)

	All Sectors			Electric Power Sector				Commercial Sector		Industrial Sector	
				Electric Utilities		Independent Power Producers					
	Generation at Utility Scale Facilities			Generation at Utility Scale Facilities		Generation at Utility Scale Facilities		Generation at Utility Scale Facilities		Generation at Utility Scale Facilities	
Census Division and State	Year 2019	Year 2018	Percentage Change	Year 2019	Year 2018	Year 2019	Year 2018	Year 2019	Year 2018	Year 2019	Year 2018
New England	49,272	51,613	-4.5%	151	258	46,503	48,764	1,055	1,087	1,562	1,504
Connecticut	21,343	20,006	6.7%	54	59	20,195	18,875	437	429	658	643
Maine	1,797	2,331	-22.9%	0	0	1,295	1,878	31	30	472	422
Massachusetts	15,407	18,386	-16.2%	92	167	14,529	17,387	529	570	258	262
New Hampshire	3,583	2,992	19.8%	5	31	3,537	2,922	11	8	30	31
Rhode Island	7,141	7,897	-9.6%	0	0	6,948	7,702	48	49	145	146
Vermont	2	2	3.0%	1	1	0	0	1	1	0	0
Middle Atlantic	186,102	166,065	12.1%	9,947	10,538	172,408	151,816	1,205	1,182	2,542	2,529
New Jersey	40,449	38,863	4.1%	158	161	39,615	38,119	251	181	425	401
New York	47,612	50,810	-6.3%	9,785	10,370	36,437	38,948	812	870	578	623
Pennsylvania	98,040	76,391	28.3%	4	7	96,356	74,749	142	130	1,538	1,505
East North Central	159,477	136,058	17.2%	51,737	45,498	102,150	85,671	1,424	1,462	4,167	3,427
Illinois	21,346	17,241	23.8%	1,534	1,224	18,923	15,040	341	364	548	613
Indiana	32,042	26,817	19.5%	13,069	10,965	16,746	14,156	201	168	2,025	1,528
Michigan	34,430	30,987	11.1%	11,751	10,493	21,475	19,459	604	612	599	423
Ohio	51,325	44,215	16.1%	7,169	7,956	43,706	35,809	214	243	236	207
Wisconsin	20,334	16,799	21.0%	18,214	14,861	1,300	1,207	63	75	758	656
West North Central	35,005	29,103	20.3%	28,492	24,754	5,316	3,245	354	321	843	783
Iowa	7,782	7,340	6.0%	7,088	6,705	0	7	117	98	576	529
Kansas	3,024	3,006	0.6%	2,931	2,922	0	0	0	0	93	84
Minnesota	12,607	8,555	47.4%	9,559	7,221	2,834	1,107	94	108	119	120
Missouri	7,675	7,050	8.9%	5,023	4,767	2,482	2,131	138	112	32	40
Nebraska	1,277	965	32.3%	1,273	961	0	0	4	3	0	0
North Dakota	1,471	1,019	44.3%	1,461	1,009	0	0	0	0	10	10
South Dakota	1,170	1,168	0.2%	1,157	1,168	0	0	0	0	12	0
South Atlantic	385,449	359,797	7.1%	316,793	293,723	62,272	60,703	1,279	970	5,105	4,402
Delaware	4,806	5,400	-11.0%	28	25	3,650	4,567	0	0	1,128	809
District of Columbia	110	23	383.6%	0	0	0	0	110	23	0	0
Florida	182,007	171,872	5.9%	173,358	162,843	6,961	7,450	19	30	1,669	1,550
Georgia	58,620	51,972	12.8%	44,720	39,240	13,356	12,139	0	0	544	594
Maryland	14,605	13,850	5.5%	3,351	3,785	10,184	9,165	1,005	812	65	88
North Carolina	41,147	43,446	-5.3%	32,238	36,506	8,626	6,713	127	90	155	136
South Carolina	23,926	21,654	10.5%	22,793	18,921	1,002	2,604	0	0	130	128
Virginia	57,985	50,160	15.6%	39,928	32,229	17,267	17,172	17	16	773	744
West Virginia	2,243	1,420	57.9%	377	174	1,225	894	0	0	641	352
East South Central	138,274	136,296	1.5%	99,001	90,460	35,589	43,021	208	225	3,477	2,591
Alabama	57,197	58,800	-2.7%	20,447	20,266	35,191	37,234	0	0	1,560	1,300
Kentucky	15,341	14,615	5.0%	14,730	13,717	377	695	0	0	235	204
Mississippi	48,781	49,482	-1.4%	48,270	43,920	4	5,078	0	0	507	484
Tennessee	16,955	13,399	26.5%	15,555	12,557	17	14	208	225	1,175	603
West South Central	391,113	363,732	7.5%	134,611	121,869	186,221	173,564	891	861	69,390	67,437
Arkansas	21,772	20,624	5.6%	20,261	18,983	1,169	1,305	42	38	300	297
Louisiana	69,523	61,782	12.5%	37,045	32,970	4,667	3,902	164	170	27,648	24,740
Oklahoma	44,188	41,613	6.2%	28,190	25,682	15,585	15,560	0	0	413	371
Texas	255,630	239,713	6.6%	49,116	44,234	164,801	152,797	685	653	41,029	42,029
Mountain	115,932	105,259	10.1%	92,575	84,423	21,479	18,878	422	413	1,456	1,545
Arizona	46,084	37,168	24.0%	34,495	28,897	11,453	8,130	136	141	0	0
Colorado	17,097	16,398	4.3%	14,717	13,804	2,351	2,575	6	1	23	19
Idaho	4,267	3,279	30.1%	2,290	1,553	1,801	1,594	39	39	136	92
Montana	507	476	6.5%	346	342	158	131	0	0	3	4
Nevada	25,775	26,689	-3.4%	23,227	24,148	2,175	2,149	63	62	310	330
New Mexico	11,803	11,628	1.5%	8,225	7,277	3,467	4,223	106	104	4	24
Utah	9,369	8,724	7.4%	8,863	8,170	72	75	71	65	363	414
Wyoming	1,029	896	14.9%	412	233	1	1	0	0	616	662
Pacific Contiguous	122,502	118,263	3.6%	49,100	45,800	60,175	59,955	1,772	1,898	11,455	10,609
California	85,841	89,805	-4.4%	28,600	29,994	44,854	47,525	1,721	1,835	10,665	10,451
Oregon	20,932	17,923	16.8%	10,246	9,032	10,570	8,773	44	45	72	73
Washington	15,729	10,535	49.3%	10,253	6,774	4,751	3,657	7	19	718	85
Pacific Noncontiguous	2,687	2,948	-8.9%	2,619	2,883	0	0	0	0	68	65
Alaska	2,687	2,948	-8.9%	2,619	2,883	0	0	0	0	68	65
Hawaii	0	0	--	0	0	0	0	0	0	0	0
U.S. Total	1,585,814	1,469,133	7.9%	785,026	720,206	692,113	645,616	8,610	8,419	100,065	94,892

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Notes: See Glossary for definitions. Values are final. See Technical Notes for a discussion of the sample design for the Form EIA-923.

Negative generation denotes that electric power consumed for plant use exceeds gross generation.

Totals may not equal sum of components because of independent rounding. Percentage change is calculated before rounding.

Source: U.S. Energy Information Administration, Form EIA-923, Power Plant Operations Report.

Table 3.12. Utility Scale Facility Net Generation from Other Gases
by State, by Sector, 2019 and 2018 (Thousand Megawatthours)

	All Sectors			Electric Power Sector				Commercial Sector		Industrial Sector	
				Electric Utilities		Independent Power Producers					
	Generation at Utility Scale Facilities			Generation at Utility Scale Facilities		Generation at Utility Scale Facilities		Generation at Utility Scale Facilities		Generation at Utility Scale Facilities	
Census Division and State	Year 2019	Year 2018	Percentage Change	Year 2019	Year 2018	Year 2019	Year 2018	Year 2019	Year 2018	Year 2019	Year 2018
New England	0	0	--	0	0	0	0	0	0	0	0
Connecticut	0	0	--	0	0	0	0	0	0	0	0
Maine	0	0	--	0	0	0	0	0	0	0	0
Massachusetts	0	0	--	0	0	0	0	0	0	0	0
New Hampshire	0	0	--	0	0	0	0	0	0	0	0
Rhode Island	0	0	--	0	0	0	0	0	0	0	0
Vermont	0	0	--	0	0	0	0	0	0	0	0
Middle Atlantic	713	741	-3.8%	0	0	0	1	0	0	713	739
New Jersey	216	212	2.0%	0	0	0	0	0	0	216	212
New York	2	0	--	0	0	0	0	0	0	2	0
Pennsylvania	494	528	-6.4%	0	0	0	1	0	0	494	527
East North Central	4,717	4,911	-4.0%	154	151	2,174	2,077	0	0	2,390	2,683
Illinois	261	201	29.9%	0	0	0	1	0	0	261	200
Indiana	1,984	2,326	-14.7%	0	0	0	0	0	0	1,984	2,326
Michigan	1,697	1,598	6.2%	154	151	1,543	1,447	0	0	0	0
Ohio	776	787	-1.4%	0	0	631	630	0	0	145	157
Wisconsin	0	0	--	0	0	0	0	0	0	0	0
West North Central	50	51	-2.6%	0	0	0	0	0	0	50	51
Iowa	0	0	--	0	0	0	0	0	0	0	0
Kansas	0	0	--	0	0	0	0	0	0	0	0
Minnesota	0	0	--	0	0	0	0	0	0	0	0
Missouri	0	0	--	0	0	0	0	0	0	0	0
Nebraska	0	0	--	0	0	0	0	0	0	0	0
North Dakota	50	51	-2.6%	0	0	0	0	0	0	50	51
South Dakota	0	0	--	0	0	0	0	0	0	0	0
South Atlantic	236	283	-16.6%	0	0	0	0	0	0	236	283
Delaware	194	252	-23.1%	0	0	0	0	0	0	194	252
District of Columbia	0	0	--	0	0	0	0	0	0	0	0
Florida	0	5	-97.1%	0	0	0	0	0	0	0	5
Georgia	0	0	--	0	0	0	0	0	0	0	0
Maryland	0	0	--	0	0	0	0	0	0	0	0
North Carolina	0	0	--	0	0	0	0	0	0	0	0
South Carolina	0	0	--	0	0	0	0	0	0	0	0
Virginia	0	0	--	0	0	0	0	0	0	0	0
West Virginia	42	25	67.4%	0	0	0	0	0	0	42	25
East South Central	15	16	-6.8%	0	0	0	0	0	0	15	16
Alabama	3	5	-44.7%	0	0	0	0	0	0	3	5
Kentucky	0	0	--	0	0	0	0	0	0	0	0
Mississippi	0	0	--	0	0	0	0	0	0	0	0
Tennessee	12	11	9.5%	0	0	0	0	0	0	12	11
West South Central	4,744	5,124	-7.4%	0	0	1,699	1,413	0	0	3,045	3,711
Arkansas	0	0	--	0	0	0	0	0	0	0	0
Louisiana	1,875	2,598	-27.8%	0	0	0	0	0	0	1,875	2,598
Oklahoma	0	0	--	0	0	0	0	0	0	0	0
Texas	2,869	2,526	13.6%	0	0	1,699	1,413	0	0	1,170	1,113
Mountain	313	397	-21.1%	0	0	10	12	0	0	303	384
Arizona	0	0	--	0	0	0	0	0	0	0	0
Colorado	0	0	--	0	0	0	0	0	0	0	0
Idaho	0	0	--	0	0	0	0	0	0	0	0
Montana	10	12	-19.2%	0	0	10	12	0	0	0	0
Nevada	0	0	--	0	0	0	0	0	0	0	0
New Mexico	0	0	--	0	0	0	0	0	0	0	0
Utah	17	7	159.5%	0	0	0	0	0	0	17	7
Wyoming	286	378	-24.3%	0	0	0	0	0	0	286	378
Pacific Contiguous	1,798	1,885	-4.6%	0	0	0	431	0	0	1,798	1,454
California	1,476	1,454	1.5%	0	0	0	0	0	0	1,476	1,454
Oregon	0	0	--	0	0	0	0	0	0	0	0
Washington	322	431	-25.2%	0	0	0	431	0	0	322	0
Pacific Noncontiguous	6	56	-89.9%	0	0	0	0	0	0	6	56
Alaska	0	0	--	0	0	0	0	0	0	0	0
Hawaii	6	56	-89.9%	0	0	0	0	0	0	6	56
U.S. Total	12,591	13,463	-6.5%	154	151	3,883	3,935	0	0	8,554	9,377

Displayed values of zero may represent small values that round to zero. The Excel version of this table provides additional precision which may be accessed by selecting individual cells.

NM = Not meaningful due to large relative standard error or excessive percentage change.

Notes: See Glossary for definitions. Values are final. See Technical Notes for a discussion of the sample design for the Form EIA-923.

Negative generation denotes that electric power consumed for plant use exceeds gross generation.

Totals may not equal sum of components because of independent rounding. Percentage change is calculated before rounding.

Source: U.S. Energy Information Administration, Form EIA-923, Power Plant Operations Report.

Table 3.13. Utility Scale Facility Net Generation from Nuclear Energy
by State, by Sector, 2019 and 2018 (Thousand Megawatthours)

Census Division and State	All Sectors			Electric Power Sector				Commercial Sector		Industrial Sector	
				Electric Utilities		Independent Power Producers					
	Generation at Utility Scale Facilities			Generation at Utility Scale Facilities		Generation at Utility Scale Facilities		Generation at Utility Scale Facilities		Generation at Utility Scale Facilities	
	Year 2019	Year 2018	Percentage Change	Year 2019	Year 2018	Year 2019	Year 2018	Year 2019	Year 2018	Year 2019	Year 2018
New England	29,818	31,385	-5.0%	0	0	29,818	31,385	0	0	0	0
Connecticut	16,733	16,881	-0.9%	0	0	16,733	16,881	0	0	0	0
Maine	0	0	--	0	0	0	0	0	0	0	0
Massachusetts	2,177	4,442	-51.0%	0	0	2,177	4,442	0	0	0	0
New Hampshire	10,907	10,062	8.4%	0	0	10,907	10,062	0	0	0	0
Rhode Island	0	0	--	0	0	0	0	0	0	0	0
Vermont	0	0	--	0	0	0	0	0	0	0	0
Middle Atlantic	154,732	158,378	-2.3%	0	0	154,732	158,378	0	0	0	0
New Jersey	26,637	31,982	-16.7%	0	0	26,637	31,982	0	0	0	0
New York	44,865	42,919	4.5%	0	0	44,865	42,919	0	0	0	0
Pennsylvania	83,230	83,477	-0.3%	0	0	83,230	83,477	0	0	0	0
East North Central	158,686	157,024	1.1%	26,044	25,023	132,642	132,002	0	0	0	0
Illinois	98,735	98,102	0.6%	0	0	98,735	98,102	0	0	0	0
Indiana	0	0	--	0	0	0	0	0	0	0	0
Michigan	32,909	30,479	8.0%	26,044	25,023	6,865	5,456	0	0	0	0
Ohio	17,011	18,315	-7.1%	0	0	17,011	18,315	0	0	0	0
Wisconsin	10,030	10,129	-1.0%	0	0	10,030	10,129	0	0	0	0
West North Central	44,729	44,952	-0.5%	39,494	40,057	5,236	4,895	0	0	0	0
Iowa	5,236	4,895	7.0%	0	0	5,236	4,895	0	0	0	0
Kansas	9,248	9,168	0.9%	9,248	9,168	0	0	0	0	0	0
Minnesota	14,105	14,601	-3.4%	14,105	14,601	0	0	0	0	0	0
Missouri	9,190	10,655	-13.8%	9,190	10,655	0	0	0	0	0	0
Nebraska	6,952	5,632	23.4%	6,952	5,632	0	0	0	0	0	0
North Dakota	0	0	--	0	0	0	0	0	0	0	0
South Dakota	0	0	--	0	0	0	0	0	0	0	0
South Atlantic	205,228	202,708	1.2%	190,215	187,720	15,013	14,988	0	0	0	0
Delaware	0	0	--	0	0	0	0	0	0	0	0
District of Columbia	0	0	--	0	0	0	0	0	0	0	0
Florida	29,108	29,312	-0.7%	29,108	29,312	0	0	0	0	0	0
Georgia	33,591	34,363	-2.2%	33,591	34,363	0	0	0	0	0	0
Maryland	15,013	14,988	0.2%	0	0	15,013	14,988	0	0	0	0
North Carolina	41,916	42,077	-0.4%	41,916	42,077	0	0	0	0	0	0
South Carolina	56,103	52,716	6.4%	56,103	52,716	0	0	0	0	0	0
Virginia	29,498	29,252	0.8%	29,498	29,252	0	0	0	0	0	0
West Virginia	0	0	--	0	0	0	0	0	0	0	0
East South Central	90,410	82,559	9.5%	90,410	82,559	0	0	0	0	0	0
Alabama	43,657	39,463	10.6%	43,657	39,463	0	0	0	0	0	0
Kentucky	0	0	--	0	0	0	0	0	0	0	0
Mississippi	11,033	6,919	59.4%	11,033	6,919	0	0	0	0	0	0
Tennessee	35,720	36,176	-1.3%	35,720	36,176	0	0	0	0	0	0
West South Central	68,854	71,059	-3.1%	27,556	29,873	41,298	41,186	0	0	0	0
Arkansas	13,575	12,721	6.7%	13,575	12,721	0	0	0	0	0	0
Louisiana	13,981	17,153	-18.5%	13,981	17,153	0	0	0	0	0	0
Oklahoma	0	0	--	0	0	0	0	0	0	0	0
Texas	41,298	41,186	0.3%	0	0	41,298	41,186	0	0	0	0
Mountain	31,920	31,097	2.6%	31,920	31,097	0	0	0	0	0	0
Arizona	31,920	31,097	2.6%	31,920	31,097	0	0	0	0	0	0
Colorado	0	0	--	0	0	0	0	0	0	0	0
Idaho	0	0	--	0	0	0	0	0	0	0	0
Montana	0	0	--	0	0	0	0	0	0	0	0
Nevada	0	0	--	0	0	0	0	0	0	0	0
New Mexico	0	0	--	0	0	0	0	0	0	0	0
Utah	0	0	--	0	0	0	0	0	0	0	0
Wyoming	0	0	--	0	0	0	0	0	0	0	0
Pacific Contiguous	25,032	27,922	-10.4%	25,032	27,922	0	0	0	0	0	0
California	16,165	18,214	-11.2%	16,165	18,214	0	0	0	0	0	0
Oregon	0	0	--	0	0	0	0	0	0	0	0
Washington	8,866	9,708	-8.7%	8,866	9,708	0	0	0	0	0	0
Pacific Noncontiguous	0	0	--	0	0	0	0	0	0	0	0
Alaska	0	0	--	0	0	0	0	0	0	0	0
Hawaii	0	0	--	0	0	0	0	0	0	0	0
U.S. Total	809,409	807,084	0.3%	430,672	424,251	378,738	382,833	0	0	0	0

Displayed values of zero may represent small values that round to zero. The Excel version of this table provides additional precision which may be accessed by selecting individual cells.

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Notes: See Glossary for definitions. Values are final. See Technical Notes for a discussion of the sample design for the Form EIA-923.

Negative generation denotes that electric power consumed for plant use exceeds gross generation.

Totals may not equal sum of components because of independent rounding. Percentage change is calculated before rounding.

Source: U.S. Energy Information Administration, Form EIA-923, Power Plant Operations Report.

Table 3.14. Utility Scale Facility Net Generation from Hydroelectric (Conventional) Power by State, by Sector, 2019 and 2018 (Thousand Megawatthours)

Census Division and State	All Sectors			Electric Power Sector				Commercial Sector		Industrial Sector	
				Electric Utilities		Independent Power Producers					
	Generation at Utility Scale Facilities			Generation at Utility Scale Facilities		Generation at Utility Scale Facilities		Generation at Utility Scale Facilities		Generation at Utility Scale Facilities	
	Year 2019	Year 2018	Percentage Change	Year 2019	Year 2018	Year 2019	Year 2018	Year 2019	Year 2018	Year 2019	Year 2018
New England	7,706	7,577	1.7%	1,068	1,078	6,520	6,380	6	4	113	114
Connecticut	428	555	-22.9%	36	41	391	514	0	0	0	0
Maine	3,499	3,261	7.3%	4	0	3,383	3,147	0	0	113	114
Massachusetts	976	1,134	-13.9%	188	268	782	862	6	4	0	0
New Hampshire	1,462	1,355	7.9%	363	371	1,099	984	0	0	0	0
Rhode Island	4	4	-11.2%	0	0	4	4	0	0	0	0
Vermont	1,337	1,268	5.4%	476	398	861	870	0	0	0	0
Middle Atlantic	34,150	33,927	0.7%	25,310	25,247	8,774	8,615	6	6	59	59
New Jersey	26	36	-25.5%	0	0	26	36	0	0	0	0
New York	30,621	29,630	3.3%	25,215	25,105	5,340	4,460	6	6	59	59
Pennsylvania	3,503	4,262	-17.8%	96	142	3,407	4,120	0	0	0	0
East North Central	5,073	4,574	10.9%	4,474	4,068	475	354	1	1	124	151
Illinois	124	147	-15.5%	42	61	81	84	1	1	0	0
Indiana	256	223	15.0%	256	223	0	0	0	0	0	0
Michigan	1,650	1,569	5.1%	1,526	1,441	114	119	0	0	10	10
Ohio	403	244	65.0%	274	227	129	17	0	0	0	0
Wisconsin	2,641	2,392	10.4%	2,377	2,116	150	135	0	0	114	141
West North Central	16,523	13,662	20.9%	16,197	13,300	230	270	0	0	97	92
Iowa	796	925	-13.9%	788	918	8	7	0	0	0	0
Kansas	20	26	-22.5%	0	0	20	26	0	0	0	0
Minnesota	1,056	1,054	0.2%	758	725	201	237	0	0	97	92
Missouri	2,216	828	167.5%	2,216	828	0	0	0	0	0	0
Nebraska	1,340	1,382	-3.0%	1,340	1,382	0	0	0	0	0	0
North Dakota	3,179	3,180	0.0%	3,179	3,180	0	0	0	0	0	0
South Dakota	7,915	6,266	26.3%	7,915	6,266	0	0	0	0	0	0
South Atlantic	18,741	19,992	-6.3%	15,333	15,729	2,810	3,549	17	15	582	699
Delaware	0	0	--	0	0	0	0	0	0	0	0
District of Columbia	0	0	--	0	0	0	0	0	0	0	0
Florida	210	233	-9.8%	210	233	0	0	0	0	0	0
Georgia	3,956	3,697	7.0%	3,929	3,676	9	10	0	0	18	11
Maryland	2,188	2,831	-22.7%	0	0	2,188	2,831	0	0	0	0
North Carolina	6,186	6,605	-6.4%	6,118	6,540	53	53	14	13	0	0
South Carolina	2,976	3,014	-1.2%	2,903	2,931	70	80	2	2	0	0
Virginia	1,519	1,765	-13.9%	1,445	1,696	74	68	0	0	0	0
West Virginia	1,706	1,848	-7.7%	728	653	415	507	0	0	563	688
East South Central	25,767	25,854	-0.3%	25,758	25,843	8	11	0	0	0	0
Alabama	11,405	11,143	2.4%	11,405	11,143	0	0	0	0	0	0
Kentucky	4,232	4,418	-4.2%	4,223	4,407	8	11	0	0	0	0
Mississippi	0	0	--	0	0	0	0	0	0	0	0
Tennessee	10,130	10,293	-1.6%	10,130	10,293	0	0	0	0	0	0
West South Central	10,879	7,350	48.0%	9,422	6,086	1,455	1,263	1	1	0	0
Arkansas	4,135	3,009	37.4%	4,085	2,959	50	50	0	0	0	0
Louisiana	1,366	1,180	15.7%	0	0	1,366	1,180	0	0	0	0
Oklahoma	3,903	2,035	91.8%	3,903	2,035	0	0	0	0	0	0
Texas	1,475	1,126	31.0%	1,434	1,092	40	33	1	1	0	0
Mountain	32,621	35,170	-7.2%	31,332	33,878	1,276	1,279	13	13	0	0
Arizona	6,204	6,982	-11.1%	6,204	6,982	0	0	0	0	0	0
Colorado	1,811	1,825	-0.8%	1,578	1,601	220	212	13	13	0	0
Idaho	10,333	11,024	-6.3%	9,517	10,177	816	847	0	0	0	0
Montana	10,005	11,405	-12.3%	9,850	11,269	155	136	0	0	0	0
Nevada	2,242	1,881	19.2%	2,176	1,815	66	67	0	0	0	0
New Mexico	158	150	5.8%	158	150	0	0	0	0	0	0
Utah	875	927	-5.6%	863	919	12	8	0	0	0	0
Wyoming	992	976	1.7%	985	967	8	9	0	0	0	0
Pacific Contiguous	134,695	142,657	-5.6%	131,966	140,598	2,716	2,048	14	11	0	0
California	38,355	26,331	45.7%	36,219	24,915	2,122	1,405	14	11	0	0
Oregon	30,322	35,443	-14.4%	30,069	35,199	253	243	0	0	0	0
Washington	66,018	80,883	-18.4%	65,677	80,483	341	400	0	0	0	0
Pacific Noncontiguous	1,718	1,761	-2.4%	1,504	1,508	24	42	130	176	59	34
Alaska	1,623	1,664	-2.5%	1,493	1,489	0	0	130	176	0	0
Hawaii	95	97	-2.0%	11	20	24	42	0	0	59	34
U.S. Total	287,874	292,524	-1.6%	262,364	267,336	24,288	23,812	188	227	1,033	1,149

Displayed values of zero may represent small values that round to zero. The Excel version of this table provides additional precision which may be accessed by selecting individual cells.
NM = Not meaningful due to large relative standard error or excessive percentage change.

Notes: See Glossary for definitions. Values are final. See Technical Notes for a discussion of the sample design for the Form EIA-923.

Negative generation denotes that electric power consumed for plant use exceeds gross generation.

Totals may not equal sum of components because of independent rounding. Percentage change is calculated before rounding.

Source: U.S. Energy Information Administration, Form EIA-923, Power Plant Operations Report.

Table 3.15. Utility Scale Facility Net Generation from Renewable Sources Excluding Hydroelectric by State, by Sector, 2019 and 2018 (Thousand Megawatthours)

Census Division and State	All Sectors			Electric Power Sector				Commercial Sector		Industrial Sector	
				Electric Utilities		Independent Power Producers					
	Generation at Utility Scale Facilities			Generation at Utility Scale Facilities		Generation at Utility Scale Facilities		Generation at Utility Scale Facilities		Generation at Utility Scale Facilities	
	Year 2019	Year 2018	Percentage Change	Year 2019	Year 2018	Year 2019	Year 2018	Year 2019	Year 2018	Year 2019	Year 2018
New England	11,095	11,398	-2.7%	830	787	8,935	9,322	155	179	1,175	1,110
Connecticut	900	873	3.0%	3	3	892	869	5	1	0	0
Maine	4,749	5,058	-6.1%	0	0	3,536	3,885	45	68	1,169	1,105
Massachusetts	2,379	2,369	0.4%	120	77	2,197	2,232	55	55	6	5
New Hampshire	1,647	1,793	-8.1%	214	253	1,393	1,495	40	45	0	0
Rhode Island	469	399	17.6%	0	0	461	391	8	7	0	0
Vermont	951	906	4.9%	493	454	456	450	2	2	0	0
Middle Atlantic	14,231	14,280	-0.3%	79	76	12,939	12,865	642	644	570	694
New Jersey	1,984	1,948	1.8%	79	76	1,608	1,588	289	279	7	5
New York	6,926	6,438	7.6%	0	0	6,528	6,037	210	220	188	180
Pennsylvania	5,322	5,894	-9.7%	0	0	4,803	5,240	143	145	375	509
East North Central	36,336	32,376	12.2%	4,628	3,896	30,040	26,619	175	242	1,493	1,618
Illinois	14,934	12,391	20.5%	128	105	14,798	12,279	8	8	0	0
Indiana	7,001	6,188	13.1%	469	427	6,447	5,670	21	22	64	69
Michigan	8,283	8,106	2.2%	2,399	2,115	5,223	5,176	56	129	604	685
Ohio	2,870	2,576	11.4%	18	19	2,536	2,264	16	13	300	280
Wisconsin	3,248	3,114	4.3%	1,614	1,231	1,035	1,231	74	69	526	583
West North Central	85,545	76,235	12.2%	28,594	24,768	56,047	50,564	177	187	726	716
Iowa	26,536	21,557	23.1%	18,649	14,857	7,787	6,619	41	47	59	35
Kansas	21,198	18,979	11.7%	1,896	1,902	19,285	17,065	17	16	0	-3
Minnesota	13,402	13,400	0.0%	2,610	2,751	10,066	9,915	61	54	664	680
Missouri	3,078	3,059	0.6%	41	37	2,990	2,967	45	53	2	3
Nebraska	7,327	5,670	29.2%	400	247	6,914	5,407	13	15	0	0
North Dakota	11,213	10,734	4.5%	4,317	4,127	6,896	6,604	0	NM	0	1
South Dakota	2,791	2,837	-1.6%	682	849	2,109	1,988	0	0	0	0
South Atlantic	37,353	34,921	7.0%	6,213	5,108	20,550	18,830	459	495	10,131	10,488
Delaware	120	114	5.6%	7	6	98	90	6	6	10	12
District of Columbia	64	57	13.1%	0	0	9	0	55	57	0	0
Florida	8,351	7,497	11.4%	4,065	2,680	2,365	2,824	50	51	1,870	1,942
Georgia	7,536	6,994	7.8%	312	293	3,052	2,583	3	2	4,169	4,116
Maryland	1,405	1,488	-5.6%	9	8	1,315	1,360	33	27	49	93
North Carolina	10,524	9,263	13.6%	450	387	8,727	7,429	168	188	1,179	1,259
South Carolina	3,027	2,802	8.0%	90	385	1,543	905	0	0	1,393	1,512
Virginia	4,696	4,936	-4.9%	1,280	1,348	1,810	1,869	144	164	1,461	1,554
West Virginia	1,631	1,770	-7.8%	0	0	1,631	1,770	0	0	0	0
East South Central	7,162	7,230	-0.9%	155	163	1,180	1,129	5	4	5,822	5,933
Alabama	3,742	3,804	-1.6%	23	31	402	507	0	0	3,317	3,266
Kentucky	419	470	-10.8%	132	131	11	10	0	0	276	329
Mississippi	1,718	1,765	-2.7%	0	0	335	338	0	0	1,382	1,427
Tennessee	1,283	1,191	7.7%	0	1	431	274	5	4	847	911
West South Central	122,620	112,403	9.1%	1,815	1,701	116,043	105,502	82	94	4,680	5,106
Arkansas	1,545	1,569	-1.5%	2	2	288	271	14	6	1,242	1,291
Louisiana	2,250	2,609	-13.8%	2	2	83	79	0	0	2,165	2,528
Oklahoma	29,378	27,729	5.9%	1,475	1,401	27,613	26,022	0	0	291	307
Texas	89,447	80,496	11.1%	337	297	88,058	79,130	68	88	983	980
Mountain	49,611	46,478	6.7%	5,912	4,213	42,739	41,742	576	150	383	373
Arizona	6,063	5,890	2.9%	741	681	5,306	5,196	16	13	0	0
Colorado	12,233	10,972	11.5%	2,288	513	9,925	10,443	17	13	3	3
Idaho	3,721	3,785	-1.7%	178	174	3,160	3,253	25	11	358	346
Montana	2,423	2,209	9.7%	250	242	2,153	1,945	0	0	20	21
Nevada	9,103	8,546	6.5%	170	41	8,424	8,406	506	97	2	3
New Mexico	8,339	7,474	11.6%	317	264	8,019	7,208	3	3	0	0
Utah	3,386	3,543	-4.4%	115	223	3,262	3,307	9	14	0	0
Wyoming	4,343	4,058	7.0%	1,853	2,074	2,490	1,984	0	0	0	0
Pacific Contiguous	75,577	77,570	-2.6%	6,775	8,197	65,488	65,952	934	975	2,380	2,446
California	58,921	58,632	0.5%	1,967	2,249	55,307	54,786	892	933	756	665
Oregon	8,392	9,233	-9.1%	1,148	1,308	6,719	7,359	27	29	499	536
Washington	8,263	9,705	-14.9%	3,660	4,641	3,462	3,807	15	13	1,126	1,245
Pacific Noncontiguous	1,269	1,403	-9.5%	186	190	862	966	220	244	1	3
Alaska	180	200	-10.2%	89	99	53	56	37	43	1	3
Hawaii	1,089	1,202	-9.4%	97	91	809	910	183	201	0	0
U.S. Total	440,799	414,292	6.4%	55,188	49,100	354,823	333,491	3,426	3,214	27,361	28,487

Displayed values of zero may represent small values that round to zero. The Excel version of this table provides additional precision which may be accessed by selecting individual cells.

NM = Not meaningful due to large relative standard error or excessive percentage change.

Notes: See Glossary for definitions. Values are final. See Technical Notes for a discussion of the sample design for the Form EIA-923.

Negative generation denotes that electric power consumed for plant use exceeds gross generation.

Totals may not equal sum of components because of independent rounding. Percentage change is calculated before rounding.

Source: U.S. Energy Information Administration, Form EIA-923, Power Plant Operations Report.

Table 3.16. Utility Scale Facility Net Generation from Hydroelectric (Pumped Storage) Power by State, by Sector, 2019 and 2018 (Thousand Megawatthours)

Census Division and State	All Sectors			Electric Power Sector				Commercial Sector		Industrial Sector	
				Electric Utilities		Independent Power Producers					
	Generation at Utility Scale Facilities			Generation at Utility Scale Facilities		Generation at Utility Scale Facilities		Generation at Utility Scale Facilities		Generation at Utility Scale Facilities	
	Year 2019	Year 2018	Percentage Change	Year 2019	Year 2018	Year 2019	Year 2018	Year 2019	Year 2018	Year 2019	Year 2018
New England	-434	-460	-5.7%	0	0	-434	-460	0	0	0	0
Connecticut	2	3	-37.9%	0	0	2	3	0	0	0	0
Maine	0	0	--	0	0	0	0	0	0	0	0
Massachusetts	-436	-464	-5.9%	0	0	-436	-464	0	0	0	0
New Hampshire	0	0	--	0	0	0	0	0	0	0	0
Rhode Island	0	0	--	0	0	0	0	0	0	0	0
Vermont	0	0	--	0	0	0	0	0	0	0	0
Middle Atlantic	-975	-1,205	-19.1%	-409	-546	-566	-659	0	0	0	0
New Jersey	-94	-115	-18.5%	-94	-115	0	0	0	0	0	0
New York	-316	-431	-26.7%	-316	-431	0	0	0	0	0	0
Pennsylvania	-566	-659	-14.2%	0	0	-566	-659	0	0	0	0
East North Central	-696	-698	-0.3%	-696	-698	0	0	0	0	0	0
Illinois	0	0	--	0	0	0	0	0	0	0	0
Indiana	0	0	--	0	0	0	0	0	0	0	0
Michigan	-696	-698	-0.3%	-696	-698	0	0	0	0	0	0
Ohio	0	0	--	0	0	0	0	0	0	0	0
Wisconsin	0	0	--	0	0	0	0	0	0	0	0
West North Central	337	47	617.9%	337	47	0	0	0	0	0	0
Iowa	0	0	--	0	0	0	0	0	0	0	0
Kansas	0	0	--	0	0	0	0	0	0	0	0
Minnesota	0	0	--	0	0	0	0	0	0	0	0
Missouri	337	47	617.9%	337	47	0	0	0	0	0	0
Nebraska	0	0	--	0	0	0	0	0	0	0	0
North Dakota	0	0	--	0	0	0	0	0	0	0	0
South Dakota	0	0	--	0	0	0	0	0	0	0	0
South Atlantic	-2,612	-2,485	5.1%	-2,612	-2,485	0	0	0	0	0	0
Delaware	0	0	--	0	0	0	0	0	0	0	0
District of Columbia	0	0	--	0	0	0	0	0	0	0	0
Florida	0	0	--	0	0	0	0	0	0	0	0
Georgia	-599	-489	22.5%	-599	-489	0	0	0	0	0	0
Maryland	0	0	--	0	0	0	0	0	0	0	0
North Carolina	0	0	--	0	0	0	0	0	0	0	0
South Carolina	-909	-705	28.9%	-909	-705	0	0	0	0	0	0
Virginia	-1,104	-1,292	-14.5%	-1,104	-1,292	0	0	0	0	0	0
West Virginia	0	0	--	0	0	0	0	0	0	0	0
East South Central	-615	-620	-0.7%	-615	-620	0	0	0	0	0	0
Alabama	0	0	--	0	0	0	0	0	0	0	0
Kentucky	0	0	--	0	0	0	0	0	0	0	0
Mississippi	0	0	--	0	0	0	0	0	0	0	0
Tennessee	-615	-620	-0.7%	-615	-620	0	0	0	0	0	0
West South Central	-53	-95	-43.7%	-53	-95	0	0	0	0	0	0
Arkansas	51	40	26.0%	51	40	0	0	0	0	0	0
Louisiana	0	0	--	0	0	0	0	0	0	0	0
Oklahoma	-104	-135	-22.9%	-104	-135	0	0	0	0	0	0
Texas	0	0	--	0	0	0	0	0	0	0	0
Mountain	-189	-267	-29.1%	-189	-267	0	0	0	0	0	0
Arizona	2	-5	-154.6%	2	-5	0	0	0	0	0	0
Colorado	-192	-263	-27.0%	-192	-263	0	0	0	0	0	0
Idaho	0	0	--	0	0	0	0	0	0	0	0
Montana	0	0	--	0	0	0	0	0	0	0	0
Nevada	0	0	--	0	0	0	0	0	0	0	0
New Mexico	0	0	--	0	0	0	0	0	0	0	0
Utah	0	0	--	0	0	0	0	0	0	0	0
Wyoming	0	0	--	0	0	0	0	0	0	0	0
Pacific Contiguous	-22	-120	-81.7%	-22	-120	0	0	0	0	0	0
California	-31	-149	-79.4%	-31	-149	0	0	0	0	0	0
Oregon	0	0	--	0	0	0	0	0	0	0	0
Washington	9	28	-69.8%	9	28	0	0	0	0	0	0
Pacific Noncontiguous	0	0	--	0	0	0	0	0	0	0	0
Alaska	0	0	--	0	0	0	0	0	0	0	0
Hawaii	0	0	--	0	0	0	0	0	0	0	0
U.S. Total	-5,261	-5,905	-10.9%	-4,261	-4,785	-1,000	-1,119	0	0	0	0

Displayed values of zero may represent small values that round to zero. The Excel version of this table provides additional precision which may be accessed by selecting individual cells.

NM = Not meaningful due to large relative standard error or excessive percentage change.

Notes: See Glossary for definitions. Values are final. See Technical Notes for a discussion of the sample design for the Form EIA-923.

Negative generation denotes that electric power consumed for plant use exceeds gross generation.

Totals may not equal sum of components because of independent rounding. Percentage change is calculated before rounding.

Source: U.S. Energy Information Administration, Form EIA-923, Power Plant Operations Report.

Table 3.17. Utility Scale Facility Net Generation from Other Energy Sources
by State, by Sector, 2019 and 2018 (Thousand Megawatthours)

Census Division and State	All Sectors			Electric Power Sector				Commercial Sector		Industrial Sector	
				Electric Utilities		Independent Power Producers					
				Generation at Utility Scale Facilities		Generation at Utility Scale Facilities		Generation at Utility Scale Facilities		Generation at Utility Scale Facilities	
	Year 2019	Year 2018	Percentage Change	Year 2019	Year 2018	Year 2019	Year 2018	Year 2019	Year 2018	Year 2019	Year 2018
New England	1,881	1,729	8.8%	-1	-1	1,707	1,531	54	65	121	134
Connecticut	578	465	24.4%	0	0	578	465	0	0	0	0
Maine	339	371	-8.6%	0	0	162	172	54	65	122	134
Massachusetts	910	846	7.5%	0	0	912	847	0	0	-2	0
New Hampshire	55	48	14.6%	0	0	55	48	0	0	0	0
Rhode Island	0	0	--	0	0	0	0	0	0	0	0
Vermont	-1	0	226.7%	-1	0	0	0	0	0	0	0
Middle Atlantic	2,433	2,206	10.3%	0	0	1,861	1,750	512	431	60	25
New Jersey	616	552	11.6%	0	0	394	391	162	136	60	25
New York	960	873	9.9%	0	0	720	671	240	202	0	0
Pennsylvania	857	781	9.8%	0	0	748	688	110	93	0	0
East North Central	795	848	-6.2%	19	14	71	89	91	143	614	601
Illinois	239	227	5.1%	0	0	-10	-19	0	0	249	246
Indiana	333	321	4.0%	0	0	0	0	24	21	310	300
Michigan	173	252	-31.4%	0	0	85	112	67	122	21	18
Ohio	8	5	50.4%	-2	-3	-3	-4	0	0	14	12
Wisconsin	42	43	-1.4%	21	17	0	0	0	0	21	26
West North Central	409	463	-11.6%	184	236	141	141	31	29	53	57
Iowa	0	0	--	0	0	0	0	0	0	0	0
Kansas	5	5	-0.3%	0	0	0	0	0	0	5	5
Minnesota	355	405	-12.4%	135	183	141	141	31	29	48	52
Missouri	0	1	-91.2%	0	1	0	0	0	0	0	0
Nebraska	0	0	--	0	0	0	0	0	0	0	0
North Dakota	50	52	-4.6%	50	52	0	0	0	0	0	0
South Dakota	0	0	--	0	0	0	0	0	0	0	0
South Atlantic	4,708	4,432	6.2%	-2	-1	2,703	2,469	163	149	1,844	1,815
Delaware	0	0	--	0	0	0	0	0	0	0	0
District of Columbia	0	0	--	0	0	0	0	0	0	0	0
Florida	3,154	2,983	5.7%	-2	0	1,656	1,523	0	0	1,500	1,461
Georgia	94	86	9.3%	0	0	0	0	0	0	94	86
Maryland	325	326	-0.2%	0	0	325	326	0	0	0	0
North Carolina	538	535	0.5%	0	0	325	302	0	0	213	233
South Carolina	45	42	7.1%	0	0	8	7	0	0	37	34
Virginia	558	471	18.5%	0	0	395	323	163	149	0	0
West Virginia	-6	-12	-44.5%	0	0	-6	-11	0	0	0	0
East South Central	58	72	-20.0%	47	64	0	0	0	0	10	8
Alabama	0	0	14.3%	0	0	0	0	0	0	0	0
Kentucky	47	64	-25.4%	47	64	0	0	0	0	0	0
Mississippi	0	0	--	0	0	0	0	0	0	0	0
Tennessee	10	8	20.3%	0	0	0	0	0	0	10	8
West South Central	1,096	1,158	-5.4%	85	0	85	122	0	0	926	1,036
Arkansas	5	5	-4.9%	0	0	0	0	0	0	5	5
Louisiana	573	643	-10.9%	85	0	0	0	0	0	488	643
Oklahoma	7	57	-87.0%	1	0	0	54	0	0	7	3
Texas	510	453	12.8%	0	0	85	69	0	0	426	384
Mountain	694	764	-9.2%	69	81	301	320	0	0	324	363
Arizona	-4	-3	75.2%	0	0	-4	-3	0	0	0	0
Colorado	60	59	1.9%	-1	0	18	18	0	0	43	42
Idaho	66	64	2.6%	0	0	0	0	0	0	66	64
Montana	287	305	-5.7%	0	0	287	305	0	0	0	0
Nevada	22	29	-25.2%	22	29	0	0	0	0	0	0
New Mexico	-1	-1	9.4%	-1	-1	0	0	0	0	0	0
Utah	189	225	-16.2%	49	53	0	0	0	0	140	172
Wyoming	75	85	-11.5%	0	0	0	0	0	0	75	85
Pacific Contiguous	867	922	-6.0%	-17	-19	269	255	0	0	615	686
California	765	829	-7.7%	-16	-17	166	160	0	0	615	686
Oregon	36	34	4.9%	-1	-1	36	35	0	0	0	0
Washington	66	59	11.7%	0	-1	67	60	0	0	0	0
Pacific Noncontiguous	391	379	3.1%	167	187	0	-1	224	193	0	0
Alaska	-4	-3	25.9%	-4	-3	0	0	0	0	0	0
Hawaii	395	382	3.3%	171	190	0	-1	224	193	0	0
U.S. Total	13,331	12,973	2.8%	551	561	7,138	6,677	1,076	1,010	4,567	4,725

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Negative generation denotes that electric power consumed for plant use exceeds gross generation.

Totals may not equal sum of components because of independent rounding. Percentage change is calculated before rounding.

Source: U.S. Energy Information Administration, Form EIA-923, Power Plant Operations Report.

Table 3.18. Utility Scale Facility Net Generation from Wind
by State, by Sector, 2019 and 2018 (Thousand Megawatthours)

	All Sectors			Electric Power Sector				Commercial Sector		Industrial Sector	
				Electric Utilities		Independent Power Producers					
	Generation at Utility Scale Facilities			Generation at Utility Scale Facilities		Generation at Utility Scale Facilities		Generation at Utility Scale Facilities		Generation at Utility Scale Facilities	
Census Division and State	Year 2019	Year 2018	Percentage Change	Year 2019	Year 2018	Year 2019	Year 2018	Year 2019	Year 2018	Year 2019	Year 2018
New England	3,734	3,556	5.0%	220	230	3,480	3,294	31	29	2	3
Connecticut	12	12	-0.7%	0	0	12	12	0	0	0	0
Maine	2,494	2,384	4.6%	0	0	2,494	2,384	0	0	0	0
Massachusetts	211	221	-4.6%	49	58	136	139	24	22	2	3
New Hampshire	433	407	6.6%	0	0	433	407	0	0	0	0
Rhode Island	206	159	30.0%	0	0	199	151	8	7	0	0
Vermont	377	373	1.1%	171	173	207	201	0	0	0	0
Middle Atlantic	7,728	7,588	1.9%	0	0	7,724	7,579	3	3	1	6
New Jersey	22	23	-2.7%	0	0	22	23	0	0	0	0
New York	4,456	3,998	11.4%	0	0	4,452	3,989	3	3	1	6
Pennsylvania	3,250	3,567	-8.9%	0	0	3,250	3,567	0	0	0	0
East North Central	30,422	26,181	16.2%	3,607	2,930	26,706	23,154	30	28	79	70
Illinois	14,460	11,899	21.5%	12	12	14,443	11,882	5	5	0	0
Indiana	6,216	5,437	14.3%	0	0	6,216	5,437	0	0	0	0
Michigan	5,826	5,457	6.8%	2,313	2,029	3,513	3,429	0	0	0	0
Ohio	2,043	1,750	16.7%	11	11	1,956	1,673	3	3	72	63
Wisconsin	1,878	1,638	14.7%	1,270	878	579	733	21	20	7	7
West North Central	82,465	72,907	13.1%	28,295	24,282	54,124	48,578	45	47	0	0
Iowa	26,305	21,334	23.3%	18,628	14,834	7,673	6,497	4	3	0	0
Kansas	21,124	18,908	11.7%	1,894	1,900	19,212	16,992	17	16	0	0
Minnesota	10,965	10,714	2.3%	2,450	2,405	8,490	8,284	25	25	0	0
Missouri	2,858	2,835	0.8%	0	0	2,858	2,835	0	0	0	0
Nebraska	7,211	5,549	30.0%	324	169	6,887	5,380	0	0	0	0
North Dakota	11,213	10,733	4.5%	4,317	4,127	6,896	6,604	0	NM	0	0
South Dakota	2,789	2,835	-1.6%	682	849	2,107	1,986	0	0	0	0
South Atlantic	2,680	2,888	-7.2%	0	0	2,675	2,883	5	5	0	0
Delaware	5	5	1.2%	0	0	0	0	5	5	0	0
District of Columbia	0	0	--	0	0	0	0	0	0	0	0
Florida	0	0	--	0	0	0	0	0	0	0	0
Georgia	0	0	--	0	0	0	0	0	0	0	0
Maryland	520	570	-8.7%	0	0	520	570	0	0	0	0
North Carolina	523	543	-3.6%	0	0	523	543	0	0	0	0
South Carolina	0	0	--	0	0	0	0	0	0	0	0
Virginia	0	0	--	0	0	0	0	0	0	0	0
West Virginia	1,631	1,770	-7.8%	0	0	1,631	1,770	0	0	0	0
East South Central	38	41	-7.4%	0	0	38	41	0	0	0	0
Alabama	0	0	--	0	0	0	0	0	0	0	0
Kentucky	0	0	--	0	0	0	0	0	0	0	0
Mississippi	0	0	--	0	0	0	0	0	0	0	0
Tennessee	38	41	-7.4%	0	0	38	41	0	0	0	0
West South Central	112,629	103,039	9.3%	1,671	1,628	110,895	101,348	54	53	9	10
Arkansas	0	0	--	0	0	0	0	0	0	0	0
Louisiana	0	0	--	0	0	0	0	0	0	0	0
Oklahoma	29,008	27,338	6.1%	1,415	1,339	27,593	25,999	0	0	0	0
Texas	83,620	75,700	10.5%	256	289	83,302	75,349	54	53	9	10
Mountain	28,534	26,339	8.3%	4,548	2,984	23,979	23,349	4	3	3	3
Arizona	554	530	4.6%	0	0	554	530	0	0	0	0
Colorado	10,852	9,745	11.4%	2,282	508	8,566	9,234	2	0	3	3
Idaho	2,551	2,655	-3.9%	163	160	2,388	2,495	0	0	0	0
Montana	2,373	2,153	10.2%	250	242	2,124	1,911	0	0	0	0
Nevada	329	312	5.5%	0	0	329	312	0	0	0	0
New Mexico	6,892	6,092	13.1%	0	0	6,889	6,089	3	3	0	0
Utah	819	795	3.0%	0	0	819	795	0	0	0	0
Wyoming	4,163	4,057	2.6%	1,853	2,074	2,309	1,983	0	0	0	0
Pacific Contiguous	26,981	29,371	-8.1%	5,206	6,313	21,765	23,048	6	6	5	5
California	13,735	14,024	-2.1%	780	850	12,944	13,163	6	6	5	5
Oregon	6,569	7,447	-11.8%	1,081	1,244	5,488	6,204	0	0	0	0
Washington	6,677	7,900	-15.5%	3,344	4,219	3,333	3,681	0	0	0	0
Pacific Noncontiguous	672	757	-11.2%	89	99	583	658	0	0	0	0
Alaska	143	155	-8.0%	89	99	53	56	0	0	0	0
Hawaii	529	602	-12.1%	0	0	529	602	0	0	0	0
U.S. Total	295,882	272,667	8.5%	43,636	38,466	251,968	233,931	179	174	100	97

Displayed values of zero may represent small values that round to zero. The Excel version of this table provides additional precision which may be accessed by selecting individual cells.

NM = Not meaningful due to large relative standard error or excessive percentage change.

Notes: See Glossary for definitions. Values are final. See Technical Notes for a discussion of the sample design for the Form EIA-923.

Negative generation denotes that electric power consumed for plant use exceeds gross generation.

Totals may not equal sum of components because of independent rounding. Percentage change is calculated before rounding.

Source: U.S. Energy Information Administration, Form EIA-923, Power Plant Operations Report.

Table 3.19. Utility Scale Facility Net Generation from Biomass
by State, by Sector, 2019 and 2018 (Thousand Megawatthours)

	All Sectors			Electric Power Sector				Commercial Sector		Industrial Sector	
				Electric Utilities		Independent Power Producers					
	Generation at Utility Scale Facilities			Generation at Utility Scale Facilities		Generation at Utility Scale Facilities		Generation at Utility Scale Facilities		Generation at Utility Scale Facilities	
Census Division and State	Year 2019	Year 2018	Percentage Change	Year 2019	Year 2018	Year 2019	Year 2018	Year 2019	Year 2018	Year 2019	Year 2018
New England	5,850	6,610	-11.5%	496	498	4,072	4,862	113	146	1,169	1,105
Connecticut	749	756	-0.8%	0	0	749	756	0	0	0	0
Maine	2,248	2,662	-15.5%	0	0	1,035	1,489	45	68	1,169	1,105
Massachusetts	1,004	1,169	-14.1%	0	0	978	1,139	26	30	0	0
New Hampshire	1,214	1,386	-12.4%	214	253	960	1,088	40	45	0	0
Rhode Island	208	211	-1.5%	0	0	208	211	0	0	0	0
Vermont	426	426	0.0%	282	245	142	179	2	2	0	0
Middle Atlantic	4,732	5,342	-11.4%	0	0	3,702	4,157	482	509	547	676
New Jersey	797	935	-14.8%	0	0	650	780	147	155	0	0
New York	1,946	2,142	-9.1%	0	0	1,569	1,754	197	213	180	174
Pennsylvania	1,988	2,265	-12.2%	0	0	1,482	1,623	139	140	367	501
East North Central	5,207	5,561	-6.4%	787	763	2,875	3,051	133	201	1,412	1,546
Illinois	412	426	-3.3%	114	90	299	336	0	0	0	0
Indiana	463	460	0.6%	330	320	49	49	20	22	64	69
Michigan	2,314	2,531	-8.6%	0	0	1,655	1,718	55	127	604	685
Ohio	685	707	-3.1%	0	0	452	484	8	7	226	216
Wisconsin	1,333	1,437	-7.3%	343	352	420	463	51	45	518	577
West North Central	1,671	2,147	-22.1%	271	470	543	823	131	138	726	716
Iowa	216	211	2.1%	12	16	107	117	37	43	59	35
Kansas	63	64	-1.3%	0	0	63	67	0	0	0	-3
Minnesota	1,188	1,645	-27.8%	158	343	330	592	36	29	664	680
Missouri	120	133	-9.6%	30	32	44	47	44	51	2	3
Nebraska	85	93	-9.4%	71	78	0	0	13	15	0	0
North Dakota	0	1	-82.2%	0	0	0	0	0	0	0	1
South Dakota	0	0	--	0	0	0	0	0	0	0	0
South Atlantic	18,795	19,794	-5.0%	1,772	2,244	6,586	6,706	312	358	10,124	10,486
Delaware	61	59	3.9%	0	0	52	47	0	0	10	12
District of Columbia	55	57	-2.5%	0	0	0	0	55	57	0	0
Florida	4,449	5,084	-12.5%	670	654	1,872	2,446	40	45	1,867	1,939
Georgia	5,376	4,999	7.5%	0	0	1,206	882	0	0	4,169	4,116
Maryland	391	521	-25.1%	0	0	326	412	15	17	49	93
North Carolina	2,549	2,610	-2.3%	0	0	1,312	1,275	59	76	1,179	1,259
South Carolina	2,168	2,291	-5.4%	86	383	692	397	0	0	1,390	1,512
Virginia	3,746	4,173	-10.2%	1,016	1,207	1,126	1,248	143	164	1,461	1,554
West Virginia	0	0	--	0	0	0	0	0	0	0	0
East South Central	6,045	6,299	-4.0%	88	93	141	278	0	0	5,816	5,927
Alabama	3,357	3,446	-2.6%	0	0	40	180	0	0	3,317	3,266
Kentucky	374	431	-13.1%	88	93	10	8	0	0	276	329
Mississippi	1,395	1,439	-3.1%	0	0	13	13	0	0	1,382	1,427
Tennessee	919	982	-6.5%	0	0	78	77	0	0	840	905
West South Central	5,354	5,892	-9.1%	72	0	596	757	16	39	4,671	5,096
Arkansas	1,335	1,366	-2.3%	0	0	88	69	5	6	1,242	1,291
Louisiana	2,248	2,607	-13.8%	0	0	83	79	0	0	2,165	2,528
Oklahoma	311	329	-5.6%	0	0	20	23	0	0	291	307
Texas	1,461	1,590	-8.1%	72	0	405	586	11	33	974	970
Mountain	1,078	1,049	2.7%	15	15	652	643	34	25	376	367
Arizona	231	219	5.1%	0	0	231	219	0	0	0	0
Colorado	162	164	-1.5%	0	0	162	164	0	0	0	0
Idaho	518	491	5.5%	15	15	121	119	25	11	356	346
Montana	20	21	-5.6%	0	0	0	0	0	0	20	21
Nevada	54	53	2.3%	0	0	54	53	0	0	0	0
New Mexico	23	21	6.7%	0	0	23	21	0	0	0	0
Utah	71	79	-11.0%	0	0	62	66	9	14	0	0
Wyoming	0	0	--	0	0	0	0	0	0	0	0
Pacific Contiguous	8,445	8,787	-3.9%	437	573	4,896	4,972	777	821	2,335	2,422
California	5,941	5,946	-0.1%	60	93	4,435	4,434	735	779	710	640
Oregon	962	1,037	-7.3%	61	59	375	413	27	29	499	536
Washington	1,542	1,803	-14.5%	316	421	86	124	15	13	1,126	1,245
Pacific Noncontiguous	329	351	-6.2%	57	53	51	51	220	244	1	3
Alaska	38	45	-17.4%	0	0	0	0	37	43	1	3
Hawaii	292	306	-4.6%	57	53	51	51	183	201	0	0
U.S. Total	57,507	61,832	-7.0%	3,997	4,708	24,115	26,300	2,219	2,481	27,176	28,343

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Negative generation denotes that electric power consumed for plant use exceeds gross generation.

Totals may not equal sum of components because of independent rounding. Percentage change is calculated before rounding.

Source: U.S. Energy Information Administration, Form EIA-923, Power Plant Operations Report.

Table 3.20. Utility Scale Facility Net Generation from Geothermal
by State, by Sector, 2019 and 2018 (Thousand Megawatthours)

	All Sectors			Electric Power Sector				Commercial Sector		Industrial Sector	
				Electric Utilities		Independent Power Producers					
	Generation at Utility Scale Facilities			Generation at Utility Scale Facilities		Generation at Utility Scale Facilities		Generation at Utility Scale Facilities		Generation at Utility Scale Facilities	
Census Division and State	Year 2019	Year 2018	Percentage Change	Year 2019	Year 2018	Year 2019	Year 2018	Year 2019	Year 2018	Year 2019	Year 2018
New England	0	0	--	0	0	0	0	0	0	0	0
Connecticut	0	0	--	0	0	0	0	0	0	0	0
Maine	0	0	--	0	0	0	0	0	0	0	0
Massachusetts	0	0	--	0	0	0	0	0	0	0	0
New Hampshire	0	0	--	0	0	0	0	0	0	0	0
Rhode Island	0	0	--	0	0	0	0	0	0	0	0
Vermont	0	0	--	0	0	0	0	0	0	0	0
Middle Atlantic	0	0	--	0	0	0	0	0	0	0	0
New Jersey	0	0	--	0	0	0	0	0	0	0	0
New York	0	0	--	0	0	0	0	0	0	0	0
Pennsylvania	0	0	--	0	0	0	0	0	0	0	0
East North Central	0	0	--	0	0	0	0	0	0	0	0
Illinois	0	0	--	0	0	0	0	0	0	0	0
Indiana	0	0	--	0	0	0	0	0	0	0	0
Michigan	0	0	--	0	0	0	0	0	0	0	0
Ohio	0	0	--	0	0	0	0	0	0	0	0
Wisconsin	0	0	--	0	0	0	0	0	0	0	0
West North Central	0	0	--	0	0	0	0	0	0	0	0
Iowa	0	0	--	0	0	0	0	0	0	0	0
Kansas	0	0	--	0	0	0	0	0	0	0	0
Minnesota	0	0	--	0	0	0	0	0	0	0	0
Missouri	0	0	--	0	0	0	0	0	0	0	0
Nebraska	0	0	--	0	0	0	0	0	0	0	0
North Dakota	0	0	--	0	0	0	0	0	0	0	0
South Dakota	0	0	--	0	0	0	0	0	0	0	0
South Atlantic	0	0	--	0	0	0	0	0	0	0	0
Delaware	0	0	--	0	0	0	0	0	0	0	0
District of Columbia	0	0	--	0	0	0	0	0	0	0	0
Florida	0	0	--	0	0	0	0	0	0	0	0
Georgia	0	0	--	0	0	0	0	0	0	0	0
Maryland	0	0	--	0	0	0	0	0	0	0	0
North Carolina	0	0	--	0	0	0	0	0	0	0	0
South Carolina	0	0	--	0	0	0	0	0	0	0	0
Virginia	0	0	--	0	0	0	0	0	0	0	0
West Virginia	0	0	--	0	0	0	0	0	0	0	0
East South Central	0	0	--	0	0	0	0	0	0	0	0
Alabama	0	0	--	0	0	0	0	0	0	0	0
Kentucky	0	0	--	0	0	0	0	0	0	0	0
Mississippi	0	0	--	0	0	0	0	0	0	0	0
Tennessee	0	0	--	0	0	0	0	0	0	0	0
West South Central	0	0	--	0	0	0	0	0	0	0	0
Arkansas	0	0	--	0	0	0	0	0	0	0	0
Louisiana	0	0	--	0	0	0	0	0	0	0	0
Oklahoma	0	0	--	0	0	0	0	0	0	0	0
Texas	0	0	--	0	0	0	0	0	0	0	0
Mountain	4,373	4,004	9.2%	115	223	3,816	3,747	442	33	0	0
Arizona	0	0	--	0	0	0	0	0	0	0	0
Colorado	0	0	--	0	0	0	0	0	0	0	0
Idaho	96	83	15.0%	0	0	96	83	0	0	0	0
Montana	0	0	--	0	0	0	0	0	0	0	0
Nevada	3,909	3,462	12.9%	0	0	3,467	3,429	442	33	0	0
New Mexico	58	13	342.2%	0	0	58	13	0	0	0	0
Utah	310	446	-30.4%	115	223	195	223	0	0	0	0
Wyoming	0	0	--	0	0	0	0	0	0	0	0
Pacific Contiguous	11,100	11,853	-6.4%	656	786	10,444	11,067	0	0	0	0
California	10,914	11,677	-6.5%	656	786	10,258	10,891	0	0	0	0
Oregon	185	176	5.2%	0	0	185	176	0	0	0	0
Washington	0	0	--	0	0	0	0	0	0	0	0
Pacific Noncontiguous	0	110	-100.0%	0	0	0	110	0	0	0	0
Alaska	0	0	--	0	0	0	0	0	0	0	0
Hawaii	0	110	-100.0%	0	0	0	110	0	0	0	0
U.S. Total	15,473	15,967	-3.1%	771	1,009	14,260	14,924	442	33	0	0

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Negative generation denotes that electric power consumed for plant use exceeds gross generation.

Totals may not equal sum of components because of independent rounding. Percentage change is calculated before rounding.

Source: U.S. Energy Information Administration, Form EIA-923, Power Plant Operations Report.

Table 3.21. Net Generation from Solar Photovoltaic
by State, by Sector, 2019 and 2018 (Thousand Megawatthours)

	All Sectors						Electric Power Sector				Commercial Sector						Industrial Sector						Residential Sector		
							Electric Utilities		Independent Power Producers								Estimated Generation From Utility and Small Scale Facilities		Generation at Utility Scale Facilities		Estimated Small Scale Generation				
	Estimated Generation From Utility and Small Scale Facilities			Generation at Utility Scale Facilities		Estimated Small Scale Generation		Generation at Utility Scale Facilities		Generation at Utility Scale Facilities		Estimated Generation From Utility and Small Scale Facilities		Generation at Utility Scale Facilities		Estimated Small Scale Generation		Estimated Generation From Utility and Small Scale Facilities		Generation at Utility Scale Facilities		Estimated Small Scale Generation		Estimated Small Scale Generation	
Census Division and State	Year 2019	Year 2018	Percentage Change	Year 2019	Year 2018	Year 2019	Year 2018	Year 2019	Year 2018	Year 2019	Year 2018	Year 2019	Year 2018	Year 2019	Year 2018	Year 2019	Year 2018	Year 2019	Year 2018	Year 2019	Year 2018	Year 2019	Year 2018	Year 2019	Year 2018
New England	4,767	4,204	13.4%	1,511	1,232	3,255	2,972	114	59	1,382	1,167	1,751	1,629	11	4	1,740	1,626	135	118	5	2	130	116	1,385	1,231
Connecticut	738	605	22.0%	138	106	600	500	3	3	130	101	226	200	5	1	221	199	30	25	0	0	30	25	349	276
Maine	84	68	24.1%	7	12	77	55	0	0	7	12	32	19	0	0	32	19	0	0	0	0	0	0	45	36
Massachusetts	3,280	3,062	7.1%	1,164	978	2,116	2,083	71	19	1,083	954	1,273	1,280	6	3	1,267	1,277	95	84	4	2	90	82	759	724
New Hampshire	130	108	20.2%	0	0	130	108	0	0	0	0	41	32	0	0	41	32	8	7	0	0	8	7	81	69
Rhode Island	235	124	88.9%	55	29	180	95	0	0	55	29	122	51	0	0	122	51	0	0	0	0	0	0	58	44
Vermont	300	237	26.6%	147	107	153	130	40	37	108	70	57	47	0	0	57	47	2	2	0	0	2	2	94	81
Middle Atlantic	6,308	5,176	21.9%	1,771	1,350	4,537	3,825	79	76	1,513	1,129	2,138	1,853	157	132	1,981	1,721	258	214	22	12	236	202	2,320	1,903
New Jersey	3,357	2,903	15.7%	1,165	990	2,193	1,912	79	76	936	785	1,163	1,083	142	124	1,021	959	164	131	7	5	156	126	1,015	827
New York	2,376	1,794	32.4%	524	297	1,852	1,497	0	0	507	294	806	616	10	4	796	612	23	17	6	0	17	17	1,039	868
Pennsylvania	575	479	20.1%	83	62	492	416	0	0	70	50	169	155	4	5	164	150	70	66	8	7	63	59	265	207
East North Central	1,428	1,134	25.9%	707	634	721	501	234	204	459	415	397	326	12	13	385	312	49	28	2	2	47	26	289	162
Illinois	251	161	55.3%	62	66	189	95	2	2	57	60	108	65	3	3	105	61	0	1	0	0	0	1	84	34
Indiana	450	389	15.7%	323	291	128	98	138	107	183	184	73	66	2	0	71	66	3	3	0	0	3	3	54	29
Michigan	253	197	28.0%	143	118	110	79	87	87	55	29	54	45	1	2	52	43	3	2	0	0	3	2	54	34
Ohio	336	272	23.4%	142	119	194	153	7	7	129	107	121	116	4	3	117	113	26	9	2	2	24	7	53	34
Wisconsin	139	115	21.4%	38	40	101	75	0	0	36	35	41	35	2	5	39	30	17	14	0	0	17	14	45	32
West North Central	2,022	1,660	21.8%	1,408	1,181	613	478	28	16	1,379	1,164	290	235	1	2	289	233	24	18	0	0	24	18	301	227
Iowa	176	138	27.8%	15	11	160	126	8	7	7	5	99	80	0	0	99	80	5	4	0	0	5	4	56	43
Kansas	50	35	42.8%	11	8	38	27	2	2	9	6	15	10	0	0	15	10	0	0	0	0	0	0	23	17
Minnesota	1,353	1,123	20.5%	1,249	1,042	104	81	3	3	1,246	1,039	35	28	0	0	35	28	12	10	0	0	12	10	58	43
Missouri	393	324	21.5%	100	91	293	232	11	5	88	85	135	112	1	2	134	111	6	4	0	0	6	4	153	118
Nebraska	46	38	22.6%	31	27	15	11	5	0	27	27	5	4	0	0	5	4	1	1	0	0	1	1	9	6
North Dakota	1	0	92.8%	0	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
South Dakota	3	3	16.0%	2	2	1	1	0	0	2	2	0	0	0	0	0	0	0	0	0	0	0	0	1	1
South Atlantic	18,775	14,469	29.8%	15,850	12,187	2,925	2,282	4,413	2,812	11,289	9,241	905	788	142	131	763	657	341	307	7	2	334	305	1,828	1,320
Delaware	178	160	11.8%	54	50	124	110	7	6	47	43	35	32	0	1	35	32	8	9	0	0	8	9	81	69
District of Columbia	103	71	44.7%	9	0	94	71	0	0	9	0	50	43	0	0	50	43	0	0	0	0	0	0	44	29
Florida	4,562	2,790	63.5%	3,873	2,361	689	429	3,368	1,974	493	378	145	116	10	6	135	110	13	13	3	2	10	11	544	308
Georgia	2,467	2,265	8.9%	2,161	1,996	307	270	312	293	1,846	1,701	45	37	3	2	42	35	244	218	0	0	244	218	20	17
Maryland	1,460	1,246	17.2%	494	397	965	849	9	8	468	378	275	242	17	11	258	232	36	37	0	0	36	37	672	580
North Carolina	7,725	6,323	22.2%	7,451	6,110	273	212	450	387	6,892	5,611	233	228	109	112	123	117	7	7	0	0	7	7	143	89
South Carolina	1,187	759	56.3%	859	510	329	249	4	2	851	508	79	64	0	0	79	64	30	22	4	0	27	22	222	163
Virginia	1,081	845	27.8%	949	763	132	82	264	141	683	622	38	23	2	0	37	23	2	2	0	0	2	2	93	58
West Virginia	12	10	29.6%	0	0	12	10	0	0	0	0	4	2	0	0	4	2	0	0	0	0	0	0	8	7
East South Central	1,240	1,034	19.9%	1,079	890	162	144	67	69	1,001	810	111	103	5	4	107	98	9	8	6	6	3	2	52	44
Alabama	399	368	8.4%	385	357	14	11	23	31	362	327	10	7	0	0	10	7	1	1	0	0	1	1	3	3
Kentucky	85	71	19.3%	45	39	40	32	43	38	2	2	22	19	0	0	22	19	1	1	0	0	1	1	17	12
Mississippi	336	337	-0.2%	322	326	14	11	0	0	322	326	8	7	0	0	8	7	1	0	0	0	1	0	6	4
Tennessee	420	258	62.8%	326	168	94	90	0	1	315	156	72	70	5	4	67	65	6	6	6	6	0	0	27	25
West South Central	5,933	4,449	33.3%	4,637	3,472	1,297	977	73	73	4,552	3,397	287	215	12	2	274	213	6	2	0	0	6	2	1,016	762
Arkansas	246	225	9.1%	210	203	35	22	2	2	200	202	19	8	9	0	11	8	3	1	0	0	3	1	21	13
Louisiana	242	230	5.2%	2	2	241	229	2	2	0	0	16	15	0	0	16	15	0	0	0	0	0	0	224	214
Oklahoma	79	73	8.8%	60	62	20	11	60	62	0	0	5	4	0	0	5	4	1	0	0	0	1	0	14	7
Texas	5,366	3,921	36.8%	4,365	3,206	1,001	716	10	8	4,352	3,195	246	189	3	2	243	187	2	1	0	0	2	1	756	528
Mountain	19,411	18,058	7.5%	14,673	14,003	4,738	4,055	1,234	991	13,340	12,920	1,378	1,322	96	89	1,282	1,233	72	71	4	3	68	69	3,388	2,754
Arizona	7,058	6,630	6.5%	4,486	4,364	2,572	2,265	741	681	3,729	3,670	776	744	16	13	760	731	14	24	0	0	14	24	1,798	1,511
Colorado	1,852	1,653	12.0%	1,218	1,062	633	590	5	5	1,198	1,045	2363													

Table 3.22. Utility Scale Facility Net Generation from Solar Thermal
by State, by Sector, 2019 and 2018 (Thousand Megawatthours)

Census Division and State	All Sectors			Electric Power Sector				Commercial Sector		Industrial Sector	
				Electric Utilities		Independent Power Producers					
	Generation at Utility Scale Facilities			Generation at Utility Scale Facilities		Generation at Utility Scale Facilities		Generation at Utility Scale Facilities		Generation at Utility Scale Facilities	
	Year 2019	Year 2018	Percentage Change	Year 2019	Year 2018	Year 2019	Year 2018	Year 2019	Year 2018	Year 2019	Year 2018
New England	0	0	--	0	0	0	0	0	0	0	0
Connecticut	0	0	--	0	0	0	0	0	0	0	0
Maine	0	0	--	0	0	0	0	0	0	0	0
Massachusetts	0	0	--	0	0	0	0	0	0	0	0
New Hampshire	0	0	--	0	0	0	0	0	0	0	0
Rhode Island	0	0	--	0	0	0	0	0	0	0	0
Vermont	0	0	--	0	0	0	0	0	0	0	0
Middle Atlantic	0	0	--	0	0	0	0	0	0	0	0
New Jersey	0	0	--	0	0	0	0	0	0	0	0
New York	0	0	--	0	0	0	0	0	0	0	0
Pennsylvania	0	0	--	0	0	0	0	0	0	0	0
East North Central	0	0	--	0	0	0	0	0	0	0	0
Illinois	0	0	--	0	0	0	0	0	0	0	0
Indiana	0	0	--	0	0	0	0	0	0	0	0
Michigan	0	0	--	0	0	0	0	0	0	0	0
Ohio	0	0	--	0	0	0	0	0	0	0	0
Wisconsin	0	0	--	0	0	0	0	0	0	0	0
West North Central	0	0	--	0	0	0	0	0	0	0	0
Iowa	0	0	--	0	0	0	0	0	0	0	0
Kansas	0	0	--	0	0	0	0	0	0	0	0
Minnesota	0	0	--	0	0	0	0	0	0	0	0
Missouri	0	0	--	0	0	0	0	0	0	0	0
Nebraska	0	0	--	0	0	0	0	0	0	0	0
North Dakota	0	0	--	0	0	0	0	0	0	0	0
South Dakota	0	0	--	0	0	0	0	0	0	0	0
South Atlantic	28	51	-45.6%	28	51	0	0	0	0	0	0
Delaware	0	0	--	0	0	0	0	0	0	0	0
District of Columbia	0	0	--	0	0	0	0	0	0	0	0
Florida	28	51	-45.6%	28	51	0	0	0	0	0	0
Georgia	0	0	--	0	0	0	0	0	0	0	0
Maryland	0	0	--	0	0	0	0	0	0	0	0
North Carolina	0	0	--	0	0	0	0	0	0	0	0
South Carolina	0	0	--	0	0	0	0	0	0	0	0
Virginia	0	0	--	0	0	0	0	0	0	0	0
West Virginia	0	0	--	0	0	0	0	0	0	0	0
East South Central	0	0	--	0	0	0	0	0	0	0	0
Alabama	0	0	--	0	0	0	0	0	0	0	0
Kentucky	0	0	--	0	0	0	0	0	0	0	0
Mississippi	0	0	--	0	0	0	0	0	0	0	0
Tennessee	0	0	--	0	0	0	0	0	0	0	0
West South Central	0	0	--	0	0	0	0	0	0	0	0
Arkansas	0	0	--	0	0	0	0	0	0	0	0
Louisiana	0	0	--	0	0	0	0	0	0	0	0
Oklahoma	0	0	--	0	0	0	0	0	0	0	0
Texas	0	0	--	0	0	0	0	0	0	0	0
Mountain	952	1,082	-12.0%	0	0	952	1,082	0	0	0	0
Arizona	792	776	2.0%	0	0	792	776	0	0	0	0
Colorado	0	0	--	0	0	0	0	0	0	0	0
Idaho	0	0	--	0	0	0	0	0	0	0	0
Montana	0	0	--	0	0	0	0	0	0	0	0
Nevada	160	306	-47.6%	0	0	160	306	0	0	0	0
New Mexico	0	0	--	0	0	0	0	0	0	0	0
Utah	0	0	--	0	0	0	0	0	0	0	0
Wyoming	0	0	--	0	0	0	0	0	0	0	0
Pacific Contiguous	2,237	2,458	-9.0%	0	0	2,237	2,458	0	0	0	0
California	2,237	2,458	-9.0%	0	0	2,237	2,458	0	0	0	0
Oregon	0	0	--	0	0	0	0	0	0	0	0
Washington	0	0	--	0	0	0	0	0	0	0	0
Pacific Noncontiguous	0	0	--	0	0	0	0	0	0	0	0
Alaska	0	0	--	0	0	0	0	0	0	0	0
Hawaii	0	0	--	0	0	0	0	0	0	0	0
U.S. Total	3,218	3,592	-10.4%	28	51	3,190	3,540	0	0	0	0

Displayed values of zero may represent small values that round to zero. The Excel version of this table provides additional precision which may be accessed by selecting individual cells.
NM = Not meaningful due to large relative standard error or excessive percentage change.
Notes: See Glossary for definitions. Values are final. See Technical Notes for a discussion of the sample design for the Form EIA-923.
Negative generation denotes that electric power consumed for plant use exceeds gross generation.
Totals may not equal sum of components because of independent rounding. Percentage change is calculated before rounding.
Source: U.S. Energy Information Administration, Form EIA-923, Power Plant Operations Report.

Table 3.23. Useful Thermal Output by Energy Source: Total Combined Heat and Power (All Sectors), 2009 - 2019
(Billion Btus)

Period	Coal	Petroleum Liquids	Petroleum Coke	Natural Gas	Other Gas	Renewable Sources	Other	Total
Annual Totals								
2009	281,557	32,591	20,308	513,002	99,556	546,974	33,287	1,527,276
2010	300,303	19,914	21,448	524,494	91,439	581,310	28,755	1,567,662
2011	286,210	15,230	21,552	535,150	103,615	586,299	31,067	1,579,124
2012	252,605	12,452	24,419	556,945	113,147	580,513	24,571	1,564,653
2013	243,043	12,828	25,224	553,696	103,719	611,443	22,171	1,572,124
2014	232,509	11,990	23,457	545,624	104,868	624,086	21,390	1,563,923
2015	211,030	11,796	21,748	591,749	98,910	626,887	19,729	1,581,849
2016	220,162	8,607	20,122	785,413	148,881	698,858	25,342	1,907,384
2017	193,164	7,922	17,322	789,485	151,579	674,248	23,685	1,857,405
2018	182,373	9,878	16,581	813,127	172,677	663,644	23,169	1,881,448
2019	162,108	7,992	14,278	802,153	142,229	643,548	22,429	1,794,736
Year 2017								
January	19,055	720	1,525	68,635	13,591	59,191	2,181	164,899
February	15,587	494	1,248	61,025	11,816	53,805	1,874	145,848
March	16,988	610	1,617	65,599	12,595	57,856	2,038	157,304
April	15,081	568	1,336	60,483	12,040	53,825	1,948	145,281
May	14,971	539	1,391	62,274	13,346	53,637	1,868	148,026
June	15,501	462	1,576	64,085	12,285	55,874	2,022	151,806
July	15,676	457	1,521	70,083	12,721	57,072	2,032	159,561
August	15,848	447	1,581	68,728	12,505	58,224	2,147	159,481
September	14,580	552	1,281	65,718	12,212	52,154	1,869	148,366
October	16,389	552	1,485	66,078	12,973	55,368	1,811	154,657
November	16,308	1,040	1,398	64,589	12,441	57,071	1,878	154,727
December	17,179	1,480	1,362	72,187	13,054	60,171	2,017	167,450
Year 2018								
January	18,956	2,597	1,662	72,379	13,963	58,883	1,994	170,434
February	16,841	708	1,539	64,059	13,591	52,908	1,886	151,532
March	16,639	601	1,390	67,685	14,652	57,112	2,034	160,113
April	14,584	532	1,472	62,177	13,569	53,599	1,838	147,771
May	14,238	567	1,435	63,879	14,587	54,802	1,821	151,330
June	14,229	634	1,370	65,579	14,392	53,137	2,053	151,393
July	14,346	534	1,361	72,049	14,604	56,586	2,017	161,498
August	14,217	532	1,308	71,554	16,097	56,410	2,065	162,182
September	13,791	491	1,245	66,851	13,972	51,546	1,662	149,558
October	13,254	768	1,287	66,578	14,976	54,658	1,877	153,399
November	15,056	914	1,141	68,771	13,821	55,116	1,925	156,745
December	16,223	998	1,371	71,565	14,452	58,887	1,997	165,493
Year 2019								
January	17,187	1,511	1,276	72,612	12,164	58,244	2,116	165,110
February	15,124	734	1,182	64,964	11,146	52,831	1,957	147,938
March	14,793	609	1,273	68,303	12,304	55,403	1,998	154,682
April	13,488	529	1,257	61,359	12,016	51,489	1,759	141,898
May	12,639	864	1,243	63,354	11,527	52,084	1,647	143,357
June	12,452	409	1,224	64,013	11,309	51,440	1,833	142,681
July	12,106	376	1,204	68,751	12,492	53,785	1,830	150,545
August	12,265	450	1,146	69,982	12,002	54,256	1,915	152,017
September	11,754	468	1,284	65,274	11,652	50,594	1,683	142,709
October	12,909	507	1,055	65,018	11,765	53,397	1,765	146,417
November	13,417	957	950	67,055	11,641	54,062	1,991	150,074
December	13,973	576	1,183	71,467	12,211	55,962	1,936	157,309

Coal includes anthracite, bituminous, subbituminous, lignite, and waste coal; synthetic coal and refined coal; and beginning in 2011, coal-derived synthesis gas. Prior to 2011 coal-derived synthesis gas was included in Other Gases.

Petroleum Liquids includes distillate and residual fuel oils, jet fuel, kerosene, waste oil, and beginning in 2011, propane. Prior to 2011 propane was included in Other Gases.

Petroleum Coke includes petroleum coke-derived synthesis gas. Prior to 2011, petroleum coke-derived synthesis gas was included in Other Gases.

Other Gas includes blast furnace gas and other manufactured and waste gases derived from fossil fuels. Prior to 2011, Other Gas included propane and synthesis gases.

See the Technical Notes for fuel conversion factors.

Renewable Sources include wood, black liquor, other wood waste, biogenic municipal solid waste, landfill gas, sludge waste, agriculture byproducts, other biomass, geothermal, and solar thermal.

Other includes non-biogenic municipal solid waste, batteries, hydrogen, purchased steam, sulfur, tire-derived fuel, and other miscellaneous energy sources.

Notes: Beginning with 2001 data, non-biogenic municipal solid waste and tire-derived fuels are reclassified as non-renewable energy sources and included in Other. Biogenic municipal solid waste is included in Other Renewable Sources.

Beginning with the collection of Form EIA-923 in January 2008, the methodology for separating the fuel used for electricity generation and useful thermal output from combined heat and power plants changed. The new methodology was retroactively applied to 2004-2007, as well as 2008-2015. Beginning with the 2016 Form EIA-923 data, the methodology for separating the fuel used for electricity generation and useful thermal output from CHP plants was updated. This update will apply to the 2016 data and future data years. See the Technical Notes (Appendix C) for further information.

See Glossary for definitions. Values are final. See Technical Notes for a discussion of the sample design for the Form EIA-923 and predecessor forms.

Totals may not equal sum of components because of independent rounding. NM=Not meaningful due to large standard error. W=Withheld to avoid disclosure of individual company data.

Sources: U.S. Energy Information Administration, Form EIA-923, Power Plant Operations Report; U.S. Energy Information Administration, Form EIA-906, Power Plant Report; U.S. Energy Information Administration, Form EIA-920 Combined Heat and Power Plant Report; and predecessor forms.

Beginning with 2008 data, the Form EIA-923, Power Plant Operations Report, replaced the following: 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 Federal Energy Regulatory Commission, FERC Form 423, Monthly Report of Cost and Quality of Fuels for Electric Plants.

Table 3.24. Useful Thermal Output by Energy Source: Electric Power Sector Combined Heat and Power, 2009 - 2019
(Billion Btus)

Period	Coal	Petroleum Liquids	Petroleum Coke	Natural Gas	Other Gas	Renewable Sources	Other	Total
Annual Totals								
2009	38,015	5,341	1,445	190,875	19,830	17,625	5,055	278,187
2010	38,325	4,702	1,108	186,772	19,707	17,589	5,040	273,244
2011	35,209	4,484	1,231	190,712	20,435	16,029	6,044	274,143
2012	26,093	4,405	1,246	200,294	20,948	16,369	5,545	274,900
2013	21,306	4,614	993	188,094	10,303	16,225	4,966	246,501
2014	15,513	4,931	936	182,148	7,732	17,736	5,666	234,662
2015	16,036	4,894	1,143	178,167	7,161	16,999	5,180	229,580
2016	13,922	695	1,237	227,427	17,400	24,993	8,046	293,719
2017	11,269	627	1,267	192,299	17,798	24,279	7,422	254,961
2018	13,573	1,023	1,023	207,459	18,692	23,375	7,119	272,265
2019	12,759	655	1,019	197,106	19,684	26,057	7,544	264,823
Year 2017								
January	1,178	102	106	16,884	1,474	2,419	645	22,809
February	1,004	49	104	14,583	1,327	2,107	570	19,744
March	1,047	22	113	16,687	1,467	2,451	641	22,428
April	799	25	109	14,805	1,394	1,786	629	19,549
May	766	32	112	15,047	1,453	1,727	643	19,780
June	797	33	104	16,004	1,448	1,786	645	20,817
July	925	34	104	17,300	1,518	1,893	684	22,459
August	937	27	102	17,112	1,396	1,860	678	22,113
September	872	58	101	15,575	1,535	1,779	577	20,496
October	932	45	105	15,753	1,615	1,985	488	20,922
November	909	64	98	15,335	1,570	2,154	561	20,691
December	1,104	136	109	17,213	1,599	2,331	663	23,154
Year 2018								
January	1,483	437	104	18,095	1,467	2,384	625	24,596
February	1,151	36	88	16,586	1,398	2,279	568	22,104
March	1,194	35	97	17,454	1,412	2,354	632	23,177
April	1,005	32	105	15,767	1,579	1,614	561	20,663
May	1,050	51	64	16,311	1,661	1,542	573	21,253
June	1,069	37	14	16,547	1,535	1,664	643	21,509
July	1,087	28	97	18,937	1,576	1,794	635	24,154
August	1,073	32	99	18,736	1,569	1,763	620	23,891
September	882	35	80	16,902	1,510	1,594	439	21,442
October	793	46	99	17,040	1,776	1,980	578	22,311
November	1,396	49	86	17,026	1,571	2,200	625	22,954
December	1,391	204	90	18,059	1,639	2,208	619	24,210
Year 2019								
January	1,756	131	85	18,139	1,736	2,518	643	25,008
February	1,186	58	89	15,487	1,764	2,366	595	21,547
March	1,241	58	95	17,184	1,790	2,422	622	23,412
April	1,166	46	98	15,213	1,699	2,226	610	21,057
May	1,089	41	94	14,942	1,511	2,078	690	20,445
June	1,051	42	79	15,814	1,424	1,971	672	21,052
July	995	33	84	16,967	1,643	1,874	661	22,257
August	968	29	91	17,942	1,552	1,970	637	23,188
September	782	63	79	15,907	1,519	1,794	525	20,669
October	901	54	23	15,836	1,721	2,051	551	21,137
November	828	51	100	16,240	1,629	2,367	656	21,871
December	795	50	102	17,435	1,697	2,420	680	23,179

Coal includes anthracite, bituminous, subbituminous, lignite, and waste coal; synthetic coal and refined coal; and beginning in 2011, coal-derived synthesis gas. Prior to 2011 coal-derived synthesis gas was included in Other Gases.

Petroleum Liquids includes distillate and residual fuel oils, jet fuel, kerosene, waste oil, and beginning in 2011, propane. Prior to 2011 propane was included in Other Gases.

Petroleum Coke includes petroleum coke-derived synthesis gas. Prior to 2011, petroleum coke-derived synthesis gas was included in Other Gases.

Other Gas includes blast furnace gas and other manufactured and waste gases derived from fossil fuels. Prior to 2011, Other Gas included propane and synthesis gases.

See the Technical Notes for fuel conversion factors.

Renewable Sources include wood, black liquor, other wood waste, biogenic municipal solid waste, landfill gas, sludge waste, agriculture byproducts, other biomass, geothermal, and solar thermal.

Other includes non-biogenic municipal solid waste, batteries, hydrogen, purchased steam, sulfur, tire-derived fuel, and other miscellaneous energy sources.

Notes: Beginning with 2001 data, non-biogenic municipal solid waste and tire-derived fuels are reclassified as non-renewable energy sources and included in Other. Biogenic municipal solid waste is included in Other Renewable Sources.

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See Glossary for definitions. Values are final. See Technical Notes for a discussion of the sample design for the Form EIA-923 and predecessor forms.

Totals may not equal sum of components because of independent rounding. NM=Not meaningful due to large standard error. W=Withheld to avoid disclosure of individual company data.

Sources: U.S. Energy Information Administration, Form EIA-923, Power Plant Operations Report; U.S. Energy Information Administration, Form EIA-906, Power Plant Report; U.S. Energy Information Administration, Form EIA-920 Combined Heat and Power Plant Report; and predecessor forms.

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Table 3.25. Useful Thermal Output by Energy Source: Commercial Sector Combined Heat and Power, 2009 - 2019
(Billion Btus)

Period	Coal	Petroleum Liquids	Petroleum Coke	Natural Gas	Other Gas	Renewable Sources	Other	Total
Annual Totals								
2009	20,057	1,095	155	25,902	0	8,450	5,761	61,420
2010	19,216	845	216	29,791	13	7,917	5,333	63,330
2011	17,234	687	111	24,848	14	7,433	5,988	56,314
2012	13,992	523	229	27,922	0	7,970	6,426	57,063
2013	10,942	1,017	222	27,562	0	7,054	5,693	52,489
2014	11,081	820	327	26,876	0	7,610	5,123	51,837
2015	7,966	823	325	26,498	0	8,228	5,641	49,482
2016	8,313	924	140	57,356	0	11,017	5,381	83,131
2017	7,360	806	234	71,149	0	10,762	5,140	95,450
2018	6,943	1,020	165	58,312	0	10,902	4,918	82,260
2019	6,211	1,346	95	56,356	0	8,307	3,335	75,650
Year 2017								
January	848	133	31	6,820	0	1,141	544	9,516
February	689	85	18	5,777	0	946	447	7,962
March	813	94	27	5,569	0	875	444	7,821
April	529	44	9	4,741	0	843	414	6,580
May	493	40	12	4,952	0	830	408	6,734
June	475	29	8	5,725	0	902	448	7,588
July	572	38	6	6,706	0	889	442	8,654
August	506	37	32	6,700	0	920	446	8,641
September	532	34	30	6,039	0	705	357	7,697
October	476	43	20	5,888	0	833	378	7,639
November	632	61	12	5,746	0	929	405	7,785
December	795	166	29	6,486	0	949	407	8,833
Year 2018								
January	952	314	29	5,302	0	964	436	7,998
February	719	87	25	4,783	0	967	423	7,006
March	691	80	23	4,924	0	989	421	7,128
April	573	59	9	4,382	0	904	428	6,354
May	455	43	0	4,357	0	897	449	6,201
June	429	39	0	4,655	0	889	407	6,419
July	474	60	0	5,401	0	914	431	7,280
August	491	53	0	5,442	0	945	421	7,352
September	525	43	14	4,686	0	755	297	6,321
October	496	49	13	4,576	0	831	373	6,338
November	565	93	24	4,858	0	864	403	6,808
December	573	100	26	4,946	0	982	429	7,056
Year 2019								
January	724	200	28	5,239	0	966	482	7,639
February	678	111	16	4,804	0	824	411	6,843
March	691	101	22	4,740	0	816	357	6,728
April	481	52	19	4,242	0	577	178	5,549
May	451	467	0	4,067	0	582	222	5,790
June	305	28	0	4,308	0	613	242	5,497
July	409	48	0	5,172	0	605	213	6,447
August	440	77	0	4,892	0	671	257	6,337
September	474	51	0	4,494	0	647	223	5,888
October	435	55	0	4,370	0	691	242	5,794
November	524	82	0	4,692	0	675	251	6,224
December	599	72	11	5,335	0	640	257	6,914

Coal includes anthracite, bituminous, subbituminous, lignite, and waste coal; synthetic coal and refined coal; and beginning in 2011, coal-derived synthesis gas. Prior to 2011 coal-derived synthesis gas was included in Other Gases.

Petroleum Liquids includes distillate and residual fuel oils, jet fuel, kerosene, waste oil, and beginning in 2011, propane. Prior to 2011 propane was included in Other Gases.

Petroleum Coke includes petroleum coke-derived synthesis gas. Prior to 2011, petroleum coke-derived synthesis gas was included in Other Gases.

Other Gas includes blast furnace gas and other manufactured and waste gases derived from fossil fuels. Prior to 2011, Other Gas included propane and synthesis gases.

See the Technical Notes for fuel conversion factors.

Renewable Sources include wood, black liquor, other wood waste, biogenic municipal solid waste, landfill gas, sludge waste, agriculture byproducts, other biomass, geothermal, and solar thermal.

Other includes non-biogenic municipal solid waste, batteries, hydrogen, purchased steam, sulfur, tire-derived fuel, and other miscellaneous energy sources.

Notes: Beginning with 2001 data, non-biogenic municipal solid waste and tire-derived fuels are reclassified as non-renewable energy sources and included in Other. Biogenic municipal solid waste is included in Other Renewable Sources.

Beginning with the collection of Form EIA-923 in January 2008, the methodology for separating the fuel used for electricity generation and useful thermal output from combined heat and power plants changed. The new methodology was retroactively applied to 2004-2007, as well as 2008-2015. Beginning with the 2016 Form EIA-923 data, the methodology for separating the fuel used for electricity generation and useful thermal output from CHP plants was updated. This update will apply to the 2016 data and future data years. See the Technical Notes (Appendix C) for further information.

See Glossary for definitions. Values are final. See Technical Notes for a discussion of the sample design for the Form EIA-923 and predecessor forms.

Totals may not equal sum of components because of independent rounding. NM=Not meaningful due to large standard error. W=Withheld to avoid disclosure of individual company data.

Sources: U.S. Energy Information Administration, Form EIA-923, Power Plant Operations Report; U.S. Energy Information Administration, Form EIA-906, Power Plant Report; U.S. Energy Information Administration, Form EIA-920 Combined Heat and Power Plant Report; and predecessor forms.

Beginning with 2008 data, the Form EIA-923, Power Plant Operations Report, replaced the following: 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 Federal Energy Regulatory Commission, FERC Form 423, Monthly Report of Cost and Quality of Fuels for Electric Plants.

Table 3.26. Useful Thermal Output by Energy Source: Industrial Sector Combined Heat and Power, 2009 - 2019
(Billion Btus)

Period	Coal	Petroleum Liquids	Petroleum Coke	Natural Gas	Other Gas	Renewable Sources	Other	Total
Annual Totals								
2009	223,485	26,155	18,708	296,225	79,726	520,898	22,471	1,187,669
2010	242,762	14,366	20,124	307,931	71,719	555,804	18,382	1,231,088
2011	233,767	10,059	20,209	319,590	83,167	562,838	19,035	1,248,666
2012	212,520	7,524	22,944	328,729	92,199	556,174	12,599	1,232,689
2013	210,795	7,196	24,009	338,041	93,416	588,165	11,512	1,273,134
2014	199,512	6,120	22,167	334,901	97,137	596,087	10,600	1,266,524
2015	180,501	5,965	20,203	384,369	91,749	598,890	8,899	1,290,576
2016	173,589	6,792	18,692	478,068	131,481	655,831	11,904	1,476,358
2017	151,780	6,289	15,721	503,614	133,781	631,768	11,112	1,454,066
2018	142,671	7,535	15,281	521,936	153,985	622,699	11,118	1,475,224
2019	127,411	5,787	13,012	523,919	122,544	607,138	11,535	1,411,347
Year 2017								
January	14,596	452	1,387	42,833	12,117	54,855	992	127,232
February	12,236	341	1,122	38,798	10,489	50,096	856	113,937
March	13,192	483	1,472	41,319	11,127	53,791	952	122,336
April	11,876	490	1,217	39,194	10,646	50,519	904	114,845
May	12,013	457	1,260	40,419	11,893	50,615	818	117,475
June	12,505	386	1,456	40,850	10,837	52,544	928	119,505
July	12,097	374	1,400	44,074	11,203	53,848	905	123,901
August	12,388	373	1,428	43,041	11,109	54,822	1,022	124,183
September	11,528	450	1,140	42,385	10,676	49,080	934	116,192
October	13,159	452	1,352	42,676	11,359	51,977	944	121,920
November	12,704	904	1,277	41,707	10,871	53,411	912	121,785
December	13,486	1,128	1,212	46,318	11,455	56,210	945	130,754
Year 2018								
January	14,472	1,677	1,516	46,673	12,496	54,988	932	132,754
February	13,139	572	1,417	40,743	12,193	49,103	894	118,061
March	13,006	476	1,262	43,193	13,241	53,174	978	125,329
April	11,359	432	1,345	40,349	11,989	50,528	848	116,851
May	11,248	462	1,364	41,234	12,926	51,916	800	119,948
June	11,183	544	1,344	42,224	12,857	50,140	1,002	119,295
July	11,209	437	1,253	45,047	13,028	53,237	950	125,161
August	11,104	436	1,199	44,958	14,528	53,149	1,023	126,397
September	10,875	395	1,143	43,198	12,463	48,750	924	117,747
October	10,610	658	1,172	43,194	13,200	51,191	926	120,951
November	11,718	763	1,022	45,021	12,250	51,484	894	123,152
December	12,749	684	1,245	46,103	12,813	55,038	947	129,578
Year 2019								
January	13,124	1,129	1,151	46,960	10,428	54,504	990	128,286
February	11,791	540	1,065	42,487	9,382	49,408	950	115,622
March	11,431	434	1,148	44,198	10,513	51,928	1,018	120,672
April	10,724	421	1,118	40,351	10,317	48,442	970	112,343
May	10,189	342	1,143	42,727	10,016	49,351	731	114,500
June	9,849	330	1,137	42,011	9,886	48,749	919	112,879
July	9,400	285	1,097	44,343	10,848	51,142	955	118,071
August	9,396	329	1,053	44,741	10,450	51,506	1,019	118,495
September	9,268	340	1,185	42,651	10,133	48,088	933	112,599
October	10,273	385	1,026	43,037	10,045	50,520	972	116,257
November	10,745	812	836	44,067	10,012	50,820	1,082	118,376
December	11,220	440	1,052	46,346	10,514	52,680	996	123,248

Coal includes anthracite, bituminous, subbituminous, lignite, and waste coal; synthetic coal and refined coal; and beginning in 2011, coal-derived synthesis gas. Prior to 2011 coal-derived synthesis gas was included in Other Gases.

Petroleum Liquids includes distillate and residual fuel oils, jet fuel, kerosene, waste oil, and beginning in 2011, propane. Prior to 2011 propane was included in Other Gases.

Petroleum Coke includes petroleum coke-derived synthesis gas. Prior to 2011, petroleum coke-derived synthesis gas was included in Other Gases.

Other Gas includes blast furnace gas and other manufactured and waste gases derived from fossil fuels. Prior to 2011, Other Gas included propane and synthesis gases.

See the Technical Notes for fuel conversion factors.

Renewable Sources include wood, black liquor, other wood waste, biogenic municipal solid waste, landfill gas, sludge waste, agriculture byproducts, other biomass, geothermal, and solar thermal.

Other includes non-biogenic municipal solid waste, batteries, hydrogen, purchased steam, sulfur, tire-derived fuel, and other miscellaneous energy sources.

Notes: Beginning with 2001 data, non-biogenic municipal solid waste and tire-derived fuels are reclassified as non-renewable energy sources and included in Other. Biogenic municipal solid waste is included in Other Renewable Sources.

Beginning with the collection of Form EIA-923 in January 2008, the methodology for separating the fuel used for electricity generation and useful thermal output from combined heat and power plants changed. The new methodology was retroactively applied to 2004-2007, as well as 2008-2015. Beginning with the 2016 Form EIA-923 data, the methodology for separating the fuel used for electricity generation and useful thermal output from CHP plants was updated. This update will apply to the 2016 data and future data years. See the Technical Notes (Appendix C) for further information.

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Totals may not equal sum of components because of independent rounding. NM=Not meaningful due to large standard error. W=Withheld to avoid disclosure of individual company data.

Sources: U.S. Energy Information Administration, Form EIA-923, Power Plant Operations Report; U.S. Energy Information Administration, Form EIA-906, Power Plant Report; U.S. Energy Information Administration, Form EIA-920 Combined Heat and Power Plant Report; and predecessor forms.

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

Chapter 4

Generation Capacity

Table 4.1. Count of Electric Power Industry Power Plants, by Sector, by Predominant Energy Sources within Plant, 2009 through 2019

Year	Coal	Petroleum	Natural Gas	Other Gases	Nuclear	Hydroelectric Conventional	Other Renewables	Hydroelectric Pumped Storage	Other Energy Sources
Total (All Sectors)									
2009	593	1,168	1,652	43	66	1,427	1,219	39	28
2010	580	1,169	1,657	48	66	1,432	1,355	39	32
2011	589	1,146	1,646	41	66	1,434	1,582	40	54
2012	557	1,129	1,714	44	66	1,426	1,956	41	64
2013	518	1,101	1,725	44	63	1,435	2,299	41	78
2014	491	1,082	1,749	43	62	1,441	2,674	41	94
2015	427	1,082	1,779	45	62	1,440	3,043	41	83
2016	381	1,076	1,801	45	61	1,451	3,624	40	117
2017	359	1,080	1,820	44	61	1,458	4,174	40	148
2018	336	1,087	1,854	46	60	1,458	4,667	40	171
2019	308	1,090	1,899	43	58	1,452	5,244	40	212
Electric Utilities									
2009	340	855	768	--	34	887	129	34	1
2010	333	855	775	3	34	888	155	34	--
2011	332	829	777	--	34	884	189	35	1
2012	315	815	797	--	34	875	238	36	5
2013	300	795	787	1	32	873	253	36	15
2014	286	780	803	1	32	889	272	35	20
2015	256	782	816	1	32	890	318	35	15
2016	230	771	819	1	31	893	375	35	36
2017	219	765	820	1	31	894	417	35	53
2018	206	751	819	1	31	896	462	35	60
2019	194	743	818	1	31	898	512	35	71
Independent Power Producers, Non-Combined Heat and Power Plants									
2009	100	173	377	1	32	485	868	5	2
2010	102	175	380	1	32	488	966	5	6
2011	98	166	373	--	32	490	1,106	5	12
2012	88	150	368	--	32	494	1,388	5	16
2013	86	147	384	1	31	505	1,670	5	15
2014	87	148	395	1	30	499	2,006	5	18
2015	80	143	397	--	30	497	2,309	5	21
2016	75	142	406	--	30	500	2,826	5	34
2017	71	145	415	--	30	505	3,320	5	43
2018	65	140	450	--	29	514	3,749	5	59
2019	59	141	476	--	27	506	4,251	5	74
Independent Power Producers, Combined Heat and Power Plants									
2009	51	10	166	3	--	--	41	--	--
2010	48	10	161	2	--	--	41	--	--
2011	45	11	156	1	--	--	38	--	1
2012	42	12	157	2	--	--	47	--	--
2013	35	11	152	2	--	1	51	--	5
2014	30	9	145	2	--	--	54	--	7
2015	27	8	143	3	--	--	58	--	3
2016	24	7	143	3	--	--	57	--	2
2017	22	7	138	3	--	--	56	--	3
2018	19	8	133	3	--	--	56	--	3
2019	14	6	128	3	--	--	56	--	3
Commercial Sector									
2009	18	68	107	1	--	9	47	--	1
2010	17	69	110	1	--	9	57	--	1
2011	22	80	118	--	--	10	105	--	2
2012	22	89	153	--	--	9	129	--	2
2013	19	92	164	--	--	9	160	--	3
2014	17	93	169	--	--	10	178	1	6
2015	12	94	176	--	--	10	186	1	3
2016	9	101	181	--	--	14	195	--	3
2017	9	112	189	--	--	15	203	--	4
2018	7	139	192	--	--	15	220	--	5
2019	6	152	203	--	--	15	242	--	20
Industrial Sector									
2009	84	62	234	38	--	46	134	--	24
2010	80	60	231	41	--	47	136	--	25
2011	92	60	222	40	--	50	144	--	38
2012	90	63	239	42	--	48	154	--	41
2013	78	56	238	40	--	47	165	--	40
2014	71	52	237	39	--	43	164	--	43
2015	52	55	247	41	--	43	172	--	41
2016	43	55	252	41	--	44	171	--	42
2017	38	51	258	40	--	44	178	--	45
2018	39	49	260	42	--	33	180	--	44
2019	35	48	274	39	--	33	183	--	44

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 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 sites. In addition, changes to predominant energy sources and status codes from year to year may result in changes to previously-posted data.

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.

In 2011, EIA corrected the NAICS codes of several plants which resulted in a net capacity shift from the electric utility sector to the commercial sector.

Table 4.2.A. Existing Net Summer Capacity by Energy Source and Producer Type, 2009 through 2019 (Megawatts)

Utility Scale Capacity											Small Scale Capacity
Year	Coal	Petroleum	Natural Gas	Other Gases	Nuclear	Hydroelectric Conventional	Other Renewable Sources	Hydroelectric Pumped Storage	Other Energy Sources	Utility Total	Estimated Photovoltaic
Total (All Sectors)											
2009	314,294.1	56,780.5	401,271.8	1,932.4	101,003.7	78,517.7	48,552.0	22,160.4	887.8	1,025,400.4	--
2010	316,800.1	55,646.9	407,028.4	2,700.3	101,167.4	78,824.7	53,811.3	22,198.9	883.8	1,039,061.8	--
2011	317,640.3	51,481.6	415,191.3	1,934.2	101,418.8	78,651.6	61,221.0	22,292.6	1,419.6	1,051,251.0	--
2012	309,680.4	47,167.2	422,364.4	1,945.6	101,885.0	78,738.0	77,155.2	22,368.3	1,728.9	1,063,033.0	--
2013	303,306.3	43,523.0	425,389.7	2,107.8	99,240.3	79,200.0	82,600.1	22,389.3	2,307.0	1,060,063.5	--
2014	299,094.2	41,135.4	432,150.3	1,914.3	98,569.3	79,677.3	90,603.7	22,485.1	2,792.6	1,068,422.2	7,326.6
2015	279,719.9	36,830.3	439,425.4	2,500.4	98,672.0	79,664.2	102,871.6	22,575.1	1,795.6	1,064,054.5	9,778.5
2016	266,619.9	34,382.4	446,823.2	2,456.9	99,564.8	79,912.9	119,778.9	22,778.7	2,015.1	1,074,332.8	12,765.1
2017	256,547.3	33,306.7	456,011.6	2,375.8	99,628.9	79,794.5	131,008.1	22,810.4	2,886.3	1,084,369.6	16,147.8
2018	242,785.6	32,218.2	470,236.9	2,543.9	99,432.9	79,871.8	142,473.6	22,830.2	2,346.7	1,094,739.8	19,547.1
2019	228,657.4	31,400.3	476,567.4	2,499.2	98,119.0	79,773.1	156,708.2	22,778.3	2,606.4	1,099,109.3	23,213.6
Electric Utilities											
2009	234,396.6	30,174.1	180,570.7	--	54,355.2	72,689.7	5,613.9	18,930.0	39.0	596,769.2	--
2010	235,706.8	28,971.9	184,230.5	539.0	54,369.3	72,973.9	6,316.1	18,968.5	--	602,076.0	--
2011	236,391.7	27,669.9	193,630.5	--	54,351.6	72,182.4	7,811.1	19,062.2	5.3	611,104.7	--
2012	232,078.5	26,731.8	206,774.4	--	54,716.7	72,505.1	9,823.8	19,093.9	60.7	621,784.9	--
2013	228,478.0	24,648.8	208,485.7	12.0	52,399.1	72,755.2	10,118.4	19,114.9	787.3	616,799.4	--
2014	219,837.9	24,045.0	215,690.8	12.0	52,390.9	73,725.4	10,893.7	19,121.3	914.5	616,631.5	--
2015	202,922.4	22,269.7	223,215.6	12.0	52,457.2	73,713.0	12,654.3	19,211.3	87.5	606,543.0	--
2016	193,122.6	20,285.5	229,677.1	12.0	53,274.1	73,879.3	14,236.4	19,398.3	236.1	604,121.4	--
2017	186,623.1	19,999.9	236,557.8	12.0	53,343.6	73,739.5	15,281.3	19,430.0	519.3	605,506.5	--
2018	179,047.8	18,642.6	241,477.0	12.0	53,725.6	73,818.2	18,155.9	19,449.8	341.8	604,670.7	--
2019	171,088.7	18,219.8	247,018.9	12.0	53,880.6	73,719.7	20,745.8	19,428.9	418.3	604,532.7	--
Independent Power Producers, Non-Combined Heat and Power Plants											
2009	70,122.5	24,657.1	176,034.8	7.6	46,648.5	5,469.6	36,556.4	3,230.4	45.9	362,772.8	--
2010	71,214.4	24,866.8	178,190.4	7.6	46,798.1	5,488.6	41,013.7	3,230.4	76.9	370,886.9	--
2011	72,119.5	22,398.8	176,516.5	--	47,067.2	5,539.0	46,698.4	3,230.4	169.2	373,739.0	--
2012	69,068.4	18,643.9	170,653.8	--	47,168.3	5,568.6	60,116.8	3,274.4	470.2	374,964.4	--
2013	67,153.5	17,444.7	171,653.6	47.0	46,841.2	5,762.2	64,890.5	3,274.4	231.2	377,298.3	--
2014	71,994.6	15,724.4	172,224.5	47.0	46,178.4	5,651.2	72,144.4	3,358.4	238.7	387,561.6	--
2015	70,217.8	13,102.9	172,519.2	--	46,214.8	5,650.5	82,014.6	3,358.4	354.3	393,432.5	--
2016	67,667.7	12,587.4	173,455.8	--	46,290.7	5,676.9	97,408.4	3,380.4	487.5	406,954.8	--
2017	64,419.3	11,777.0	176,029.0	--	46,285.3	5,697.9	107,618.0	3,380.4	989.3	416,196.2	--
2018	58,716.2	11,733.2	186,542.1	--	45,707.3	5,770.0	116,197.3	3,380.4	670.1	428,716.6	--
2019	53,646.5	11,514.8	187,715.6	--	44,238.4	5,764.3	127,964.3	3,349.4	760.7	434,954.0	--
Independent Power Producers, Combined Heat and Power Plants											
2009	5,939.5	897.0	28,875.4	205.8	--	--	739.9	--	--	36,657.6	--
2010	5,450.6	766.0	29,005.6	182.3	--	--	845.5	--	--	36,250.0	--
2011	5,146.0	317.0	29,372.6	30.0	--	--	792.9	--	53.0	35,711.5	--
2012	4,755.9	317.2	29,128.6	83.0	--	--	981.2	--	--	35,265.9	--
2013	4,313.7	322.2	29,081.2	83.0	--	4.3	945.1	--	121.8	34,871.3	--
2014	4,073.0	308.2	27,676.7	83.0	--	--	885.9	--	335.8	33,362.6	--
2015	3,843.6	307.2	27,284.1	350.0	--	--	970.5	--	126.0	32,881.4	--
2016	3,552.4	301.2	27,222.4	350.0	--	--	1,068.3	--	19.0	32,513.3	--
2017	3,338.0	301.2	26,922.1	350.0	--	--	969.8	--	21.0	31,902.1	--
2018	2,922.0	458.0	25,658.1	350.0	--	--	884.2	--	21.0	30,293.3	--
2019	2,074.1	298.8	24,782.0	350.0	--	--	944.9	--	112.0	28,561.8	--
Commercial Sector											
2009	423.7	348.3	1,104.7	4.7	--	21.7	480.1	--	2.8	2,386.0	--
2010	418.2	368.2	1,154.5	4.7	--	21.7	519.7	--	2.8	2,489.8	--
2011	435.7	406.3	1,282.6	--	--	233.5	694.1	--	4.2	3,056.4	--
2012	435.6	442.7	1,544.9	--	--	18.4	776.8	--	4.2	3,222.6	--
2013	341.9	455.7	1,778.9	--	--	17.8	947.6	--	9.1	3,551.0	--
2014	290.1	463.5	1,832.6	--	--	21.4	1,066.8	5.4	15.6	3,695.4	3,279.7
2015	226.6	466.1	1,932.5	--	--	21.4	1,126.5	5.4	6.7	3,785.2	3,706.7
2016	202.4	511.0	1,982.6	--	--	74.5	1,132.0	--	6.7	3,909.2	4,022.8
2017	202.4	596.5	2,018.7	--	--	74.9	1,162.0	--	11.6	4,066.1	5,155.8
2018	144.2	823.6	2,157.6	--	--	74.7	1,241.5	--	13.0	4,454.6	6,271.4
2019	123.2	856.7	2,247.5	--	--	74.9	1,218.6	--	49.1	4,570.0	7,167.9
Industrial Sector											
2009	3,411.8	704.0	14,686.2	1,714.3	--	336.7	5,161.7	--	800.1	26,814.8	--
2010	4,010.1	674.0	14,447.4	1,966.7	--	340.5	5,116.3	--	804.1	27,359.1	--
2011	3,547.4	689.6	14,389.1	1,904.2	--	696.7	5,224.5	--	1,187.9	27,639.4	--
2012	3,342.0	1,031.6	14,262.7	1,862.6	--	645.9	5,456.6	--	1,193.8	27,795.2	--
2013	3,019.2	651.6	14,390.3	1,965.8	--	660.5	5,698.5	--	1,157.6	27,543.5	--
2014	2,898.6	594.3	14,725.7	1,772.3	--	279.3	5,612.9	--	1,288.0	27,171.1	700.6
2015	2,509.5	684.4	14,474.0	2,138.4	--	279.3	6,105.7	--	1,221.1	27,412.4	880.3
2016	2,074.8	697.3	14,485.3	2,094.9	--	282.2	5,933.8	--	1,265.8	26,834.1	1,215.3
2017	1,964.5	632.1	14,484.0	2,013.8	--	282.2	5,977.0	--	1,345.1	26,698.7	1,365.1
2018	1,955.4	560.8	14,402.1	2,181.9	--	208.9	5,994.7	--	1,300.8	26,604.6	1,555.4
2019	1,724.9	510.2	14,803.4	2,137.2	--	214.2	5,834.6	--	1,266.3	26,490.8	1,796.6
Residential Sector											
2014	--	--	--	--	--	--	--	--	--	--	3,346.3
2015	--	--	--	--	--	--	--	--	--	--	5,191.5
2016	--	--	--	--	--	--	--	--	--	--	7,527.0
2017	--	--	--	--	--	--	--	--	--	--	9,626.8
2018	--	--	--	--	--	--	--	--	--	--	11,720.4
2019	--	--	--	--	--	--	--	--	--	--	14,249.0

Notes: Coal includes anthracite, bituminous, subbituminous, lignite, and waste coal; coal synfuel and refined coal; and beginning in 2011, coal-derived synthesis gas. Prior to 2011, coal-derived synthesis gas was included in Other Gases. Petroleum includes 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), waste oil, and beginning in 2011, synthetic gas and propane. Prior to 2011, synthetic gas and propane were included in Other Gases. Other Gases also includes blast furnace gas. Prior to 2011, waste heat was included in Natural Gas. Hydroelectric Conventional capacity includes conventional hydroelectric power excluding pumped storage facilities. Other Renewable Sources include wood, black liquor, other wood waste, municipal solid waste, landfill gas, sludge waste, agriculture byproducts, other biomass, geothermal, solar thermal, photovoltaic energy, and wind. Other Energy Sources include batteries, hydrogen, purchased steam, sulfur, tire-derived fuels and other miscellaneous energy sources. In 2011, EIA corrected the NAICS codes of several plants which resulted in a net capacity shift from the electric utility sector to the commercial sector. Source: U.S. Energy Information Administration, Form EIA-860, 'Annual Electric Generator Report.' Estimated small scale solar photovoltaic generation and capacity are based on data from Form EIA-826, Form EIA-861M, Form EIA-861 and from estimation methods described in the technical notes.

Table 4.2.B. Existing Net Summer Capacity of Other Renewable Sources by Producer Type, 2009 through 2019 (Megawatts) (Page 1)

Utility Scale Capacity								Utility and Small Scale Capacity		
Year	Wind	Solar Photovoltaic	Solar Thermal	Wood and Wood-Derived Fuels	Geothermal	Other Biomass	Total Utility (Other Renewable Sources)	Estimated Small Scale Photovoltaic	Total Solar Photovoltaic	Total Solar
Total (All Sectors)										
2009	34,295.8	145.5	473.0	6,939.3	2,381.9	4,316.5	48,552.0	--	145.5	618.5
2010	39,134.5	393.4	473.0	7,037.3	2,404.6	4,368.5	53,811.3	--	393.4	866.4
2011	45,675.9	1,052.0	471.5	7,076.5	2,409.2	4,535.9	61,221.0	--	1,052.0	1,523.5
2012	59,074.8	2,694.1	476.0	7,507.6	2,592.1	4,810.6	77,155.2	--	2,694.1	3,170.1
2013	59,973.4	5,336.1	1,286.4	8,354.2	2,607.0	5,043.0	82,600.1	--	5,336.1	6,622.5
2014	64,231.5	8,656.6	1,666.7	8,368.1	2,514.3	5,166.5	90,603.7	7,326.6	15,983.2	17,649.9
2015	72,573.4	11,905.4	1,757.9	8,968.9	2,541.5	5,124.5	102,871.6	9,778.5	21,683.9	23,441.8
2016	81,286.6	20,192.9	1,757.9	8,936.1	2,516.6	5,088.8	119,778.9	12,765.1	32,958.0	34,715.9
2017	87,597.5	25,209.0	1,757.9	8,830.9	2,483.3	5,129.5	131,008.1	16,147.8	41,356.8	43,114.7
2018	94,417.7	30,120.5	1,757.9	8,694.6	2,444.3	5,038.6	142,473.6	19,547.1	49,667.6	51,425.5
2019	103,571.2	35,710.2	1,758.1	8,374.5	2,555.4	4,738.8	156,708.2	23,213.6	58,923.8	60,681.9
Electric Utilities										
2009	4,654.8	41.0	1.0	431.3	158.9	326.9	5,613.9	--	41.0	42.0
2010	5,338.3	78.2	1.0	414.3	158.9	325.4	6,316.1	--	78.2	79.2
2011	6,735.2	201.4	1.0	359.1	158.9	355.5	7,811.1	--	201.4	202.4
2012	8,488.7	331.2	1.0	364.1	162.1	476.7	9,823.8	--	331.2	332.2
2013	8,424.7	487.9	--	564.3	164.1	477.4	10,118.4	--	487.9	487.9
2014	9,022.6	568.5	--	654.8	164.1	483.7	10,893.7	--	568.5	568.5
2015	10,580.9	842.9	--	623.8	165.9	440.8	12,654.3	--	842.9	842.9
2016	11,552.6	1,388.4	--	708.8	167.9	418.7	14,236.4	--	1,388.4	1,388.4
2017	12,150.8	1,724.5	--	811.3	161.9	432.8	15,281.3	--	1,724.5	1,724.5
2018	14,031.7	2,683.5	--	807.0	148.8	484.9	18,155.9	--	2,683.5	2,683.5
2019	15,715.0	3,851.4	--	696.2	146.5	336.7	20,745.8	--	3,851.4	3,851.4
Independent Power Producers, Non-Combined Heat and Power Plants										
2009	29,639.8	103.4	472.0	1,220.2	2,223.0	2,898.0	36,556.4	--	103.4	575.4
2010	33,783.9	307.9	472.0	1,274.5	2,245.7	2,929.7	41,013.7	--	307.9	779.9
2011	38,911.8	792.1	470.5	1,312.5	2,250.3	2,961.2	46,698.4	--	792.1	1,262.6
2012	50,547.6	2,255.7	475.0	1,398.8	2,384.2	3,055.5	60,116.8	--	2,255.7	2,730.7
2013	51,497.8	4,647.6	1,286.4	1,845.4	2,401.1	3,212.2	64,890.5	--	4,647.6	5,934.0
2014	55,133.0	7,857.0	1,666.7	1,816.6	2,308.8	3,362.3	72,144.4	--	7,857.0	9,523.7
2015	61,905.4	10,768.2	1,757.9	1,873.3	2,375.6	3,334.2	82,014.6	--	10,768.2	12,526.1
2016	69,645.4	18,483.3	1,757.9	1,789.6	2,348.7	3,383.5	97,408.4	--	18,483.3	20,241.2
2017	75,346.6	23,127.0	1,757.9	1,649.1	2,321.4	3,416.0	107,618.0	--	23,127.0	24,884.9
2018	80,267.6	27,055.8	1,757.9	1,576.2	2,246.1	3,293.7	116,197.3	--	27,055.8	28,813.7
2019	87,737.8	31,416.4	1,758.1	1,475.7	2,359.5	3,216.8	127,964.3	--	31,416.4	33,174.5

Notes: Wood and wood-derived fuels include 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.

Other Biomass includes 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).

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

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

Estimated small scale solar photovoltaic generation capacity are based on data from Form EIA-826, Form EIA-861M, Form EIA-861 and from estimation methods described in the technical notes.

Table 4.2.B. Existing Net Summer Capacity of Other Renewable Sources by Producer Type,

2009 through 2019 (Megawatts) (Page 2)

Utility Scale Capacity								Utility and Small Scale Capacity		
Year	Wind	Solar Photovoltaic	Solar Thermal	Wood and Wood-Derived Fuels	Geothermal	Other Biomass	Total Utility (Other Renewable Sources)	Estimated Small Scale Photovoltaic	Total Solar Photovoltaic	Total Solar
Independent Power Producers, Combined Heat and Power Plants										
2009	--	--	--	237.2	--	502.7	739.9	--	--	--
2010	--	--	--	392.8	--	452.7	845.5	--	--	--
2011	--	--	--	356.3	--	436.6	792.9	--	--	--
2012	--	--	--	489.8	45.8	445.6	981.2	--	--	--
2013	--	--	--	469.2	41.8	434.1	945.1	--	--	--
2014	--	--	--	465.5	41.4	379.0	885.9	--	--	--
2015	--	--	--	568.2	--	402.3	970.5	--	--	--
2016	--	1.0	--	667.2	--	400.1	1,068.3	--	1.0	1.0
2017	--	2.5	--	582.0	--	385.3	969.8	--	2.5	2.5
2018	--	3.3	--	492.7	--	388.2	884.2	--	3.3	3.3
2019	--	3.3	--	554.7	--	386.9	944.9	--	3.3	3.3
Commercial Sector										
2009	1.2	0.1	--	7.6	--	471.2	480.1	--	0.1	0.1
2010	10.5	5.9	--	7.6	--	495.7	519.7	--	5.9	5.9
2011	24.6	54.1	--	7.6	--	607.8	694.1	--	54.1	54.1
2012	29.8	99.9	--	7.6	--	639.5	776.8	--	99.9	99.9
2013	33.2	192.9	--	8.4	--	713.1	947.6	--	192.9	192.9
2014	51.6	223.4	--	65.4	--	726.4	1,066.8	3,279.7	3,503.1	3,503.1
2015	55.3	282.1	--	65.3	--	723.8	1,126.5	3,706.7	3,988.8	3,988.8
2016	56.8	300.8	--	67.1	--	707.3	1,132.0	4,022.8	4,323.6	4,323.6
2017	60.8	311.6	--	63.1	--	726.5	1,162.0	5,155.8	5,467.4	5,467.4
2018	73.4	330.6	--	63.1	49.4	725.0	1,241.5	6,271.4	6,602.0	6,602.0
2019	73.4	381.1	--	63.1	49.4	651.6	1,218.6	7,167.9	7,549.0	7,549.0
Industrial Sector										
2009	--	1.0	--	5,043.0	--	117.7	5,161.7	--	1.0	1.0
2010	1.8	1.4	--	4,948.1	--	165.0	5,116.3	--	1.4	1.4
2011	4.3	4.4	--	5,041.0	--	174.8	5,224.5	--	4.4	4.4
2012	8.7	7.3	--	5,247.3	--	193.3	5,456.6	--	7.3	7.3
2013	17.7	7.7	--	5,466.9	--	206.2	5,698.5	--	7.7	7.7
2014	24.3	7.7	--	5,365.8	--	215.1	5,612.9	700.6	708.3	708.3
2015	31.8	12.2	--	5,838.3	--	223.4	6,105.7	880.3	892.5	892.5
2016	31.8	19.4	--	5,703.4	--	179.2	5,933.8	1,215.3	1,234.7	1,234.7
2017	39.3	43.4	--	5,725.4	--	168.9	5,977.0	1,365.1	1,408.5	1,408.5
2018	45.0	47.3	--	5,755.6	--	146.8	5,994.7	1,555.4	1,602.7	1,602.7
2019	45.0	58.0	--	5,584.8	--	146.8	5,834.6	1,796.6	1,854.6	1,854.6
Residential Sector										
2014	--	--	--	--	--	--	--	3,346.3	3,346.3	3,346.3
2015	--	--	--	--	--	--	--	5,191.5	5,191.5	5,191.5
2016	--	--	--	--	--	--	--	7,527.0	7,527.0	7,527.0
2017	--	--	--	--	--	--	--	9,626.8	9,626.8	9,626.8
2018	--	--	--	--	--	--	--	11,720.4	11,720.4	11,720.4
2019	--	--	--	--	--	--	--	14,249.0	14,249.0	14,249.0

Notes: Wood and wood-derived fuels include 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.
Other Biomass includes 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).
* = Value is less than half of the smallest unit 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.
Source: U.S. Energy Information Administration, Form EIA-860, 'Annual Electric Generator Report.'
Estimated small scale solar photovoltaic generation capacity are based on data from Form EIA-826, Form EIA-861M, Form EIA-861 and from estimation methods described in the technical notes.

Table 4.3. Existing Capacity by Energy Source, 2019 (Megawatts)

Energy Source	Facility Type	Number of Generators	Generator Nameplate Capacity	Net Summer Capacity	Net Winter Capacity
Coal	Utility Scale	668	248,286.3	228,657.4	229,623.7
Petroleum	Utility Scale	3,691	36,120.0	31,400.3	33,727.7
Natural Gas	Utility Scale	6,020	542,413.2	476,567.4	511,196.1
Other Gases	Utility Scale	91	2,863.3	2,499.2	2,551.1
Nuclear	Utility Scale	96	102,877.3	98,119.0	100,141.5
Hydroelectric Conventional	Utility Scale	4,014	79,787.1	79,773.1	79,172.2
Wind	Utility Scale	1,354	104,333.6	103,571.2	103,667.8
Solar Photovoltaic	Utility Scale	3,948	36,013.4	35,710.2	35,267.9
Solar Thermal	Utility Scale	19	1,774.6	1,758.1	1,597.4
Wood and Wood-Derived Fuels	Utility Scale	333	9,519.1	8,374.5	8,496.2
Geothermal	Utility Scale	172	3,849.3	2,555.4	2,963.3
Other Biomass	Utility Scale	1,917	5,382.7	4,738.8	4,799.2
Hydroelectric Pumped Storage	Utility Scale	153	21,871.3	22,778.3	22,598.6
Other Energy Sources	Utility Scale	255	2,825.9	2,606.4	2,656.5
Total	Utility Scale	22,731	1,197,917.1	1,099,109.3	1,138,459.2
Small Scale Photovoltaic	Small Scale	--	--	23,213.6	--
Estimated Total Photovoltaic	Utility and Small Scale	--	--	58,923.8	--
Estimated Total Solar	Utility and Small Scale	--	--	60,681.9	--

Notes: Coal includes anthracite, bituminous, subbituminous, lignite, and waste coal; coal synfuel and refined coal; and beginning in 2011, coal-derived synthesis gas. Prior to 2011, coal-derived synthesis gas was included in Other Gases.

Petroleum includes 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), waste oil, and beginning in 2011, synthetic gas and propane. Prior to 2011, synthetic gas and propane were included in Other Gases.

Other Gases includes blast furnace gas. Prior to 2011, waste heat was included in Natural Gas.

Hydroelectric Conventional capacity includes conventional hydroelectric power excluding pumped storage facilities.

Wood and wood-derived fuels include 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.

Other Biomass include 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).

Hydroelectric Conventional capacity includes conventional hydroelectric power excluding pumped storage facilities.

Other Energy Sources include batteries, hydrogen, purchased steam, sulfur, tire-derived fuels and other miscellaneous energy sources.

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.

In 2011, EIA corrected the NAICS codes of several plants which resulted in a net capacity shift from the electric utility sector to the commercial sector.

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

Estimated small scale solar photovoltaic capacity is based on data from Form EIA-826, Form EIA-861M, Form EIA-861 and from estimation methods described in the technical notes.

Table 4.4. Existing Capacity by Producer Type, 2019 (Megawatts)

Producer Type	Facility Type	Number of Generators	Generator Nameplate Capacity	Net Summer Capacity	Net Winter Capacity
Electric Power Sector					
Electric Utilities	Utility Scale	9,559	660,512.2	604,532.7	624,823.4
Independent Power Producers, Non-Combined Heat and Power Plants	Utility Scale	9,629	469,617.6	434,954.0	449,868.6
Independent Power Producers, Combined Heat and Power Plants	Utility Scale	477	32,166.2	28,561.8	30,818.6
Total	Utility Scale	19,665	1,162,296.0	1,068,048.5	1,105,510.6
Commercial and Industrial Sectors					
Commercial Sector	Utility Scale	1,555	5,028.3	4,570.0	4,663.7
Industrial Sector	Utility Scale	1,511	30,592.8	26,490.8	28,284.9
Total	Utility Scale	3,066	35,621.1	31,060.8	32,948.6
All Sectors					
Total	Utility Scale	22,731	1,197,917.1	1,099,109.3	1,138,459.2
Small Scale					
Estimated Solar Photovoltaic	Small Scale	--	--	23,213.6	--

Notes:
See Glossary reference for definitions.
Totals may not equal sum of components because of independent rounding.
In the case of some 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 generator count.
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.'
Estimated small scale solar photovoltaic capacity is based on data from Form EIA-826, Form EIA-861M, Form EIA-861 and from estimation methods described in the technical notes.

Table 4.5. Planned Utility-Scale Generating Capacity Changes, by Energy Source, 2020-2024 (Page 1)

Energy Source	Generator Additions		Generator Retirements		Net Capacity Additions	
	Number of Generators	Net Summer Capacity	Number of Generators	Net Summer Capacity	Number of Generators	Net Summer Capacity
Year 2020						
U.S. Total	802	44,866.9	146	12,760.7	656	32,106.2
Coal	1	17.0	35	8,824.2	-34	-8,807.2
Petroleum	9	10.4	13	282.3	-4	-271.9
Natural Gas	64	6,565.6	60	1,805.8	4	4,759.8
Other Gases	--	--	--	--	--	--
Nuclear	--	--	2	1,617.5	-2	-1,617.5
Hydroelectric Conventional	12	161.5	2	1.8	10	159.7
Wind	132	23,470.7	10	123.1	122	23,347.6
Solar Thermal and Photovoltaic	515	13,535.7	--	--	515	13,535.7
Wood and Wood-Derived Fuels	1	8.5	1	20.0	--	-11.5
Geothermal	--	--	--	--	--	--
Other Biomass	12	55.0	23	86.0	-11	-31.0
Hydroelectric Pumped Storage	--	--	--	--	--	--
Other Energy Sources	56	1,042.5	--	--	56	1,042.5
Year 2021						
U.S. Total	447	31,873.8	54	9,635.6	393	22,238.2
Coal	--	--	14	3,308.8	-14	-3,308.8
Petroleum	--	--	15	808.4	-15	-808.4
Natural Gas	90	7,282.1	15	367.7	75	6,914.4
Other Gases	--	--	--	--	--	--
Nuclear	1	1,100.0	5	5,134.9	-4	-4,034.9
Hydroelectric Conventional	22	102.3	4	4.2	18	98.1
Wind	54	7,825.8	1	11.6	53	7,814.2
Solar Thermal and Photovoltaic	211	12,151.1	--	--	211	12,151.1
Wood and Wood-Derived Fuels	--	--	--	--	--	--
Geothermal	2	42.0	--	--	2	42.0
Other Biomass	1	2.0	--	--	1	2.0
Hydroelectric Pumped Storage	--	--	--	--	--	--
Other Energy Sources	66	3,368.5	--	--	66	3,368.5
Year 2022						
U.S. Total	228	27,124.3	52	11,406.4	176	15,717.9
Coal	--	--	23	7,720.1	-23	-7,720.1
Petroleum	--	--	9	1,749.6	-9	-1,749.6
Natural Gas	47	14,431.8	17	1,155.8	30	13,276.0
Other Gases	--	--	--	--	--	--
Nuclear	1	1,100.0	1	771.6	--	328.4
Hydroelectric Conventional	10	19.8	--	--	10	19.8
Wind	17	2,493.9	--	--	17	2,493.9
Solar Thermal and Photovoltaic	127	7,702.2	--	--	127	7,702.2
Wood and Wood-Derived Fuels	2	48.0	1	7.8	1	40.2
Geothermal	--	--	--	--	--	--
Other Biomass	3	4.2	--	--	3	4.2
Hydroelectric Pumped Storage	--	--	--	--	--	--
Other Energy Sources	21	1,324.4	1	1.5	20	1,322.9

Notes: These data reflect plans as of December 31, 2019

Coal includes anthracite, bituminous, subbituminous, lignite, waste coal, coal synfuel, refined coal, and coal-derived synthesis gas.

Petroleum includes 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), waste oil, synthetic gas, and propane.

Other Gases also includes blast furnace gas.

Hydroelectric Conventional capacity includes conventional hydroelectric power excluding pumped storage facilities.

Wood and wood-derived fuels include 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.

Other Biomass include 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).

Hydroelectric Conventional capacity includes conventional hydroelectric power excluding pumped storage facilities.

Other Energy Sources include batteries, hydrogen, purchased steam, sulfur, tire-derived fuels and other miscellaneous energy sources.

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.

In the case of 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 generator count.

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

Table 4.5. Planned Generating Capacity Changes, by Energy Source, 2020-2024 (Page 2)

Energy Source	Generator Additions		Generator Retirements		Net Capacity Additions	
	Number of Generators	Net Summer Capacity	Number of Generators	Net Summer Capacity	Number of Generators	Net Summer Capacity
Year 2023						
U.S. Total	117	15,664.7	76	11,738.9	41	3,925.8
Coal	--	--	17	5,309.5	-17	-5,309.5
Petroleum	--	--	12	977.9	-12	-977.9
Natural Gas	24	7,457.5	37	5,411.7	-13	2,045.8
Other Gases	--	--	--	--	--	--
Nuclear	--	--	--	--	--	--
Hydroelectric Conventional	56	177.6	7	22.8	49	154.8
Wind	4	2,050.0	--	--	4	2,050.0
Solar Thermal and Photovoltaic	20	4,623.1	--	--	20	4,623.1
Wood and Wood-Derived Fuels	--	--	2	16.0	-2	-16.0
Geothermal	--	--	--	--	--	--
Other Biomass	2	19.0	--	--	2	19.0
Hydroelectric Pumped Storage	--	--	--	--	--	--
Other Energy Sources	11	1,337.5	1	1.0	10	1,336.5
Year 2024						
U.S. Total	18	5,187.6	39	6,664.4	-21	-1,476.8
Coal	--	--	9	3,318.0	-9	-3,318.0
Petroleum	--	--	4	32.4	-4	-32.4
Natural Gas	6	3,188.9	18	2,188.6	-12	1,000.3
Other Gases	--	--	--	--	--	--
Nuclear	--	--	1	1,122.0	-1	-1,122.0
Hydroelectric Conventional	--	--	7	3.4	-7	-3.4
Wind	7	895.5	--	--	7	895.5
Solar Thermal and Photovoltaic	3	1,100.0	--	--	3	1,100.0
Wood and Wood-Derived Fuels	--	--	--	--	--	--
Geothermal	--	--	--	--	--	--
Other Biomass	2	3.2	--	--	2	3.2
Hydroelectric Pumped Storage	--	--	--	--	--	--
Other Energy Sources	--	--	--	--	--	--
Years 2020-2024						
U.S. Total	1,612	124,717.3	367	52,206.0	1,245	72,511.3
Coal	1	17.0	98	28,480.6	-97	-28,463.6
Petroleum	9	10.4	53	3,850.6	-44	-3,840.2
Natural Gas	231	38,925.9	147	10,929.6	84	27,996.3
Other Gases	--	--	--	--	--	--
Nuclear	2	2,200.0	9	8,646.0	-7	-6,446.0
Hydroelectric Conventional	100	461.2	20	32.2	80	429.0
Wind	214	36,735.9	11	134.7	203	36,601.2
Solar Thermal and Photovoltaic	876	39,112.1	--	--	876	39,112.1
Wood and Wood-Derived Fuels	3	56.5	4	43.8	-1	12.7
Geothermal	2	42.0	--	--	2	42.0
Other Biomass	20	83.4	23	86.0	-3	-2.6
Hydroelectric Pumped Storage	--	--	--	--	--	--
Other Energy Sources	154	7,072.9	2	2.5	152	7,070.4

Notes: These data reflect plans as of December 31, 2019

Coal includes anthracite, bituminous, subbituminous, lignite, waste coal, coal synfuel, refined coal, and coal-derived synthesis gas.

Petroleum includes 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), waste oil, synthetic gas, and propane.

Other Gases also includes blast furnace gas.

Hydroelectric Conventional capacity includes conventional hydroelectric power excluding pumped storage facilities.

Wood and wood-derived fuels include 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.

Other Biomass include 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).

Hydroelectric Conventional capacity includes conventional hydroelectric power excluding pumped storage facilities.

Other Energy Sources include batteries, hydrogen, purchased steam, sulfur, tire-derived fuels and other miscellaneous energy sources.

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.

In the case of 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 generator count.

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

Table 4.6. Utility-Scale Capacity Additions, Retirements and Changes by Energy Source, 2019 (Count, Megawatts)

Energy Source	Generator Additions				Generator Retirements			
	Number of Generators	Generator Nameplate Capacity	Net Summer Capacity	Net Winter Capacity	Number of Generators	Generator Nameplate Capacity	Net Summer Capacity	Net Winter Capacity
Coal	--	--	--	--	59	14,352.1	12,895.1	12,914.9
Petroleum	24	49.1	46.6	42.7	53	423.6	353.0	361.5
Natural Gas	106	8,631.8	8,075.3	8,179.7	76	4,843.3	4,292.4	4,418.1
Other Gases	--	--	--	--	3	30.0	14.8	13.0
Nuclear	--	--	--	--	2	1,650.8	1,476.4	1,509.6
Hydroelectric Conventional	3	11.2	11.1	11.1	26	147.2	148.2	148.2
Wind	60	9,328.2	9,314.6	9,314.6	11	132.2	131.0	131.0
Solar Thermal and Photovoltaic	493	5,488.7	5,478.9	5,437.8	16	8.0	8.0	8.0
Wood and Wood-Derived Fuels	3	156.3	145.4	145.7	17	577.3	538.6	540.4
Geothermal	1	26.0	20.0	20.0	4	5.1	3.7	3.5
Other Biomass	19	16.9	16.7	16.7	54	202.7	172.6	175.4
Hydroelectric Pumped Storage	--	--	--	--	--	--	--	--
Other Energy Sources	39	210.0	193.1	200.4	3	42.3	29.7	24.0
Total	748	23,918.2	23,301.7	23,368.7	324	22,414.6	20,063.5	20,247.6

Energy Source	Other Changes to Existing Capacity			
		Generator Nameplate Capacity	Net Summer Capacity	Net Winter Capacity
Coal		-1,944.1	-1,687.5	-2,199.7
Petroleum		-4,535.3	-4,118.2	-4,865.8
Natural Gas		-61.4	1,213.0	345.9
Other Gases		-1.1	-29.9	-20.9
Nuclear		257.9	162.5	-38.7
Hydroelectric Conventional		-86.6	-59.7	-53.1
Wind		41.9	-129.1	-136.9
Solar Thermal and Photovoltaic		-79.1	-25.6	89.4
Wood and Wood-Derived Fuels		90.8	73.1	85.0
Geothermal		22.4	94.8	170.2
Other Biomass		-150.0	-148.7	-150.0
Hydroelectric Pumped Storage		--	-51.9	-91.0
Other Energy Sources		58.6	65.8	65.7
Total		-6,386.0	-4,641.4	-6,799.9

Notes: Coal includes anthracite, bituminous, subbituminous, lignite, and waste coal, coal synfuel, refined coal, and coal-derived synthesis gas. Petroleum includes 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), waste oil, synthetic gas, and propane. Other Gases also includes blast furnace gas and other manufactured and waste gases derived from fossil fuels. Hydroelectric Conventional capacity includes conventional hydroelectric power excluding pumped storage facilities. Wood and wood-derived fuels include 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. Other Biomass include 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). Other Energy Sources include batteries, hydrogen, purchased steam, sulfur, tire-derived fuels and other miscellaneous energy sources. 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. In the case of some 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 generator count. Other Changes to Existing Capacity reflect uprates, derates, repowerings, and changes to previously reported generator capacity. * = Value is less than half of the smallest unit of measure.

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

Table 4.7.A. Net Summer Capacity of Utility Scale Units by Technology and by State, 2019 and 2018 (Megawatts)

Census Division and State	Renewable Sources		Fossil Fuels		Hydroelectric Pumped Storage		Other Energy Storage		Nuclear		All Other Sources		All Sources	
	Year 2019	Year 2018	Year 2019	Year 2018	Year 2019	Year 2018	Year 2019	Year 2018	Year 2019	Year 2018	Year 2019	Year 2018	Year 2019	Year 2018
New England	6,027.9	5,862.1	24,227.5	23,024.1	1,797.4	1,797.4	63.1	28.7	3,323.5	4,003.5	48.0	48.0	35,487.4	34,763.8
Connecticut	457.7	412.6	7,866.2	7,290.6	29.4	29.4	1.6	1.6	2,073.1	2,073.1	26.0	26.0	10,454.0	9,833.3
Maine	2,222.0	2,346.5	2,495.3	2,478.8	0.0	0.0	16.2	16.2	0.0	0.0	22.0	22.0	4,755.5	4,863.5
Massachusetts	1,511.5	1,385.0	9,598.4	9,034.8	1,768.0	1,768.0	34.4	7.9	0.0	679.0	0.0	0.0	12,912.3	12,874.7
New Hampshire	956.9	928.1	2,289.9	2,289.9	0.0	0.0	0.0	0.0	1,250.4	1,251.4	0.0	0.0	4,497.2	4,469.4
Rhode Island	195.1	126.2	1,832.1	1,832.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	2,027.2	1,958.3
Vermont	684.7	663.7	145.6	97.9	0.0	0.0	10.9	3.0	0.0	0.0	0.0	0.0	841.2	764.6
Middle Atlantic	11,532.5	11,202.0	73,131.3	73,664.0	3,383.3	3,411.6	143.5	96.7	17,956.6	18,700.2	11.2	11.2	106,158.4	107,085.7
New Jersey	1,085.5	1,012.0	12,241.5	12,437.7	420.0	420.0	42.1	22.3	3,467.1	3,500.2	11.2	11.2	17,267.4	17,403.4
New York	7,487.2	7,335.6	26,731.2	26,951.1	1,411.3	1,408.6	53.0	26.0	5,396.3	5,403.0	0.0	0.0	41,079.0	41,124.3
Pennsylvania	2,959.8	2,854.4	34,158.6	34,275.2	1,552.0	1,583.0	48.4	48.4	9,093.2	9,797.0	0.0	0.0	47,812.0	48,558.0
East North Central	13,349.2	12,561.2	109,176.8	112,580.4	2,232.0	2,152.0	194.7	188.7	19,007.1	19,034.4	187.1	187.1	144,146.9	146,703.8
Illinois	5,397.1	4,782.3	27,059.7	29,055.3	0.0	0.0	132.7	132.7	11,582.4	11,582.4	78.0	78.0	44,249.9	45,630.7
Indiana	2,691.1	2,657.2	23,857.6	23,928.4	0.0	0.0	28.0	22.0	0.0	0.0	88.0	88.0	26,664.7	26,695.6
Michigan	3,065.1	2,830.6	20,069.2	20,614.2	2,232.0	2,152.0	1.0	1.0	4,089.6	4,122.2	0.0	0.0	29,456.9	29,720.0
Ohio	1,068.0	1,053.7	25,228.6	25,920.9	0.0	0.0	33.0	33.0	2,134.0	2,134.0	0.0	0.0	28,463.6	29,141.6
Wisconsin	1,127.9	1,237.4	12,961.7	13,061.6	0.0	0.0	0.0	0.0	1,201.1	1,195.8	21.1	21.1	15,311.8	15,515.9
West North Central	32,525.2	28,741.4	59,202.2	59,156.2	657.0	657.0	20.1	17.1	5,443.4	5,443.4	22.8	22.8	97,870.7	94,037.9
Iowa	9,964.4	8,433.3	9,842.6	9,806.4	0.0	0.0	1.1	1.1	601.4	601.4	0.0	0.0	20,409.5	18,842.2
Kansas	6,159.6	5,379.4	8,846.1	9,025.4	0.0	0.0	0.0	0.0	1,225.0	1,225.0	0.8	0.8	16,231.5	15,630.6
Minnesota	5,294.1	5,119.5	10,389.6	10,147.5	0.0	0.0	16.0	13.0	1,657.0	1,657.0	16.7	16.7	17,373.4	16,953.7
Missouri	1,579.0	1,579.0	17,625.1	17,650.0	657.0	657.0	2.2	2.2	1,190.0	1,190.0	0.0	0.0	21,053.3	21,078.2
Nebraska	2,499.5	2,011.8	6,196.3	6,202.0	0.0	0.0	0.0	0.0	770.0	770.0	0.0	0.0	9,465.8	8,983.8
North Dakota	4,048.3	3,741.6	4,601.4	4,633.6	0.0	0.0	0.0	0.0	0.0	0.0	5.3	5.3	8,655.0	8,380.5
South Dakota	2,980.3	2,476.8	1,701.1	1,691.3	0.0	0.0	0.8	0.8	0.0	0.0	0.0	0.0	4,682.2	4,168.9
South Atlantic	22,314.5	20,104.1	161,436.8	161,659.0	7,906.4	7,905.2	81.5	76.5	24,688.6	24,706.6	468.9	408.7	216,896.7	214,860.1
Delaware	50.9	47.5	3,321.5	3,330.4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	3,372.4	3,377.9
District of Columbia	18.9	23.0	20.6	9.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	39.5	32.0
Florida	3,370.4	2,681.9	53,183.7	50,688.1	0.0	0.0	19.0	14.0	3,626.0	3,626.0	312.9	348.7	60,512.0	57,358.7
Georgia	4,603.2	4,013.8	26,100.8	27,050.6	1,863.4	1,862.2	1.0	1.0	4,061.0	4,061.0	0.0	0.0	36,629.4	36,988.6
Maryland	1,237.4	1,191.4	11,650.7	11,847.1	0.0	0.0	7.0	7.0	1,707.8	1,725.8	6.0	6.0	14,608.9	14,777.3
North Carolina	7,253.8	6,767.0	22,315.8	22,120.5	86.0	86.0	1.0	1.0	5,149.6	5,149.6	54.0	54.0	34,860.2	34,178.1
South Carolina	2,522.6	2,201.5	12,143.1	12,164.3	2,716.0	2,716.0	4.0	4.0	6,576.2	6,576.2	0.0	0.0	23,961.9	23,662.0
Virginia	2,227.0	2,150.9	18,912.7	20,674.9	3,241.0	3,241.0	0.0	0.0	3,568.0	3,568.0	96.0	0.0	28,044.7	29,634.8
West Virginia	1,030.3	1,027.1	13,787.9	13,774.1	0.0	0.0	49.5	49.5	0.0	0.0	0.0	0.0	14,867.7	14,850.7
East South Central	8,909.5	8,814.5	62,718.2	64,592.7	1,616.3	1,616.3	1.0	1.0	11,449.1	11,294.1	1.4	1.4	84,695.5	86,320.0
Alabama	4,119.0	4,086.4	19,610.1	20,660.4	0.0	0.0	1.0	1.0	5,525.4	5,370.4	0.0	0.0	29,255.5	30,118.2
Kentucky	1,247.6	1,245.4	18,247.9	18,874.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	19,495.5	20,119.7
Mississippi	520.5	463.0	12,617.9	12,867.7	0.0	0.0	0.0	0.0	1,401.0	1,401.0	1.4	1.4	14,540.8	14,733.1
Tennessee	3,022.4	3,019.7	12,242.3	12,190.3	1,616.3	1,616.3	0.0	0.0	4,522.7	4,522.7	0.0	0.0	21,403.7	21,349.0
West South Central	42,975.7	38,640.3	138,761.3	139,035.5	286.0	286.0	131.7	99.8	8,910.7	8,910.7	548.6	512.5	191,614.0	187,484.8
Arkansas	1,642.7	1,697.1	11,281.0	11,219.7	28.0	28.0	12.0	0.0	1,817.8	1,817.8	0.0	0.0	14,781.5	14,762.6
Louisiana	615.2	683.2	21,262.2	20,056.9	0.0	0.0	0.5	0.5	2,132.9	2,132.9	329.6	288.5	24,340.4	23,162.0
Oklahoma	9,139.0	9,041.0	17,978.6	18,102.0	258.0	258.0	0.0	0.0	0.0	0.0	0.0	0.0	27,375.6	27,401.0
Texas	31,578.8	27,219.0	88,239.5	89,656.9	0.0	0.0	119.2	99.3	4,960.0	4,960.0	219.0	224.0	125,116.5	122,159.2
Mountain	28,373.6	27,308.9	60,068.1	62,239.7	778.8	778.8	54.3	40.6	3,937.0	3,937.0	123.7	123.0	93,335.5	94,428.0
Arizona	5,179.8	5,091.1	17,417.2	19,395.3	216.3	216.3	42.0	32.0	3,937.0	3,937.0	0.0	0.0	26,792.3	28,671.7
Colorado	5,077.3	4,950.1	10,932.9	11,063.0	562.5	562.5	10.5	5.0	0.0	0.0	9.1	9.1	16,592.3	16,589.7
Idaho	4,075.3	4,068.5	1,121.8	1,127.1	0.0	0.0	0.0	0.0	0.0	0.0	14.8	14.8	5,211.9	5,210.4
Montana	3,594.0	3,571.2	2,739.1	2,744.9	0.0	0.0	0.0	0.0	0.0	0.0	40.0	40.0	6,373.1	6,356.1
Nevada	4,109.7	3,665.4	7,821.6	7,821.6	0.0	0.0	0.0	0.0	0.0	0.0	6.5	6.5	11,937.8	11,493.5
New Mexico	2,804.5	2,473.7	5,962.9	5,953.3	0.0	0.0	1.8	3.6	0.0	0.0	0.7	0.0	8,769.9	8,430.6
Utah	1,648.0	1,602.5	7,303.3	7,360.2	0.0	0.0	0.0	0.0	0.0	0.0	40.2	40.2	8,991.5	9,002.9
Wyoming	1,885.0	1,886.4	6,769.3	6,774.3	0.0	0.0	0.0	0.0	0.0	0.0	12.4	12.4	8,666.7	8,673.1
Pacific Contiguous	69,232.0	67,907.2	46,057.2	47,614.6	4,121.1	4,225.9	263.7	242.8	3,403.0	3,403.0	106.3	106.3	123,183.3	123,499.8
California	32,062.2	30,889.7	37,000.4	38,546.7	3,807.1	3,911.9	252.5	231.6	2,240.0	2,240.0	106.3	106.3	75,468.5	75,926.2
Oregon	12,467.2	12,259.2	4,315.2	4,326.1	0.0	0.0	5.0	5.0	0.0	0.0	0.0	0.0	16,787.4	16,590.3
Washington	24,702.6	24,758.3	4,741.6	4,741.8	314.0	314.0	6.2	6.2	1,163.0	1,163.0	0.0	0.0	30,927.4	30,983.3
Pacific Noncontiguous	1,241.2	1,203.7	4,345.9	4,218.4	0.0	0.0	108.2	107.2	0.0	0.0	26.6	26.6	5,721.9	5,555.9
Alaska	538.6	538.2	2,174.6	2,160.1	0.0	0.0	47.2	46.2	0.0	0.0	0.0	0.0	2,760.4	2,744.5
Hawaii	702.6	665.5	2,171.3	2,058.3	0.0	0.0	61.0	61.0	0.0	0.0	26.6	26.6	2,961.5	2,811.4
U.S. Total	236,481.3	222,345.4	739,125.3	747,784.6	22,778.3	22,830.2	1,061.8	899.1	98,119.0	99,432.9	1,544.6	1,447.6	1,099,110.3	1,094,739.8

NM = Not meaningful due to large relative standard error.
Values are final.

NOTES:
Capacity from facilities with a total generator nameplate capacity less than 1 MW are excluded from this report. This exclusion may represent a significant portion of capacity for some technologies such as solar photovoltaic generation.
Concentrated Solar Power Energy Storage is included in 'Renewable sources'; it is not included in 'Other Energy Storage'

Sources: U.S. Energy Information Administration, Form EIA-860, 'Annual Electric Generator Report' and Form EIA-860M, 'Monthly Update to the Annual Electric Generator Report.'

Table 4.7.B. Net Summer Capacity Using Primarily Renewable Energy Sources and by State, 2019 and 2018 (Megawatts)

	Summer Capacity at Utility Scale Facilities														Small Scale Capacity		Capacity From Utility and Small Scale Facilities			
Census Division and State	Wind		Solar Photovoltaic		Solar Thermal		Conventional Hydroelectric		Biomass Sources		Geothermal		Total Renewable Sources		Estimated Solar Photovoltaic		Estimated Total Solar Photovoltaic		Estimated Total Solar	
	Year 2019	Year 2018	Year 2019	Year 2018	Year 2019	Year 2018	Year 2019	Year 2018	Year 2019	Year 2018	Year 2019	Year 2018	Year 2019	Year 2018	Year 2019	Year 2018	Year 2019	Year 2018	Year 2019	Year 2018
New England	1,463.2	1,403.8	1,198.6	961.1	0.0	0.0	1,957.6	1,959.5	1,408.5	1,537.7	0.0	0.0	6,027.9	5,862.1	2,563.6	2,309.0	3,762.2	3,270.1	3,762.2	3,270.1
Connecticut	1.0	1.0	137.4	86.8	0.0	0.0	119.4	122.2	199.9	202.6	0.0	0.0	457.7	412.6	511.7	416.8	649.1	503.6	649.1	503.6
Maine	921.6	921.6	5.6	5.6	0.0	0.0	734.0	732.4	560.8	686.9	0.0	0.0	2,222.0	2,346.5	60.0	43.6	65.6	49.2	65.6	49.2
Massachusetts	105.7	96.1	854.6	736.6	0.0	0.0	266.3	267.0	284.9	285.3	0.0	0.0	1,511.5	1,385.0	1,587.9	1,568.6	2,442.5	2,305.2	2,442.5	2,305.2
New Hampshire	211.9	183.1	0.0	0.0	0.0	0.0	504.0	504.0	241.0	241.0	0.0	0.0	956.9	928.1	102.3	83.7	102.3	83.7	102.3	83.7
Rhode Island	72.8	51.8	79.5	31.6	0.0	0.0	2.7	2.7	40.1	40.1	0.0	0.0	195.1	126.2	182.3	93.5	261.8	125.1	261.8	125.1
Vermont	150.2	150.2	121.5	100.5	0.0	0.0	331.2	331.2	81.8	81.8	0.0	0.0	684.7	663.7	119.4	102.8	240.9	203.3	240.9	203.3
Middle Atlantic	3,453.3	3,363.3	1,420.1	1,087.1	0.0	0.0	5,471.6	5,473.2	1,187.5	1,278.4	0.0	0.0	11,532.5	11,202.0	3,567.3	2,997.6	4,987.4	4,084.7	4,987.4	4,084.7
New Jersey	7.6	7.6	856.7	764.8	0.0	0.0	12.3	12.3	208.9	227.3	0.0	0.0	1,085.5	1,012.0	1,668.2	1,448.5	2,524.9	2,213.3	2,524.9	2,213.3
New York	1,985.7	1,985.7	482.5	264.5	0.0	0.0	4,559.7	4,561.3	459.3	524.1	0.0	0.0	7,487.2	7,335.6	1,515.3	1,227.1	1,997.8	1,491.6	1,997.8	1,491.6
Pennsylvania	1,460.0	1,370.0	80.9	57.8	0.0	0.0	899.6	899.6	519.3	527.0	0.0	0.0	2,959.8	2,854.4	383.9	322.0	464.8	379.8	464.8	379.8
East North Central	10,764.6	9,985.9	539.5	462.5	0.0	0.0	884.6	859.9	1,160.5	1,252.9	0.0	0.0	13,349.2	12,561.2	644.9	392.0	1,184.4	854.5	1,184.4	854.5
Illinois	5,231.0	4,618.8	43.8	40.6	0.0	0.0	34.1	34.1	88.2	88.8	0.0	0.0	5,397.1	4,782.3	205.9	78.7	249.7	119.3	249.7	119.3
Indiana	2,309.8	2,309.8	244.3	216.2	0.0	0.0	66.2	60.4	70.8	70.8	0.0	0.0	2,691.1	2,657.2	96.2	73.9	340.5	290.1	340.5	290.1
Michigan	2,185.7	1,900.5	102.0	98.2	0.0	0.0	273.4	269.9	504.0	562.0	0.0	0.0	3,065.1	2,830.6	96.2	62.7	198.2	160.9	198.2	160.9
Ohio	718.4	718.4	109.0	83.6	0.0	0.0	101.9	101.9	138.7	149.8	0.0	0.0	1,068.0	1,053.7	161.6	119.5	270.6	203.1	270.6	203.1
Wisconsin	319.7	438.4	40.4	23.9	0.0	0.0	409.0	393.6	358.8	381.5	0.0	0.0	1,127.9	1,237.4	85.0	57.2	125.4	81.1	125.4	81.1
West North Central	27,804.1	24,120.4	1,004.6	828.1	0.0	0.0	3,295.5	3,293.7	421.0	499.2	0.0	0.0	32,525.2	28,741.4	439.7	331.1	1,444.3	1,159.2	1,444.3	1,159.2
Iowa	9,784.0	8,256.6	13.4	8.9	0.0	0.0	146.4	146.4	20.6	21.4	0.0	0.0	9,964.4	8,433.3	117.6	92.7	131.0	101.6	131.0	101.6
Kansas	6,133.4	5,359.2	10.2	4.2	0.0	0.0	7.0	7.0	9.0	9.0	0.0	0.0	6,159.6	5,379.4	25.3	18.6	35.5	22.8	35.5	22.8
Minnesota	3,847.2	3,750.5	894.6	733.9	0.0	0.0	205.9	205.9	346.4	429.2	0.0	0.0	5,294.1	5,119.5	82.2	60.9	976.8	794.8	976.8	794.8
Missouri	954.3	954.3	62.1	62.1	0.0	0.0	548.5	548.5	14.1	14.1	0.0	0.0	1,579.0	1,579.0	203.3	150.4	265.4	212.5	265.4	212.5
Nebraska	2,180.8	1,700.2	23.3	18.0	0.0	0.0	279.7	277.9	15.7	15.7	0.0	0.0	2,499.5	2,011.8	9.9	7.5	33.2	25.5	33.2	25.5
North Dakota	3,528.5	3,221.8	0.0	0.0	0.0	0.0	510.0	510.0	9.8	9.8	0.0	0.0	4,048.3	3,741.6	0.5	0.4	0.5	0.4	0.5	0.4
South Dakota	1,375.9	877.8	1.0	1.0	0.0	0.0	1,598.0	1,598.0	5.4	0.0	0.0	0.0	2,980.3	2,476.8	0.8	0.6	1.8	1.6	1.8	1.6
South Atlantic	1,086.3	1,086.3	9,705.4	7,463.1	0.0	0.0	7,187.2	7,224.4	4,335.6	4,330.3	0.0	0.0	22,314.5	20,104.1	2,130.0	1,691.3	11,835.3	9,154.4	11,835.3	9,154.4
Delaware	2.0	2.0	36.7	33.3	0.0	0.0	0.0	0.0	12.2	12.2	0.0	0.0	50.9	47.5	86.2	78.9	122.9	112.2	122.9	112.2
District of Columbia	0.0	0.0	6.9	0.0	0.0	0.0	0.0	0.0	12.0	23.0	0.0	0.0	18.9	23.0	66.5	50.9	73.4	50.9	73.4	50.9
Florida	0.0	0.0	2,142.8	1,399.5	0.0	0.0	43.5	54.5	1,184.1	1,227.9	0.0	0.0	3,370.4	2,681.9	492.0	281.7	2,634.8	1,681.2	2,634.8	1,681.2
Georgia	0.0	0.0	1,512.4	1,017.2	0.0	0.0	2,031.0	2,047.2	1,059.8	949.4	0.0	0.0	4,603.2	4,013.8	NM	166.7	NM	1,183.9	NM	1,183.9
Maryland	190.0	190.0	316.5	271.4	0.0	0.0	590.0	590.0	140.9	140.0	0.0	0.0	1,237.4	1,191.4	779.7	709.8	1,096.2	981.2	1,096.2	981.2
North Carolina	208.0	208.0	4,477.8	3,998.1	0.0	0.0	2,004.0	2,002.0	564.0	558.9	0.0	0.0	7,253.8	6,767.0	182.4	140.9	4,660.2	4,139.0	4,660.2	4,139.0
South Carolina	0.0	0.0	656.2	351.1	0.0	0.0	1,311.9	1,323.9	554.5	526.5	0.0	0.0	2,522.6	2,201.5	231.4	194.9	887.6	546.0	887.6	546.0
Virginia	0.0	0.0	556.1	392.5	0.0	0.0	866.0	866.0	804.9	892.4	0.0	0.0	2,227.0	2,150.9	100.6	60.7	656.7	453.2	656.7	453.2
West Virginia	686.3	686.3	0.0	0.0	0.0	0.0	340.8	340.8	3.2	0.0	0.0	0.0	1,030.3	1,027.1	9.3	6.8	9.3	6.8	9.3	6.8
East South Central	29.1	29.1	618.8	558.8	0.0	0.0	7,055.3	7,055.5	1,206.3	1,171.1	0.0	0.0	8,909.5	8,814.5	107.1	94.0	725.9	652.8	725.9	652.8
Alabama	0.0	0.0	194.1	194.1	0.0	0.0	3,291.8	3,292.0	633.1	600.3	0.0	0.0	4,119.0	4,086.4	NM	NM	NM	NM	NM	NM
Kentucky	0.0	0.0	26.1	26.3	0.0	0.0	1,146.9	1,146.9	74.6	72.2	0.0	0.0	1,247.6	1,245.4	30.4	23.2	56.5	49.5	56.5	49.5
Mississippi	0.0	0.0	218.1	160.6	0.0	0.0	0.0	0.0	302.4	302.4	0.0	0.0	520.5	463.0	9.2	6.9	227.3	167.5	227.3	167.5
Tennessee	29.1	29.1	180.5	177.8	0.0	0.0	2,616.6	2,616.6	196.2	196.2	0.0	0.0	3,022.4	3,019.7	58.8	56.7	239.3	234.5	239.3	234.5
West South Central	36,228.2	32,257.9	2,591.7	2,080.4	0.0	0.0	2,991.4	2,991.4	1,164.4	1,310.6	0.0	0.0	42,975.7	38,640.3	855.8	636.9	3,447.5	2,717.3	3,447.5	2,717.3
Arkansas	0.0	0.0	112.2	100.0	0.0	0.0	1,265.8	1,265.8	264.7	331.3	0.0	0.0	1,642.7	1,697.1	25.3	15.3	137.5	115.3	137.5	115.3
Louisiana	0.0	0.0	1.1	1.1	0.0	0.0	192.0	192.0	422.1	490.1	0.0	0.0	615.2	683.2	147.4	139.7	148.5	140.8	148.5	140.8
Oklahoma	8,168.7	8,070.7	30.5	30.5	0.0	0.0	863.6	863.6	76.2	76.2	0.0	0.0	9,139.0	9,041.0	12.6	7.3	43.1	37.8	43.1	37.8
Texas	28,059.5	24,187.2	2,447.9	1,948.8	0.0	0.0	670.0	670.0	401.4	413.0	0.0	0.0	31,578.8	27,219.0	670.5	474.7	3,118.4	2,423.5	3,118.4	2,423.5
Mountain	9,846.9	9,565.8	6,563.9	5,799.3	474.1	473.9	10,652.9	10,650.0	179.1	174.3	656.7	645.6	28,373.6	27,308.9	2,743.4	2,327.7	9,307.3	8,127.0	9,781.4	8,600.9
Arizona	267.3	267.3	1,865																	

Table 4.7.C. Net Summer Capacity of Utility Scale Units Using Primarily Fossil Fuels and by State, 2019 and 2018 (Megawatts)

Census Division and State	Natural Gas Fired Combined Cycle		Natural Gas Fired Combustion Turbine		Other Natural Gas		Coal		Petroleum Coke		Petroleum Liquids		Other Gases		Total Fossil Fuels	
	Year 2019	Year 2018	Year 2019	Year 2018	Year 2019	Year 2018	Year 2019	Year 2018	Year 2019	Year 2018	Year 2019	Year 2018	Year 2019	Year 2018	Year 2019	Year 2018
New England	14,271.6	13,675.0	1,776.0	1,056.6	1,525.7	1,112.6	917.3	917.3	0.0	0.0	5,736.9	6,262.6	0.0	0.0	24,227.5	23,024.1
Connecticut	3,984.2	3,442.7	580.4	563.0	883.3	875.0	383.4	383.4	0.0	0.0	2,034.9	2,026.5	0.0	0.0	7,866.2	7,290.6
Maine	1,281.6	1,284.3	322.3	144.3	12.5	12.5	0.0	0.0	0.0	0.0	878.9	1,037.7	0.0	0.0	2,495.3	2,478.8
Massachusetts	5,960.6	5,902.8	857.1	333.1	204.3	199.7	0.0	0.0	0.0	0.0	2,576.4	2,599.2	0.0	0.0	9,598.4	9,034.8
New Hampshire	1,258.0	1,258.0	3.8	3.8	400.2	0.0	533.9	533.9	0.0	0.0	94.0	494.2	0.0	0.0	2,289.9	2,289.9
Rhode Island	1,787.2	1,787.2	12.4	12.4	25.4	25.4	0.0	0.0	0.0	0.0	7.1	7.1	0.0	0.0	1,832.1	1,832.1
Vermont	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	145.6	97.9	0.0	0.0	145.6	97.9
Middle Atlantic	34,419.5	31,831.4	7,894.3	7,909.1	14,142.8	14,505.4	11,183.7	13,776.7	11.6	11.6	5,363.5	5,499.1	115.9	130.7	73,131.3	73,664.0
New Jersey	8,579.0	8,529.9	2,844.3	2,826.3	68.5	46.9	463.0	609.0	11.6	11.6	246.1	385.0	29.0	29.0	12,241.5	12,437.7
New York	8,927.9	8,922.6	3,177.6	3,173.0	9,739.1	9,665.2	1,336.5	1,631.5	0.0	0.0	3,550.1	3,558.8	0.0	0.0	26,731.2	26,951.1
Pennsylvania	16,912.6	14,378.9	1,872.4	1,909.8	4,335.2	4,793.3	9,384.2	11,536.2	0.0	0.0	1,567.3	1,555.3	86.9	101.7	34,158.6	34,275.2
East North Central	21,711.8	21,661.3	26,681.0	26,654.4	5,615.4	5,563.6	51,488.3	54,908.0	247.6	247.6	2,347.8	2,452.6	1,084.9	1,092.9	109,176.8	112,580.4
Illinois	3,577.7	3,580.2	10,530.4	10,504.8	1,626.7	1,633.6	10,615.5	12,826.0	0.0	0.0	672.9	674.2	36.5	36.5	27,059.7	29,055.3
Indiana	3,866.0	3,836.0	3,287.3	3,353.4	741.0	730.0	15,245.7	15,291.4	0.0	0.0	98.3	98.3	619.3	619.3	23,857.6	23,928.4
Michigan	4,451.9	4,413.6	3,852.9	3,874.0	2,412.1	2,375.5	8,590.3	9,190.4	47.2	47.2	464.8	463.5	250.0	250.0	20,069.2	20,614.2
Ohio	7,037.8	7,020.4	5,636.7	5,559.2	205.5	185.1	11,496.0	12,246.0	142.0	142.0	531.5	581.1	179.1	187.1	25,228.6	25,920.9
Wisconsin	2,778.4	2,811.1	3,373.7	3,363.0	630.1	639.4	5,540.8	5,554.2	58.4	58.4	580.3	635.5	0.0	0.0	12,961.7	13,061.6
West North Central	7,019.1	6,640.9	11,587.5	11,737.3	3,748.6	3,807.2	32,957.1	33,054.1	32.0	39.5	3,849.5	3,868.8	8.4	8.4	59,202.2	59,156.2
Iowa	1,829.0	1,779.8	1,226.8	1,260.4	591.3	540.5	5,343.8	5,371.7	32.0	39.5	819.7	814.5	0.0	0.0	9,842.6	9,806.4
Kansas	266.0	266.0	2,158.1	2,156.8	1,185.6	1,367.9	4,678.5	4,670.2	0.0	0.0	557.9	564.5	0.0	0.0	8,846.1	9,025.4
Minnesota	2,496.0	2,172.0	2,544.8	2,667.9	401.2	381.6	4,180.5	4,157.9	0.0	0.0	767.1	768.1	0.0	0.0	10,389.6	10,147.5
Missouri	1,794.9	1,794.9	3,390.7	3,400.6	869.5	871.1	10,464.5	10,470.9	0.0	0.0	1,105.5	1,112.5	0.0	0.0	17,625.1	17,650.0
Nebraska	338.2	338.2	1,148.4	1,149.0	521.7	525.8	3,867.0	3,867.0	0.0	0.0	321.0	322.0	0.0	0.0	6,196.3	6,202.0
North Dakota	0.0	0.0	414.0	408.0	167.0	111.6	3,948.8	4,042.4	0.0	0.0	63.2	63.2	8.4	8.4	4,601.4	4,633.6
South Dakota	295.0	290.0	704.7	694.6	12.3	8.7	474.0	474.0	0.0	0.0	215.1	224.0	0.0	0.0	1,701.1	1,691.3
South Atlantic	61,366.0	59,181.2	32,167.0	31,914.2	7,250.4	7,334.2	51,483.1	53,994.3	142.8	142.8	8,892.5	8,957.3	135.0	135.0	161,436.8	161,659.0
Delaware	1,604.0	1,511.0	272.0	317.2	842.0	843.1	410.0	410.0	0.0	0.0	158.5	114.1	135.0	135.0	3,321.5	3,330.4
District of Columbia	0.0	0.0	20.6	9.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	20.6	9.0
Florida	31,717.2	29,345.7	7,825.7	7,759.2	2,503.2	2,419.2	7,782.0	7,804.0	59.0	59.0	3,296.6	3,301.0	0.0	0.0	53,183.7	50,688.1
Georgia	8,009.5	7,989.0	7,803.2	7,791.0	842.9	842.9	8,416.0	9,398.5	83.8	83.8	945.4	945.4	0.0	0.0	26,100.8	27,050.6
Maryland	2,709.1	2,849.1	2,084.2	1,899.9	1,416.1	1,494.2	4,270.0	4,327.0	0.0	0.0	1,171.3	1,276.9	0.0	0.0	11,650.7	11,847.1
North Carolina	5,373.2	5,068.0	6,050.4	6,045.1	1.0	0.0	10,389.2	10,504.8	0.0	0.0	502.0	502.6	0.0	0.0	22,315.8	22,120.5
South Carolina	3,185.0	3,185.0	2,772.2	2,757.9	950.0	546.0	4,769.0	5,212.0	0.0	0.0	466.9	463.4	0.0	0.0	12,143.1	12,164.3
Virginia	8,868.0	9,233.4	4,245.3	4,245.3	579.7	1,073.3	2,878.9	3,780.0	0.0	0.0	2,340.8	2,342.9	0.0	0.0	18,912.7	20,674.9
West Virginia	0.0	0.0	1,093.4	1,089.6	115.5	115.5	12,568.0	12,558.0	0.0	0.0	11.0	11.0	0.0	0.0	13,787.9	13,774.1
East South Central	21,772.2	21,746.2	12,678.3	12,626.1	4,285.8	4,592.8	23,855.4	25,490.8	0.0	0.0	106.7	117.0	19.8	19.8	62,718.2	64,592.7
Alabama	9,729.8	9,699.0	2,575.8	2,532.2	1,957.8	2,028.1	5,284.3	6,338.7	0.0	0.0	42.6	42.6	19.8	19.8	19,610.1	20,660.4
Kentucky	1,763.0	1,763.0	4,931.2	4,976.6	260.0	260.0	11,281.8	11,862.8	0.0	0.0	11.9	11.9	0.0	0.0	18,247.9	18,874.3
Mississippi	7,824.3	7,829.1	1,338.8	1,336.8	2,001.8	2,238.5	1,444.0	1,444.0	0.0	0.0	9.0	19.3	0.0	0.0	12,617.9	12,867.7
Tennessee	2,455.1	2,455.1	3,832.5	3,780.5	66.2	66.2	5,845.3	5,845.3	0.0	0.0	43.2	43.2	0.0	0.0	12,242.3	12,190.3
West South Central	61,694.7	60,239.5	14,548.7	14,419.5	30,540.5	30,856.3	30,119.1	31,564.1	878.9	954.7	169.1	175.6	810.3	825.8	138,761.3	139,035.5
Arkansas	4,609.8	4,603.4	702.8	702.8	796.0	796.0	5,163.4	5,105.3	0.0	0.0	9.0	12.2	0.0	0.0	11,281.0	11,219.7
Louisiana	8,654.2	7,474.6	2,415.1	2,349.6	6,090.1	6,057.6	2,837.1	2,833.7	815.1	890.9	43.2	43.1	407.4	407.4	21,262.2	20,056.9
Oklahoma	7,321.2	7,263.6	1,630.9	1,686.9	5,706.1	4,773.6	3,246.0	4,303.5	0.0	0.0	74.4	74.4	0.0	0.0	17,978.6	18,102.0
Texas	41,109.5	40,897.9	9,799.9	9,680.2	17,948.3	19,229.1	18,872.6	19,321.6	63.8	63.8	42.5	45.9	402.9	418.4	88,239.5	89,656.9
Mountain	22,545.0	22,510.8	9,137.3	8,625.6	3,540.9	3,832.4	24,339.5	26,765.5	52.0	52.0	349.9	349.9	103.5	103.5	60,068.1	62,239.7
Arizona	9,908.6	9,879.6	2,899.0	2,367.6	1,190.1	1,478.6	3,329.0	5,579.0	0.0	0.0	90.5	90.5	0.0	0.0	17,417.2	19,395.3
Colorado	3,249.5	3,249.5	2,538.0	2,568.1	639.0	639.0	4,340.0	4,440.0	0.0	0.0	166.4	166.4	0.0	0.0	10,932.9	11,063.0
Idaho	547.7	547.7	552.0	552.0	8.2	13.5	8.5	8.5	0.0	0.0	5.4	5.4	0.0	0.0	1,121.8	1,127.1
Montana	0.0	0.0	315.8	321.6	72.2	72.2	2,297.6	2,297.6	52.0	52.0	0.0	0.0	1.5	1.5	2,739.1	2,744.9
Nevada	5,445.0	5,445.0	1,185.6	1,185.6	444.6	444.6	740.4	740.4	0.0	0.0	6.0	6.0	0.0	0.0	7,821.6	7,821.6
New Mexico	1,470.2	1,465.0	957.0	956.9	847.7	843.4	2,640.0	2,640.0	0.0	0.0	48.0	48.0	0.0	0.0	5,962.9	5,953.3
Utah	1,830.0	1,830.0	536.3	520.2	328.2	328.2	4,581.0	4,654.0	0.0	0.0	27.8	27.8	0.0	0.0	7,303.3	7,360.2
Wyoming	94.0	94.0	153.6	153.6	10.9	12.9	6,403.0	6,406.0	0.0	0.0	5.8	5.8	102.0	102.0	6,769.3	6,774.3
Pacific Contiguous	25,908.9	25,897.1	12,009.9	12,066.7	5,445.2	6,959.0	1,982.0	1,982.0	20.0	17.0	469.8	471.4	221.4	221.4	46,057.2	47,614.6
California	19,901.3	19,878.6	11,156.9	11,213.5	5,189.2	6,703.0	57.0	57.0	20.0	17.0	454.6	456.2	221.4	221.4	37,000.4	38,546.7
Oregon	3,372.0	3,382.9	133.8	133.8	224.4	224.4	585.0	585.0	0.0	0.0	0.0	0.0	0.0	0.0	4,315.2	4,326.1
Washington	2,635.6	2,635.6	719.2	719.4	31.6	31.6	1,340.0	1,340.0	0.0	0.0	15.2	15.2	0.0	0.0	4,741.6	4,741.8
Pacific Noncontiguous	477.2	479.2	631.1	626.3	175.0	175.0	331.9	332.8	0.0	0.0	2,730.7	2,598.7	0.0	6.4	4,345.9	4,218.4
Alaska	477.2	479.2	631.1	626.3	175.0	175.0	151.9	152.8	0.0	0.0	739.4	726.8	0.0	0.0	2,174.6	2,160.1
Hawaii	0.0	0.0	0.0	0.0	0.0	0.0	180.0	180.0	0.0	0.0	1,991.3	1,871.9	0.0	6.4	2,171.3	2,058.3
U.S. Total	271,186.0	263,862.6	129,111.1	127,635.8	76,270.3	78,738.5	228,657.4	242,785.6	1,384.9	1,465.2	30,016.4	30,753.0	2,499.2	2,543.9	739,125.3	747,784.6

NM = Not meaningful due to large relative standard error.
Values are final.

NOTES:
Capacity from facilities with a total generator nameplate capacity less than 1 MW are excluded from this report. This exclusion may represent a significant portion of existing or planned capacity for some technologies such as solar photovoltaic generation.

Sources: U.S. Energy Information Administration, Form EIA-860, 'Annual Electric Generator Report' and Form EIA-860M, 'Monthly Update to the Annual Electric Generator Report.'

Table 4.08.A. Capacity Factors for Utility Scale Generators Primarily Using Fossil Fuels

Year/Month	Coal		Natural Gas								Petroleum					
			Combined Cycle		Gas Turbine		Steam Turbine		Internal Combustion		Steam Turbine		Gas Turbine		Internal Combustion	
	Time Adjusted Capacity	Capacity Factor	Time Adjusted Capacity	Capacity Factor	Time Adjusted Capacity	Capacity Factor	Time Adjusted Capacity	Capacity Factor	Time Adjusted Capacity	Capacity Factor	Time Adjusted Capacity	Capacity Factor	Time Adjusted Capacity	Capacity Factor	Time Adjusted Capacity	Capacity Factor
Annual Data																
2009	312,091.2	64.2%	200,546.1	43.9%	117,120.3	6.8%	80,357.5	10.9%	2,360.1	6.6%	32,621.3	15.0%	19,812.2	1.7%	5,002.0	2.4%
2010	313,393.9	67.1%	202,404.4	44.3%	116,426.0	7.8%	80,233.7	11.1%	2,543.0	6.5%	29,871.2	13.6%	19,565.5	2.0%	5,016.0	2.1%
2011	314,056.1	62.8%	210,518.7	44.3%	119,144.1	7.9%	78,898.6	11.7%	2,822.5	8.4%	26,683.0	12.6%	18,397.7	1.3%	4,986.0	2.2%
2012	304,974.9	56.2%	217,938.2	52.2%	119,319.4	8.9%	74,200.2	13.3%	2,988.8	7.3%	22,483.7	13.7%	17,773.5	1.3%	4,942.5	2.0%
2013	302,604.4	59.4%	219,902.9	48.8%	123,025.6	8.3%	75,810.5	11.2%	2,996.2	8.8%	20,022.9	12.6%	17,224.1	0.9%	4,999.4	2.1%
2014	299,064.7	60.5%	224,183.2	48.6%	124,736.9	8.3%	75,049.1	10.3%	3,026.7	10.8%	18,057.0	13.0%	16,791.5	1.2%	5,011.3	2.1%
2015	286,082.7	54.3%	231,467.5	55.8%	123,444.3	9.8%	80,348.0	11.3%	3,507.8	11.9%	14,965.4	14.0%	16,122.8	1.3%	5,075.2	2.1%
2016	269,477.1	52.8%	236,442.8	55.4%	125,148.4	11.0%	81,225.1	12.3%	3,684.3	11.5%	13,993.7	12.2%	15,114.0	1.3%	5,082.8	2.3%
2017	259,930.2	53.1%	242,839.1	51.2%	125,806.6	9.6%	79,149.4	10.7%	4,225.5	11.6%	13,290.9	13.7%	14,275.3	1.0%	5,153.3	2.1%
2018	246,866.8	53.6%	254,403.3	55.0%	126,763.4	11.9%	76,177.8	12.6%	4,446.6	13.0%	13,300.1	14.2%	14,234.9	1.3%	5,289.7	1.9%
2019	235,089.3	47.5%	266,846.5	57.3%	128,832.5	11.3%	72,797.3	14.1%	4,848.3	15.3%	11,214.7	12.8%	14,009.7	1.0%	5,287.8	2.0%
Year 2017																
January	262,832.9	59.2%	238,604.9	47.1%	125,758.5	8.2%	79,997.2	5.0%	3,984.2	10.8%	13,545.9	11.5%	14,360.0	0.9%	5,165.1	2.3%
February	262,623.9	49.4%	238,711.5	44.7%	125,637.1	8.3%	79,997.2	4.6%	4,151.9	9.5%	13,545.9	10.9%	14,360.0	0.9%	5,162.5	1.9%
March	262,179.7	45.8%	239,783.7	44.8%	125,636.3	9.4%	79,980.6	7.6%	4,198.4	9.5%	13,545.9	13.7%	14,336.4	1.1%	5,153.8	2.2%
April	260,949.7	43.3%	239,783.7	42.6%	125,704.3	8.4%	79,618.6	9.0%	4,218.8	9.6%	13,545.9	10.5%	14,336.4	0.8%	5,159.8	1.8%
May	260,949.7	47.9%	242,325.8	45.6%	125,668.3	8.9%	79,584.1	9.4%	4,239.0	9.8%	13,545.9	16.0%	14,336.4	1.0%	5,158.8	1.9%
June	259,190.0	57.8%	242,355.4	55.5%	125,748.3	10.4%	78,791.5	14.1%	4,240.1	12.0%	13,110.9	16.4%	14,286.4	1.0%	5,149.4	2.0%
July	259,190.0	66.3%	244,634.3	66.3%	125,748.3	12.2%	78,791.5	20.4%	4,240.6	15.3%	13,110.9	17.0%	14,238.4	1.1%	5,149.0	2.0%
August	259,190.0	62.2%	245,481.9	64.9%	125,797.8	11.3%	78,697.5	16.0%	4,246.9	14.5%	13,110.9	15.5%	14,238.4	1.1%	5,137.2	2.2%
September	259,006.0	53.2%	245,481.9	53.2%	125,887.8	10.5%	78,645.7	13.2%	4,297.0	12.7%	13,110.9	14.6%	14,238.4	1.3%	5,144.8	2.3%
October	258,429.0	47.2%	245,521.9	48.1%	125,894.8	9.5%	78,643.7	12.5%	4,297.0	12.0%	13,110.9	12.0%	14,238.4	1.1%	5,148.9	2.1%
November	258,278.0	49.0%	245,521.9	45.8%	126,098.8	8.6%	78,551.6	7.6%	4,297.0	11.5%	13,110.9	12.8%	14,191.8	0.9%	5,144.3	1.9%
December	256,530.0	55.8%	245,520.9	52.3%	126,089.8	9.4%	78,543.2	9.0%	4,293.0	12.0%	13,110.9	13.5%	14,149.8	1.4%	5,165.9	2.2%
Year 2018																
January	251,730.8	64.0%	247,709.0	51.4%	126,362.3	11.7%	78,615.1	10.9%	4,280.9	11.8%	13,440.4	19.9%	14,336.6	3.5%	5,330.8	2.5%
February	250,522.8	49.1%	247,709.0	51.6%	126,189.1	9.3%	78,185.1	5.8%	4,292.9	12.0%	13,440.4	12.1%	14,336.6	0.8%	5,333.5	1.8%
March	249,781.8	43.8%	247,709.0	49.1%	126,170.5	10.3%	77,411.2	7.5%	4,288.5	11.9%	13,440.4	10.9%	14,336.6	0.9%	5,326.9	1.8%
April	248,603.8	41.5%	248,199.0	45.6%	126,338.5	10.5%	77,369.9	8.5%	4,372.4	10.9%	13,440.4	12.9%	14,336.6	1.0%	5,317.8	2.0%
May	248,603.8	46.7%	252,604.7	49.8%	126,690.5	11.3%	76,359.3	15.3%	4,372.4	12.0%	13,440.4	10.0%	14,336.6	1.1%	5,319.2	1.8%
June	245,407.8	58.0%	255,100.3	58.7%	126,881.1	12.4%	75,658.1	16.3%	4,362.4	13.1%	13,440.4	15.0%	14,166.6	1.4%	5,275.1	1.8%
July	245,407.8	63.8%	256,721.3	69.8%	126,878.6	16.3%	75,658.1	23.3%	4,369.0	18.3%	13,440.4	16.6%	14,166.6	1.5%	5,276.5	1.8%
August	245,407.8	63.6%	257,487.3	69.3%	127,267.4	15.0%	75,658.1	20.3%	4,594.6	16.9%	13,440.4	15.6%	14,166.6	1.3%	5,277.8	2.1%
September	245,113.4	55.3%	258,463.3	63.2%	127,146.3	13.8%	75,650.6	15.6%	4,594.3	13.8%	13,440.4	16.9%	14,166.6	1.3%	5,274.0	2.0%
October	244,837.5	48.5%	258,836.7	52.9%	127,104.0	11.6%	75,120.6	12.6%	4,595.0	12.4%	13,440.4	13.7%	14,166.6	1.1%	5,269.0	2.0%
November	244,426.5	53.2%	260,948.0	48.8%	126,977.7	10.5%	74,758.6	8.7%	4,613.6	11.7%	13,440.4	13.4%	14,154.6	1.1%	5,240.4	1.8%
December	242,785.6	55.9%	260,868.5	48.9%	127,108.3	9.1%	73,841.6	6.3%	4,613.6	11.0%	11,788.4	12.6%	14,154.6	1.0%	5,237.9	1.7%
Year 2019																
January	241,507.5	56.6%	261,918.1	54.6%	128,218.2	9.6%	73,728.3	8.4%	4,620.8	12.9%	11,347.1	12.8%	14,037.5	1.4%	5,285.8	2.0%
February	239,252.5	50.4%	261,918.1	55.8%	128,218.2	9.9%	73,730.3	6.9%	4,695.3	14.2%	11,347.1	12.5%	14,037.5	0.9%	5,287.8	1.9%
March	238,021.5	45.0%	261,601.1	51.0%	128,164.0	9.3%	73,188.3	9.3%	4,695.3	12.8%	11,347.1	11.8%	14,018.5	0.6%	5,287.4	1.7%
April	236,625.1	35.7%	264,436.4	45.8%	128,276.4	9.7%	73,191.0	10.9%	4,878.7	12.5%	11,201.1	10.9%	14,018.5	0.8%	5,283.2	1.7%
May	235,815.1	41.7%	265,631.1	49.2%	128,705.3	10.2%	73,191.0	13.7%	4,881.2	12.4%	11,201.1	16.4%	14,018.5	1.0%	5,290.0	1.9%
June	235,767.5	46.9%	268,823.5	59.9%	128,828.7	11.2%	72,899.9	16.7%	4,881.2	14.4%	11,201.1	15.6%	14,008.2	1.1%	5,289.2	1.9%
July	234,785.0	58.3%	269,658.1	70.5%	129,173.4	15.0%	72,853.9	24.9%	4,903.2	20.1%	11,201.1	17.5%	14,008.2	1.1%	5,293.9	2.1%
August	234,785.0	54.6%	269,658.1	71.6%	129,318.4	14.9%	72,853.9	26.1%	4,903.2	20.4%	11,201.1	16.7%	14,002.5	1.3%	5,292.1	2.2%
September	233,847.0	51.4%	269,658.1	64.2%	129,278.4	12.9%	72,853.9	19.8%	4,903.2	17.4%	11,134.1	14.4%	14,002.5	1.2%	5,292.6	2.4%
October	233,086.4	39.3%	269,110.5	54.5%	129,348.4	11.6%	72,211.9	14.6%	4,903.2	15.5%	11,134.1	8.8%	14,002.5	1.2%	5,292.1	2.3%
November	229,164.4	46.0%	269,670.1	52.2%	129,314.4	10.9%	72,038.9	8.7%	4,903.2	16.1%	11,134.1	7.6%	14,002.5	0.8%	5,292.9	2.0%
December	228,657.4	43.3%	269,766.0	57.4%	129,098.3	10.2%	70,909.4	8.4%	5,001.6	14.1%	11,134.1	8.6%	13,962.5	0.8%	5,267.4	2.1%

Values are final.

Time adjusted capacity for month rows is the summer capacity of generators in operation for the entire month; units that began operation during the month or that retired during the month are excluded. Time adjusted capacity for year rows is a time weighted average of the month rows.

Capacity factors are a comparison of net generation with available capacity. See the technical note for an explanation of how capacity factors are calculated.

Sources: U.S. Energy Information Administration, Form EIA-923, Power Plant Operations Report; U.S. Energy Information Administration, Form EIA-860, 'Annual Electric Generator Report' and Form EIA-860M, 'Monthly Update to the Annual Electric Generator Report.'

Table 4.08.B. Capacity Factors for Utility Scale Generators Primarily Using Non-Fossil Fuels

	Geothermal		Hydroelectric		Nuclear		Other Biomass		Other Gas		Solar				Wind		Wood	
Year/Month											Photovoltaic		Thermal					
	Time Adjusted Capacity	Capacity Factor	Time Adjusted Capacity	Capacity Factor	Time Adjusted Capacity	Capacity Factor	Time Adjusted Capacity	Capacity Factor	Time Adjusted Capacity	Capacity Factor	Time Adjusted Capacity	Capacity Factor	Time Adjusted Capacity	Capacity Factor	Time Adjusted Capacity	Capacity Factor	Time Adjusted Capacity	Capacity Factor
Annual Data																		
2009	2,278.0	73.0%	78,500.4	39.6%	101,003.7	90.3%	4,183.9	65.0%	1,752.2	43.4%	81.9	20.0%	468.2	23.6%	28,996.9	28.1%	6,936.4	61.7%
2010	2,392.1	71.6%	78,810.3	37.5%	101,167.4	91.1%	4,298.7	64.2%	1,929.0	50.5%	206.8	20.2%	473.0	24.5%	35,702.6	29.7%	6,991.5	61.5%
2011	2,407.9	71.5%	78,564.7	45.8%	101,265.1	89.1%	4,469.8	64.2%	1,902.7	54.1%	537.0	19.0%	485.3	23.9%	42,019.2	32.1%	7,000.3	59.6%
2012	2,531.8	68.3%	78,296.6	39.6%	101,166.0	86.6%	4,639.7	63.3%	1,802.8	59.6%	1,527.1	20.4%	476.0	23.6%	49,458.0	31.8%	7,089.1	61.3%
2013	2,509.5	71.8%	78,873.5	38.8%	99,006.8	90.8%	4,949.7	62.3%	2,171.6	55.9%	3,525.2	24.5%	552.1	17.4%	59,175.6	32.4%	7,887.9	59.0%
2014	2,513.3	72.0%	79,582.8	37.2%	98,569.3	91.7%	5,114.6	62.7%	1,994.0	54.0%	6,555.6	25.6%	1,445.3	18.3%	60,587.8	34.0%	8,319.7	60.0%
2015	2,523.0	71.9%	79,650.8	35.7%	98,614.6	92.3%	5,104.5	62.6%	2,527.7	60.8%	9,521.6	25.5%	1,697.3	21.7%	67,106.2	32.2%	9,024.5	59.3%
2016	2,516.6	71.6%	79,806.0	38.2%	99,364.8	92.3%	5,099.5	62.7%	2,458.8	64.8%	14,161.4	25.0%	1,757.9	22.1%	74,162.7	34.5%	8,979.8	58.3%
2017	2,460.4	73.2%	79,698.8	43.0%	99,619.5	92.3%	5,125.6	61.8%	2,375.8	62.8%	21,940.9	25.6%	1,757.9	21.8%	83,355.6	34.6%	8,807.5	60.2%
2018	2,391.5	76.0%	79,771.9	41.9%	99,605.2	92.5%	5,059.0	61.8%	2,543.9	65.4%	27,143.3	25.1%	1,757.9	23.6%	89,228.5	34.6%	8,760.2	60.6%
2019	2,535.2	69.6%	79,838.0	41.2%	98,836.7	93.4%	4,786.5	62.5%	2,504.1	67.4%	31,840.8	24.3%	1,758.1	21.2%	97,564.8	34.4%	8,485.0	59.0%
Year 2017																		
January	2,511.1	74.9%	79,657.2	44.9%	99,609.9	98.7%	5,095.1	64.2%	2,375.8	63.8%	20,249.8	14.6%	1,757.9	7.3%	81,337.2	34.2%	8,748.6	61.4%
February	2,511.1	73.0%	79,657.2	44.6%	99,609.9	95.0%	5,097.3	63.2%	2,375.8	65.4%	20,603.7	18.6%	1,757.9	11.6%	81,713.0	40.2%	8,748.6	61.6%
March	2,451.1	73.8%	79,657.2	50.0%	99,609.9	87.8%	5,097.3	61.1%	2,375.8	64.8%	20,792.6	26.7%	1,757.9	22.9%	81,962.1	41.8%	8,741.6	60.0%
April	2,451.1	75.6%	79,660.1	51.3%	99,609.9	79.2%	5,105.7	60.0%	2,375.8	61.8%	21,177.9	29.6%	1,757.9	24.8%	83,041.4	42.4%	8,789.1	56.4%
May	2,451.1	71.0%	79,660.1	55.0%	99,609.9	82.8%	5,122.7	62.5%	2,375.8	58.1%	21,700.6	33.1%	1,757.9	30.9%	83,182.1	37.2%	8,796.6	55.0%
June	2,451.1	72.4%	79,660.1	53.3%	99,609.9	93.5%	5,126.7	62.8%	2,375.8	59.1%	22,006.1	35.4%	1,757.9	37.9%	83,313.5	33.4%	8,802.9	60.6%
July	2,451.1	74.9%	79,667.4	44.8%	99,628.9	96.2%	5,145.2	61.7%	2,375.8	58.9%	22,242.6	31.5%	1,757.9	25.3%	83,498.6	25.8%	8,802.9	62.1%
August	2,451.1	74.4%	79,614.2	37.1%	99,628.9	97.7%	5,147.3	62.0%	2,375.8	65.0%	22,356.4	29.9%	1,757.9	27.5%	83,980.6	22.2%	8,856.4	63.3%
September	2,451.1	75.1%	79,761.5	33.3%	99,628.9	95.0%	5,147.2	59.4%	2,375.8	61.8%	22,547.7	28.7%	1,757.9	29.1%	83,980.6	29.5%	8,856.4	58.6%
October	2,451.1	66.2%	79,797.5	29.8%	99,628.9	89.0%	5,147.2	58.2%	2,375.8	62.1%	22,762.8	25.2%	1,757.9	24.1%	84,229.8	38.7%	8,856.4	57.4%
November	2,451.1	73.5%	79,797.1	34.6%	99,628.9	92.9%	5,143.9	62.3%	2,375.8	65.1%	23,095.3	18.1%	1,757.9	10.3%	84,483.3	36.6%	8,856.4	61.2%
December	2,446.3	74.2%	79,794.4	37.5%	99,628.9	99.4%	5,129.5	63.9%	2,375.8	67.4%	23,660.0	15.6%	1,757.9	9.0%	85,431.2	34.2%	8,830.9	65.3%
Year 2018																		
January	2,387.5	75.3%	79,771.8	42.2%	99,730.6	100.6%	5,108.5	62.2%	2,543.9	66.2%	25,311.1	16.3%	1,757.9	10.0%	87,552.6	38.7%	8,813.0	65.3%
February	2,403.5	78.9%	79,771.8	46.4%	99,730.6	96.7%	5,083.1	64.6%	2,543.9	66.6%	25,968.4	20.9%	1,757.9	16.1%	88,563.2	38.8%	8,813.0	62.5%
March	2,382.2	76.8%	79,785.3	43.6%	99,730.6	90.3%	5,086.1	62.0%	2,543.9	63.3%	26,067.6	24.3%	1,757.9	19.2%	88,787.7	40.1%	8,780.5	61.7%
April	2,392.2	69.0%	79,792.3	48.9%	99,730.6	82.4%	5,086.1	60.9%	2,543.9	61.6%	26,591.3	29.7%	1,757.9	24.4%	88,789.2	41.3%	8,780.5	55.6%
May	2,392.2	77.7%	79,753.3	51.3%	99,730.6	90.7%	5,083.5	59.4%	2,543.9	63.2%	26,859.7	31.8%	1,757.9	32.9%	89,086.2	36.0%	8,761.5	58.0%
June	2,392.2	75.5%	79,753.8	48.1%	99,730.6	97.1%	5,006.9	63.0%	2,543.9	64.1%	27,291.3	34.9%	1,757.9	41.7%	89,078.2	38.4%	8,775.5	61.7%
July	2,392.2	77.0%	79,751.6	42.3%	99,730.6	97.7%	5,050.2	62.3%	2,543.9	65.8%	27,451.7	31.1%	1,757.9	30.1%	89,227.2	24.7%	8,767.2	63.7%
August	2,392.2	76.8%	79,751.6	37.1%	99,730.6	97.4%	5,042.5	62.6%	2,543.9	68.7%	27,590.1	30.5%	1,757.9	32.5%	89,387.5	29.8%	8,748.7	62.2%
September	2,392.2	77.1%	79,751.6	33.4%	99,277.9	90.3%	5,042.5	58.3%	2,543.9	67.2%	27,674.0	27.7%	1,757.9	34.8%	89,469.5	28.6%	8,748.7	58.5%
October	2,392.2	71.5%	79,753.6	32.9%	99,277.9	80.4%	5,041.4	61.0%	2,543.9	64.3%	27,989.5	22.4%	1,757.9	20.7%	89,941.8	31.5%	8,748.7	56.5%
November	2,392.2	77.3%	79,753.6	38.1%	99,432.9	89.3%	5,039.0	62.3%	2,543.9	67.4%	28,158.3	17.3%	1,757.9	13.3%	90,282.8	33.8%	8,694.6	60.4%
December	2,387.9	79.4%	79,870.8	38.4%	99,432.9	96.9%	5,038.6	63.2%	2,543.9	67.0%	28,690.2	13.7%	1,757.9	7.0%	90,534.1	34.8%	8,694.6	61.4%
Year 2019																		
January	2,527.5	73.9%	79,881.1	41.7%	99,440.4	99.6%	4,894.7	63.2%	2,509.0	68.2%	30,238.8	15.2%	1,758.1	8.4%	94,361.8	34.4%	8,716.6	62.0%
February	2,527.5	76.1%	79,883.6	42.6%	99,440.4	96.8%	4,894.7	62.3%	2,509.0	64.8%	30,911.4	17.7%	1,758.1	10.9%	95,284.6	35.3%	8,716.6	60.7%
March	2,527.5	75.6%	79,897.2	44.3%	99,440.4	88.0%	4,796.3	61.4%	2,509.0	61.6%	31,124.1	24.1%	1,758.1	19.8%	95,776.4	36.0%	8,565.9	57.6%
April	2,535.4	68.7%	79,897.2	48.4%	99,595.4	84.5%	4,785.1	59.9%	2,514.0	62.1%	31,355.0	28.4%	1,758.1	25.5%	96,608.9	41.6%	8,553.5	52.8%
May	2,535.4	71.1%	79,874.5	53.8%	98,921.8	90.8%	4,783.7	61.5%	2,514.0	67.6%	31,466.6	29.1%	1,758.1	25.7%	96,610.5	35.7%	8,538.5	54.1%
June	2,535.4	72.8%	79,878.4	48.8%	98,921.8	96.6%	4,764.2	64.2%	2,499.2	67.5%	31,528.4	32.9%	1,758.1	35.5%	96,840.0	31.9%	8,469.0	58.2%
July	2,535.4	72.9%	79,879.9	41.9%	98,921.8	98.1%	4,765.8	63.8%	2,499.2	68.5%	31,803.5	32.4%	1,758.1	31.4%	98,084.1	30.1%	8,498.4	61.4%
August	2,535.4	73.9%	79,776.1	38.0%	98,921.8	97.7%	4,765.9	64.4%	2,499.2	68.0%	32,079.8	31.0%	1,758.1	32.0%	98,359.7	27.1%	8,498.4	62.7%
September	2,535.4	74.9%	79,775.9	32.3%	98,119.0	93.1%	4,754.4	62.6%	2,499.2	72.4%	32,302.5	27.4%	1,758.1	24.3%	98,668.1	34.1%	8,409.1	59.2%
October	2,535.4	60.5%	79,772.0	30.8%	98,119.0	85.0%	4,754.4	61.5%	2,499.2	64.4%	32,556.1	23.3%	1,758.1	23.0%	99,662.8	37.2%	8,305.5	57.0%
November	2,535.4	53.3%	79,772.0	35.2%	98,119.0	90.8%	4,751.2	61.5%	2,499.2	71.6%	33,001.5	17.4%	1,758.1	11.3%	99,618.3	34.9%	8,305.5	60.2%
December	2,555.4	61.5%	79,772.0	36.2%	98,119.0	100.1%	4,735.4	63.7%	2,499.2	72.2%	33,658.4	12.8%	1,758.1	5.4%	100,729.8	34.9%	8,258.5	62.7%

Values are final.

Time adjusted capacity for month rows is the summer capacity of generators in operation for the entire month; units that began operation during the month or that retired during the month are excluded. Time adjusted capacity for year rows is a time weighted average of the month rows.

Capacity factors are a comparison of net generation with available capacity. See the technical note for an explanation of how capacity factors are calculated.

Sources: U.S. Energy Information Administration, Form EIA-923, Power Plant Operations Report; U.S. Energy Information Administration, Form EIA-860, 'Annual Electric Generator Report' and Form EIA-860M, 'Monthly Update to the Annual Electric Generator Report.'

Table 4.08.C. Usage Factors for Utility Scale Storage Generators

Year/Month	Battery		Pumped Storage	
	Time Adjusted Capacity	Usage Factor	Time Adjusted Capacity	Usage Factor
Annual Data				
2013	126.7	0.7%	22,389.3	9.8%
2014	155.1	1.7%	22,477.9	10.2%
2015	206.8	3.6%	22,568.9	10.2%
2016	423.0	3.8%	22,752.7	11.2%
2017	632.8	6.8%	22,791.7	11.4%
2018	713.6	5.2%	22,815.4	10.8%
2019	949.8	5.4%	22,754.7	10.4%
Year 2017				
January	562.8	6.9%	22,753.4	10.2%
February	573.8	7.1%	22,753.4	8.0%
March	581.8	8.1%	22,753.4	8.5%
April	611.8	7.7%	22,753.4	9.5%
May	627.7	6.6%	22,810.4	11.7%
June	641.2	7.0%	22,810.4	14.2%
July	643.2	6.5%	22,810.4	16.9%
August	645.4	6.7%	22,810.4	16.2%
September	678.2	6.2%	22,810.4	12.9%
October	679.4	6.4%	22,810.4	10.2%
November	681.4	6.9%	22,810.4	9.0%
December	663.4	6.5%	22,810.4	9.1%
Year 2018				
January	643.7	5.2%	22,785.2	9.8%
February	663.5	5.1%	22,785.2	9.6%
March	667.1	5.2%	22,785.2	7.9%
April	681.1	5.0%	22,785.2	8.2%
May	690.6	5.2%	22,830.2	11.0%
June	696.1	4.9%	22,830.2	13.2%
July	742.1	5.6%	22,830.2	15.5%
August	740.1	5.6%	22,830.2	16.1%
September	746.4	5.6%	22,830.2	12.2%
October	748.9	5.0%	22,830.2	9.4%
November	768.9	5.3%	22,830.2	8.2%
December	770.7	5.1%	22,830.2	7.7%
Year 2019				
January	864.8	5.5%	22,721.3	9.3%
February	877.1	5.7%	22,721.3	9.2%
March	901.9	6.3%	22,721.3	8.3%
April	931.0	5.9%	22,721.3	10.2%
May	934.7	5.9%	22,721.3	11.8%
June	939.7	5.2%	22,778.3	11.7%
July	962.9	5.2%	22,778.3	15.1%
August	983.9	5.0%	22,778.3	13.7%
September	990.8	5.8%	22,778.3	12.4%
October	998.7	4.5%	22,778.3	8.3%
November	1,001.2	5.2%	22,778.3	7.2%
December	1,006.2	5.0%	22,778.3	7.8%

Values are final.

Time adjusted capacity for month rows is the summer capacity of generators in operation for the entire month; units that began operation during the month or that retired during the month are excluded. Time adjusted capacity for year rows is a time weighted average of the month rows.

Usage factors are a comparison of gross generation with available capacity. See the technical note for an explanation of how usage factors are calculated.

Sources: U.S. Energy Information Administration, Form EIA-923, Power Plant Operations Report; U.S. Energy Information Administration, Form EIA-860, 'Annual Electric Generator Report' and Form EIA-860M, 'Monthly Update to the Annual Electric Generator Report.'

Table 4.9.A. Total Capacity of Distributed and Dispersed Generators by Technology Type, 2009 through 2015 (Table Discontinued)

	Capacity (MW)										
	Internal Combustion	Combustion Turbine	Steam Turbine	Hydro	Wind	Photovoltaic	Storage	Other	Wind and Other	Total	Number of Generators
Year											
Distributed Generators											
2009	4,339.0	4,147.0	4,621.0	1,166.0	--	--	--	--	1,729.0	16,002.0	13,006
2010	886.8	186.0	109.9	97.4	98.9	236.3	--	372.7	--	1,988.0	15,630
2011	791.1	115.5	64.9	97.9	36.7	314.8	0.2	264.3	--	1,685.4	20,941
2012	756.1	105.8	60.2	119.9	252.9	543.7	15.2	324.4	--	1,990.6	28,252
2013	981.3	106.4	31.1	103.9	78.3	556.0	2.0	89.0	--	1,947.4	196,141
2014	813.8	81.3	12.9	108.2	33.7	692.0	7.2	101.0	--	1,855.5	203,099
2015	797.6	49.3	10.5	121.2	26.7	876.4	24.4	88.4	--	1,994.6	215,825
Dispersed Generators											
2009	9,751.0	329.0	204.0	81.0	--	--	--	--	108.0	10,475.0	13,928
2010	2,771.2	64.4	13.8	8.4	6.3	95.2	7.0	17.9	--	2,984.2	16,874
2011	2,916.9	40.3	14.6	6.0	3.2	2.7	8.0	7.9	--	2,999.6	14,123
2012	3,180.9	49.8	--	2.2	3.1	8.5	7.7	13.5	--	3,265.5	14,557
2013	3,249.7	159.8	17.0	1.9	4.5	21.6	8.7	25.8	--	3,489.0	17,929
2014	3,479.3	169.7	16.7	0.7	3.7	14.3	6.6	5.7	--	3,696.8	22,599
2015	3,160.9	199.1	16.7	0.7	4.7	17.6	7.2	5.7	--	3,412.6	23,665
Distributed and Dispersed Generators											
2009	14,090.0	4,476.0	4,825.0	1,247.0	--	--	--	--	1,837.0	26,477.0	26,934
2010	3,658.0	250.4	123.7	105.8	105.2	331.5	7.0	390.6	--	4,972.2	32,504
2011	3,708.0	155.8	79.5	103.9	39.9	317.5	8.2	272.2	--	4,685.0	35,064
2012	3,937.0	155.6	60.2	122.1	256.0	552.2	22.9	337.9	--	5,256.1	42,809
2013	4,231.0	266.2	48.1	105.8	82.8	577.6	10.7	114.8	--	5,436.4	214,070
2014	4,293.1	251.0	29.6	108.9	37.5	706.3	13.8	106.7	--	5,552.2	225,698
2015	3,958.5	248.5	27.2	121.9	31.4	893.9	31.6	94.1	--	5,407.1	239,490

Starting in 2013, the residential sector is now included and all net metering units are excluded.

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

Prior to 2010, data contains generators over and under 1 MW, from 2010 forward, data contains only generators under 1 MW.

Distributed generators are commercial and industrial generators which are connected to the grid. Dispersed generators are commercial and industrial generators which are not connected to the grid. Both types 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.

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 4.9.B Total Capacity of Non Net Metered Distributed Generators by Technology Type and Sector, 2010 through 2019

Year	Residential	Generators by Technology and Sector				Total
		Commercial	Industrial	Transportation	Direct Connected	
Internal Combustion						
2010	--	--	--	--	--	886.800
2011	--	--	--	--	--	791.100
2012	--	--	--	--	--	756.100
2013	--	--	--	--	--	981.311
2014	--	--	--	--	--	813.847
2015	--	--	--	--	--	797.595
2016	46.974	679.239	223.037	--	69.217	1,018.467
2017	86.766	851.363	306.305	--	78.180	1,322.614
2018	69.428	909.278	336.970	--	91.159	1,406.835
2019	76.934	955.455	263.507	0.275	111.981	1,408.152
Combustion Turbine						
2010	--	--	--	--	--	186.000
2011	--	--	--	--	--	115.500
2012	--	--	--	--	--	105.800
2013	--	--	--	--	--	106.385
2014	--	--	--	--	--	81.325
2015	--	--	--	--	--	49.329
2016	0.233	62.127	24.415	--	2.728	89.503
2017	11.750	56.187	25.069	--	5.893	98.899
2018	0.070	75.151	24.568	--	3.488	103.277
2019	0.077	76.695	22.128	--	4.488	103.388
Steam Turbine						
2010	--	--	--	--	--	109.900
2011	--	--	--	--	--	64.900
2012	--	--	--	--	--	60.200
2013	--	--	--	--	--	31.050
2014	--	--	--	--	--	12.925
2015	--	--	--	--	--	10.531
2016	--	2.995	0.524	--	0.431	3.950
2017	1.250	1.920	1.254	--	0.431	4.855
2018	--	4.626	0.539	--	2.581	7.746
2019	--	8.439	0.539	--	2.581	11.559
Hydroelectric						
2010	--	--	--	--	--	97.400
2011	--	--	--	--	--	97.900
2012	--	--	--	--	--	119.900
2013	--	--	--	--	--	103.935
2014	--	--	--	--	--	108.235
2015	--	--	--	--	--	121.234
2016	6.140	39.930	8.533	--	101.146	155.749
2017	5.915	30.763	8.033	--	103.607	148.318
2018	5.422	36.048	5.503	--	113.592	160.565
2019	7.482	37.818	5.503	--	113.910	164.713
Wind						
2010	--	--	--	--	--	98.900
2011	--	--	--	--	--	36.700
2012	--	--	--	--	--	252.900
2013	--	--	--	--	--	78.299
2014	--	--	--	--	--	33.727
2015	--	--	--	--	--	26.658
2016	2.616	15.742	1.366	--	8.828	28.552
2017	2.632	16.453	1.044	--	8.988	29.117
2018	2.579	15.527	1.441	--	9.071	28.618
2019	2.437	15.707	1.452	--	9.918	29.514
Photovoltaic						
2010	--	--	--	--	--	236.300
2011	--	--	--	--	--	314.800
2012	--	--	--	--	--	543.700
2013	--	--	--	--	--	555.965
2014	--	--	--	--	--	692.034
2015	--	--	--	--	--	876.351
2016	80.577	388.911	132.970	--	112.922	715.380
2017	186.910	513.251	177.192	--	120.946	998.299
2018	289.151	594.877	188.874	--	126.793	1,199.698
2019	437.911	688.600	202.899	--	131.391	1,460.800
Storage						
2010	--	--	--	--	--	--
2011	--	--	--	--	--	0.200
2012	--	--	--	--	--	15.200
2013	--	--	--	--	--	1.950
2014	--	--	--	--	--	7.227
2015	--	--	--	--	--	24.443
2016	0.070	32.678	8.714	--	1.246	42.708
2017	3.916	42.884	12.271	--	1.444	60.515
2018	6.935	79.042	10.674	--	7.276	103.927
2019	14.308	113.788	15.519	--	15.929	159.544
Fuel Cell						
2010	--	--	--	--	--	--
2011	--	--	--	--	--	--
2012	--	--	--	--	--	--
2013	--	--	--	--	--	--
2014	--	--	--	--	--	--
2015	--	--	--	--	--	--
2016	0.161	6.229	3.700	--	0.225	10.315
2017	0.167	7.953	6.336	--	0.625	15.081
2018	0.150	12.793	3.959	--	0.625	17.527
2019	0.150	19.943	3.601	--	0.625	24.319
Other						
2010	--	--	--	--	--	372.700
2011	--	--	--	--	--	264.300
2012	--	--	--	--	--	324.400
2013	--	--	--	--	--	89.000
2014	--	--	--	--	--	100.995
2015	--	--	--	--	--	88.423
2016	0.753	34.050	10.389	--	6.050	51.242
2017	1.139	33.093	12.729	--	4.950	51.911
2018	0.629	36.452	16.209	--	3.310	56.600
2019	0.464	37.306	14.954	--	3.579	56.303
Total						
2010	--	--	--	--	--	1,988.000
2011	--	--	--	--	--	1,685.400
2012	--	--	--	--	--	1,990.600
2013	--	--	--	--	--	1,947.394
2014	--	--	--	--	--	1,855.455
2015	--	--	--	--	--	1,994.564
2016	137.524	1,261.901	413.648	--	302.793	2,115.866
2017	300.445	1,553.867	550.233	--	325.064	2,729.609
2018	374.368	1,763.792	588.737	--	357.895	3,084.792
2019	539.763	1,953.751	530.102	0.275	394.402	3,418.292
Total Number of Generators						
2010	--	--	--	--	--	15,630
2011	--	--	--	--	--	20,941
2012	--	--	--	--	--	28,252
2013	--	--	--	--	--	196,141
2014	--	--	--	--	--	203,099
2015	--	--	--	--	--	215,825
2016	--	--	--	--	--	195,703
2017	--	--	--	--	--	215,889
2018	--	--	--	--	--	231,220
2019	--	--	--	--	--	251,357

Starting in 2016, Capacity is now collected by technology and sector.

Starting in 2013, the residential sector is now included and all net metering units are excluded.

Distributed generators are 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.

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 4.10. Net Metering Customers and Capacity by Technology Type, by End Use Sector, 2009 through 2019

Year	Capacity (MW)					Customers				
	Residential	Commercial	Industrial	Transportation	Total	Residential	Commercial	Industrial	Transportation	Total
Historical Data										
2009	N/A	N/A	N/A	N/A	N/A	88,205	7,365	919	--	96,489
Photovoltaic										
2010	697.890	517.861	243.051	--	1,458.802	137,618	11,897	1,225	--	150,740
2011	1,024.139	1,089.275	381.670	--	2,495.410	198,255	18,345	2,418	--	219,018
2012	1,542.226	1,741.821	395.328	--	3,679.630	294,437	27,611	1,317	--	323,365
2013	2,286.567	2,294.831	565.982	--	5,147.380	442,195	35,379	2,480	--	480,054
2014	3,452.987	2,933.122	710.719	--	7,096.828	642,276	43,335	3,131	--	688,742
2015	5,357.358	3,455.124	884.664	--	9,697.146	958,850	51,501	3,624	--	1,013,975
2016	7,487.643	3,975.813	1,078.607	--	12,542.064	1,321,277	60,456	4,391	--	1,386,124
2017	9,486.987	5,119.870	1,197.785	--	15,804.641	1,626,283	69,538	5,267	--	1,701,088
2018	11,356.711	6,173.324	1,378.863	--	18,908.896	1,911,892	78,912	5,844	--	1,996,648
2019	13,863.288	7,181.594	1,613.248	--	22,658.129	2,283,702	86,552	6,499	--	2,376,753
Storage										
2016	4.489	7.575	11.698	--	23.762	793	79	31	--	903
2017	13.276	15.356	12.328	--	40.960	2,316	137	34	--	2,487
2018	65.199	40.141	24.526	--	129.866	10,633	303	61	--	10,997
2019	153.282	48.397	40.441	--	242.120	24,007	427	93	--	24,527
Virtual PV (1 MW and over)										
2016	15.171	194.318	--	--	209.489	5,193	322	--	--	5,515
2017	11.115	287.440	2.000	--	300.555	3,611	535	2	--	4,148
2018	19.719	360.749	2.603	--	383.071	6,045	2,037	17	--	8,099
2019	19.883	401.179	4.212	--	425.274	5,939	2,164	22	--	8,125
Virtual PV (under 1 MW)										
2016	27.482	73.116	3.168	--	103.766	8,705	1,506	11	--	10,222
2017	42.005	129.547	5.136	--	176.689	11,337	2,372	17	--	13,726
2018	49.232	163.228	5.466	--	217.926	13,071	2,959	16	--	16,046
2019	57.609	223.409	6.472	--	287.489	14,814	3,744	18	--	18,576
Wind										
2010	83.797	26.106	6.392	--	116.295	3,467	583	37	--	4,087
2011	28.063	44.373	9.932	--	82.368	4,456	905	50	--	5,411
2012	33.484	74.620	17.495	--	125.599	4,796	1,143	48	--	5,987
2013	38.987	92.818	14.659	--	146.464	5,265	1,308	92	--	6,665
2014	37.918	101.622	25.426	--	164.966	5,379	1,351	94	--	6,824
2015	34.893	103.086	29.137	--	167.116	5,387	1,434	109	--	6,930
2016	37.030	108.726	41.454	--	187.210	5,759	1,470	113	--	7,342
2017	35.005	119.651	49.507	--	204.163	5,258	1,429	111	--	6,798
2018	33.625	133.856	52.386	--	219.867	5,368	1,452	110	--	6,930
2019	33.668	148.594	52.580	--	234.842	5,218	1,438	107	--	6,763
Other										
2010	11.455	34.752	24.835	--	71.042	767	271	56	--	1,094
2011	5.030	49.010	56.681	--	110.721	807	242	100	--	1,149
2012	7.539	65.821	83.170	--	156.530	862	314	122	--	1,298
2013	6.785	80.405	80.568	--	167.758	598	331	169	--	1,098
2014	7.633	102.797	98.277	--	208.707	857	397	201	--	1,455
2015	7.873	116.382	116.780	--	241.035	821	445	249	--	1,515
2016	7.952	155.889	149.608	--	313.449	862	592	325	--	1,779
2017	9.064	208.639	199.398	--	417.101	915	693	330	--	1,938
2018	6.351	258.601	241.416	--	506.368	692	826	347	--	1,865
2019	23.364	254.281	263.966	--	541.611	2,226	842	381	--	3,449
All Technologies										
2010	793.142	578.719	274.278	--	1,646.139	141,852	12,751	1,318	--	155,921
2011	1,057.232	1,182.658	448.283	--	2,688.173	203,518	19,492	2,568	--	225,578
2012	1,583.249	1,882.262	495.993	--	3,961.504	300,095	29,068	1,487	--	330,650
2013	2,332.339	2,468.054	661.209	--	5,461.602	448,058	37,018	2,741	--	487,817
2014	3,498.538	3,137.541	834.422	--	7,470.501	648,512	45,083	3,426	--	697,021
2015	5,400.124	3,674.592	1,030.581	--	10,105.297	965,058	53,380	3,982	--	1,022,420
2016	7,715.715	4,576.384	1,289.946	--	13,582.045	1,341,796	64,346	4,840	--	1,410,982
2017	9,584.177	5,865.147	1,453.826	--	16,903.148	1,647,404	74,567	5,727	--	1,727,698
2018	11,465.638	7,089.758	1,680.734	--	20,236.128	1,937,068	86,186	6,334	--	2,029,588
2019	13,997.811	8,209.056	1,940.478	--	24,147.345	2,311,899	94,740	7,027	--	2,413,666

N/A = Not Available.

Total customer count for the years 2007, 2009, and 2010 were revised based on requests from respondents.

Capacity and customer count was not collected by technology type before 2010.

Starting in 2013, there is no maximum capacity on installed units.

Starting in 2016, utilities have the option to report photovoltaic in DC or AC. Values have been converted to AC.

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

Table 4.11. Fuel-Switching Capacity of Operable Generators Reporting Natural Gas as the Primary Fuel, by Producer Type, 2019
(Megawatts, Percent)

		Fuel-Switchable Part of Total			
Producer Type	Total Net Summer Capacity of All Generators Reporting Natural Gas as the Primary Fuel	Net Summer Capacity of Natural Gas-Fired Generators Reporting the Ability to Switch to Petroleum Liquids	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 Utilities	247,018.9	81,920.1	33.2%	77,263.5	16,088.7
Independent Power Producers, Non-Combined Heat and Power Plants	187,715.6	45,039.8	24.0%	42,366.4	7,776.7
Independent Power Producers, Combined Heat and Power Plants	24,782.0	4,000.7	16.1%	3,835.1	298.1
Electric Power Sector Subtotal	459,516.5	130,960.6	28.5%	123,465.0	24,163.5
Commercial Sector	2,247.5	918.8	40.9%	864.4	97.2
Industrial Sector	14,803.4	920.7	6.2%	885.2	89.2
All Sectors	476,567.4	132,800.1	27.9%	125,214.6	24,349.9

Notes: Petroleum liquids include 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, waste oil, and propane.

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

Table 4.12. Fuel-Switching Capacity of Operable Generators Reporting Petroleum Liquids as the Primary Fuel, by Producer Type, 2019 (Megawatts, Percent)

		Fuel-Switchable Part of Total		
Producer Type	Total Net Summer Capacity of All Generators Reporting Petroleum Liquids as the Primary Fuel	Net Summer Capacity of Petroleum Liquids-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 Utilities	17,287.3	2,292.9	13.3%	2,273.8
Independent Power Producers, Non-Combined Heat and Power Plants	11,378.8	2,775.2	24.4%	1,911.6
Independent Power Producers, Combined Heat and Power Plants	246.8	--	0.0%	--
Electric Power Sector Subtotal	28,912.9	5,068.1	17.5%	4,185.4
Commercial Sector	856.7	5.9	0.7%	5.6
Industrial Sector	245.8	29.0	11.8%	25.0
All Sectors	30,015.4	5,103.0	17.0%	4,215.9

Notes: Petroleum liquids include 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, waste oil, and propane.
Source: U.S. Energy Information Administration, Form EIA-860, 'Annual Electric Generator Report.'

Table 4.13. Fuel-Switching Capacity of Operable Generators Reporting Natural Gas as the Primary Fuel, by Type of Prime Mover, 2019 (Megawatts, Percent)

Prime Mover Type	Number of Natural Gas-Fired Generators Reporting the Ability to Switch to Petroleum Liquids	Net Summer Capacity of Natural Gas-Fired Generators Reporting the Ability to Switch to Petroleum Liquids	Fuel Switchable Net Summer Capacity Reported to Have No Factors that Limit the Ability to Switch to Petroleum Liquids
Steam Generator	174	26,091.0	7,309.3
Combined Cycle	379	48,106.6	5,391.7
Internal Combustion	312	1,230.0	386.2
Gas Turbine	876	57,372.5	11,262.7
All Fuel Switchable Prime Movers	1,741	132,800.1	24,349.9

Notes: Petroleum liquids include 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, waste oil, and propane.

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

Table 4.14. Fuel-Switching Capacity of Operable Generators Reporting Natural Gas as the Primary Fuel,

by Year of Initial Commercial Operation, 2019 (Megawatts, Percent)

Year of Initial Commercial Operation	Number of Natural Gas-Fired Generators Reporting the Ability to Switch to Petroleum Liquids	Net Summer Capacity of Natural Gas-Fired Generators Reporting the Ability to Switch to Petroleum Liquids	Fuel Switchable Net Summer Capacity Reported to Have No Factors that Limit the Ability to Switch to Petroleum Liquids
Pre-1970	265	10,584.0	3,258.7
1970-1974	258	14,024.6	4,206.3
1975-1979	95	10,371.5	2,473.4
1980-1984	38	822.8	199.3
1985-1989	84	2,738.5	195.3
1990-1994	193	11,645.8	1,359.8
1995-1999	128	9,070.7	1,656.6
2000-2004	396	37,734.2	6,345.5
2005-2009	118	15,505.8	1,729.6
2010-2014	99	11,409.8	241.2
2015-2019	67	8,892.4	2,684.2
Total	1,741	132,800.1	24,349.9

Notes: Petroleum liquids include 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, waste oil, and propane.

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

Chapter 5

Consumption of Fossil Fuels

**Table 5.1.A. Coal: Consumption for Electricity Generation,
by Sector, 2009 - 2019 (Thousand Tons)**

		Electric Power Sector			
Period	Total (all sectors)	Electric Utilities	Independent Power Producers	Commercial Sector	Industrial Sector
Annual Totals					
2009	934,683	695,615	234,077	317	4,674
2010	979,684	721,431	249,814	314	8,125
2011	934,938	689,316	239,541	347	5,735
2012	825,734	615,467	205,295	307	4,665
2013	860,729	638,327	217,219	513	4,670
2014	853,634	624,235	224,568	202	4,629
2015	739,594	539,506	195,927	163	3,999
2016	677,371	496,192	178,047	111	3,021
2017	663,911	484,389	176,643	95	2,783
2018	636,213	473,617	159,976	87	2,534
2019	537,620	399,545	135,838	76	2,161
Year 2017					
January	63,460	46,708	16,471	11	270
February	47,985	35,491	12,240	9	245
March	48,840	35,655	12,926	9	250
April	44,279	31,403	12,656	6	214
May	50,897	37,373	13,294	6	224
June	58,852	43,744	14,881	6	221
July	69,769	51,971	17,560	7	230
August	65,761	48,954	16,574	7	227
September	54,713	39,390	15,098	8	218
October	50,015	36,190	13,591	7	227
November	50,882	35,778	14,873	8	222
December	58,457	41,733	16,479	9	236
Year 2018					
January	64,845	47,762	16,817	11	255
February	45,793	34,002	11,552	9	230
March	44,474	32,312	11,930	8	224
April	40,515	30,350	9,965	7	193
May	47,293	35,261	11,815	6	211
June	56,078	42,502	13,360	6	210
July	63,818	48,277	15,322	6	212
August	63,737	47,866	15,660	7	204
September	53,914	40,293	13,415	7	199
October	48,422	35,547	12,695	6	173
November	51,702	37,956	13,537	7	202
December	55,624	41,488	13,908	7	221
Year 2019					
January	55,834	41,306	14,305	8	214
February	45,025	33,349	11,471	8	197
March	43,976	31,666	12,133	9	168
April	33,353	24,495	8,691	6	161
May	40,015	30,285	9,547	6	178
June	44,218	33,558	10,482	4	174
July	55,863	42,319	13,345	5	193
August	52,349	39,741	12,412	5	190
September	47,188	35,453	11,554	6	175
October	37,431	27,150	10,119	6	157
November	41,907	30,453	11,274	6	173
December	40,461	29,769	10,505	7	180

Notes: Beginning with the collection of Form EIA-923 in January 2008, the methodology to allocate total fuel consumption for electricity generation and consumption for useful thermal output was changed.

The new methodology was retroactively applied to 2004-2007 data. See the Technical Notes (Appendix C) for further information. See Glossary for definitions.

Values are final. See Technical Notes for a discussion of the sample design for the Form EIA-923 and predecessor forms.

Coal includes anthracite, bituminous, subbituminous, lignite, and waste coal; synthetic coal and refined coal; and beginning in 2011, coal-derived synthesis gas. Prior to 2011 coal-derived synthesis gas was included in Other Gases.

See the Technical Notes for fuel conversion factors.

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

Sources: U.S. Energy Information Administration, Form EIA-906, Power Plant Report; U.S. Energy Information Administration, Form EIA-920

Combined Heat and Power Plant Report, and predecessor forms.

Beginning with 2008 data, the Form EIA-923, Power Plant Operations Report, replaced the following: Form EIA-906, Power Plant Report; Form EIA-920, Combined Heat and Power Plant Report.

**Table 5.1.B. Coal: Consumption for Useful Thermal Output,
by Sector, 2009 - 2019 (Thousand Tons)**

		Electric Power Sector			
Period	Total (all sectors)	Electric Utilities	Independent Power Producers	Commercial Sector	Industrial Sector
Annual Totals					
2009	20,507	0	3,935	1,481	15,091
2010	21,727	0	3,808	1,406	16,513
2011	21,532	0	3,628	1,321	16,584
2012	19,333	0	2,790	1,143	15,400
2013	18,350	0	2,416	843	15,090
2014	18,107	978	1,821	861	14,448
2015	16,632	1,032	1,980	635	12,985
2016	16,586	2,979	1,336	572	11,700
2017	14,667	2,802	1,158	515	10,192
2018	13,813	2,268	1,356	490	9,700
2019	12,397	2,062	1,161	443	8,731
Year 2017					
January	1,470	300	117	59	995
February	1,198	213	104	48	832
March	1,293	238	106	57	892
April	1,128	221	78	36	793
May	1,137	209	75	34	819
June	1,152	211	84	34	823
July	1,203	254	96	40	813
August	1,215	256	100	36	824
September	1,102	207	86	38	771
October	1,223	223	94	35	871
November	1,261	263	98	44	856
December	1,285	208	119	56	903
Year 2018					
January	1,434	237	144	65	987
February	1,285	216	126	51	892
March	1,254	202	119	49	885
April	1,095	188	100	40	767
May	1,081	173	106	33	769
June	1,081	184	107	30	759
July	1,078	189	105	34	750
August	1,064	181	103	35	745
September	1,061	183	97	38	743
October	984	159	72	35	718
November	1,167	173	141	40	813
December	1,229	182	135	40	872
Year 2019					
January	1,312	198	158	51	905
February	1,158	189	114	47	808
March	1,112	189	110	49	764
April	1,009	141	102	34	732
May	941	123	90	33	695
June	950	161	95	23	671
July	950	171	97	30	653
August	974	190	88	32	664
September	914	168	73	34	640
October	985	174	81	31	699
November	1,019	174	76	38	731
December	1,072	184	76	42	770

Notes: Beginning with the collection of Form EIA-923 in January 2008, the methodology to allocate total fuel consumption for electricity generation and consumption for useful thermal output was changed.

The new methodology was retroactively applied to 2004-2007 data. See the Technical Notes (Appendix C) for further information. See Glossary for definitions.

Values are final. See Technical Notes for a discussion of the sample design for the Form EIA-923 and predecessor forms.

Coal includes anthracite, bituminous, subbituminous, lignite, and waste coal; synthetic coal and refined coal; and beginning in 2011, coal-derived synthesis gas. Prior to 2011 coal-derived synthesis gas was included in Other Gases.

See the Technical Notes for fuel conversion factors.

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

Sources: U.S. Energy Information Administration, Form EIA-906, Power Plant Report; U.S. Energy Information Administration, Form EIA-920

Combined Heat and Power Plant Report, and predecessor forms.

Beginning with 2008 data, the Form EIA-923, Power Plant Operations Report, replaced the following: Form EIA-906, Power Plant Report; Form EIA-920, Combined Heat and Power Plant Report.

Table 5.1.C. Coal: Consumption for Electricity Generation and Useful Thermal Output, by Sector, 2009 - 2019 (Thousand Tons)

		Electric Power Sector			
Period	Total (all sectors)	Electric Utilities	Independent Power Producers	Commercial Sector	Industrial Sector
Annual Totals					
2009	955,190	695,615	238,012	1,798	19,766
2010	1,001,411	721,431	253,621	1,720	24,638
2011	956,470	689,316	243,168	1,668	22,319
2012	845,066	615,467	208,085	1,450	20,065
2013	879,078	638,327	219,635	1,356	19,761
2014	871,741	625,212	226,389	1,063	19,076
2015	756,226	540,538	197,906	798	16,984
2016	693,958	499,172	179,383	683	14,720
2017	678,578	487,192	177,801	610	12,975
2018	650,027	475,885	161,332	577	12,233
2019	550,017	401,607	136,998	519	10,892
Year 2017					
January	64,930	47,008	16,588	71	1,264
February	49,183	35,705	12,344	58	1,077
March	50,132	35,893	13,032	66	1,142
April	45,407	31,624	12,735	42	1,007
May	52,034	37,582	13,370	39	1,043
June	60,004	43,955	14,965	40	1,044
July	70,972	52,225	17,656	47	1,043
August	66,976	49,209	16,673	43	1,050
September	55,815	39,596	15,184	45	989
October	51,239	36,413	13,686	42	1,098
November	52,143	36,042	14,971	52	1,078
December	59,742	41,940	16,598	66	1,139
Year 2018					
January	66,279	47,999	16,961	76	1,242
February	47,079	34,219	11,679	59	1,122
March	45,728	32,513	12,049	57	1,109
April	41,610	30,538	10,065	47	960
May	48,374	35,435	11,921	39	979
June	57,159	42,687	13,467	36	969
July	64,895	48,467	15,427	40	962
August	64,801	48,047	15,763	42	949
September	54,975	40,475	13,512	45	943
October	49,406	35,706	12,768	42	891
November	52,868	38,129	13,677	47	1,015
December	56,853	41,670	14,043	47	1,093
Year 2019					
January	57,146	41,504	14,463	59	1,119
February	46,183	33,539	11,586	54	1,005
March	45,088	31,855	12,243	58	932
April	34,362	24,636	8,793	40	893
May	40,956	30,408	9,637	38	873
June	45,168	33,720	10,577	27	844
July	56,813	42,490	13,442	35	846
August	53,323	39,931	12,500	37	854
September	48,103	35,621	11,628	40	814
October	38,417	27,323	10,200	37	856
November	42,926	30,628	11,350	44	904
December	41,533	29,953	10,581	49	950

Notes: Beginning with the collection of Form EIA-923 in January 2008, the methodology to allocate total fuel consumption for electricity generation and consumption for useful thermal output was changed.

The new methodology was retroactively applied to 2004-2007 data. See the Technical Notes (Appendix C) for further information. See Glossary for definitions.

Values are final. See Technical Notes for a discussion of the sample design for the Form EIA-923 and predecessor forms.

Coal includes anthracite, bituminous, subbituminous, lignite, and waste coal; synthetic coal and refined coal; and beginning in 2011, coal-derived synthesis gas. Prior to 2011 coal-derived synthesis gas was included in Other Gases.

See the Technical Notes for fuel conversion factors.

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

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

Beginning with 2008 data, the Form EIA-923, Power Plant Operations Report, replaced the following: Form EIA-906, Power Plant Report; Form EIA-920, Combined Heat and Power Plant Report.

Table 5.1.D. Coal: Consumption for Electricity Generation, by Sector, 2009 - 2019 (Billion Btus)

		Electric Power Sector			
Period	Total (all sectors)	Electric Utilities	Independent Power Producers	Commercial Sector	Industrial Sector
Annual Totals					
2009	18,240,611	13,744,178	4,390,596	7,007	98,829
2010	19,196,315	14,333,496	4,709,686	6,815	146,318
2011	18,074,298	13,551,416	4,399,144	7,263	116,475
2012	15,867,141	11,995,971	3,767,011	6,383	97,775
2013	16,509,468	12,421,537	3,981,216	9,444	97,270
2014	16,472,004	12,217,628	4,154,134	4,344	95,898
2015	14,167,878	10,456,910	3,624,869	3,443	82,656
2016	12,979,911	9,641,625	3,274,103	2,293	61,889
2017	12,606,527	9,328,961	3,219,833	1,914	55,820
2018	12,037,444	9,041,357	2,944,321	1,736	50,029
2019	10,166,309	7,623,281	2,498,944	1,509	42,575
Year 2017					
January	1,200,949	894,562	300,722	238	5,428
February	907,774	677,464	225,239	194	4,876
March	934,820	690,256	239,313	187	5,064
April	849,821	613,913	231,356	117	4,435
May	970,719	724,208	241,926	112	4,473
June	1,125,322	850,061	270,677	127	4,458
July	1,336,227	1,009,439	322,063	148	4,577
August	1,249,577	943,848	301,025	137	4,567
September	1,029,569	752,508	272,541	157	4,363
October	941,498	695,389	241,428	139	4,542
November	950,247	676,718	268,997	162	4,370
December	1,110,004	800,595	304,546	195	4,667
Year 2018					
January	1,244,183	925,236	313,697	231	5,019
February	861,400	642,512	214,188	184	4,516
March	843,941	615,379	223,981	162	4,419
April	764,142	577,004	183,171	133	3,833
May	897,675	675,299	218,106	121	4,149
June	1,069,511	819,784	245,472	114	4,140
July	1,211,799	922,838	284,640	123	4,199
August	1,208,987	915,915	288,894	135	4,044
September	1,014,778	767,264	243,419	138	3,958
October	907,352	675,385	228,441	117	3,409
November	965,757	716,357	245,287	139	3,973
December	1,047,918	788,385	255,025	138	4,371
Year 2019					
January	1,058,823	786,243	268,166	166	4,248
February	838,849	624,443	210,371	154	3,881
March	828,164	600,433	224,131	185	3,415
April	629,315	466,253	159,689	123	3,250
May	763,488	588,629	171,298	105	3,456
June	829,510	636,160	189,866	74	3,409
July	1,063,468	810,341	249,251	98	3,778
August	991,865	759,041	229,009	98	3,717
September	901,139	683,373	214,211	117	3,439
October	705,106	520,520	181,422	118	3,046
November	792,714	583,352	205,856	126	3,380
December	763,869	564,494	195,673	146	3,556

Notes: Beginning with the collection of Form EIA-923 in January 2008, the methodology to allocate total fuel consumption for electricity generation and consumption for useful thermal output was changed.

The new methodology was retroactively applied to 2004-2007 data. See the Technical Notes (Appendix C) for further information. See Glossary for definitions.

Values are final. See Technical Notes for a discussion of the sample design for the Form EIA-923 and predecessor forms.

Coal includes anthracite, bituminous, subbituminous, lignite, and waste coal; synthetic coal and refined coal; and beginning in 2011, coal-derived synthesis gas. Prior to 2011 coal-derived synthesis gas was included in Other Gases.

See the Technical Notes for fuel conversion factors.

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

Sources: U.S. Energy Information Administration, Form EIA-906, Power Plant Report; U.S. Energy Information Administration, Form EIA-920

Combined Heat and Power Plant Report, and predecessor forms.

Beginning with 2008 data, the Form EIA-923, Power Plant Operations Report, replaced the following: Form EIA-906, Power Plant Report; Form EIA-920, Combined Heat and Power Plant Report.

**Table 5.1.E. Coal: Consumption for Useful Thermal Output,
by Sector, 2009 - 2019 (Billion Btus)**

		Electric Power Sector			
Period	Total (all sectors)	Electric Utilities	Independent Power Producers	Commercial Sector	Industrial Sector
Annual Totals					
2009	462,674	0	90,867	32,651	339,156
2010	490,931	0	90,184	30,725	370,022
2011	479,822	0	84,855	28,056	366,911
2012	420,923	0	58,275	23,673	338,975
2013	401,108	0	47,677	18,535	334,897
2014	391,550	18,332	37,139	18,805	317,274
2015	356,895	18,640	37,815	13,483	286,956
2016	342,370	51,590	29,330	11,736	249,714
2017	297,521	48,745	24,682	10,284	213,810
2018	278,277	38,513	28,829	9,719	201,217
2019	247,251	33,559	25,686	8,571	179,436
Year 2017					
January	29,761	5,162	2,524	1,194	20,883
February	24,175	3,662	2,172	966	17,375
March	26,114	4,069	2,292	1,125	18,627
April	23,166	3,834	1,753	720	16,859
May	23,095	3,697	1,703	677	17,018
June	23,522	3,737	1,779	678	17,327
July	24,291	4,509	2,038	813	16,931
August	24,587	4,500	2,062	710	17,315
September	22,578	3,663	1,898	748	16,269
October	24,856	3,851	2,040	659	18,307
November	25,263	4,533	1,992	869	17,869
December	26,112	3,527	2,428	1,125	19,031
Year 2018					
January	29,072	4,032	3,117	1,353	20,569
February	25,883	3,681	2,508	1,019	18,675
March	25,351	3,449	2,553	979	18,371
April	22,087	3,256	2,109	800	15,923
May	21,807	3,009	2,249	633	15,916
June	21,792	3,174	2,288	596	15,734
July	21,795	3,202	2,298	663	15,632
August	21,520	3,063	2,255	691	15,512
September	21,039	3,042	1,864	741	15,392
October	19,687	2,697	1,579	682	14,730
November	23,428	2,861	3,081	784	16,702
December	24,814	3,047	2,929	778	18,060
Year 2019					
January	26,507	3,253	3,590	997	18,667
February	23,132	3,102	2,419	931	16,680
March	22,498	3,035	2,448	976	16,039
April	20,420	2,310	2,280	666	15,164
May	18,923	2,002	2,074	622	14,226
June	18,934	2,665	2,087	418	13,763
July	18,828	2,837	2,047	572	13,372
August	19,330	3,116	1,994	610	13,610
September	18,125	2,675	1,600	658	13,192
October	19,298	2,778	1,830	593	14,097
November	20,082	2,812	1,672	716	14,882
December	21,177	2,974	1,646	813	15,744

Notes: Beginning with the collection of Form EIA-923 in January 2008, the methodology to allocate total fuel consumption for electricity generation and consumption for useful thermal output was changed.

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Values are final. See Technical Notes for a discussion of the sample design for the Form EIA-923 and predecessor forms.

Coal includes anthracite, bituminous, subbituminous, lignite, and waste coal; synthetic coal and refined coal; and beginning in 2011, coal-derived synthesis gas. Prior to 2011 coal-derived synthesis gas was included in Other Gases.

See the Technical Notes for fuel conversion factors.

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

Sources: U.S. Energy Information Administration, Form EIA-906, Power Plant Report; U.S. Energy Information Administration, Form EIA-920

Combined Heat and Power Plant Report, and predecessor forms.

Beginning with 2008 data, the Form EIA-923, Power Plant Operations Report, replaced the following: Form EIA-906, Power Plant Report; Form EIA-920, Combined Heat and Power Plant Report.

Table 5.1.F. Coal: Consumption for Electricity Generation and Useful Thermal Output, by Sector, 2009 - 2019 (Billion Btus)

		Electric Power Sector			
Period	Total (all sectors)	Electric Utilities	Independent Power Producers	Commercial Sector	Industrial Sector
Annual Totals					
2009	18,703,284	13,744,178	4,481,463	39,658	437,985
2010	19,687,246	14,333,496	4,799,870	37,540	516,341
2011	18,554,120	13,551,416	4,483,999	35,319	483,385
2012	16,288,063	11,995,971	3,825,286	30,056	436,750
2013	16,910,576	12,421,537	4,028,894	27,979	432,167
2014	16,863,554	12,235,960	4,191,273	23,149	413,173
2015	14,524,773	10,475,551	3,662,685	16,926	369,612
2016	13,322,281	9,693,215	3,303,433	14,029	311,604
2017	12,904,048	9,377,705	3,244,514	12,198	269,630
2018	12,315,720	9,079,870	2,973,150	11,455	251,245
2019	10,413,560	7,656,840	2,524,630	10,080	222,011
Year 2017					
January	1,230,710	899,723	303,245	1,432	26,310
February	931,949	681,127	227,411	1,160	22,251
March	960,934	694,325	241,606	1,312	23,691
April	872,987	617,747	233,109	837	21,294
May	993,814	727,905	243,630	790	21,490
June	1,148,844	853,799	272,456	804	21,785
July	1,360,518	1,013,948	324,101	961	21,508
August	1,274,165	948,348	303,087	847	21,883
September	1,052,147	756,171	274,439	905	20,632
October	966,354	699,240	243,468	798	22,849
November	975,510	681,251	270,989	1,031	22,239
December	1,136,115	804,122	306,975	1,320	23,698
Year 2018					
January	1,273,255	929,268	316,814	1,585	25,589
February	887,284	646,193	216,696	1,203	23,191
March	869,293	618,828	226,534	1,141	22,789
April	786,229	580,260	185,280	933	19,756
May	919,483	678,308	220,355	754	20,065
June	1,091,302	822,958	247,760	710	19,874
July	1,233,595	926,040	286,938	786	19,831
August	1,230,507	918,977	291,149	825	19,556
September	1,035,817	770,306	245,282	879	19,350
October	927,039	678,082	230,020	799	18,139
November	989,185	719,218	248,368	923	20,675
December	1,072,732	791,432	257,954	916	22,431
Year 2019					
January	1,085,331	789,496	271,757	1,163	22,915
February	861,980	627,545	212,790	1,085	20,561
March	850,662	603,468	226,579	1,161	19,453
April	649,735	468,563	161,969	788	18,414
May	782,411	590,631	173,372	726	17,682
June	848,443	638,825	191,954	492	17,173
July	1,082,295	813,178	251,298	669	17,150
August	1,011,195	762,157	231,002	708	17,327
September	919,264	686,047	215,811	775	16,631
October	724,403	523,298	183,252	710	17,143
November	812,796	586,163	207,528	842	18,263
December	785,046	567,469	197,319	959	19,299

Notes: Beginning with the collection of Form EIA-923 in January 2008, the methodology to allocate total fuel consumption for electricity generation and consumption for useful thermal output was changed. The new methodology was retroactively applied to 2004-2007 data. See the Technical Notes (Appendix C) for further information. See Glossary for definitions.

Values are final. See Technical Notes for a discussion of the sample design for the Form EIA-923 and predecessor forms.

Coal includes anthracite, bituminous, subbituminous, lignite, and waste coal; synthetic coal and refined coal; and beginning in 2011, coal-derived synthesis gas. Prior to 2011 coal-derived synthesis gas was included in Other Gases.

See the Technical Notes for fuel conversion factors.

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

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

Beginning with 2008 data, the Form EIA-923, Power Plant Operations Report, replaced the following: Form EIA-906, Power Plant Report; Form EIA-920, Combined Heat and Power Plant Report.

Table 5.2.A. Petroleum Liquids: Consumption for Electricity Generation, by Sector, 2009 - 2019 (Thousand Barrels)

		Electric Power Sector				
Period	Total (all sectors)	Electric Utilities	Independent Power Producers	Commercial Sector	Industrial Sector	
Annual Totals						
2009	43,562	31,847	9,880	184	1,652	
2010	40,103	30,806	8,278	164	855	
2011	27,326	20,844	5,633	133	716	
2012	22,604	17,521	4,110	272	702	
2013	23,231	16,827	5,494	328	582	
2014	31,531	19,652	10,689	451	739	
2015	28,925	18,562	9,473	249	641	
2016	22,405	16,137	5,624	108	536	
2017	21,696	15,567	5,461	191	476	
2018	28,614	18,345	9,467	269	534	
2019	20,836	15,677	4,464	251	444	
Year 2017						
January	1,901	1,410	425	20	45	
February	1,536	1,137	347	12	40	
March	1,677	1,342	281	15	38	
April	1,508	1,173	288	10	37	
May	1,711	1,285	376	15	36	
June	1,742	1,296	398	13	35	
July	1,600	1,179	371	16	34	
August	1,704	1,260	392	18	35	
September	1,633	1,205	376	14	39	
October	1,706	1,325	328	13	40	
November	1,617	1,183	374	15	45	
December	3,360	1,772	1,505	31	52	
Year 2018						
January	9,468	4,469	4,861	66	72	
February	1,451	1,118	270	14	49	
March	1,497	1,096	348	12	42	
April	1,601	1,169	383	15	34	
May	1,863	1,340	463	18	43	
June	1,895	1,378	464	18	35	
July	1,753	1,216	454	27	56	
August	1,870	1,295	516	24	35	
September	1,863	1,401	411	18	33	
October	1,814	1,368	390	16	40	
November	1,799	1,281	452	22	45	
December	1,740	1,216	455	20	49	
Year 2019						
January	2,506	1,672	755	32	46	
February	1,482	1,099	327	15	42	
March	1,476	1,159	263	16	38	
April	1,417	1,046	313	15	44	
May	1,702	1,305	346	17	33	
June	1,747	1,369	328	17	33	
July	1,818	1,328	436	24	30	
August	1,868	1,473	340	21	34	
September	1,669	1,305	302	27	35	
October	1,709	1,305	347	23	34	
November	1,626	1,228	339	23	37	
December	1,816	1,388	369	22	37	

Notes: Beginning with the collection of Form EIA-923 in January 2008, the methodology to allocate total fuel consumption for electricity generation and consumption for useful thermal output was changed.

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Values are final. See Technical Notes for a discussion of the sample design for the Form EIA-923 and predecessor forms.

Petroleum Liquids includes distillate and residual fuel oils, jet fuel, kerosene, waste oil, and beginning in 2011, propane. Prior to 2011 propane was included in Other Gases.

See the Technical Notes for fuel conversion factors.

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

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

Beginning with 2008 data, the Form EIA-923, Power Plant Operations Report, replaced the following: Form EIA-906, Power Plant Report; Form EIA-920, Combined Heat and Power Plant Report.

Table 5.2.B. Petroleum Liquids: Consumption for Useful Thermal Output, by Sector, 2009 - 2019 (Thousand Barrels)

		Electric Power Sector			
Period	Total (all sectors)	Electric Utilities	Independent Power Producers	Commercial Sector	Industrial Sector
Annual Totals					
2009	8,128	0	1,301	293	6,534
2010	4,866	0	1,086	212	3,567
2011	3,826	0	1,004	168	2,654
2012	3,097	0	992	122	1,984
2013	3,456	0	1,050	498	1,908
2014	3,099	64	1,170	216	1,650
2015	3,142	62	1,155	282	1,643
2016	2,277	68	245	245	1,719
2017	2,012	72	220	238	1,482
2018	2,614	103	354	350	1,807
2019	2,162	71	226	419	1,446
Year 2017					
January	198	12	37	36	113
February	136	8	17	23	87
March	151	4	8	26	113
April	141	3	10	12	117
May	137	3	12	14	107
June	120	5	13	10	92
July	117	4	12	13	89
August	119	3	10	14	91
September	134	4	18	11	102
October	143	4	16	13	110
November	242	4	19	19	200
December	373	18	47	46	262
Year 2018					
January	701	58	132	109	402
February	179	4	12	25	138
March	156	3	13	21	118
April	136	3	12	17	104
May	147	4	18	16	109
June	162	5	14	15	128
July	156	3	11	28	114
August	143	4	12	23	104
September	130	7	15	15	93
October	190	5	16	16	153
November	228	3	20	30	174
December	287	3	80	35	169
Year 2019					
January	404	18	42	58	287
February	195	9	22	30	135
March	160	5	18	29	108
April	143	4	16	17	106
May	228	5	16	120	86
June	115	3	16	12	83
July	110	3	12	24	71
August	124	5	11	23	84
September	138	5	20	28	86
October	140	5	18	21	96
November	249	4	17	32	195
December	157	5	16	26	109

Notes: Beginning with the collection of Form EIA-923 in January 2008, the methodology to allocate total fuel consumption for electricity generation and consumption for useful thermal output was changed.

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Values are final. See Technical Notes for a discussion of the sample design for the Form EIA-923 and predecessor forms.

Petroleum Liquids includes distillate and residual fuel oils, jet fuel, kerosene, waste oil, and beginning in 2011, propane. Prior to 2011 propane was included in Other Gases.

See the Technical Notes for fuel conversion factors.

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

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

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Table 5.2.C. Petroleum Liquids: Consumption for Electricity Generation and Useful Thermal Output, by Sector, 2009 - 2019 (Thousand Barrels)

		Electric Power Sector				
Period	Total (all sectors)	Electric Utilities	Independent Power Producers	Commercial Sector	Industrial Sector	
Annual Totals						
2009	51,690	31,847	11,181	477	8,185	
2010	44,968	30,806	9,364	376	4,422	
2011	31,152	20,844	6,637	301	3,370	
2012	25,702	17,521	5,102	394	2,685	
2013	26,687	16,827	6,544	826	2,490	
2014	34,630	19,716	11,859	667	2,389	
2015	32,067	18,624	10,629	531	2,283	
2016	24,682	16,205	5,869	352	2,255	
2017	23,708	15,640	5,681	429	1,958	
2018	31,228	18,448	9,820	619	2,341	
2019	22,998	15,748	4,690	670	1,890	
Year 2017						
January	2,099	1,422	462	56	158	
February	1,672	1,146	364	35	127	
March	1,828	1,346	290	41	151	
April	1,650	1,176	298	22	154	
May	1,848	1,288	388	29	143	
June	1,862	1,301	411	23	127	
July	1,717	1,183	383	29	123	
August	1,823	1,263	402	33	125	
September	1,768	1,208	394	24	141	
October	1,849	1,329	344	26	150	
November	1,860	1,187	394	34	245	
December	3,734	1,790	1,552	78	314	
Year 2018						
January	10,169	4,527	4,993	175	474	
February	1,630	1,122	282	39	187	
March	1,653	1,099	361	33	160	
April	1,738	1,172	395	32	138	
May	2,010	1,343	480	34	152	
June	2,057	1,383	478	33	164	
July	1,909	1,219	465	55	170	
August	2,012	1,298	528	46	140	
September	1,993	1,407	426	34	127	
October	2,003	1,373	406	31	193	
November	2,027	1,284	472	52	219	
December	2,027	1,220	534	55	218	
Year 2019						
January	2,911	1,691	797	90	333	
February	1,678	1,108	349	44	177	
March	1,635	1,164	281	44	145	
April	1,560	1,049	329	32	150	
May	1,929	1,311	362	137	119	
June	1,862	1,372	344	29	117	
July	1,928	1,332	448	48	101	
August	1,992	1,478	352	44	118	
September	1,807	1,310	321	54	121	
October	1,848	1,309	365	44	130	
November	1,875	1,231	356	55	232	
December	1,972	1,393	385	48	146	

Notes: Beginning with the collection of Form EIA-923 in January 2008, the methodology to allocate total fuel consumption for electricity generation and consumption for useful thermal output was changed.

The new methodology was retroactively applied to 2004-2007 data. See the Technical Notes (Appendix C) for further information. See Glossary for definitions.

Values are final. See Technical Notes for a discussion of the sample design for the Form EIA-923 and predecessor forms.

Petroleum Liquids includes distillate and residual fuel oils, jet fuel, kerosene, waste oil, and beginning in 2011, propane. Prior to 2011 propane was included in Other Gases.

See the Technical Notes for fuel conversion factors.

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

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

Beginning with 2008 data, the Form EIA-923, Power Plant Operations Report, replaced the following: Form EIA-906, Power Plant Report; Form EIA-920, Combined Heat and Power Plant Report.

Table 5.2.D. Petroleum Liquids: Consumption for Electricity Generation, by Sector, 2009 - 2019 (Billion Btus)

		Electric Power Sector			
Period	Total (all sectors)	Electric Utilities	Independent Power Producers	Commercial Sector	Industrial Sector
Annual Totals					
2009	266,508	196,346	59,277	1,101	9,784
2010	244,114	188,987	49,042	970	5,115
2011	163,954	125,755	33,166	801	4,233
2012	134,956	105,179	24,081	1,618	4,078
2013	139,139	101,217	32,504	2,038	3,380
2014	188,814	118,226	63,488	2,765	4,335
2015	172,884	111,808	55,979	1,482	3,616
2016	133,457	96,967	32,922	639	2,928
2017	128,649	92,975	31,895	1,125	2,654
2018	169,663	109,734	55,433	1,579	2,916
2019	122,591	93,088	25,678	1,466	2,359
Year 2017					
January	11,190	8,387	2,434	117	252
February	9,084	6,751	2,048	70	215
March	9,887	7,958	1,626	88	215
April	8,921	6,984	1,669	58	210
May	10,155	7,684	2,186	86	198
June	10,349	7,786	2,299	75	189
July	9,510	7,060	2,168	94	188
August	10,150	7,562	2,289	107	193
September	9,677	7,215	2,166	79	217
October	10,152	7,961	1,890	79	222
November	9,559	7,050	2,163	89	257
December	20,015	10,576	8,957	184	298
Year 2018					
January	56,277	26,582	28,891	387	416
February	8,576	6,672	1,557	84	263
March	8,849	6,526	2,027	69	227
April	9,497	6,984	2,242	88	183
May	11,024	8,040	2,653	105	226
June	11,266	8,316	2,652	107	191
July	10,412	7,314	2,661	156	280
August	11,110	7,771	3,005	139	196
September	11,112	8,453	2,362	107	190
October	10,729	8,200	2,220	92	217
November	10,637	7,650	2,606	130	251
December	10,173	7,225	2,556	114	278
Year 2019					
January	14,739	9,930	4,366	187	256
February	8,675	6,498	1,866	86	225
March	8,661	6,854	1,510	91	205
April	8,308	6,209	1,785	86	228
May	9,986	7,741	1,975	100	169
June	10,289	8,141	1,876	99	173
July	10,743	7,908	2,538	139	158
August	11,039	8,791	1,945	121	183
September	9,817	7,760	1,716	156	186
October	10,036	7,746	1,972	136	182
November	9,666	7,293	2,041	135	197
December	10,630	8,215	2,088	129	198

Notes: Beginning with the collection of Form EIA-923 in January 2008, the methodology to allocate total fuel consumption for electricity generation and consumption for useful thermal output was changed.

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Petroleum Liquids includes distillate and residual fuel oils, jet fuel, kerosene, waste oil, and beginning in 2011, propane. Prior to 2011 propane was included in Other Gases.

See the Technical Notes for fuel conversion factors.

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

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

Beginning with 2008 data, the Form EIA-923, Power Plant Operations Report, replaced the following: Form EIA-906, Power Plant Report; Form EIA-920, Combined Heat and Power Plant Report.

Table 5.2.E. Petroleum Liquids: Consumption for Useful Thermal Output, by Sector, 2009 - 2019 (Billion Btus)

		Electric Power Sector			
Period	Total (all sectors)	Electric Utilities	Independent Power Producers	Commercial Sector	Industrial Sector
Annual Totals					
2009	48,912	0	7,557	1,802	39,552
2010	29,243	0	6,402	1,297	21,545
2011	22,799	0	5,927	1,039	15,833
2012	18,233	0	5,871	746	11,616
2013	20,717	0	6,176	3,292	11,248
2014	18,181	395	6,802	1,311	9,672
2015	18,449	379	6,748	1,755	9,568
2016	13,164	395	1,391	1,496	9,882
2017	11,825	405	1,253	1,432	8,736
2018	15,163	598	1,951	2,082	10,533
2019	12,383	403	1,319	2,472	8,189
Year 2017					
January	1,136	70	194	217	654
February	774	36	102	143	493
March	894	23	49	156	666
April	829	17	56	73	683
May	798	19	72	86	622
June	695	27	73	61	533
July	681	19	73	75	514
August	693	18	62	85	528
September	791	20	104	65	603
October	837	22	94	78	643
November	1,471	22	116	114	1,219
December	2,227	111	259	279	1,578
Year 2018					
January	4,121	353	733	645	2,390
February	1,046	26	71	148	801
March	898	17	77	127	677
April	794	17	71	105	601
May	848	20	106	94	628
June	942	28	82	89	743
July	873	18	63	166	625
August	832	21	70	134	608
September	760	38	86	90	546
October	1,104	27	92	94	891
November	1,353	17	120	181	1,035
December	1,592	19	379	208	987
Year 2019					
January	2,342	107	229	341	1,664
February	1,123	50	130	179	764
March	923	28	109	171	614
April	806	20	97	100	589
May	1,299	31	95	700	473
June	649	17	95	74	462
July	626	18	70	142	396
August	699	30	67	134	467
September	786	26	117	164	479
October	800	25	109	121	544
November	1,432	22	103	187	1,121
December	899	29	97	158	615

Notes: Beginning with the collection of Form EIA-923 in January 2008, the methodology to allocate total fuel consumption for electricity generation and consumption for useful thermal output was changed.

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Petroleum Liquids includes distillate and residual fuel oils, jet fuel, kerosene, waste oil, and beginning in 2011, propane. Prior to 2011 propane was included in Other Gases.

See the Technical Notes for fuel conversion factors.

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

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

Beginning with 2008 data, the Form EIA-923, Power Plant Operations Report, replaced the following: Form EIA-906, Power Plant Report; Form EIA-920, Combined Heat and Power Plant Report.

Table 5.2.F. Petroleum Liquids: Consumption for Electricity Generation and Useful Thermal Output, by Sector, 2009 - 2019 (Billion Btus)

		Electric Power Sector			
Period	Total (all sectors)	Electric Utilities	Independent Power Producers	Commercial Sector	Industrial Sector
Annual Totals					
2009	315,420	196,346	66,834	2,903	49,336
2010	273,357	188,987	55,444	2,267	26,660
2011	186,753	125,755	39,093	1,840	20,066
2012	153,189	105,179	29,952	2,364	15,695
2013	159,855	101,217	38,681	5,330	14,628
2014	206,995	118,621	70,291	4,076	14,008
2015	191,333	112,186	62,727	3,236	13,184
2016	146,621	97,363	34,313	2,135	12,810
2017	140,474	93,380	33,148	2,557	11,389
2018	184,826	110,332	57,383	3,661	13,449
2019	134,974	93,491	26,998	3,937	10,548
Year 2017					
January	12,326	8,457	2,628	334	906
February	9,858	6,788	2,150	212	707
March	10,781	7,981	1,675	244	881
April	9,749	7,001	1,725	131	892
May	10,953	7,703	2,258	172	820
June	11,045	7,813	2,372	136	723
July	10,190	7,080	2,241	168	702
August	10,843	7,580	2,350	192	721
September	10,468	7,235	2,270	144	819
October	10,988	7,983	1,984	157	865
November	11,030	7,072	2,279	203	1,476
December	22,243	10,687	9,216	464	1,877
Year 2018					
January	60,398	26,935	29,625	1,032	2,806
February	9,622	6,697	1,628	232	1,064
March	9,747	6,543	2,105	195	904
April	10,291	7,002	2,313	193	784
May	11,872	8,060	2,759	199	854
June	12,208	8,344	2,734	196	934
July	11,284	7,332	2,725	323	905
August	11,942	7,792	3,074	273	804
September	11,872	8,491	2,448	198	736
October	11,834	8,227	2,312	186	1,107
November	11,990	7,667	2,725	312	1,286
December	11,765	7,244	2,935	322	1,264
Year 2019					
January	17,081	10,038	4,595	527	1,921
February	9,798	6,549	1,996	265	988
March	9,584	6,883	1,619	263	819
April	9,114	6,229	1,883	186	816
May	11,285	7,772	2,070	801	643
June	10,938	8,159	1,971	173	635
July	11,369	7,926	2,609	281	554
August	11,738	8,821	2,011	255	650
September	10,603	7,786	1,833	319	665
October	10,836	7,772	2,082	257	725
November	11,099	7,315	2,144	322	1,318
December	11,529	8,244	2,185	286	813

Notes: Beginning with the collection of Form EIA-923 in January 2008, the methodology to allocate total fuel consumption for electricity generation and consumption for useful thermal output was changed.

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Petroleum Liquids includes distillate and residual fuel oils, jet fuel, kerosene, waste oil, and beginning in 2011, propane. Prior to 2011 propane was included in Other Gases.

See the Technical Notes for fuel conversion factors.

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

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

Beginning with 2008 data, the Form EIA-923, Power Plant Operations Report, replaced the following: Form EIA-906, Power Plant Report; Form EIA-920, Combined Heat and Power Plant Report.

**Table 5.3.A. Petroleum Coke: Consumption for Electricity Generation,
by Sector, 2009 - 2019 (Thousand Tons)**

		Electric Power Sector			
Period	Total (all sectors)	Electric Utilities	Independent Power Producers	Commercial Sector	Industrial Sector
Annual Totals					
2009	4,821	2,761	1,724	1	335
2010	4,994	3,325	1,354	2	313
2011	5,012	3,449	1,277	1	286
2012	3,675	2,105	756	1	812
2013	4,852	3,409	779	1	662
2014	4,412	3,440	599	2	371
2015	4,044	3,120	669	2	253
2016	4,253	3,427	591	2	233
2017	3,490	2,731	542	3	214
2018	3,623	2,740	704	2	177
2019	2,724	2,067	478	1	177
Year 2017					
January	368	301	51	0	15
February	277	217	44	0	15
March	265	214	31	0	20
April	168	110	41	0	16
May	329	264	49	0	16
June	350	282	48	0	20
July	344	271	51	0	22
August	300	226	52	0	22
September	276	209	50	0	16
October	228	171	40	0	18
November	293	234	40	0	18
December	292	231	44	0	16
Year 2018					
January	377	296	67	0	14
February	305	234	60	0	11
March	255	198	43	0	13
April	271	193	63	0	15
May	212	140	58	0	14
June	338	269	51	0	18
July	367	284	66	0	17
August	352	272	66	0	15
September	325	259	50	0	15
October	229	158	54	0	16
November	271	196	63	0	13
December	321	241	65	0	16
Year 2019					
January	326	258	54	0	13
February	272	222	39	0	11
March	235	193	28	0	13
April	155	107	32	0	16
May	294	219	60	0	14
June	216	151	51	0	14
July	309	227	58	0	24
August	276	203	58	0	15
September	231	183	33	0	15
October	83	64	3	0	15
November	129	101	15	0	14
December	197	137	46	0	14

Notes: Beginning with the collection of Form EIA-923 in January 2008, the methodology to allocate total fuel consumption for electricity generation and consumption for useful thermal output was changed.

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Values are final. See Technical Notes for a discussion of the sample design for the Form EIA-923 and predecessor forms.

Petroleum Coke includes petroleum coke-derived synthesis gas. Prior to 2011, petroleum coke-derived synthesis gas was included in Other Gases.

See the Technical Notes for fuel conversion factors.

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

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

Beginning with 2008 data, the Form EIA-923, Power Plant Operations Report, replaced the following: Form EIA-906, Power Plant Report; Form EIA-920, Combined Heat and Power Plant Report.

Table 5.3.B. Petroleum Coke: Consumption for Useful Thermal Output, by Sector, 2009 - 2019 (Thousand Tons)

		Electric Power Sector			
Period	Total (all sectors)	Electric Utilities	Independent Power Producers	Commercial Sector	Industrial Sector
Annual Totals					
2009	1,007	0	126	8	873
2010	1,059	0	98	11	950
2011	1,080	0	112	6	962
2012	1,346	0	113	11	1,222
2013	1,486	0	96	11	1,379
2014	1,283	3	90	16	1,174
2015	1,144	9	109	16	1,010
2016	1,099	6	113	9	971
2017	977	11	115	15	836
2018	929	12	93	10	814
2019	839	17	93	6	724
Year 2017					
January	81	0	10	2	70
February	69	0	10	1	58
March	90	1	10	2	77
April	74	0	10	1	63
May	78	1	10	1	66
June	91	1	9	1	80
July	86	1	10	0	75
August	90	2	9	2	77
September	76	1	9	2	64
October	85	1	9	1	74
November	80	1	9	1	69
December	76	1	10	2	63
Year 2018					
January	88	1	9	2	76
February	78	1	8	2	67
March	72	1	9	1	61
April	83	1	10	1	71
May	70	1	6	0	63
June	75	1	1	0	73
July	81	1	9	0	71
August	77	1	9	0	66
September	74	1	7	1	65
October	77	0	9	1	67
November	71	1	8	2	61
December	83	1	8	2	72
Year 2019					
January	73	1	8	2	62
February	66	1	8	1	55
March	73	1	9	1	62
April	71	2	9	1	59
May	70	1	9	0	61
June	70	1	7	0	62
July	76	2	8	0	65
August	69	0	8	0	61
September	79	2	7	0	69
October	64	1	2	0	61
November	57	2	9	0	46
December	72	2	9	1	60

Notes: Beginning with the collection of Form EIA-923 in January 2008, the methodology to allocate total fuel consumption for electricity generation and consumption for useful thermal output was changed.

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Petroleum Coke includes petroleum coke-derived synthesis gas. Prior to 2011, petroleum coke-derived synthesis gas was included in Other Gases.

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

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

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Table 5.3.C. Petroleum Coke: Consumption for Electricity Generation and Useful Thermal Output, by Sector, 2009 - 2019 (Thousand Tons)

		Electric Power Sector				
Period	Total (all sectors)	Electric Utilities	Independent Power Producers	Commercial Sector	Industrial Sector	
Annual Totals						
2009	5,828	2,761	1,850	9	1,209	
2010	6,053	3,325	1,452	12	1,264	
2011	6,092	3,449	1,388	6	1,248	
2012	5,021	2,105	869	13	2,034	
2013	6,338	3,409	875	12	2,041	
2014	5,695	3,443	689	18	1,545	
2015	5,188	3,128	779	18	1,263	
2016	5,352	3,433	705	10	1,204	
2017	4,467	2,742	657	17	1,050	
2018	4,552	2,752	797	12	991	
2019	3,563	2,083	571	7	900	
Year 2017						
January	449	301	61	2	85	
February	347	218	54	1	74	
March	355	215	41	2	97	
April	241	110	51	1	79	
May	406	265	59	1	82	
June	441	283	57	1	100	
July	430	272	60	0	98	
August	390	228	61	2	99	
September	352	211	60	2	80	
October	314	172	49	2	91	
November	373	235	49	1	87	
December	368	233	54	2	80	
Year 2018						
January	466	297	76	2	90	
February	382	235	68	2	78	
March	327	199	52	2	74	
April	354	195	72	1	86	
May	281	141	63	0	77	
June	413	270	52	0	91	
July	448	285	75	0	88	
August	429	273	75	0	81	
September	399	260	58	1	80	
October	306	159	63	1	83	
November	342	196	70	2	74	
December	404	242	73	2	88	
Year 2019						
January	399	260	62	2	75	
February	338	224	47	1	66	
March	308	194	37	2	75	
April	227	110	41	1	74	
May	364	220	69	0	75	
June	287	152	58	0	76	
July	385	230	66	0	89	
August	346	203	66	0	76	
September	310	185	40	0	84	
October	146	65	5	0	76	
November	186	102	24	0	60	
December	269	139	55	1	74	

Notes: Beginning with the collection of Form EIA-923 in January 2008, the methodology to allocate total fuel consumption for electricity generation and consumption for useful thermal output was changed.

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Petroleum Coke includes petroleum coke-derived synthesis gas. Prior to 2011, petroleum coke-derived synthesis gas was included in Other Gases.

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**Table 5.3.D. Petroleum Coke: Consumption for Electricity Generation,
by Sector, 2009 - 2019 (Billion Btus)**

		Electric Power Sector			
Period	Total (all sectors)	Electric Utilities	Independent Power Producers	Commercial Sector	Industrial Sector
Annual Totals					
2009	136,474	77,919	48,776	32	9,747
2010	141,774	94,331	38,235	44	9,165
2011	144,406	99,257	36,923	20	8,206
2012	105,488	60,862	21,643	39	22,944
2013	138,774	97,626	22,052	38	19,058
2014	123,736	95,642	17,032	59	11,003
2015	113,568	87,210	18,889	58	7,411
2016	118,303	94,892	16,591	47	6,774
2017	94,136	72,919	15,100	72	6,045
2018	100,362	73,895	21,327	57	5,083
2019	74,970	56,411	13,472	37	5,050
Year 2017					
January	9,816	7,962	1,411	9	434
February	7,611	5,942	1,225	6	439
March	7,257	5,813	864	8	573
April	4,481	2,859	1,154	3	466
May	8,922	7,123	1,351	4	444
June	9,520	7,640	1,338	3	539
July	9,185	7,140	1,420	2	623
August	8,115	6,024	1,461	9	620
September	7,540	5,658	1,418	9	455
October	6,092	4,478	1,114	6	494
November	7,861	6,242	1,111	4	504
December	7,735	6,038	1,234	9	454
Year 2018					
January	10,384	7,942	2,030	9	403
February	8,297	6,172	1,814	8	303
March	6,943	5,268	1,282	9	384
April	7,506	5,193	1,892	3	418
May	5,886	3,704	1,757	0	425
June	9,342	7,272	1,553	0	517
July	10,232	7,741	2,003	0	488
August	9,875	7,469	1,984	0	422
September	9,022	7,059	1,515	4	443
October	6,353	4,237	1,638	5	472
November	7,587	5,320	1,900	9	358
December	8,935	6,517	1,958	10	449
Year 2019					
January	8,808	6,917	1,522	10	359
February	7,433	6,030	1,079	7	316
March	6,367	5,167	810	8	382
April	4,444	3,063	904	7	469
May	8,002	5,898	1,688	0	416
June	6,199	4,342	1,448	0	409
July	8,365	6,078	1,623	0	664
August	7,657	5,605	1,626	0	427
September	6,427	5,076	941	0	411
October	2,236	1,716	98	0	422
November	3,682	2,867	433	0	382
December	5,350	3,653	1,299	4	394

Notes: Beginning with the collection of Form EIA-923 in January 2008, the methodology to allocate total fuel consumption for electricity generation and consumption for useful thermal output was changed.

The new methodology was retroactively applied to 2004-2007 data. See the Technical Notes (Appendix C) for further information. See Glossary for definitions.

Values are final. See Technical Notes for a discussion of the sample design for the Form EIA-923 and predecessor forms.

Petroleum Coke includes petroleum coke-derived synthesis gas. Prior to 2011, petroleum coke-derived synthesis gas was included in Other Gases.

See the Technical Notes for fuel conversion factors.

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

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

Beginning with 2008 data, the Form EIA-923, Power Plant Operations Report, replaced the following: Form EIA-906, Power Plant Report; Form EIA-920, Combined Heat and Power Plant Report.

Table 5.3.E. Petroleum Coke: Consumption for Useful Thermal Output, by Sector, 2009 - 2019 (Billion Btus)

		Electric Power Sector			
Period	Total (all sectors)	Electric Utilities	Independent Power Producers	Commercial Sector	Industrial Sector
Annual Totals					
2009	29,974	0	3,652	213	26,109
2010	31,303	0	2,855	296	28,152
2011	31,943	0	3,244	153	28,546
2012	38,777	0	3,281	315	35,181
2013	40,846	0	2,769	305	37,772
2014	36,602	90	2,597	449	33,467
2015	33,138	255	3,167	446	29,269
2016	32,473	159	3,255	241	28,817
2017	28,680	297	3,335	403	24,645
2018	27,398	332	2,693	284	24,088
2019	24,348	470	2,681	164	21,032
Year 2017					
January	2,369	5	279	53	2,032
February	2,059	11	273	31	1,744
March	2,628	17	298	46	2,268
April	2,201	3	288	15	1,895
May	2,295	20	295	20	1,960
June	2,638	24	274	14	2,326
July	2,528	32	275	10	2,211
August	2,676	56	270	55	2,295
September	2,244	31	265	52	1,896
October	2,534	26	276	35	2,197
November	2,320	35	257	21	2,007
December	2,187	36	286	50	1,815
Year 2018					
January	2,579	36	275	51	2,217
February	2,283	24	230	44	1,984
March	2,135	27	255	39	1,815
April	2,419	39	277	16	2,087
May	2,113	24	167	0	1,922
June	2,229	31	38	0	2,160
July	2,400	31	255	0	2,114
August	2,280	29	261	0	1,990
September	2,213	23	211	25	1,954
October	2,309	11	260	23	2,015
November	2,053	26	227	42	1,757
December	2,386	31	237	45	2,073
Year 2019					
January	2,121	33	224	48	1,815
February	1,906	37	235	27	1,607
March	2,129	27	249	37	1,817
April	2,108	73	257	33	1,746
May	2,059	15	248	0	1,796
June	2,056	24	209	0	1,822
July	2,178	72	221	0	1,885
August	1,985	6	239	0	1,740
September	2,277	64	208	0	2,005
October	1,842	17	61	0	1,764
November	1,641	43	263	0	1,335
December	2,045	60	268	18	1,699

Notes: Beginning with the collection of Form EIA-923 in January 2008, the methodology to allocate total fuel consumption for electricity generation and consumption for useful thermal output was changed.

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Petroleum Coke includes petroleum coke-derived synthesis gas. Prior to 2011, petroleum coke-derived synthesis gas was included in Other Gases.

See the Technical Notes for fuel conversion factors.

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

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

Beginning with 2008 data, the Form EIA-923, Power Plant Operations Report, replaced the following: Form EIA-906, Power Plant Report; Form EIA-920, Combined Heat and Power Plant Report.

Table 5.3.F. Petroleum Coke: Consumption for Electricity Generation and Useful Thermal Output, by Sector, 2009 - 2019 (Billion Btus)

		Electric Power Sector			
Period	Total (all sectors)	Electric Utilities	Independent Power Producers	Commercial Sector	Industrial Sector
Annual Totals					
2009	166,449	77,919	52,428	245	35,856
2010	173,078	94,331	41,090	340	37,317
2011	176,349	99,257	40,167	173	36,752
2012	144,266	60,862	24,925	353	58,126
2013	179,621	97,626	24,821	343	56,831
2014	160,338	95,731	19,629	508	44,470
2015	146,706	87,465	22,056	505	36,680
2016	150,776	95,051	19,846	288	35,591
2017	122,816	73,216	18,435	475	30,690
2018	127,760	74,227	24,020	341	29,171
2019	99,318	56,881	16,153	201	26,083
Year 2017					
January	12,185	7,967	1,690	63	2,466
February	9,671	5,953	1,498	37	2,183
March	9,885	5,829	1,161	54	2,841
April	6,682	2,862	1,442	18	2,361
May	11,217	7,144	1,646	24	2,404
June	12,158	7,664	1,612	17	2,865
July	11,712	7,172	1,695	11	2,834
August	10,791	6,080	1,731	65	2,915
September	9,784	5,690	1,683	61	2,350
October	8,626	4,503	1,390	41	2,691
November	10,181	6,276	1,368	26	2,511
December	9,922	6,074	1,521	58	2,269
Year 2018					
January	12,964	7,978	2,305	60	2,621
February	10,580	6,196	2,045	52	2,287
March	9,078	5,295	1,536	48	2,199
April	9,926	5,233	2,169	19	2,505
May	7,999	3,728	1,925	0	2,346
June	11,571	7,303	1,591	0	2,677
July	12,632	7,773	2,258	0	2,602
August	12,155	7,498	2,244	0	2,413
September	11,234	7,082	1,726	29	2,397
October	8,662	4,248	1,898	28	2,487
November	9,640	5,346	2,127	51	2,116
December	11,321	6,548	2,195	55	2,522
Year 2019					
January	10,929	6,950	1,746	59	2,174
February	9,339	6,067	1,315	34	1,924
March	8,496	5,194	1,058	46	2,198
April	6,552	3,136	1,161	41	2,215
May	10,060	5,913	1,936	0	2,211
June	8,255	4,366	1,657	0	2,232
July	10,543	6,150	1,844	0	2,549
August	9,642	5,611	1,864	0	2,167
September	8,704	5,139	1,148	0	2,416
October	4,078	1,733	159	0	2,187
November	5,323	2,910	696	0	1,717
December	7,395	3,712	1,567	23	2,093

Notes: Beginning with the collection of Form EIA-923 in January 2008, the methodology to allocate total fuel consumption for electricity generation and consumption for useful thermal output was changed.

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Petroleum Coke includes petroleum coke-derived synthesis gas. Prior to 2011, petroleum coke-derived synthesis gas was included in Other Gases.

See the Technical Notes for fuel conversion factors.

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

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

Beginning with 2008 data, the Form EIA-923, Power Plant Operations Report, replaced the following: Form EIA-906, Power Plant Report; Form EIA-920, Combined Heat and Power Plant Report.

Table 5.4.A. Natural Gas: Consumption for Electricity Generation, by Sector, 2009 - 2019 (Million Cubic Feet)

		Electric Power Sector			
Period	Total (all sectors)	Electric Utilities	Independent Power Producers	Commercial Sector	Industrial Sector
Annual Totals					
2009	7,121,069	2,911,279	3,655,712	34,279	519,799
2010	7,680,185	3,290,993	3,794,423	39,462	555,307
2011	7,883,865	3,446,087	3,819,107	47,170	571,501
2012	9,484,710	4,101,927	4,686,260	63,116	633,407
2013	8,596,299	3,970,447	3,917,131	66,570	642,152
2014	8,544,387	3,895,008	3,954,032	71,957	623,390
2015	10,016,576	4,745,255	4,576,683	70,092	624,545
2016	10,170,110	5,018,894	4,571,375	46,304	533,537
2017	9,508,062	4,754,893	4,161,984	50,060	541,126
2018	10,833,043	5,551,181	4,663,935	52,650	565,276
2019	11,601,600	5,969,422	4,958,798	55,575	617,805
Year 2017					
January	680,323	337,744	291,564	4,242	46,773
February	588,021	292,116	250,305	3,800	41,801
March	690,819	351,273	290,929	4,062	44,554
April	647,308	331,864	268,629	3,561	43,255
May	720,158	374,092	298,415	3,835	43,816
June	872,286	435,724	386,279	4,378	45,904
July	1,104,270	552,590	497,819	4,912	48,948
August	1,043,343	516,908	474,369	4,804	47,262
September	877,043	432,895	397,619	4,352	42,177
October	791,359	385,130	358,651	4,091	43,488
November	686,661	340,219	298,198	3,766	44,478
December	806,472	404,337	349,206	4,257	48,671
Year 2018					
January	805,929	425,891	327,351	4,145	48,542
February	706,517	363,824	296,296	3,886	42,511
March	772,448	395,826	329,151	4,071	43,400
April	722,667	372,401	303,383	3,616	43,268
May	868,518	459,568	359,038	4,201	45,712
June	973,956	520,305	402,054	4,633	46,963
July	1,245,648	639,299	549,546	5,518	51,285
August	1,208,900	605,610	546,123	5,593	51,575
September	1,051,922	530,570	468,776	4,838	47,737
October	909,338	457,374	400,338	4,290	47,335
November	784,673	395,480	337,321	3,760	48,112
December	782,527	385,034	344,559	4,098	48,836
Year 2019					
January	873,321	441,671	373,529	4,566	53,555
February	801,111	411,897	338,638	4,217	46,359
March	835,730	431,601	350,686	4,516	48,926
April	762,597	398,966	313,343	4,173	46,115
May	863,169	458,759	350,386	4,217	49,806
June	1,016,521	538,873	422,755	4,619	50,274
July	1,283,658	657,397	566,007	5,625	54,630
August	1,305,990	676,294	568,683	5,493	55,519
September	1,108,966	572,673	478,814	4,824	52,654
October	964,547	493,811	414,452	4,356	51,926
November	846,614	423,092	366,212	4,253	53,057
December	939,376	464,388	415,293	4,715	54,981

Notes: Beginning with the collection of Form EIA-923 in January 2008, the methodology to allocate total fuel consumption for electricity generation and consumption for useful thermal output was changed.

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Values are final. See Technical Notes for a discussion of the sample design for the Form EIA-923 and predecessor forms.

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

Sources: U.S. Energy Information Administration, Form EIA-906, Power Plant Report; U.S. Energy Information Administration, Form EIA-920

Combined Heat and Power Plant Report, and predecessor forms.

Beginning with 2008 data, the Form EIA-923, Power Plant Operations Report, replaced the following: Form EIA-906, Power Plant Report; Form EIA-920, Combined Heat and Power Plant Report.

Table 5.4.B. Natural Gas: Consumption for Useful Thermal Output, by Sector, 2009 - 2019 (Million Cubic Feet)

		Electric Power Sector			
Period	Total (all sectors)	Electric Utilities	Independent Power Producers	Commercial Sector	Industrial Sector
Annual Totals					
2009	816,787	0	305,542	41,275	469,970
2010	821,775	0	301,769	46,324	473,683
2011	839,681	0	308,669	39,856	491,155
2012	886,103	0	322,607	47,883	515,613
2013	882,385	0	303,177	51,057	528,151
2014	865,146	4,926	292,016	46,635	521,569
2015	935,098	8,060	283,372	46,287	597,379
2016	1,151,866	38,096	356,905	80,943	675,922
2017	1,168,544	38,740	309,949	104,324	715,532
2018	1,205,962	43,156	331,952	81,856	748,997
2019	1,196,025	42,645	317,231	79,734	756,415
Year 2017					
January	101,549	3,706	27,280	9,873	60,690
February	90,407	3,220	23,641	8,410	55,135
March	97,294	3,494	27,032	8,162	58,606
April	89,369	2,988	23,820	6,875	55,687
May	91,989	3,096	24,254	7,268	57,371
June	95,015	2,718	25,783	8,423	58,091
July	103,478	3,437	27,754	9,924	62,363
August	101,700	3,212	27,478	9,947	61,063
September	97,286	2,968	25,062	8,898	60,357
October	97,642	3,045	25,404	8,648	60,544
November	95,784	3,124	24,761	8,412	59,488
December	107,031	3,731	27,680	9,485	66,136
Year 2018					
January	107,213	3,929	28,934	7,417	66,933
February	94,793	3,366	26,629	6,706	58,093
March	100,213	3,557	28,088	6,844	61,724
April	92,932	2,942	25,265	6,133	58,592
May	94,707	3,306	26,238	6,099	59,064
June	97,016	3,642	26,642	6,537	60,196
July	107,003	4,484	30,339	7,649	64,531
August	105,929	4,079	29,861	7,691	64,297
September	99,289	3,479	27,089	6,581	62,140
October	99,045	3,013	27,218	6,411	62,402
November	101,846	3,185	27,080	6,829	64,751
December	105,976	4,174	28,570	6,959	66,273
Year 2019					
January	108,272	3,951	29,369	7,409	67,543
February	97,224	3,804	24,972	6,793	61,656
March	101,583	3,690	27,549	6,684	63,661
April	91,878	2,748	24,623	6,027	58,480
May	94,224	2,863	24,079	5,727	61,556
June	95,837	3,342	25,592	6,130	60,772
July	102,404	3,983	27,280	7,354	63,786
August	104,051	4,098	28,829	6,950	64,175
September	97,399	3,762	25,526	6,377	61,734
October	96,976	2,931	25,473	6,171	62,402
November	100,030	3,527	26,036	6,628	63,839
December	106,147	3,946	27,902	7,486	66,812

Notes: Beginning with the collection of Form EIA-923 in January 2008, the methodology to allocate total fuel consumption for electricity generation and consumption for useful thermal output was changed.

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Values are final. See Technical Notes for a discussion of the sample design for the Form EIA-923 and predecessor forms.

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

Sources: U.S. Energy Information Administration, Form EIA-906, Power Plant Report; U.S. Energy Information Administration, Form EIA-920

Combined Heat and Power Plant Report, and predecessor forms.

Beginning with 2008 data, the Form EIA-923, Power Plant Operations Report, replaced the following: Form EIA-906, Power Plant Report; Form EIA-920, Combined Heat and Power Plant Report.

Table 5.4.C. Natural Gas: Consumption for Electricity Generation and Useful Thermal Output, by Sector, 2009 - 2019 (Million Cubic Feet)

		Electric Power Sector			
Period	Total (all sectors)	Electric Utilities	Independent Power Producers	Commercial Sector	Industrial Sector
Annual Totals					
2009	7,937,856	2,911,279	3,961,254	75,555	989,769
2010	8,501,960	3,290,993	4,096,192	85,786	1,028,990
2011	8,723,546	3,446,087	4,127,777	87,026	1,062,657
2012	10,370,812	4,101,927	5,008,867	110,999	1,149,020
2013	9,478,685	3,970,447	4,220,309	117,626	1,170,303
2014	9,409,532	3,899,934	4,246,048	118,591	1,144,959
2015	10,951,674	4,753,315	4,860,055	116,380	1,221,924
2016	11,321,975	5,056,990	4,928,280	127,246	1,209,459
2017	10,676,606	4,793,632	4,471,933	154,383	1,256,658
2018	12,039,005	5,594,338	4,995,888	134,507	1,314,273
2019	12,797,626	6,012,067	5,276,029	135,310	1,374,220
Year 2017					
January	781,872	341,450	318,844	14,114	107,463
February	678,428	295,336	273,946	12,210	96,936
March	788,112	354,767	317,961	12,224	103,160
April	736,677	334,851	292,448	10,435	98,942
May	812,147	377,189	322,669	11,102	101,187
June	967,301	438,443	412,062	12,802	103,994
July	1,207,748	556,028	525,573	14,836	111,310
August	1,145,043	520,120	501,847	14,751	108,326
September	974,328	435,863	422,681	13,250	102,535
October	889,001	388,175	384,055	12,739	104,032
November	782,445	343,343	322,959	12,177	103,966
December	913,503	408,068	376,887	13,742	114,807
Year 2018					
January	913,142	429,820	356,285	11,562	115,475
February	801,310	367,190	322,924	10,592	100,604
March	872,661	399,383	357,239	10,914	105,124
April	815,600	375,343	328,647	9,750	101,860
May	963,226	462,873	385,276	10,300	104,776
June	1,070,972	523,947	428,696	11,170	107,159
July	1,352,652	643,783	579,885	13,167	115,816
August	1,314,829	609,689	575,984	13,285	115,872
September	1,151,210	534,049	495,866	11,419	109,877
October	1,008,383	460,387	427,556	10,702	109,738
November	886,519	398,665	364,401	10,589	112,863
December	888,503	389,208	373,128	11,058	115,109
Year 2019					
January	981,593	445,621	402,898	11,975	121,099
February	898,335	415,700	363,610	11,010	108,015
March	937,313	435,291	378,235	11,200	112,587
April	854,475	401,714	337,966	10,200	104,595
May	957,393	461,622	374,465	9,944	111,362
June	1,112,358	542,215	448,347	10,749	111,046
July	1,386,062	661,380	593,287	12,979	118,416
August	1,410,041	680,392	597,512	12,443	119,694
September	1,206,364	576,435	504,340	11,201	114,389
October	1,061,523	496,742	439,925	10,527	114,328
November	946,645	426,619	392,248	10,881	116,896
December	1,045,523	468,333	443,195	12,201	121,793

Notes: Beginning with the collection of Form EIA-923 in January 2008, the methodology to allocate total fuel consumption for electricity generation and consumption for useful thermal output was changed.

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

Sources: U.S. Energy Information Administration, Form EIA-906, Power Plant Report; U.S. Energy Information Administration, Form EIA-920

Combined Heat and Power Plant Report, and predecessor forms.

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Table 5.4.D. Natural Gas: Consumption for Electricity Generation, by Sector, 2009 - 2019 (Billion Btus)

		Electric Power Sector			
Period	Total (all sectors)	Electric Utilities	Independent Power Producers	Commercial Sector	Industrial Sector
Annual Totals					
2009	7,301,522	2,981,285	3,750,080	35,046	535,111
2010	7,852,665	3,359,035	3,882,995	40,356	570,279
2011	8,052,309	3,511,732	3,906,484	48,509	585,584
2012	9,696,575	4,179,725	4,802,741	64,987	649,122
2013	8,813,288	4,059,838	4,026,793	67,918	658,740
2014	8,795,303	4,001,826	4,076,787	74,194	642,495
2015	10,360,990	4,905,009	4,739,438	71,929	644,615
2016	10,515,826	5,189,543	4,728,444	47,550	550,288
2017	9,827,794	4,911,629	4,308,241	51,592	556,331
2018	11,191,452	5,730,408	4,825,957	54,390	580,696
2019	11,996,976	6,166,728	5,137,826	57,028	635,394
Year 2017					
January	703,875	349,666	302,008	4,368	47,833
February	607,776	301,718	259,154	3,915	42,989
March	713,669	362,690	301,014	4,188	45,776
April	668,682	342,733	277,802	3,669	44,479
May	743,595	386,053	308,547	3,934	45,060
June	901,473	450,067	399,664	4,508	47,234
July	1,142,502	571,579	515,481	5,060	50,383
August	1,079,042	534,306	491,131	4,951	48,654
September	907,689	447,592	412,178	4,490	43,429
October	817,248	397,175	371,168	4,220	44,685
November	708,836	350,721	308,473	3,889	45,753
December	833,407	417,330	361,621	4,400	50,056
Year 2018					
January	832,763	439,632	338,891	4,297	49,943
February	729,643	375,307	306,626	4,024	43,685
March	798,583	408,805	341,003	4,213	44,562
April	745,888	383,881	313,808	3,744	44,456
May	896,969	474,489	371,190	4,322	46,968
June	1,005,861	536,851	415,986	4,775	48,249
July	1,286,597	660,362	567,947	5,689	52,598
August	1,248,419	625,212	564,433	5,775	52,999
September	1,087,420	548,304	485,082	5,011	49,023
October	939,342	471,956	414,310	4,446	48,630
November	810,660	407,831	349,539	3,876	49,415
December	809,307	397,779	357,144	4,217	50,168
Year 2019					
January	901,900	455,045	387,180	4,684	54,991
February	827,416	424,560	350,869	4,326	47,662
March	862,791	444,842	363,075	4,635	50,238
April	787,711	412,207	323,855	4,288	47,361
May	890,239	472,669	362,071	4,323	51,176
June	1,049,852	556,057	437,389	4,738	51,668
July	1,328,690	680,354	586,332	5,762	56,242
August	1,353,214	700,522	589,832	5,629	57,230
September	1,147,718	591,980	496,535	4,954	54,249
October	997,755	510,360	429,551	4,473	53,371
November	876,616	437,601	380,018	4,370	54,627
December	973,075	480,530	431,121	4,845	56,579

Notes: Beginning with the collection of Form EIA-923 in January 2008, the methodology to allocate total fuel consumption for electricity generation and consumption for useful thermal output was changed.

The new methodology was retroactively applied to 2004-2007 data. See the Technical Notes (Appendix C) for further information. See Glossary for definitions.

Values are final. See Technical Notes for a discussion of the sample design for the Form EIA-923 and predecessor forms.

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

Sources: U.S. Energy Information Administration, Form EIA-906, Power Plant Report; U.S. Energy Information Administration, Form EIA-920

Combined Heat and Power Plant Report, and predecessor forms.

Beginning with 2008 data, the Form EIA-923, Power Plant Operations Report, replaced the following: Form EIA-906, Power Plant Report; Form EIA-920, Combined Heat and Power Plant Report.

Table 5.4.E. Natural Gas: Consumption for Useful Thermal Output, by Sector, 2009 - 2019 (Billion Btus)

		Electric Power Sector			
Period	Total (all sectors)	Electric Utilities	Independent Power Producers	Commercial Sector	Industrial Sector
Annual Totals					
2009	836,863	0	312,553	42,032	482,279
2010	841,521	0	308,246	47,001	486,274
2011	861,006	0	315,411	40,976	504,619
2012	909,087	0	330,354	48,944	529,788
2013	905,583	0	311,058	51,939	542,587
2014	891,994	5,033	300,870	47,579	538,514
2015	965,573	8,254	292,629	47,573	617,118
2016	1,188,399	39,123	367,919	83,938	697,418
2017	1,204,582	39,828	318,611	107,987	738,156
2018	1,242,771	44,393	341,707	85,108	771,563
2019	1,232,925	43,862	327,203	82,455	779,405
Year 2017					
January	104,758	3,813	28,045	10,223	62,676
February	93,160	3,310	24,273	8,706	56,871
March	100,229	3,588	27,763	8,440	60,438
April	92,042	3,069	24,463	7,102	57,408
May	94,753	3,181	24,908	7,500	59,164
June	97,955	2,795	26,507	8,718	59,935
July	106,716	3,537	28,533	10,280	64,365
August	104,854	3,308	28,247	10,300	63,000
September	100,432	3,053	25,827	9,217	62,336
October	100,639	3,126	26,136	8,955	62,422
November	98,711	3,206	25,452	8,716	61,336
December	110,333	3,842	28,457	9,829	68,204
Year 2018					
January	110,628	4,042	29,790	7,723	69,074
February	97,708	3,459	27,364	6,975	59,910
March	103,291	3,651	28,924	7,105	63,610
April	95,684	3,016	25,979	6,378	60,311
May	97,553	3,393	26,998	6,338	60,824
June	99,927	3,741	27,426	6,796	61,964
July	110,227	4,625	31,245	7,946	66,410
August	109,218	4,214	30,755	7,989	66,261
September	102,279	3,587	27,861	6,855	63,976
October	102,003	3,095	27,963	6,679	64,267
November	104,969	3,272	27,893	7,097	66,706
December	109,284	4,299	29,508	7,228	68,250
Year 2019					
January	111,586	4,062	30,283	7,654	69,588
February	100,131	3,910	25,665	7,015	63,541
March	104,540	3,780	28,320	6,904	65,536
April	94,549	2,814	25,348	6,231	60,157
May	96,983	2,936	24,765	5,921	63,360
June	98,713	3,437	26,357	6,342	62,577
July	105,625	4,109	28,188	7,602	65,726
August	107,481	4,228	29,837	7,188	66,227
September	100,509	3,875	26,356	6,603	63,675
October	100,070	3,008	26,323	6,391	64,347
November	103,186	3,633	26,907	6,865	65,781
December	109,550	4,069	28,852	7,739	68,889

Notes: Beginning with the collection of Form EIA-923 in January 2008, the methodology to allocate total fuel consumption for electricity generation and consumption for useful thermal output was changed.

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Values are final. See Technical Notes for a discussion of the sample design for the Form EIA-923 and predecessor forms.

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

Sources: U.S. Energy Information Administration, Form EIA-906, Power Plant Report; U.S. Energy Information Administration, Form EIA-920

Combined Heat and Power Plant Report, and predecessor forms.

Beginning with 2008 data, the Form EIA-923, Power Plant Operations Report, replaced the following: Form EIA-906, Power Plant Report; Form EIA-920, Combined Heat and Power Plant Report.

Table 5.4.F. Natural Gas: Consumption for Electricity Generation and Useful Thermal Output, by Sector, 2009 - 2019 (Billion Btus)

		Electric Power Sector			
Period	Total (all sectors)	Electric Utilities	Independent Power Producers	Commercial Sector	Industrial Sector
Annual Totals					
2009	8,138,385	2,981,285	4,062,633	77,077	1,017,390
2010	8,694,186	3,359,035	4,191,241	87,357	1,056,553
2011	8,913,315	3,511,732	4,221,895	89,485	1,090,203
2012	10,605,661	4,179,725	5,133,095	113,932	1,178,910
2013	9,718,871	4,059,838	4,337,851	119,857	1,201,326
2014	9,687,297	4,006,859	4,377,657	121,773	1,181,009
2015	11,326,564	4,913,263	5,032,066	119,502	1,261,732
2016	11,704,224	5,228,667	5,096,363	131,489	1,247,706
2017	11,032,375	4,951,457	4,626,852	159,580	1,294,487
2018	12,434,223	5,774,801	5,167,665	139,498	1,352,259
2019	13,229,901	6,210,590	5,465,029	139,483	1,414,799
Year 2017					
January	808,633	353,479	330,054	14,591	110,509
February	700,936	305,028	283,427	12,621	99,860
March	813,898	366,278	328,777	12,628	106,215
April	760,724	345,802	302,264	10,771	101,886
May	838,347	389,234	333,454	11,435	104,225
June	999,428	452,862	426,171	13,226	107,168
July	1,249,218	575,116	544,014	15,340	114,748
August	1,183,897	537,613	519,378	15,251	111,654
September	1,008,121	450,644	438,005	13,706	105,765
October	917,888	400,301	397,304	13,175	107,108
November	807,547	353,926	333,925	12,606	107,089
December	943,740	421,172	390,078	14,229	118,260
Year 2018					
January	943,391	443,674	368,681	12,020	119,017
February	827,351	378,767	333,990	10,999	103,595
March	901,874	412,456	369,928	11,318	108,172
April	841,572	386,896	339,787	10,121	104,768
May	994,522	477,882	398,187	10,660	107,792
June	1,105,788	540,592	443,412	11,572	110,213
July	1,396,824	664,987	599,192	13,636	119,009
August	1,357,638	629,426	595,188	13,764	119,260
September	1,189,699	551,891	512,943	11,866	112,999
October	1,041,345	475,051	442,273	11,125	112,896
November	915,629	411,103	377,431	10,973	116,121
December	918,591	402,077	386,652	11,444	118,418
Year 2019					
January	1,013,486	459,106	417,463	12,338	124,578
February	927,548	428,469	376,534	11,341	111,203
March	967,331	448,623	391,394	11,540	115,774
April	882,261	415,021	349,203	10,518	107,518
May	987,221	475,605	386,836	10,244	114,536
June	1,148,565	559,494	463,746	11,080	114,245
July	1,434,315	684,463	614,520	13,363	121,968
August	1,460,694	704,751	619,669	12,817	123,457
September	1,248,228	595,855	522,891	11,557	117,924
October	1,097,826	513,369	455,874	10,864	117,718
November	979,802	441,234	406,924	11,235	120,409
December	1,082,625	484,600	459,973	12,584	125,468

Notes: Beginning with the collection of Form EIA-923 in January 2008, the methodology to allocate total fuel consumption for electricity generation and consumption for useful thermal output was changed.

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Values are final. See Technical Notes for a discussion of the sample design for the Form EIA-923 and predecessor forms.

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

Sources: U.S. Energy Information Administration, Form EIA-906, Power Plant Report; U.S. Energy Information Administration, Form EIA-920

Combined Heat and Power Plant Report, and predecessor forms.

Beginning with 2008 data, the Form EIA-923, Power Plant Operations Report, replaced the following: Form EIA-906, Power Plant Report; Form EIA-920, Combined Heat and Power Plant Report.

Table 5.5.D. Wood / Wood Waste Biomass: Consumption for Electricity Generation, by Sector, 2009 - 2019 (Billion Btus)

		Electric Power Sector			
Period	Total (all sectors)	Electric Utilities	Independent Power Producers	Commercial Sector	Industrial Sector
Annual Totals					
2009	320,444	29,565	130,894	274	159,712
2010	349,530	40,167	137,072	274	172,016
2011	347,623	35,474	130,108	482	181,559
2012	390,342	32,723	138,217	478	218,924
2013	397,929	43,363	143,721	536	210,308
2014	431,285	45,643	174,513	961	210,167
2015	406,650	43,919	171,387	504	190,840
2016	359,983	41,036	149,516	473	168,959
2017	363,646	42,806	151,877	460	168,503
2018	361,703	45,856	143,288	520	172,039
2019	338,317	42,240	128,980	583	166,514
Year 2017					
January	31,076	4,492	12,650	56	13,878
February	28,393	3,584	11,989	50	12,771
March	31,265	4,210	13,446	26	13,584
April	27,467	3,136	11,064	34	13,232
May	28,262	2,799	11,620	43	13,800
June	30,235	3,180	12,595	38	14,422
July	32,592	3,942	13,504	41	15,105
August	33,309	3,803	14,250	41	15,214
September	28,549	2,090	13,002	15	13,442
October	28,927	3,387	11,786	33	13,720
November	30,409	3,608	12,597	41	14,163
December	33,163	4,575	13,373	43	15,172
Year 2018					
January	33,136	4,713	13,790	63	14,571
February	28,906	3,689	12,141	42	13,033
March	31,435	4,501	12,243	36	14,655
April	26,860	2,966	10,597	16	13,280
May	29,530	3,196	11,683	32	14,619
June	31,205	3,909	12,733	53	14,509
July	33,490	4,670	13,260	59	15,501
August	32,186	4,427	12,624	69	15,067
September	28,704	3,340	11,278	52	14,034
October	27,972	3,376	10,642	27	13,927
November	28,539	3,741	10,733	20	14,044
December	29,741	3,326	11,563	51	14,801
Year 2019					
January	31,330	4,132	12,533	52	14,613
February	26,761	3,408	10,117	57	13,179
March	28,083	3,232	10,362	72	14,418
April	23,804	2,677	8,499	24	12,604
May	26,723	3,451	10,257	18	12,997
June	27,518	2,894	10,815	31	13,778
July	31,373	4,740	11,694	101	14,838
August	31,913	5,205	11,694	63	14,951
September	28,163	3,594	11,078	51	13,440
October	26,246	2,962	9,729	42	13,513
November	26,964	2,194	11,052	35	13,684
December	29,438	3,751	11,151	37	14,500

Notes: Beginning with the collection of Form EIA-923 in January 2008, the methodology to allocate total fuel consumption for electricity generation and consumption for useful thermal output was changed.

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Values are final. See Technical Notes for a discussion of the sample design for the Form EIA-923 and predecessor forms.

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

Sources: U.S. Energy Information Administration, Form EIA-906, Power Plant Report; U.S. Energy Information Administration, Form EIA-920

Combined Heat and Power Plant Report, and predecessor forms.

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Table 5.5.E. Wood / Wood Waste Biomass: Consumption for Useful Thermal Output, by Sector, 2009 - 2019 (Billion Btus)

		Electric Power Sector			
Period	Total (all sectors)	Electric Utilities	Independent Power Producers	Commercial Sector	Industrial Sector
Annual Totals					
2009	816,285	0	19,587	1,135	795,563
2010	876,041	0	18,357	1,064	856,620
2011	893,314	0	16,577	1,022	875,716
2012	883,158	0	19,251	949	862,958
2013	919,631	0	20,342	950	898,339
2014	946,344	8,835	22,262	3,766	911,481
2015	943,962	9,351	19,200	3,714	911,697
2016	969,841	10,950	22,905	4,520	931,465
2017	939,633	11,656	22,986	4,522	900,469
2018	929,365	10,297	21,623	4,806	892,639
2019	907,420	3,564	25,740	4,969	873,147
Year 2017					
January	81,329	1,206	2,090	525	77,508
February	74,084	1,037	1,879	430	70,738
March	80,057	1,170	2,113	299	76,475
April	74,348	1,044	1,548	295	71,461
May	75,155	716	1,623	301	72,516
June	78,685	1,007	1,641	322	75,716
July	80,804	683	1,963	355	77,803
August	81,948	989	2,010	365	78,585
September	73,629	931	2,032	233	70,432
October	77,295	893	1,972	402	74,028
November	78,977	902	1,929	473	75,674
December	83,321	1,079	2,186	524	79,532
Year 2018					
January	81,175	844	2,115	454	77,762
February	73,007	878	2,141	474	69,514
March	78,989	948	1,966	493	75,583
April	73,967	869	1,533	339	71,225
May	77,198	673	1,679	319	74,528
June	75,544	655	1,683	402	72,805
July	80,237	991	1,899	382	76,964
August	79,868	854	1,930	417	76,667
September	73,254	655	1,676	336	70,587
October	76,266	1,005	1,607	329	73,326
November	76,373	891	1,635	343	73,503
December	83,486	1,033	1,759	518	80,175
Year 2019					
January	81,039	449	2,361	544	77,685
February	73,341	412	2,142	478	70,309
March	77,242	410	2,134	436	74,262
April	72,647	421	2,095	344	69,788
May	74,589	127	2,256	356	71,850
June	73,406	186	2,365	342	70,512
July	76,941	286	2,031	403	74,220
August	77,355	190	2,179	398	74,588
September	72,370	117	2,067	394	69,791
October	74,506	233	1,711	423	72,140
November	75,571	346	2,122	442	72,662
December	78,415	386	2,277	410	75,342

Notes: Beginning with the collection of Form EIA-923 in January 2008, the methodology to allocate total fuel consumption for electricity generation and consumption for useful thermal output was changed.

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

Sources: U.S. Energy Information Administration, Form EIA-906, Power Plant Report; U.S. Energy Information Administration, Form EIA-920

Combined Heat and Power Plant Report, and predecessor forms.

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Table 5.5.F. Wood / Wood Waste Biomass: Consumption for Electricity Generation and Useful Thermal Output, by Sector, 2009 - 2019 (Billion Btus)

		Electric Power Sector			
Period	Total (all sectors)	Electric Utilities	Independent Power Producers	Commercial Sector	Industrial Sector
Annual Totals					
2009	1,136,729	29,565	150,481	1,408	955,276
2010	1,225,571	40,167	155,429	1,338	1,028,637
2011	1,240,937	35,474	146,684	1,504	1,057,275
2012	1,273,500	32,723	157,468	1,427	1,081,882
2013	1,317,560	43,363	164,063	1,486	1,108,647
2014	1,377,629	54,478	196,775	4,727	1,121,648
2015	1,350,612	53,269	190,587	4,219	1,102,537
2016	1,329,824	51,986	172,421	4,993	1,100,424
2017	1,303,279	54,462	174,862	4,982	1,068,972
2018	1,291,068	56,153	164,911	5,326	1,064,678
2019	1,245,737	45,804	154,720	5,552	1,039,661
Year 2017					
January	112,404	5,698	14,740	581	91,385
February	102,477	4,621	13,868	480	83,508
March	111,322	5,380	15,559	325	90,059
April	101,815	4,180	12,612	328	84,694
May	103,417	3,515	13,243	344	86,316
June	108,920	4,187	14,235	360	90,138
July	113,396	4,625	15,468	395	92,908
August	115,257	4,792	16,260	406	93,800
September	102,178	3,021	15,034	249	83,874
October	106,222	4,281	13,758	435	87,748
November	109,386	4,509	14,526	514	89,837
December	116,483	5,654	15,558	566	94,705
Year 2018					
January	114,312	5,557	15,905	517	92,333
February	101,913	4,567	14,282	516	82,547
March	110,425	5,449	14,209	528	90,238
April	100,826	3,835	12,131	356	84,505
May	106,728	3,869	13,362	351	89,146
June	106,749	4,564	14,416	455	87,314
July	113,727	5,661	15,160	441	92,465
August	112,054	5,281	14,554	486	91,733
September	101,958	3,995	12,954	388	84,621
October	104,238	4,381	12,248	356	87,253
November	104,912	4,633	12,368	363	87,548
December	113,227	4,360	13,322	569	94,976
Year 2019					
January	112,369	4,581	14,894	596	92,297
February	100,102	3,820	12,259	535	83,488
March	105,325	3,641	12,496	508	88,680
April	96,451	3,098	10,594	368	82,392
May	101,311	3,578	12,513	374	84,847
June	100,924	3,081	13,179	373	84,291
July	108,314	5,026	13,725	505	89,058
August	109,267	5,395	13,873	461	89,539
September	100,533	3,712	13,145	446	83,230
October	100,752	3,195	11,441	464	85,652
November	102,536	2,540	13,174	477	86,345
December	107,853	4,138	13,428	447	89,841

Notes: Beginning with the collection of Form EIA-923 in January 2008, the methodology to allocate total fuel consumption for electricity generation and consumption for useful thermal output was changed.

The new methodology was retroactively applied to 2004-2007 data. See the Technical Notes (Appendix C) for further information. See Glossary for definitions.

Values are final. See Technical Notes for a discussion of the sample design for the Form EIA-923 and predecessor forms.

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

Sources: U.S. Energy Information Administration, Form EIA-906, Power Plant Report; U.S. Energy Information Administration, Form EIA-920

Combined Heat and Power Plant Report, and predecessor forms.

Beginning with 2008 data, the Form EIA-923, Power Plant Operations Report, replaced the following: Form EIA-906, Power Plant Report; Form EIA-920, Combined Heat and Power Plant Report.

Table 5.6.A. Landfill Gas: Consumption for Electricity Generation, by Sector, 2009 - 2019 (Million Cubic Feet)

		Electric Power Sector			
Period	Total (all sectors)	Electric Utilities	Independent Power Producers	Commercial Sector	Industrial Sector
Annual Totals					
2009	206,792	19,583	180,689	5,931	589
2010	218,331	19,975	192,428	5,535	393
2011	232,795	22,086	180,856	29,469	384
2012	256,376	25,193	201,965	26,672	2,545
2013	271,967	27,259	211,942	28,143	4,623
2014	285,982	25,819	228,447	27,038	4,678
2015	282,530	25,257	227,381	25,250	4,642
2016	273,557	24,280	224,993	20,445	3,839
2017	278,112	25,074	229,050	20,121	3,866
2018	270,235	23,580	223,513	19,790	3,352
2019	257,494	22,726	214,819	16,874	3,075
Year 2017					
January	24,099	2,197	19,771	1,785	346
February	21,927	2,063	17,956	1,570	337
March	24,031	2,237	19,679	1,754	361
April	22,649	2,155	18,538	1,627	330
May	23,637	2,240	19,409	1,696	292
June	23,095	1,955	19,137	1,666	336
July	23,176	1,905	19,286	1,705	280
August	23,354	2,006	19,340	1,702	306
September	22,287	1,901	18,440	1,654	293
October	22,352	2,047	18,534	1,450	321
November	23,123	2,141	18,950	1,706	327
December	24,383	2,228	20,011	1,806	338
Year 2018					
January	23,568	2,389	19,205	1,673	301
February	22,069	2,186	17,993	1,576	314
March	23,672	2,377	19,280	1,692	324
April	22,281	2,159	18,159	1,633	330
May	22,748	2,125	18,722	1,609	291
June	21,854	1,777	18,189	1,607	281
July	22,507	1,817	18,773	1,651	266
August	23,061	1,739	19,377	1,696	249
September	20,472	1,604	17,004	1,643	222
October	22,360	1,779	18,634	1,687	259
November	22,405	1,812	18,708	1,630	255
December	23,237	1,815	19,468	1,695	259
Year 2019					
January	22,792	2,043	18,790	1,704	255
February	20,542	1,803	16,998	1,508	233
March	22,380	2,008	18,459	1,642	271
April	20,457	1,890	17,249	1,057	261
May	20,947	1,952	17,959	778	258
June	21,359	1,857	17,889	1,360	254
July	21,932	1,873	18,326	1,493	240
August	21,963	1,898	18,295	1,518	253
September	20,789	1,811	17,246	1,477	256
October	21,252	1,843	17,705	1,436	268
November	20,712	1,807	17,237	1,419	248
December	22,369	1,942	18,665	1,482	280

Notes: Beginning with the collection of Form EIA-923 in January 2008, the methodology to allocate total fuel consumption for electricity generation and consumption for useful thermal output was changed.

The new methodology was retroactively applied to 2004-2007 data. See the Technical Notes (Appendix C) for further information. See Glossary for definitions.

Values are final. See Technical Notes for a discussion of the sample design for the Form EIA-923 and predecessor forms.

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

Sources: U.S. Energy Information Administration, Form EIA-906, Power Plant Report; U.S. Energy Information Administration, Form EIA-920

Combined Heat and Power Plant Report, and predecessor forms.

Beginning with 2008 data, the Form EIA-923, Power Plant Operations Report, replaced the following: Form EIA-906, Power Plant Report; Form EIA-920, Combined Heat and Power Plant Report.

**Table 5.6.B. Landfill Gas: Consumption for Useful Thermal Output,
by Sector, 2009 - 2019 (Million Cubic Feet)**

		Electric Power Sector			
Period	Total (all sectors)	Electric Utilities	Independent Power Producers	Commercial Sector	Industrial Sector
Annual Totals					
2009	793	0	545	176	72
2010	1,623	0	1,195	370	58
2011	3,195	0	2,753	351	91
2012	3,189	0	2,788	340	61
2013	831	0	261	423	147
2014	1,710	176	525	674	335
2015	1,522	2	644	515	362
2016	4,163	3	2,339	1,034	788
2017	3,940	2	1,948	1,099	891
2018	3,621	0	1,867	911	843
2019	3,570	5	1,933	820	812
Year 2017					
January	352	0	171	94	86
February	332	0	159	92	81
March	351	0	174	92	84
April	346	0	153	107	87
May	296	0	131	85	80
June	329	0	165	89	75
July	313	0	177	85	51
August	351	0	175	98	78
September	330	0	170	98	62
October	319	0	170	93	56
November	296	0	138	85	74
December	324	0	166	81	77
Year 2018					
January	321	0	176	68	77
February	320	0	165	79	77
March	340	0	175	82	83
April	335	0	164	85	86
May	285	0	140	71	74
June	259	0	146	46	68
July	278	0	139	76	64
August	302	0	157	82	63
September	290	0	150	82	58
October	334	0	170	95	69
November	276	0	134	73	68
December	280	0	152	71	57
Year 2019					
January	331	0	181	84	66
February	301	0	175	67	58
March	357	0	203	80	73
April	362	0	184	102	75
May	250	0	112	64	74
June	283	0	146	77	59
July	282	0	166	42	73
August	267	0	128	73	65
September	264	0	125	74	65
October	317	0	168	77	71
November	284	0	155	59	70
December	273	0	190	21	62

Notes: Beginning with the collection of Form EIA-923 in January 2008, the methodology to allocate total fuel consumption for electricity generation and consumption for useful thermal output was changed.

The new methodology was retroactively applied to 2004-2007 data. See the Technical Notes (Appendix C) for further information. See Glossary for definitions.

Values are final. See Technical Notes for a discussion of the sample design for the Form EIA-923 and predecessor forms.

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

Sources: U.S. Energy Information Administration, Form EIA-906, Power Plant Report; U.S. Energy Information Administration, Form EIA-920

Combined Heat and Power Plant Report, and predecessor forms.

Beginning with 2008 data, the Form EIA-923, Power Plant Operations Report, replaced the following: Form EIA-906, Power Plant Report; Form EIA-920, Combined Heat and Power Plant Report.

Table 5.6.C. Landfill Gas: Consumption for Electricity Generation and Useful Thermal Output, by Sector, 2009 - 2019 (Million Cubic Feet)

		Electric Power Sector			
Period	Total (all sectors)	Electric Utilities	Independent Power Producers	Commercial Sector	Industrial Sector
Annual Totals					
2009	207,585	19,583	181,234	6,106	661
2010	219,954	19,975	193,623	5,905	451
2011	235,990	22,086	183,609	29,820	474
2012	259,564	25,193	204,753	27,012	2,606
2013	272,798	27,259	212,203	28,566	4,770
2014	287,692	25,995	228,971	27,713	5,013
2015	284,052	25,259	228,024	25,765	5,004
2016	277,720	24,283	227,332	21,479	4,626
2017	282,051	25,076	230,998	21,220	4,757
2018	273,856	23,580	225,380	20,701	4,196
2019	261,064	22,731	216,753	17,694	3,887
Year 2017					
January	24,451	2,197	19,942	1,880	432
February	22,259	2,063	18,116	1,662	418
March	24,382	2,237	19,853	1,846	445
April	22,995	2,155	18,690	1,734	417
May	23,933	2,240	19,539	1,781	372
June	23,423	1,955	19,302	1,754	411
July	23,489	1,905	19,463	1,789	331
August	23,704	2,006	19,515	1,800	383
September	22,617	1,901	18,609	1,752	355
October	22,670	2,047	18,704	1,543	377
November	23,419	2,141	19,088	1,791	400
December	24,707	2,228	20,176	1,887	415
Year 2018					
January	23,890	2,389	19,382	1,741	378
February	22,390	2,186	18,158	1,655	390
March	24,012	2,377	19,455	1,774	407
April	22,616	2,159	18,323	1,718	416
May	23,033	2,125	18,862	1,680	366
June	22,113	1,777	18,335	1,652	349
July	22,785	1,817	18,912	1,726	330
August	23,363	1,739	19,534	1,778	313
September	20,763	1,604	17,154	1,725	280
October	22,694	1,779	18,804	1,783	328
November	22,681	1,812	18,842	1,703	324
December	23,516	1,815	19,620	1,766	316
Year 2019					
January	23,123	2,043	18,971	1,788	321
February	20,843	1,804	17,173	1,576	291
March	22,737	2,008	18,662	1,722	344
April	20,819	1,891	17,433	1,159	336
May	21,197	1,952	18,072	842	332
June	21,642	1,857	18,035	1,438	313
July	22,214	1,874	18,492	1,535	313
August	22,230	1,898	18,423	1,591	317
September	21,053	1,811	17,371	1,550	321
October	21,569	1,843	17,873	1,514	339
November	20,996	1,807	17,392	1,478	319
December	22,642	1,942	18,855	1,503	342

Notes: Beginning with the collection of Form EIA-923 in January 2008, the methodology to allocate total fuel consumption for electricity generation and consumption for useful thermal output was changed.

The new methodology was retroactively applied to 2004-2007 data. See the Technical Notes (Appendix C) for further information. See Glossary for definitions.

Values are final. See Technical Notes for a discussion of the sample design for the Form EIA-923 and predecessor forms.

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

Sources: U.S. Energy Information Administration, Form EIA-906, Power Plant Report; U.S. Energy Information Administration, Form EIA-920

Combined Heat and Power Plant Report, and predecessor forms.

Beginning with 2008 data, the Form EIA-923, Power Plant Operations Report, replaced the following: Form EIA-906, Power Plant Report; Form EIA-920, Combined Heat and Power Plant Report.

Table 5.6.D. Landfill Gas: Consumption for Electricity Generation, by Sector, 2009 - 2019 (Billion Btus)

		Electric Power Sector			
Period	Total (all sectors)	Electric Utilities	Independent Power Producers	Commercial Sector	Industrial Sector
Annual Totals					
2009	99,821	9,748	86,773	2,999	301
2010	105,835	10,029	92,763	2,837	205
2011	112,538	11,146	89,857	11,332	203
2012	124,297	12,721	99,938	10,356	1,282
2013	132,766	13,819	105,330	11,290	2,327
2014	140,779	13,132	114,333	10,937	2,377
2015	138,085	12,846	112,911	10,023	2,304
2016	135,365	12,294	112,770	8,374	1,927
2017	137,635	13,071	114,131	8,508	1,926
2018	133,957	12,395	111,769	8,104	1,689
2019	127,540	11,794	107,100	7,086	1,560
Year 2017					
January	11,915	1,146	9,852	745	172
February	10,857	1,074	8,953	665	165
March	11,881	1,161	9,798	743	180
April	11,204	1,119	9,242	681	162
May	11,718	1,153	9,694	725	146
June	11,460	1,044	9,532	715	169
July	11,493	1,023	9,598	729	142
August	11,554	1,055	9,620	724	154
September	11,014	987	9,190	689	147
October	11,096	1,062	9,257	620	157
November	11,430	1,102	9,451	715	162
December	12,013	1,145	9,944	756	168
Year 2018					
January	11,667	1,237	9,582	699	150
February	10,937	1,129	8,994	657	157
March	11,740	1,237	9,638	704	161
April	11,060	1,150	9,069	676	165
May	11,319	1,142	9,368	664	146
June	10,808	938	9,079	650	141
July	11,116	957	9,354	671	134
August	11,416	914	9,683	690	128
September	10,140	845	8,524	658	113
October	11,091	941	9,333	685	132
November	11,142	948	9,404	660	131
December	11,522	958	9,742	690	131
Year 2019					
January	11,250	1,062	9,360	697	130
February	10,167	936	8,493	620	118
March	11,055	1,043	9,204	671	137
April	10,195	982	8,612	469	132
May	10,504	1,017	8,987	371	129
June	10,673	964	8,953	629	127
July	10,857	971	9,141	621	124
August	10,838	984	9,092	633	129
September	10,247	939	8,571	608	129
October	10,514	956	8,839	585	135
November	10,218	934	8,577	579	128
December	11,022	1,006	9,273	600	143

Notes: Beginning with the collection of Form EIA-923 in January 2008, the methodology to allocate total fuel consumption for electricity generation and consumption for useful thermal output was changed.

The new methodology was retroactively applied to 2004-2007 data. See the Technical Notes (Appendix C) for further information. See Glossary for definitions.

Values are final. See Technical Notes for a discussion of the sample design for the Form EIA-923 and predecessor forms.

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

Sources: U.S. Energy Information Administration, Form EIA-906, Power Plant Report; U.S. Energy Information Administration, Form EIA-920

Combined Heat and Power Plant Report, and predecessor forms.

Beginning with 2008 data, the Form EIA-923, Power Plant Operations Report, replaced the following: Form EIA-906, Power Plant Report; Form EIA-920, Combined Heat and Power Plant Report.

**Table 5.6.E. Landfill Gas: Consumption for Useful Thermal Output,
by Sector, 2009 - 2019 (Billion Btus)**

		Electric Power Sector			
Period	Total (all sectors)	Electric Utilities	Independent Power Producers	Commercial Sector	Industrial Sector
Annual Totals					
2009	440	0	313	91	37
2010	847	0	643	174	30
2011	1,635	0	1,422	165	48
2012	1,630	0	1,441	156	32
2013	414	0	132	206	76
2014	852	88	266	326	173
2015	756	1	326	250	179
2016	2,236	1	1,266	589	380
2017	2,196	1	1,066	698	431
2018	1,964	0	966	594	403
2019	1,960	2	1,034	531	394
Year 2017					
January	192	0	94	56	42
February	181	0	88	55	39
March	193	0	95	57	40
April	197	0	84	72	42
May	163	0	72	52	38
June	184	0	90	58	36
July	178	0	96	56	26
August	195	0	95	63	37
September	184	0	92	62	30
October	181	0	93	61	27
November	167	0	76	56	35
December	181	0	91	51	39
Year 2018					
January	169	0	91	42	36
February	172	0	85	50	36
March	185	0	91	55	39
April	183	0	86	56	41
May	151	0	73	43	35
June	135	0	77	26	33
July	153	0	73	50	30
August	166	0	82	54	31
September	161	0	78	55	28
October	185	0	87	65	33
November	152	0	69	49	34
December	151	0	74	50	27
Year 2019					
January	184	0	96	56	32
February	165	0	93	44	28
March	194	0	108	52	35
April	197	0	99	62	36
May	137	0	63	39	35
June	158	0	80	50	29
July	151	0	89	24	37
August	150	0	69	49	32
September	150	0	67	51	31
October	176	0	89	52	34
November	160	0	82	42	36
December	138	0	97	10	30

Notes: Beginning with the collection of Form EIA-923 in January 2008, the methodology to allocate total fuel consumption for electricity generation and consumption for useful thermal output was changed.

The new methodology was retroactively applied to 2004-2007 data. See the Technical Notes (Appendix C) for further information. See Glossary for definitions.

Values are final. See Technical Notes for a discussion of the sample design for the Form EIA-923 and predecessor forms.

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

Sources: U.S. Energy Information Administration, Form EIA-906, Power Plant Report; U.S. Energy Information Administration, Form EIA-920

Combined Heat and Power Plant Report, and predecessor forms.

Beginning with 2008 data, the Form EIA-923, Power Plant Operations Report, replaced the following: Form EIA-906, Power Plant Report; Form EIA-920, Combined Heat and Power Plant Report.

Table 5.6.F. Landfill Gas: Consumption for Electricity Generation and Useful Thermal Output, by Sector, 2009 - 2019 (Billion Btus)

		Electric Power Sector			
Period	Total (all sectors)	Electric Utilities	Independent Power Producers	Commercial Sector	Industrial Sector
Annual Totals					
2009	100,261	9,748	87,086	3,089	337
2010	106,681	10,029	93,405	3,011	236
2011	114,173	11,146	91,279	11,497	251
2012	125,927	12,721	101,379	10,512	1,315
2013	133,180	13,819	105,462	11,497	2,403
2014	141,632	13,220	114,599	11,263	2,550
2015	138,841	12,847	113,238	10,273	2,483
2016	137,600	12,295	114,036	8,963	2,307
2017	139,831	13,072	115,197	9,206	2,357
2018	135,921	12,395	112,736	8,698	2,092
2019	129,500	11,795	108,134	7,617	1,954
Year 2017					
January	12,107	1,146	9,946	801	214
February	11,039	1,074	9,041	720	204
March	12,074	1,161	9,894	800	220
April	11,401	1,119	9,325	753	204
May	11,881	1,153	9,766	777	184
June	11,644	1,044	9,621	773	205
July	11,670	1,023	9,695	785	167
August	11,749	1,055	9,715	787	192
September	11,198	987	9,282	751	177
October	11,278	1,062	9,350	681	184
November	11,597	1,102	9,527	771	197
December	12,194	1,145	10,035	807	207
Year 2018					
January	11,836	1,237	9,673	741	186
February	11,109	1,129	9,079	707	193
March	11,925	1,237	9,728	760	201
April	11,242	1,150	9,155	733	206
May	11,470	1,142	9,441	707	181
June	10,943	938	9,155	675	174
July	11,269	957	9,427	721	164
August	11,582	914	9,765	744	159
September	10,301	845	8,602	713	140
October	11,277	941	9,420	750	165
November	11,294	948	9,473	709	165
December	11,673	958	9,817	740	158
Year 2019					
January	11,434	1,062	9,456	753	162
February	10,332	936	8,586	664	146
March	11,249	1,043	9,312	723	172
April	10,393	982	8,711	531	168
May	10,641	1,017	9,050	410	164
June	10,832	965	9,033	679	155
July	11,008	972	9,231	645	161
August	10,988	984	9,161	683	160
September	10,396	939	8,638	659	160
October	10,690	956	8,929	637	169
November	10,378	934	8,659	621	164
December	11,159	1,006	9,370	610	173

Notes: Beginning with the collection of Form EIA-923 in January 2008, the methodology to allocate total fuel consumption for electricity generation and consumption for useful thermal output was changed.

The new methodology was retroactively applied to 2004-2007 data. See the Technical Notes (Appendix C) for further information. See Glossary for definitions.

Values are final. See Technical Notes for a discussion of the sample design for the Form EIA-923 and predecessor forms.

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

Sources: U.S. Energy Information Administration, Form EIA-906, Power Plant Report; U.S. Energy Information Administration, Form EIA-920

Combined Heat and Power Plant Report, and predecessor forms.

Beginning with 2008 data, the Form EIA-923, Power Plant Operations Report, replaced the following: Form EIA-906, Power Plant Report; Form EIA-920, Combined Heat and Power Plant Report.

Table 5.7.A. Biogenic Municipal Solid Waste: Consumption for Electricity Generation, by Sector, 2009 - 2019 (Thousand Tons)

		Electric Power Sector			
Period	Total (all sectors)	Electric Utilities	Independent Power Producers	Commercial Sector	Industrial Sector
Annual Totals					
2009	19,669	465	17,048	2,155	0
2010	19,437	402	16,802	2,233	0
2011	16,972	388	14,625	1,955	4
2012	16,968	418	14,235	2,304	12
2013	17,007	456	14,057	2,485	8
2014	16,706	444	13,809	2,447	6
2015	16,631	452	13,797	2,375	8
2016	16,994	464	13,953	2,566	11
2017	16,348	422	13,381	2,537	8
2018	16,783	467	13,859	2,448	9
2019	15,559	297	12,941	2,310	10
Year 2017					
January	1,434	35	1,194	205	0
February	1,244	19	1,034	191	0
March	1,330	36	1,091	204	0
April	1,288	35	1,044	209	0
May	1,410	36	1,147	226	1
June	1,421	38	1,175	207	1
July	1,440	41	1,172	226	1
August	1,453	47	1,182	223	1
September	1,321	41	1,072	207	1
October	1,317	33	1,065	218	1
November	1,311	30	1,074	207	1
December	1,378	32	1,132	214	1
Year 2018					
January	1,370	28	1,147	195	0
February	1,297	26	1,090	180	1
March	1,398	40	1,153	204	1
April	1,356	38	1,117	200	1
May	1,419	43	1,158	217	1
June	1,476	42	1,218	214	1
July	1,479	48	1,224	207	1
August	1,483	47	1,220	215	1
September	1,334	36	1,097	199	1
October	1,387	43	1,140	205	0
November	1,369	39	1,127	202	0
December	1,416	37	1,169	210	0
Year 2019					
January	1,322	30	1,092	199	1
February	1,158	20	961	177	1
March	1,255	20	1,046	188	1
April	1,235	28	1,014	193	1
May	1,337	26	1,112	198	1
June	1,323	25	1,098	200	1
July	1,369	27	1,146	194	1
August	1,396	29	1,167	200	1
September	1,288	21	1,076	191	1
October	1,271	28	1,056	187	1
November	1,270	25	1,062	183	1
December	1,333	20	1,112	201	1

Notes: Beginning with the collection of Form EIA-923 in January 2008, the methodology to allocate total fuel consumption for electricity generation and consumption for useful thermal output was changed.

The new methodology was retroactively applied to 2004-2007 data. See the Technical Notes (Appendix C) for further information. See Glossary for definitions.

Values are final. See Technical Notes for a discussion of the sample design for the Form EIA-923 and predecessor forms.

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

Sources: U.S. Energy Information Administration, Form EIA-906, Power Plant Report; U.S. Energy Information Administration, Form EIA-920

Combined Heat and Power Plant Report, and predecessor forms.

Beginning with 2008 data, the Form EIA-923, Power Plant Operations Report, replaced the following: Form EIA-906, Power Plant Report; Form EIA-920, Combined Heat and Power Plant Report.

Table 5.7.B. Biogenic Municipal Solid Waste: Consumption for Useful Thermal Output, by Sector, 2009 - 2019 (Thousand Tons)

		Electric Power Sector			
Period	Total (all sectors)	Electric Utilities	Independent Power Producers	Commercial Sector	Industrial Sector
Annual Totals					
2009	2,426	0	823	1,466	137
2010	2,287	0	819	1,316	152
2011	2,044	0	742	1,148	154
2012	1,986	0	522	1,273	190
2013	1,865	0	517	1,160	187
2014	1,955	0	650	1,104	200
2015	1,986	0	655	1,127	203
2016	2,232	0	885	1,134	213
2017	2,124	0	814	1,102	208
2018	2,050	0	752	1,109	189
2019	1,667	0	743	737	187
Year 2017					
January	203	0	72	111	20
February	171	0	64	94	12
March	187	0	75	93	19
April	173	0	69	86	18
May	182	0	69	96	18
June	185	0	68	101	16
July	185	0	72	97	17
August	196	0	77	97	22
September	154	0	63	74	17
October	155	0	59	78	18
November	166	0	64	88	15
December	168	0	63	88	17
Year 2018					
January	182	0	64	102	17
February	163	0	60	91	12
March	169	0	64	93	12
April	160	0	54	90	16
May	176	0	59	101	16
June	177	0	65	95	18
July	180	0	65	98	17
August	183	0	66	95	21
September	144	0	58	68	17
October	160	0	61	83	16
November	173	0	66	93	14
December	182	0	70	100	13
Year 2019					
January	173	0	66	92	15
February	155	0	63	77	15
March	153	0	67	70	16
April	115	0	56	43	17
May	127	0	64	52	12
June	137	0	64	59	15
July	136	0	67	53	16
August	139	0	62	56	21
September	124	0	53	56	15
October	130	0	57	58	15
November	139	0	63	61	15
December	139	0	61	62	15

Notes: Beginning with the collection of Form EIA-923 in January 2008, the methodology to allocate total fuel consumption for electricity generation and consumption for useful thermal output was changed.

The new methodology was retroactively applied to 2004-2007 data. See the Technical Notes (Appendix C) for further information. See Glossary for definitions.

Values are final. See Technical Notes for a discussion of the sample design for the Form EIA-923 and predecessor forms.

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

Sources: U.S. Energy Information Administration, Form EIA-906, Power Plant Report; U.S. Energy Information Administration, Form EIA-920

Combined Heat and Power Plant Report, and predecessor forms.

Beginning with 2008 data, the Form EIA-923, Power Plant Operations Report, replaced the following: Form EIA-906, Power Plant Report; Form EIA-920, Combined Heat and Power Plant Report.

Table 5.7.C. Biogenic Municipal Solid Waste: Consumption for Electricity Generation and Useful Thermal Output, by Sector, 2009 - 2019 (Thousand Tons)

		Electric Power Sector			
Period	Total (all sectors)	Electric Utilities	Independent Power Producers	Commercial Sector	Industrial Sector
Annual Totals					
2009	22,095	465	17,872	3,622	137
2010	21,725	402	17,621	3,549	152
2011	19,016	388	15,367	3,103	158
2012	18,954	418	14,757	3,577	203
2013	18,871	456	14,574	3,646	195
2014	18,661	444	14,459	3,551	206
2015	18,617	452	14,452	3,502	211
2016	19,226	464	14,838	3,700	224
2017	18,473	422	14,195	3,639	216
2018	18,833	467	14,611	3,557	197
2019	17,225	297	13,684	3,047	197
Year 2017					
January	1,637	35	1,266	316	20
February	1,415	19	1,098	286	12
March	1,517	36	1,165	297	19
April	1,461	35	1,113	295	18
May	1,592	36	1,215	322	19
June	1,606	38	1,243	309	17
July	1,625	41	1,244	323	18
August	1,649	47	1,259	320	23
September	1,475	41	1,135	281	18
October	1,472	33	1,124	295	19
November	1,477	30	1,138	295	15
December	1,546	32	1,195	301	18
Year 2018					
January	1,552	28	1,211	296	17
February	1,459	26	1,150	271	13
March	1,567	40	1,217	297	13
April	1,516	38	1,171	290	17
May	1,595	43	1,217	319	17
June	1,653	42	1,283	309	19
July	1,659	48	1,288	305	18
August	1,666	47	1,286	311	22
September	1,478	36	1,156	268	18
October	1,547	43	1,201	288	16
November	1,542	39	1,193	295	14
December	1,598	37	1,238	310	13
Year 2019					
January	1,495	30	1,158	291	16
February	1,313	20	1,024	254	16
March	1,408	20	1,114	258	17
April	1,350	28	1,069	235	18
May	1,465	26	1,176	249	13
June	1,461	25	1,162	258	15
July	1,504	27	1,213	247	17
August	1,535	29	1,229	256	22
September	1,412	21	1,129	246	16
October	1,401	28	1,113	245	16
November	1,409	25	1,125	244	15
December	1,472	20	1,173	263	16

Notes: Beginning with the collection of Form EIA-923 in January 2008, the methodology to allocate total fuel consumption for electricity generation and consumption for useful thermal output was changed.

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Values are final. See Technical Notes for a discussion of the sample design for the Form EIA-923 and predecessor forms.

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

Sources: U.S. Energy Information Administration, Form EIA-906, Power Plant Report; U.S. Energy Information Administration, Form EIA-920

Combined Heat and Power Plant Report, and predecessor forms.

Beginning with 2008 data, the Form EIA-923, Power Plant Operations Report, replaced the following: Form EIA-906, Power Plant Report; Form EIA-920, Combined Heat and Power Plant Report.

Table 5.7.D. Biogenic Municipal Solid Waste: Consumption for Electricity Generation, by Sector, 2009 - 2019 (Billion Btus)

		Electric Power Sector			
Period	Total (all sectors)	Electric Utilities	Independent Power Producers	Commercial Sector	Industrial Sector
Annual Totals					
2009	146,971	3,989	126,649	16,333	0
2010	144,934	3,322	124,437	17,176	0
2011	135,241	3,433	115,841	15,933	34
2012	135,735	3,910	113,418	18,307	100
2013	135,764	4,459	111,430	19,811	64
2014	134,408	4,429	110,569	19,366	45
2015	133,117	4,295	109,691	19,068	63
2016	135,957	4,434	111,003	20,431	89
2017	130,942	4,172	106,382	20,320	67
2018	134,465	4,568	110,452	19,374	72
2019	115,114	2,454	95,638	16,946	76
Year 2017					
January	11,516	349	9,521	1,646	0
February	9,929	180	8,212	1,536	0
March	10,732	357	8,748	1,626	0
April	10,335	349	8,304	1,680	2
May	11,189	352	9,027	1,799	11
June	11,277	375	9,257	1,639	7
July	11,487	399	9,271	1,807	10
August	11,545	461	9,281	1,793	10
September	10,558	411	8,484	1,656	7
October	10,584	327	8,506	1,742	9
November	10,541	294	8,581	1,659	7
December	11,250	318	9,189	1,737	5
Year 2018					
January	11,104	278	9,239	1,583	4
February	10,426	253	8,728	1,439	7
March	11,332	400	9,296	1,628	8
April	10,904	377	8,952	1,568	7
May	11,349	431	9,212	1,702	5
June	11,807	420	9,689	1,687	10
July	11,815	477	9,677	1,651	9
August	11,828	449	9,676	1,695	8
September	10,577	348	8,681	1,540	7
October	11,083	408	9,062	1,610	3
November	10,921	371	8,955	1,595	0
December	11,319	356	9,285	1,676	2
Year 2019					
January	9,806	252	8,081	1,468	5
February	8,560	163	7,085	1,306	6
March	9,337	164	7,782	1,385	6
April	9,150	229	7,493	1,421	8
May	9,880	218	8,220	1,437	6
June	9,815	202	8,147	1,459	6
July	10,063	225	8,398	1,432	8
August	10,270	234	8,568	1,462	7
September	9,544	166	7,971	1,403	5
October	9,408	231	7,806	1,365	5
November	9,372	204	7,835	1,326	7
December	9,907	166	8,252	1,482	8

Notes: Beginning with the collection of Form EIA-923 in January 2008, the methodology to allocate total fuel consumption for electricity generation and consumption for useful thermal output was changed.

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Values are final. See Technical Notes for a discussion of the sample design for the Form EIA-923 and predecessor forms.

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

Sources: U.S. Energy Information Administration, Form EIA-906, Power Plant Report; U.S. Energy Information Administration, Form EIA-920

Combined Heat and Power Plant Report, and predecessor forms.

Beginning with 2008 data, the Form EIA-923, Power Plant Operations Report, replaced the following: Form EIA-906, Power Plant Report; Form EIA-920, Combined Heat and Power Plant Report.

Table 5.7.E. Biogenic Municipal Solid Waste: Consumption for Useful Thermal Output, by Sector, 2009 - 2019 (Billion Btus)

		Electric Power Sector			
Period	Total (all sectors)	Electric Utilities	Independent Power Producers	Commercial Sector	Industrial Sector
Annual Totals					
2009	18,785	0	6,229	11,535	1,021
2010	17,502	0	6,031	10,333	1,138
2011	16,766	0	5,807	9,731	1,227
2012	16,310	0	4,180	10,615	1,515
2013	15,168	0	4,145	9,530	1,493
2014	15,783	0	5,140	9,046	1,597
2015	16,623	0	5,195	9,752	1,676
2016	18,259	0	6,877	9,665	1,717
2017	17,720	0	6,475	9,474	1,772
2018	16,724	0	5,887	9,312	1,524
2019	12,308	0	5,362	5,527	1,419
Year 2017					
January	1,779	0	585	1,007	187
February	1,457	0	514	837	106
March	1,573	0	601	811	161
April	1,451	0	535	759	157
May	1,437	0	540	749	148
June	1,491	0	523	842	126
July	1,522	0	571	811	140
August	1,629	0	612	825	191
September	1,291	0	499	649	143
October	1,305	0	470	686	150
November	1,375	0	511	743	121
December	1,409	0	512	754	143
Year 2018					
January	1,480	0	506	840	135
February	1,331	0	470	773	88
March	1,377	0	507	777	93
April	1,361	0	423	804	133
May	1,416	0	447	836	132
June	1,441	0	517	772	152
July	1,471	0	509	823	139
August	1,488	0	513	797	179
September	1,174	0	453	579	142
October	1,296	0	472	705	119
November	1,412	0	526	778	109
December	1,478	0	545	830	103
Year 2019					
January	1,306	0	476	715	115
February	1,158	0	458	590	111
March	1,136	0	491	529	116
April	842	0	396	318	128
May	914	0	444	380	90
June	994	0	455	430	109
July	974	0	471	385	119
August	1,071	0	454	449	167
September	908	0	385	411	113
October	967	0	428	417	121
November	1,009	0	456	443	110
December	1,028	0	448	460	119

Notes: Beginning with the collection of Form EIA-923 in January 2008, the methodology to allocate total fuel consumption for electricity generation and consumption for useful thermal output was changed.

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Values are final. See Technical Notes for a discussion of the sample design for the Form EIA-923 and predecessor forms.

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

Sources: U.S. Energy Information Administration, Form EIA-906, Power Plant Report; U.S. Energy Information Administration, Form EIA-920

Combined Heat and Power Plant Report, and predecessor forms.

Beginning with 2008 data, the Form EIA-923, Power Plant Operations Report, replaced the following: Form EIA-906, Power Plant Report; Form EIA-920, Combined Heat and Power Plant Report.

Table 5.7.F. Biogenic Municipal Solid Waste: Consumption for Electricity Generation and Useful Thermal Output, by Sector, 2009 - 2019 (Billion Btus)

		Electric Power Sector			
Period	Total (all sectors)	Electric Utilities	Independent Power Producers	Commercial Sector	Industrial Sector
Annual Totals					
2009	165,755	3,989	132,877	27,868	1,021
2010	162,436	3,322	130,467	27,509	1,138
2011	152,007	3,433	121,648	25,664	1,262
2012	152,045	3,910	117,598	28,923	1,614
2013	150,932	4,459	115,574	29,342	1,557
2014	150,191	4,429	115,709	28,411	1,643
2015	149,740	4,295	114,886	28,821	1,739
2016	154,216	4,434	117,880	30,095	1,806
2017	148,662	4,172	112,857	29,794	1,839
2018	151,188	4,568	116,339	28,686	1,596
2019	127,422	2,454	101,000	22,473	1,495
Year 2017					
January	13,295	349	10,106	2,653	187
February	11,385	180	8,727	2,373	106
March	12,305	357	9,349	2,437	161
April	11,787	349	8,840	2,439	159
May	12,626	352	9,567	2,548	159
June	12,767	375	9,780	2,480	133
July	13,010	399	9,843	2,618	150
August	13,174	461	9,894	2,619	201
September	11,849	411	8,982	2,305	150
October	11,889	327	8,976	2,428	159
November	11,916	294	9,092	2,402	127
December	12,659	318	9,702	2,491	148
Year 2018					
January	12,585	278	9,745	2,423	139
February	11,757	253	9,198	2,211	95
March	12,709	400	9,802	2,405	102
April	12,265	377	9,375	2,372	140
May	12,765	431	9,659	2,538	137
June	13,248	420	10,206	2,459	162
July	13,286	477	10,186	2,474	148
August	13,316	449	10,189	2,492	187
September	11,751	348	9,134	2,119	149
October	12,379	408	9,534	2,315	122
November	12,332	371	9,480	2,372	109
December	12,797	356	9,830	2,506	105
Year 2019					
January	11,112	252	8,556	2,183	120
February	9,719	163	7,542	1,896	117
March	10,474	164	8,273	1,914	122
April	9,993	229	7,889	1,739	135
May	10,794	218	8,664	1,817	96
June	10,809	202	8,602	1,888	116
July	11,037	225	8,869	1,816	127
August	11,341	234	9,023	1,911	174
September	10,453	166	8,355	1,813	118
October	10,375	231	8,234	1,783	127
November	10,381	204	8,292	1,770	117
December	10,935	166	8,701	1,942	127

Notes: Beginning with the collection of Form EIA-923 in January 2008, the methodology to allocate total fuel consumption for electricity generation and consumption for useful thermal output was changed.

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

Sources: U.S. Energy Information Administration, Form EIA-906, Power Plant Report; U.S. Energy Information Administration, Form EIA-920

Combined Heat and Power Plant Report, and predecessor forms.

Beginning with 2008 data, the Form EIA-923, Power Plant Operations Report, replaced the following: Form EIA-906, Power Plant Report; Form EIA-920, Combined Heat and Power Plant Report.

Table 5.8.D. Other Waste Biomass: Consumption for Electricity Generation, by Sector, 2009 - 2019 (Billion Btus)

		Electric Power Sector			
Period	Total (all sectors)	Electric Utilities	Independent Power Producers	Commercial Sector	Industrial Sector
Annual Totals					
2009	24,847	3,679	13,231	3,760	4,177
2010	29,996	3,668	14,449	3,790	8,090
2011	30,771	4,488	16,115	3,816	6,352
2012	30,342	4,191	15,740	4,016	6,395
2013	29,385	2,432	13,671	4,979	8,303
2014	38,361	2,360	21,628	5,745	8,627
2015	41,785	2,853	25,058	5,935	7,939
2016	33,786	2,553	18,194	5,504	7,536
2017	35,755	1,845	22,517	5,288	6,105
2018	29,407	1,343	16,874	5,867	5,324
2019	23,947	1,133	12,606	5,668	4,540
Year 2017					
January	3,161	137	1,974	487	563
February	3,023	170	1,913	429	511
March	3,412	242	2,111	477	582
April	2,816	124	1,707	446	539
May	2,983	147	1,891	459	486
June	2,896	155	1,904	427	410
July	3,105	137	2,051	458	459
August	2,912	173	1,833	436	471
September	2,619	162	1,646	396	414
October	2,803	117	1,825	349	512
November	3,055	110	1,939	443	563
December	2,972	171	1,724	482	595
Year 2018					
January	3,130	201	1,896	507	527
February	2,990	123	1,915	474	477
March	2,880	103	1,751	495	531
April	2,858	130	1,785	479	465
May	2,721	66	1,728	475	451
June	2,431	59	1,565	481	325
July	2,025	122	1,040	486	377
August	2,036	95	1,060	495	385
September	1,833	103	934	475	322
October	2,184	125	1,090	506	463
November	2,140	112	1,041	490	496
December	2,179	102	1,069	504	504
Year 2019					
January	2,131	121	1,085	501	424
February	1,918	142	939	452	386
March	2,174	177	1,064	493	439
April	2,026	101	1,054	475	396
May	1,763	82	877	454	349
June	1,917	84	1,038	459	336
July	2,000	90	1,110	474	326
August	2,076	117	1,140	476	344
September	1,843	73	1,036	459	275
October	1,994	50	1,075	459	410
November	2,010	27	1,098	469	417
December	2,095	69	1,089	498	439

Notes: Beginning with the collection of Form EIA-923 in January 2008, the methodology to allocate total fuel consumption for electricity generation and consumption for useful thermal output was changed.

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

Sources: U.S. Energy Information Administration, Form EIA-906, Power Plant Report; U.S. Energy Information Administration, Form EIA-920

Combined Heat and Power Plant Report, and predecessor forms.

Beginning with 2008 data, the Form EIA-923, Power Plant Operations Report, replaced the following: Form EIA-906, Power Plant Report; Form EIA-920, Combined Heat and Power Plant Report.

Table 5.8.E. Other Waste Biomass: Consumption for Useful Thermal Output, by Sector, 2009 - 2019 (Billion Btus)

		Electric Power Sector			
Period	Total (all sectors)	Electric Utilities	Independent Power Producers	Commercial Sector	Industrial Sector
Annual Totals					
2009	41,810	0	10,355	1,638	29,817
2010	47,153	0	8,436	1,648	37,070
2011	43,483	0	6,460	1,566	35,458
2012	46,863	0	6,914	1,796	38,153
2013	62,445	0	6,768	1,259	54,418
2014	65,201	15	6,930	1,543	56,712
2015	67,512	1	7,845	2,000	57,666
2016	57,123	18	11,252	3,569	42,284
2017	50,518	15	10,543	3,218	36,742
2018	50,338	14	10,753	3,673	35,898
2019	41,084	39	10,452	3,282	27,312
Year 2017					
January	5,626	2	1,280	346	3,999
February	4,894	0	1,002	271	3,621
March	5,352	0	1,192	291	3,869
April	4,627	7	779	256	3,586
May	3,644	2	692	264	2,686
June	2,834	0	772	276	1,785
July	3,009	0	616	235	2,158
August	3,059	1	552	269	2,238
September	2,657	2	466	226	1,963
October	4,233	0	846	221	3,166
November	5,205	1	1,125	291	3,788
December	5,379	0	1,221	274	3,884
Year 2018					
January	5,543	0	1,334	317	3,892
February	5,058	0	1,226	316	3,516
March	5,492	0	1,313	327	3,852
April	4,392	5	656	315	3,416
May	3,563	6	462	321	2,774
June	2,468	1	534	305	1,627
July	2,687	0	551	292	1,844
August	2,720	1	465	318	1,936
September	2,733	0	550	295	1,888
October	4,872	0	1,061	297	3,514
November	5,269	0	1,332	306	3,631
December	5,541	0	1,270	264	4,007
Year 2019					
January	4,576	12	1,166	288	3,109
February	4,339	11	1,149	238	2,941
March	4,299	6	1,178	335	2,780
April	3,245	7	945	268	2,024
May	2,579	0	630	252	1,697
June	2,729	1	510	262	1,957
July	2,259	0	519	253	1,486
August	2,361	0	552	278	1,532
September	2,009	0	451	275	1,283
October	3,987	0	1,092	300	2,595
November	4,289	0	1,151	256	2,883
December	4,413	0	1,109	278	3,026

Notes: Beginning with the collection of Form EIA-923 in January 2008, the methodology to allocate total fuel consumption for electricity generation and consumption for useful thermal output was changed.

The new methodology was retroactively applied to 2004-2007 data. See the Technical Notes (Appendix C) for further information. See Glossary for definitions.

Values are final. See Technical Notes for a discussion of the sample design for the Form EIA-923 and predecessor forms.

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

Sources: U.S. Energy Information Administration, Form EIA-906, Power Plant Report; U.S. Energy Information Administration, Form EIA-920

Combined Heat and Power Plant Report, and predecessor forms.

Beginning with 2008 data, the Form EIA-923, Power Plant Operations Report, replaced the following: Form EIA-906, Power Plant Report; Form EIA-920, Combined Heat and Power Plant Report.

Table 5.8.F. Other Waste Biomass: Consumption for Electricity Generation and Useful Thermal Output, by Sector, 2009 - 2019 (Billion Btus)

		Electric Power Sector			
Period	Total (all sectors)	Electric Utilities	Independent Power Producers	Commercial Sector	Industrial Sector
Annual Totals					
2009	66,658	3,679	23,586	5,398	33,994
2010	77,150	3,668	22,884	5,438	45,159
2011	74,255	4,488	22,574	5,382	41,810
2012	77,205	4,191	22,654	5,812	44,548
2013	91,830	2,432	20,439	6,238	62,721
2014	103,561	2,375	28,558	7,289	65,339
2015	109,297	2,854	32,903	7,935	65,605
2016	90,909	2,571	29,446	9,073	49,820
2017	86,274	1,860	33,060	8,506	42,848
2018	79,745	1,357	27,627	9,540	41,221
2019	65,031	1,172	23,057	8,950	31,852
Year 2017					
January	8,787	138	3,254	833	4,562
February	7,917	171	2,915	699	4,132
March	8,764	242	3,303	769	4,451
April	7,443	131	2,485	701	4,125
May	6,627	149	2,584	723	3,172
June	5,730	155	2,677	702	2,196
July	6,113	137	2,667	692	2,617
August	5,972	174	2,385	705	2,709
September	5,275	164	2,111	622	2,377
October	7,035	117	2,671	569	3,678
November	8,260	111	3,064	734	4,351
December	8,351	172	2,945	756	4,479
Year 2018					
January	8,673	201	3,230	824	4,419
February	8,048	124	3,141	790	3,993
March	8,372	103	3,064	822	4,383
April	7,251	135	2,441	794	3,881
May	6,284	72	2,190	797	3,225
June	4,898	60	2,100	786	1,953
July	4,712	122	1,591	778	2,221
August	4,756	96	1,525	813	2,321
September	4,566	103	1,483	770	2,210
October	7,057	125	2,151	803	3,977
November	7,409	112	2,373	796	4,128
December	7,720	102	2,338	768	4,511
Year 2019					
January	6,706	133	2,251	788	3,533
February	6,257	153	2,088	689	3,327
March	6,473	183	2,242	828	3,219
April	5,270	108	1,999	743	2,420
May	4,343	83	1,508	707	2,046
June	4,646	85	1,548	721	2,293
July	4,258	90	1,629	727	1,812
August	4,438	117	1,691	753	1,876
September	3,852	73	1,487	734	1,558
October	5,981	51	2,166	759	3,005
November	6,300	27	2,249	724	3,299
December	6,508	69	2,198	776	3,465

Notes: Beginning with the collection of Form EIA-923 in January 2008, the methodology to allocate total fuel consumption for electricity generation and consumption for useful thermal output was changed.

The new methodology was retroactively applied to 2004-2007 data. See the Technical Notes (Appendix C) for further information. See Glossary for definitions.

Values are final. See Technical Notes for a discussion of the sample design for the Form EIA-923 and predecessor forms.

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

Sources: U.S. Energy Information Administration, Form EIA-906, Power Plant Report; U.S. Energy Information Administration, Form EIA-920

Combined Heat and Power Plant Report, and predecessor forms.

Beginning with 2008 data, the Form EIA-923, Power Plant Operations Report, replaced the following: Form EIA-906, Power Plant Report; Form EIA-920, Combined Heat and Power Plant Report.

Table 5.9. Consumption of Coal for Electricity Generation by State by Sector, 2019 and 2018 (Thousand Tons)

Census Division and State				Electric Power Sector							
	All Sectors			Electric Utilities		Independent Power Producers		Commercial Sector		Industrial Sector	
	Year 2019	Year 2018	Percentage Change	Year 2019	Year 2018	Year 2019	Year 2018	Year 2019	Year 2018	Year 2019	Year 2018
New England	224	531	-58.0%	159	294	61	233	0	0	4	4
Connecticut	48	221	-78.0%	0	0	48	221	0	0	0	0
Maine	17	16	3.1%	0	0	13	12	0	0	4	4
Massachusetts	0	0	--	0	0	0	0	0	0	0	0
New Hampshire	159	294	-46.0%	159	294	0	0	0	0	0	0
Rhode Island	0	0	--	0	0	0	0	0	0	0	0
Vermont	0	0	--	0	0	0	0	0	0	0	0
Middle Atlantic	20,049	24,113	-17.0%	0	0	20,027	24,075	0	0	22	39
New Jersey	440	504	-13.0%	0	0	440	504	0	0	0	0
New York	187	276	-32.0%	0	0	187	272	0	0	0	4
Pennsylvania	19,422	23,334	-17.0%	0	0	19,400	23,299	0	0	22	35
East North Central	116,185	144,074	-19.0%	69,048	86,841	46,535	56,524	15	18	587	691
Illinois	29,617	36,013	-18.0%	1,923	2,254	27,230	33,239	4	9	460	511
Indiana	30,906	39,080	-21.0%	28,888	36,910	2,008	2,161	10	9	0	0
Michigan	21,257	24,235	-12.0%	21,056	23,991	192	212	0	0	9	33
Ohio	19,596	25,122	-22.0%	2,490	4,209	17,105	20,912	0	0	0	1
Wisconsin	14,809	19,624	-25.0%	14,692	19,477	0	0	0	0	117	147
West North Central	103,233	118,759	-13.0%	102,157	117,565	0	0	20	21	1,056	1,173
Iowa	12,710	16,187	-21.0%	12,190	15,673	0	0	17	19	502	495
Kansas	11,535	13,176	-12.0%	11,535	13,176	0	0	0	0	0	0
Minnesota	10,495	13,675	-23.0%	10,345	13,421	0	0	1	0	149	253
Missouri	32,663	36,978	-12.0%	32,661	36,976	0	0	2	2	0	0
Nebraska	13,517	14,834	-8.9%	13,149	14,443	0	0	0	0	367	391
North Dakota	20,682	22,457	-7.9%	20,645	22,423	0	0	0	0	37	34
South Dakota	1,631	1,453	12.0%	1,631	1,453	0	0	0	0	0	0
South Atlantic	69,979	85,873	-19.0%	62,386	75,137	7,422	10,538	10	12	161	186
Delaware	85	167	-49.0%	0	0	85	167	0	0	0	0
District of Columbia	0	0	--	0	0	0	0	0	0	0	0
Florida	9,542	13,384	-29.0%	9,533	13,365	0	0	0	0	9	18
Georgia	13,591	16,996	-20.0%	13,552	16,953	0	0	0	0	39	43
Maryland	2,556	4,382	-42.0%	0	0	2,548	4,367	0	0	8	15
North Carolina	12,349	12,564	-1.7%	12,281	12,480	31	46	10	11	27	28
South Carolina	6,316	8,144	-22.0%	6,267	8,141	47	0	0	0	2	3
Virginia	1,781	4,565	-61.0%	1,658	4,200	45	284	1	1	76	79
West Virginia	23,760	25,671	-7.4%	19,094	19,996	4,666	5,675	0	0	0	0
East South Central	52,523	59,619	-12.0%	49,851	56,472	2,563	2,996	0	0	109	151
Alabama	14,250	16,249	-12.0%	14,245	16,235	0	0	0	0	5	14
Kentucky	24,974	28,368	-12.0%	24,974	28,368	0	0	0	0	0	0
Mississippi	3,833	4,506	-15.0%	1,271	1,510	2,563	2,996	0	0	0	0
Tennessee	9,466	10,496	-9.8%	9,362	10,359	0	0	0	0	104	137
West South Central	87,629	111,125	-21.0%	44,548	59,876	43,007	51,127	0	0	74	123
Arkansas	13,771	17,461	-21.0%	11,552	14,617	2,211	2,835	0	0	8	8
Louisiana	5,276	8,110	-35.0%	3,979	5,339	1,297	2,771	0	0	0	0
Oklahoma	5,271	9,656	-45.0%	5,206	8,348	0	1,193	0	0	66	114
Texas	63,311	75,899	-17.0%	23,812	31,572	39,499	44,327	0	0	0	0
Mountain	80,167	86,299	-7.1%	69,526	76,223	10,547	9,973	0	0	93	104
Arizona	12,875	16,814	-23.0%	12,875	16,814	0	0	0	0	0	0
Colorado	14,517	15,269	-4.9%	14,515	15,266	0	0	0	0	1	3
Idaho	4	4	1.0%	0	0	0	0	0	0	4	4
Montana	9,280	8,738	6.2%	261	233	9,014	8,500	0	0	5	5
Nevada	1,551	1,412	9.9%	945	816	606	596	0	0	0	0
New Mexico	8,148	7,262	12.0%	8,148	7,262	0	0	0	0	0	0
Utah	11,891	12,332	-3.6%	11,489	11,927	402	405	0	0	0	0
Wyoming	21,901	24,468	-10.0%	21,293	23,905	525	472	0	0	83	91
Pacific Contiguous	6,359	4,590	39.0%	1,499	898	4,804	3,628	0	0	55	63
California	49	57	-14.0%	0	0	0	0	0	0	49	57
Oregon	1,499	898	67.0%	1,499	898	0	0	0	0	0	0
Washington	4,811	3,635	32.0%	0	0	4,804	3,628	0	0	7	7
Pacific Noncontiguous	1,273	1,230	3.4%	370	312	872	882	32	36	0	0
Alaska	556	496	12.0%	370	312	155	148	32	36	0	0
Hawaii	717	734	-2.4%	0	0	717	734	0	0	0	0
U.S. Total	537,620	636,213	-15.0%	399,545	473,617	135,838	159,976	76	87	2,161	2,534

Displayed values of zero may represent small values that round to zero. The Excel version of this table provides additional precision which may be accessed by selecting individual cells.

Notes: See Glossary for definitions. Values are final. See Technical Notes for a discussion of the sample design for the Form EIA-923.

Totals may not equal sum of components because of independent rounding. Percentage change is calculated before rounding.

Source: U.S. Energy Information Administration, Form EIA-923, Power Plant Operations Report.

Table 5.10. Consumption of Petroleum Liquids for Electricity Generation by State, by Sector, 2019 and 2018 (Thousand Barrels)

Census Division and State				Electric Power Sector							
	All Sectors			Electric Utilities		Independent Power Producers		Commercial Sector		Industrial Sector	
	Year 2019	Year 2018	Percentage Change	Year 2019	Year 2018	Year 2019	Year 2018	Year 2019	Year 2018	Year 2019	Year 2018
New England	390	2,109	-81.0%	55	345	284	1,713	38	36	14	16
Connecticut	79	601	-87.0%	9	9	64	588	3	3	2	1
Maine	53	317	-83.0%	0	0	36	298	8	6	10	13
Massachusetts	190	767	-75.0%	16	124	161	631	12	10	1	2
New Hampshire	49	298	-84.0%	26	201	10	82	13	15	0	0
Rhode Island	16	115	-86.0%	0	0	13	113	2	2	1	0
Vermont	4	10	-64.0%	4	10	0	0	0	0	0	0
Middle Atlantic	1,437	4,464	-68.0%	468	1,066	905	3,306	27	36	37	55
New Jersey	115	469	-75.0%	3	6	110	458	2	4	1	1
New York	896	2,596	-65.0%	464	1,057	403	1,485	14	20	15	35
Pennsylvania	426	1,398	-70.0%	0	3	392	1,364	11	12	22	19
East North Central	952	1,126	-15.0%	605	623	331	473	4	8	12	22
Illinois	97	106	-8.9%	16	16	81	90	0	0	0	0
Indiana	241	233	3.4%	234	214	0	1	NM	1	7	18
Michigan	185	254	-27.0%	182	247	0	0	2	6	1	1
Ohio	315	450	-30.0%	70	66	242	380	1	1	3	3
Wisconsin	114	83	38.0%	104	80	8	2	1	0	0	1
West North Central	796	697	14.0%	773	647	20	47	2	2	2	1
Iowa	135	129	4.2%	128	121	7	7	0	0	0	0
Kansas	175	118	48.0%	175	118	0	0	0	0	0	0
Minnesota	101	98	3.1%	85	56	13	39	2	2	1	1
Missouri	243	223	8.9%	243	223	0	0	0	0	0	0
Nebraska	41	34	21.0%	41	34	0	0	0	0	0	0
North Dakota	67	74	-9.6%	67	74	0	0	0	0	0	0
South Dakota	33	20	70.0%	33	20	0	0	0	0	0	0
South Atlantic	2,226	6,283	-65.0%	1,661	4,460	350	1,530	148	167	66	125
Delaware	35	333	-89.0%	1	12	35	321	0	0	0	0
District of Columbia	0	0	--	0	0	0	0	0	0	0	0
Florida	547	1,031	-47.0%	506	983	26	27	0	0	16	21
Georgia	188	497	-62.0%	140	252	9	176	8	7	30	62
Maryland	173	549	-68.0%	4	11	166	533	1	2	1	3
North Carolina	355	1,231	-71.0%	335	1,128	9	77	2	5	9	21
South Carolina	154	609	-75.0%	140	586	7	11	0	0	8	12
Virginia	543	1,744	-69.0%	306	1,225	97	359	137	154	4	6
West Virginia	230	290	-20.0%	229	264	2	26	0	0	0	0
East South Central	500	603	-17.0%	481	520	8	69	0	0	10	13
Alabama	35	146	-76.0%	21	69	8	69	0	0	6	8
Kentucky	167	179	-6.8%	167	179	0	0	0	0	0	0
Mississippi	25	50	-49.0%	24	47	0	0	0	0	2	3
Tennessee	272	228	20.0%	269	225	1	0	0	0	2	2
West South Central	264	247	6.8%	197	191	56	47	1	1	10	8
Arkansas	81	59	38.0%	58	46	20	10	0	0	3	3
Louisiana	48	41	18.0%	39	41	9	0	0	0	0	0
Oklahoma	35	33	7.0%	33	31	0	0	0	0	2	2
Texas	100	115	-13.0%	66	74	27	37	1	1	5	3
Mountain	1,063	370	187.0%	1,025	326	37	44	0	0	0	0
Arizona	124	95	31.0%	124	95	0	0	0	0	0	0
Colorado	24	34	-30.0%	24	33	0	1	0	0	0	0
Idaho	0	0	132.0%	0	0	0	0	0	0	0	0
Montana	34	37	-7.4%	4	1	30	35	0	0	0	0
Nevada	25	21	16.0%	21	16	4	5	0	0	0	0
New Mexico	703	42	NM	703	42	0	0	0	0	0	0
Utah	70	64	9.5%	67	62	3	2	0	0	0	0
Wyoming	84	78	7.6%	83	78	0	0	0	0	0	0
Pacific Contiguous	147	164	-10.0%	85	80	39	35	2	2	21	47
California	101	120	-16.0%	67	64	20	17	1	1	13	38
Oregon	15	9	70.0%	14	9	0	0	0	0	0	0
Washington	31	35	-10.0%	3	7	19	18	0	0	9	9
Pacific Noncontiguous	13,059	12,552	4.0%	10,327	10,086	2,434	2,203	27	16	272	246
Alaska	1,608	1,454	11.0%	1,530	1,388	5	0	8	6	65	59
Hawaii	11,451	11,098	3.2%	8,797	8,698	2,429	2,203	19	10	207	187
U.S. Total	20,836	28,614	-27.0%	15,677	18,345	4,464	9,467	251	269	444	534

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Notes: See Glossary for definitions. Values are final. See Technical Notes for a discussion of the sample design for the Form EIA-923.

Totals may not equal sum of components because of independent rounding. Percentage change is calculated before rounding.

Source: U.S. Energy Information Administration, Form EIA-923, Power Plant Operations Report.

Table 5.11. Consumption of Petroleum Coke for Electricity Generation by State, by Sector, 2019 and 2018 (Thousand Tons)

Census Division and State				Electric Power Sector							
	All Sectors			Electric Utilities		Independent Power Producers		Commercial Sector		Industrial Sector	
	Year 2019	Year 2018	Percentage Change	Year 2019	Year 2018	Year 2019	Year 2018	Year 2019	Year 2018	Year 2019	Year 2018
New England	0	0	--	0	0	0	0	0	0	0	0
Connecticut	0	0	--	0	0	0	0	0	0	0	0
Maine	0	0	--	0	0	0	0	0	0	0	0
Massachusetts	0	0	--	0	0	0	0	0	0	0	0
New Hampshire	0	0	--	0	0	0	0	0	0	0	0
Rhode Island	0	0	--	0	0	0	0	0	0	0	0
Vermont	0	0	--	0	0	0	0	0	0	0	0
Middle Atlantic	12	20	-40.0%	0	0	0	0	0	0	12	20
New Jersey	8	7	12.0%	0	0	0	0	0	0	8	7
New York	0	0	--	0	0	0	0	0	0	0	0
Pennsylvania	5	14	-65.0%	0	0	0	0	0	0	5	14
East North Central	773	1,160	-33.0%	389	558	316	550	0	0	68	52
Illinois	0	0	--	0	0	0	0	0	0	0	0
Indiana	0	0	--	0	0	0	0	0	0	0	0
Michigan	418	564	-26.0%	350	513	0	0	0	0	68	51
Ohio	316	551	-43.0%	0	0	316	550	0	0	0	1
Wisconsin	39	45	-12.0%	39	45	0	0	0	0	0	0
West North Central	12	7	62.0%	0	0	0	0	1	2	10	5
Iowa	12	7	62.0%	0	0	0	0	1	2	10	5
Kansas	0	0	--	0	0	0	0	0	0	0	0
Minnesota	0	0	--	0	0	0	0	0	0	0	0
Missouri	0	0	--	0	0	0	0	0	0	0	0
Nebraska	0	0	--	0	0	0	0	0	0	0	0
North Dakota	0	0	--	0	0	0	0	0	0	0	0
South Dakota	0	0	--	0	0	0	0	0	0	0	0
South Atlantic	466	594	-21.0%	433	559	0	0	0	0	33	35
Delaware	0	0	--	0	0	0	0	0	0	0	0
District of Columbia	0	0	--	0	0	0	0	0	0	0	0
Florida	433	559	-22.0%	433	559	0	0	0	0	0	0
Georgia	33	35	-5.6%	0	0	0	0	0	0	33	35
Maryland	0	0	--	0	0	0	0	0	0	0	0
North Carolina	0	0	--	0	0	0	0	0	0	0	0
South Carolina	0	0	--	0	0	0	0	0	0	0	0
Virginia	0	0	--	0	0	0	0	0	0	0	0
West Virginia	0	0	--	0	0	0	0	0	0	0	0
East South Central	0	0	--	0	0	0	0	0	0	0	0
Alabama	0	0	--	0	0	0	0	0	0	0	0
Kentucky	0	0	--	0	0	0	0	0	0	0	0
Mississippi	0	0	--	0	0	0	0	0	0	0	0
Tennessee	0	0	--	0	0	0	0	0	0	0	0
West South Central	1,297	1,687	-23.0%	1,244	1,624	0	0	0	0	53	64
Arkansas	0	0	--	0	0	0	0	0	0	0	0
Louisiana	1,246	1,646	-24.0%	1,244	1,624	0	0	0	0	2	23
Oklahoma	0	0	--	0	0	0	0	0	0	0	0
Texas	51	41	24.0%	0	0	0	0	0	0	51	41
Mountain	163	154	5.6%	0	0	163	154	0	0	0	0
Arizona	0	0	--	0	0	0	0	0	0	0	0
Colorado	0	0	--	0	0	0	0	0	0	0	0
Idaho	0	0	--	0	0	0	0	0	0	0	0
Montana	163	154	5.6%	0	0	163	154	0	0	0	0
Nevada	0	0	--	0	0	0	0	0	0	0	0
New Mexico	0	0	--	0	0	0	0	0	0	0	0
Utah	0	0	--	0	0	0	0	0	0	0	0
Wyoming	0	0	--	0	0	0	0	0	0	0	0
Pacific Contiguous	0	0	--	0	0	0	0	0	0	0	0
California	0	0	--	0	0	0	0	0	0	0	0
Oregon	0	0	--	0	0	0	0	0	0	0	0
Washington	0	0	--	0	0	0	0	0	0	0	0
Pacific Noncontiguous	0	0	--	0	0	0	0	0	0	0	0
Alaska	0	0	--	0	0	0	0	0	0	0	0
Hawaii	0	0	--	0	0	0	0	0	0	0	0
U.S. Total	2,724	3,623	-25.0%	2,067	2,740	478	704	1	2	177	177

Displayed values of zero may represent small values that round to zero. The Excel version of this table provides additional precision which may be accessed by selecting individual cells.

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Source: U.S. Energy Information Administration, Form EIA-923, Power Plant Operations Report.

Table 5.12. Consumption of Natural Gas for Electricity Generation by State, by Sector, 2019 and 2018 (Million Cubic Feet)

Census Division and State				Electric Power Sector							
	All Sectors			Electric Utilities		Independent Power Producers		Commercial Sector		Industrial Sector	
	Year 2019	Year 2018	Percentage Change	Year 2019	Year 2018	Year 2019	Year 2018	Year 2019	Year 2018	Year 2019	Year 2018
New England	351,302	371,172	-5.4%	1,540	2,658	334,916	353,979	5,891	5,862	8,956	8,673
Connecticut	149,034	141,310	5.5%	496	522	142,289	134,752	2,497	2,325	3,752	3,711
Maine	11,730	15,859	-26.0%	0	0	9,361	13,718	148	148	2,221	1,993
Massachusetts	111,604	133,263	-16.0%	952	1,724	106,334	127,086	2,964	3,118	1,353	1,334
New Hampshire	25,693	21,790	18.0%	79	400	25,381	21,163	45	32	188	195
Rhode Island	53,225	58,934	-9.7%	0	0	51,551	57,260	231	234	1,442	1,440
Vermont	17	16	8.1%	12	11	0	0	5	5	0	0
Middle Atlantic	1,317,087	1,210,777	8.8%	89,507	96,344	1,204,391	1,091,715	8,791	8,068	14,398	14,649
New Jersey	277,795	270,279	2.8%	1,582	1,602	272,204	265,520	1,734	1,094	2,276	2,063
New York	365,544	401,223	-8.9%	87,886	94,681	267,693	296,061	6,269	6,305	3,696	4,176
Pennsylvania	673,749	539,276	25.0%	38	62	664,495	530,134	789	670	8,427	8,410
East North Central	1,168,361	1,028,576	14.0%	404,987	379,177	725,680	615,520	7,650	7,958	30,043	25,922
Illinois	172,502	141,840	22.0%	11,739	10,478	155,078	125,035	1,823	2,094	3,862	4,233
Indiana	230,037	200,862	15.0%	101,345	90,971	111,896	96,367	1,028	870	15,768	12,653
Michigan	253,869	234,395	8.3%	97,842	91,603	149,348	136,240	3,167	3,195	3,512	3,358
Ohio	363,846	322,524	13.0%	62,285	72,293	299,079	247,949	1,102	1,218	1,379	1,064
Wisconsin	148,107	128,955	15.0%	131,775	113,832	10,280	9,929	530	580	5,522	4,614
West North Central	262,011	224,073	17.0%	216,875	194,749	39,189	24,193	1,806	1,604	4,140	3,527
Iowa	49,948	49,227	1.5%	46,716	46,478	0	76	616	492	2,616	2,181
Kansas	28,782	28,767	0.1%	28,232	28,281	0	0	0	0	550	486
Minnesota	86,011	61,174	41.0%	65,551	52,642	19,427	7,463	445	492	588	578
Missouri	62,142	56,961	9.1%	41,554	39,575	19,762	16,654	707	586	118	146
Nebraska	12,076	9,230	31.0%	12,037	9,196	0	0	38	34	0	0
North Dakota	13,817	9,615	44.0%	13,686	9,479	0	0	0	0	131	136
South Dakota	9,235	9,099	1.5%	9,099	9,099	0	0	0	0	136	0
South Atlantic	2,817,330	2,673,712	5.4%	2,300,179	2,164,942	474,308	471,691	12,952	10,387	29,890	26,693
Delaware	33,688	40,378	-17.0%	319	282	27,606	35,931	0	0	5,764	4,165
District of Columbia	1,511	614	146.0%	0	0	0	0	1,511	614	0	0
Florida	1,327,986	1,272,791	4.3%	1,262,062	1,201,253	57,158	63,351	107	151	8,659	8,036
Georgia	430,234	376,880	14.0%	327,045	284,254	99,660	88,999	1	0	3,528	3,626
Maryland	105,316	105,437	-0.1%	22,900	26,042	72,319	70,383	9,786	8,567	312	446
North Carolina	305,954	331,804	-7.8%	241,074	280,691	62,620	49,428	1,457	974	803	711
South Carolina	178,750	169,642	5.4%	168,922	143,129	8,941	25,704	3	2	884	807
Virginia	414,935	364,055	14.0%	273,670	227,378	133,755	129,086	87	79	7,423	7,512
West Virginia	18,955	12,112	56.0%	4,188	1,913	12,249	8,809	0	0	2,519	1,391
East South Central	1,017,088	1,010,560	0.6%	742,039	694,596	252,074	301,053	962	1,079	22,013	13,832
Alabama	414,117	421,586	-1.8%	156,800	155,114	247,450	259,291	0	0	9,866	7,181
Kentucky	113,334	113,487	-0.1%	107,944	105,040	4,426	7,616	0	0	965	831
Mississippi	361,588	368,214	-1.8%	358,718	331,487	51	34,009	0	40	2,819	2,678
Tennessee	128,049	107,273	19.0%	118,577	102,955	148	136	962	1,040	8,363	3,142
West South Central	2,878,287	2,637,243	9.1%	1,113,512	1,009,781	1,336,517	1,231,936	4,787	4,233	423,471	391,292
Arkansas	155,904	148,397	5.1%	147,395	139,217	6,476	7,221	479	431	1,554	1,528
Louisiana	500,639	442,731	13.0%	299,170	266,197	37,775	28,935	718	744	162,977	146,855
Oklahoma	341,019	320,293	6.5%	226,720	205,644	110,767	111,483	0	0	3,532	3,166
Texas	1,880,725	1,725,822	9.0%	440,226	398,722	1,181,500	1,084,297	3,590	3,058	255,409	239,744
Mountain	897,474	808,494	11.0%	725,201	654,483	158,146	138,452	2,252	2,173	11,876	13,386
Arizona	356,797	285,200	25.0%	273,400	226,923	82,798	57,666	598	611	0	0
Colorado	127,897	122,889	4.1%	107,650	100,913	19,856	21,648	35	5	356	322
Idaho	32,193	24,271	33.0%	19,222	12,610	12,187	11,073	168	170	616	419
Montana	5,510	5,153	6.9%	4,067	3,953	1,428	1,176	0	0	15	24
Nevada	191,553	198,627	-3.6%	173,486	180,440	15,166	15,129	262	258	2,639	2,800
New Mexico	104,014	99,161	4.9%	77,649	67,166	25,781	31,205	530	509	54	282
Utah	72,335	66,844	8.2%	66,472	60,620	914	541	658	619	4,291	5,063
Wyoming	7,175	6,350	13.0%	3,255	1,858	16	15	0	0	3,905	4,477
Pacific Contiguous	867,974	842,767	3.0%	351,183	329,059	433,576	435,397	10,484	11,284	72,731	67,028
California	615,344	646,381	-4.8%	209,860	220,039	326,983	349,196	10,226	10,995	68,275	66,150
Oregon	143,735	123,000	17.0%	69,066	60,935	73,945	61,412	227	211	497	442
Washington	108,895	73,386	48.0%	72,257	48,085	32,648	24,789	31	77	3,959	435
Pacific Noncontiguous	24,687	25,669	-3.8%	24,401	25,393	0	0	0	3	286	273
Alaska	24,687	25,669	-3.8%	24,401	25,393	0	0	0	3	286	273
Hawaii	0	0	--	0	0	0	0	0	0	0	0
U.S. Total	11,601,600	10,833,043	7.1%	5,969,422	5,551,181	4,958,798	4,663,935	55,575	52,650	617,805	565,276

Displayed values of zero may represent small values that round to zero. The Excel version of this table provides additional precision which may be accessed by selecting individual cells.

Notes: See Glossary for definitions. Values are final. See Technical Notes for a discussion of the sample design for the Form EIA-923.

Totals may not equal sum of components because of independent rounding. Percentage change is calculated before rounding.

Source: U.S. Energy Information Administration, Form EIA-923, Power Plant Operations Report.

Table 5.13. Consumption of Landfill Gas for Electricity Generation by State, by Sector, 2019 and 2018 (Million Cubic Feet)

Census Division and State				Electric Power Sector							
	All Sectors			Electric Utilities		Independent Power Producers		Commercial Sector		Industrial Sector	
	Year 2019	Year 2018	Percentage Change	Year 2019	Year 2018	Year 2019	Year 2018	Year 2019	Year 2018	Year 2019	Year 2018
New England	12,339	11,090	11.0%	1,410	0	10,711	10,850	217	240	0	0
Connecticut	169	266	-36.0%	0	0	169	266	0	0	0	0
Maine	682	688	-0.9%	0	0	682	688	0	0	0	0
Massachusetts	3,633	4,023	-9.7%	0	0	3,633	4,023	0	0	0	0
New Hampshire	1,958	1,699	15.0%	0	0	1,741	1,459	217	240	0	0
Rhode Island	4,229	4,133	2.3%	0	0	4,229	4,133	0	0	0	0
Vermont	1,668	281	494.0%	1,410	0	257	281	0	0	0	0
Middle Atlantic	48,526	51,470	-5.7%	0	0	46,743	49,791	673	537	1,110	1,142
New Jersey	6,693	7,398	-9.5%	0	0	6,510	7,243	183	155	0	0
New York	16,168	16,333	-1.0%	0	0	16,168	16,333	0	0	0	0
Pennsylvania	25,665	27,739	-7.5%	0	0	24,064	26,215	491	382	1,110	1,142
East North Central	61,921	62,210	-0.5%	10,372	9,596	50,982	52,076	321	283	246	255
Illinois	11,432	11,915	-4.1%	3,202	2,675	8,230	9,240	0	0	0	0
Indiana	8,317	8,124	2.4%	7,170	6,922	1,147	1,202	0	0	0	0
Michigan	21,180	20,083	5.5%	0	0	21,180	20,083	0	0	0	0
Ohio	10,990	11,338	-3.1%	0	0	10,990	11,338	0	0	0	0
Wisconsin	10,002	10,751	-7.0%	0	0	9,435	10,213	321	283	246	255
West North Central	8,716	9,885	-12.0%	3,008	3,204	5,708	6,681	0	0	0	0
Iowa	2,242	2,434	-7.9%	0	0	2,242	2,434	0	0	0	0
Kansas	1,390	1,501	-7.5%	0	0	1,390	1,501	0	0	0	0
Minnesota	1,694	2,413	-30.0%	671	683	1,024	1,730	0	0	0	0
Missouri	1,886	1,857	1.6%	833	841	1,052	1,016	0	0	0	0
Nebraska	1,504	1,680	-10.0%	1,504	1,680	0	0	0	0	0	0
North Dakota	0	0	--	0	0	0	0	0	0	0	0
South Dakota	0	0	--	0	0	0	0	0	0	0	0
South Atlantic	50,216	53,351	-5.9%	3,785	4,154	43,366	45,449	1,708	2,139	1,358	1,609
Delaware	1,305	1,159	13.0%	0	0	1,220	1,048	0	0	86	111
District of Columbia	0	0	--	0	0	0	0	0	0	0	0
Florida	10,573	11,366	-7.0%	1,575	1,693	8,998	9,672	0	0	0	0
Georgia	6,096	6,748	-9.7%	0	0	5,949	6,651	0	0	147	97
Maryland	2,251	2,666	-16.0%	0	0	1,471	1,777	780	889	0	0
North Carolina	11,378	11,313	0.6%	0	0	10,641	10,269	737	1,044	0	0
South Carolina	3,493	4,155	-16.0%	2,134	2,407	233	347	0	0	1,126	1,401
Virginia	15,120	15,943	-5.2%	75	54	14,854	15,684	191	205	0	0
West Virginia	0	0	--	0	0	0	0	0	0	0	0
East South Central	5,405	5,292	2.1%	2,212	2,363	3,193	2,929	0	0	0	0
Alabama	1,045	824	27.0%	0	0	1,045	824	0	0	0	0
Kentucky	2,455	2,562	-4.2%	2,212	2,363	243	199	0	0	0	0
Mississippi	236	231	2.1%	0	0	236	231	0	0	0	0
Tennessee	1,669	1,675	-0.4%	0	0	1,669	1,675	0	0	0	0
West South Central	11,627	13,020	-11.0%	0	0	11,438	12,417	189	603	0	0
Arkansas	1,472	1,097	34.0%	0	0	1,472	1,097	0	0	0	0
Louisiana	0	0	--	0	0	0	0	0	0	0	0
Oklahoma	453	470	-3.6%	0	0	453	470	0	0	0	0
Texas	9,702	11,453	-15.0%	0	0	9,513	10,850	189	603	0	0
Mountain	6,774	6,454	5.0%	332	327	5,720	5,573	721	554	0	0
Arizona	747	950	-21.0%	0	0	747	950	0	0	0	0
Colorado	1,283	1,360	-5.7%	0	0	1,283	1,360	0	0	0	0
Idaho	945	683	38.0%	332	327	113	157	500	199	0	0
Montana	0	0	--	0	0	0	0	0	0	0	0
Nevada	1,716	1,504	14.0%	0	0	1,716	1,504	0	0	0	0
New Mexico	409	168	144.0%	0	0	409	168	0	0	0	0
Utah	1,674	1,789	-6.4%	0	0	1,453	1,435	221	354	0	0
Wyoming	0	0	--	0	0	0	0	0	0	0	0
Pacific Contiguous	51,258	56,662	-9.5%	1,606	3,936	36,959	37,747	12,332	14,634	361	346
California	44,573	48,145	-7.4%	108	920	32,125	32,654	11,980	14,225	361	346
Oregon	5,631	5,758	-2.2%	1,498	1,453	3,780	3,895	352	409	0	0
Washington	1,053	2,760	-62.0%	0	1,562	1,053	1,198	0	0	0	0
Pacific Noncontiguous	712	801	-11.0%	0	0	0	0	712	801	0	0
Alaska	712	801	-11.0%	0	0	0	0	712	801	0	0
Hawaii	0	0	--	0	0	0	0	0	0	0	0
U.S. Total	257,494	270,235	-4.7%	22,726	23,580	214,819	223,513	16,874	19,790	3,075	3,352

Displayed values of zero may represent small values that round to zero. The Excel version of this table provides additional precision which may be accessed by selecting individual cells.

Notes: See Glossary for definitions. Values are final. See Technical Notes for a discussion of the sample design for the Form EIA-923.

Totals may not equal sum of components because of independent rounding. Percentage change is calculated before rounding.

Source: U.S. Energy Information Administration, Form EIA-923, Power Plant Operations Report.

Table 5.14. Consumption of Biogenic Municipal Solid Waste for Electricity Generation by State, by Sector, 2019 and 2018 (Thousand Tons)

Census Division and State				Electric Power Sector							
	All Sectors			Electric Utilities		Independent Power Producers		Commercial Sector		Industrial Sector	
	Year 2019	Year 2018	Percentage Change	Year 2019	Year 2018	Year 2019	Year 2018	Year 2019	Year 2018	Year 2019	Year 2018
New England	3,391,400	3,567,698	-4.9%	0	0	3,251,436	3,393,693	139,964	174,005	0	0
Connecticut	1,152,812	1,142,714	0.9%	0	0	1,152,812	1,142,714	0	0	0	0
Maine	247,953	286,752	-14.0%	0	0	107,989	112,747	139,964	174,005	0	0
Massachusetts	1,874,608	2,015,957	-7.0%	0	0	1,874,608	2,015,957	0	0	0	0
New Hampshire	116,027	122,275	-5.1%	0	0	116,027	122,275	0	0	0	0
Rhode Island	0	0	--	0	0	0	0	0	0	0	0
Vermont	0	0	--	0	0	0	0	0	0	0	0
Middle Atlantic	5,092,928	5,448,704	-6.5%	0	0	3,952,827	4,292,063	1,140,101	1,156,641	0	0
New Jersey	1,280,530	1,431,562	-11.0%	0	0	950,747	1,087,763	329,783	343,799	0	0
New York	1,958,517	2,054,078	-4.7%	0	0	1,388,113	1,495,386	570,404	558,692	0	0
Pennsylvania	1,853,881	1,963,064	-5.6%	0	0	1,613,967	1,708,914	239,914	254,150	0	0
East North Central	179,378	233,587	-23.0%	35,106	34,080	0	0	144,272	199,507	0	0
Illinois	0	0	--	0	0	0	0	0	0	0	0
Indiana	18,485	19,959	-7.4%	0	0	0	0	18,485	19,959	0	0
Michigan	125,787	179,548	-30.0%	0	0	0	0	125,787	179,548	0	0
Ohio	0	0	--	0	0	0	0	0	0	0	0
Wisconsin	35,106	34,080	3.0%	35,106	34,080	0	0	0	0	0	0
West North Central	482,950	672,132	-28.0%	262,383	432,826	209,879	227,847	10,688	11,459	0	0
Iowa	0	0	--	0	0	0	0	0	0	0	0
Kansas	0	0	--	0	0	0	0	0	0	0	0
Minnesota	482,950	672,132	-28.0%	262,383	432,826	209,879	227,847	10,688	11,459	0	0
Missouri	0	0	--	0	0	0	0	0	0	0	0
Nebraska	0	0	--	0	0	0	0	0	0	0	0
North Dakota	0	0	--	0	0	0	0	0	0	0	0
South Dakota	0	0	--	0	0	0	0	0	0	0	0
South Atlantic	5,297,915	5,700,696	-7.1%	0	0	4,876,934	5,248,306	420,981	452,390	0	0
Delaware	0	0	--	0	0	0	0	0	0	0	0
District of Columbia	0	0	--	0	0	0	0	0	0	0	0
Florida	3,545,259	3,878,338	-8.6%	0	0	3,545,259	3,878,338	0	0	0	0
Georgia	0	0	--	0	0	0	0	0	0	0	0
Maryland	610,344	648,455	-5.9%	0	0	610,344	648,455	0	0	0	0
North Carolina	0	0	--	0	0	0	0	0	0	0	0
South Carolina	0	0	--	0	0	0	0	0	0	0	0
Virginia	1,142,312	1,173,903	-2.7%	0	0	721,331	721,513	420,981	452,390	0	0
West Virginia	0	0	--	0	0	0	0	0	0	0	0
East South Central	0	0	--	0	0	0	0	0	0	0	0
Alabama	0	0	--	0	0	0	0	0	0	0	0
Kentucky	0	0	--	0	0	0	0	0	0	0	0
Mississippi	0	0	--	0	0	0	0	0	0	0	0
Tennessee	0	0	--	0	0	0	0	0	0	0	0
West South Central	10,086	8,805	15.0%	0	0	0	0	0	0	10,086	8,805
Arkansas	0	0	--	0	0	0	0	0	0	0	0
Louisiana	0	0	--	0	0	0	0	0	0	0	0
Oklahoma	10,086	8,805	15.0%	0	0	0	0	0	0	10,086	8,805
Texas	0	0	--	0	0	0	0	0	0	0	0
Mountain	0	0	--	0	0	0	0	0	0	0	0
Arizona	0	0	--	0	0	0	0	0	0	0	0
Colorado	0	0	--	0	0	0	0	0	0	0	0
Idaho	0	0	--	0	0	0	0	0	0	0	0
Montana	0	0	--	0	0	0	0	0	0	0	0
Nevada	0	0	--	0	0	0	0	0	0	0	0
New Mexico	0	0	--	0	0	0	0	0	0	0	0
Utah	0	0	--	0	0	0	0	0	0	0	0
Wyoming	0	0	--	0	0	0	0	0	0	0	0
Pacific Contiguous	650,245	697,555	-6.8%	0	0	650,245	697,555	0	0	0	0
California	385,958	426,524	-9.5%	0	0	385,958	426,524	0	0	0	0
Oregon	114,155	112,909	1.1%	0	0	114,155	112,909	0	0	0	0
Washington	150,132	158,122	-5.1%	0	0	150,132	158,122	0	0	0	0
Pacific Noncontiguous	453,635	454,307	-0.1%	0	0	0	0	453,635	454,307	0	0
Alaska	0	0	--	0	0	0	0	0	0	0	0
Hawaii	453,635	454,307	-0.1%	0	0	0	0	453,635	454,307	0	0
U.S. Total	15,558,537	16,783,484	-7.3%	297,489	466,906	12,941,321	13,859,464	2,309,641	2,448,309	10,086	8,805

Displayed values of zero may represent small values that round to zero. The Excel version of this table provides additional precision which may be accessed by selecting individual cells.

Notes: See Glossary for definitions. Values are final. See Technical Notes for a discussion of the sample design for the Form EIA-923.

Totals may not equal sum of components because of independent rounding. Percentage change is calculated before rounding.

Source: U.S. Energy Information Administration, Form EIA-923, Power Plant Operations Report.

Chapter 6

Fossil Fuel Stocks for Electricity Generation

Table 6.1. Stocks of Coal, Petroleum Liquids, and Petroleum Coke: Electric Power Sector, 2009 - 2019

Period	Electric Power Sector			Electric Utilities			Independent Power Producers		
	Coal (Thousand Tons)	Petroluem Liquids (Thousand Barrels)	Petroleum Coke (Thousand Tons)	Coal (Thousand Tons)	Petroluem Liquids (Thousand Barrels)	Petroleum Coke (Thousand Tons)	Coal (Thousand Tons)	Petroluem Liquids (Thousand Barrels)	Petroleum Coke (Thousand Tons)
End of Year Stocks									
2009	189,467	38,604	1,394	154,815	25,205	1,194	34,652	13,399	201
2010	174,917	34,841	1,019	143,744	23,934	850	31,173	10,908	168
2011	172,387	33,742	508	142,103	24,544	404	30,284	9,198	104
2012	185,116	30,862	495	150,942	22,513	414	34,174	8,349	81
2013	147,884	30,387	390	120,792	21,208	303	27,092	9,179	86
2014	151,548	32,322	827	116,684	21,304	686	34,864	11,018	142
2015	195,548	31,694	1,340	153,226	20,253	1,163	42,322	11,441	177
2016	162,009	30,593	845	130,885	19,767	603	31,124	10,827	241
2017	137,687	28,089	864	114,782	19,047	692	22,905	9,041	171
2018	102,793	25,977	539	84,728	16,553	521	18,065	9,423	19
2019	128,176	25,960	471	104,265	16,435	428	23,911	9,525	43
Year 2017, End of Month Stocks									
January	156,214	30,536	768	125,221	19,681	540	30,994	10,855	228
February	160,502	30,293	756	128,051	19,517	544	32,451	10,776	212
March	161,815	30,939	785	128,645	20,342	558	33,170	10,597	227
April	163,937	30,688	844	130,461	20,268	622	33,475	10,420	221
May	162,542	30,326	772	129,300	19,893	562	33,242	10,433	210
June	158,014	29,974	742	126,564	19,823	535	31,450	10,151	207
July	145,811	29,798	724	117,584	19,686	544	28,228	10,111	180
August	141,204	29,533	749	114,228	19,491	569	26,976	10,042	181
September	139,571	29,123	798	113,247	19,319	624	26,324	9,805	173
October	141,463	28,976	862	114,939	19,119	683	26,524	9,857	179
November	143,424	29,227	859	117,758	19,397	677	25,666	9,830	182
December	137,687	28,089	864	114,782	19,047	692	22,905	9,041	171
Year 2018, End of Month Stocks									
January	123,235	25,853	720	103,761	17,653	579	19,474	8,200	141
February	120,526	26,831	692	101,532	18,213	561	18,994	8,618	131
March	126,008	26,763	736	106,377	18,301	612	19,631	8,462	124
April	128,571	26,608	731	107,870	18,236	647	20,701	8,372	84
May	127,982	26,794	709	107,176	18,315	648	20,806	8,479	61
June	121,041	26,494	591	101,498	17,964	526	19,544	8,530	65
July	110,348	25,912	668	93,099	17,412	614	17,249	8,500	53
August	103,744	24,815	625	87,944	16,602	580	15,800	8,213	45
September	100,384	24,595	608	84,696	16,378	557	15,688	8,217	51
October	104,855	24,591	541	87,394	16,183	511	17,461	8,409	30
November	104,075	24,720	557	86,252	16,114	540	17,823	8,606	16
December	102,793	25,977	539	84,728	16,553	521	18,065	9,423	19
Year 2019, End of Month Stocks									
January	99,145	25,791	528	81,550	16,464	518	17,595	9,327	9
February	98,637	26,154	505	81,171	16,781	494	17,467	9,373	11
March	96,932	26,202	503	79,482	16,870	482	17,450	9,332	21
April	108,072	26,330	513	88,197	16,994	500	19,875	9,336	13
May	115,700	26,407	444	93,461	17,063	434	22,239	9,344	10
June	116,861	26,185	388	93,750	16,862	381	23,111	9,323	7
July	110,661	25,827	354	89,490	16,598	347	21,171	9,230	8
August	110,268	25,208	380	89,041	16,128	372	21,227	9,080	8
September	110,615	25,448	292	89,616	16,352	281	20,998	9,096	11
October	118,566	25,413	292	96,194	16,359	277	22,372	9,055	16
November	122,357	25,720	464	99,459	16,480	407	22,898	9,240	57
December	128,176	25,960	471	104,265	16,435	428	23,911	9,525	43

Notes: See Glossary for definitions. Values are final.
See Technical Notes for a discussion of the sample design for the Form EIA-923 and predecessor forms. Totals may not equal sum of components because of independent rounding.
Sources: U.S. Energy Information Administration, Form EIA-906, Power Plant Report; U.S. Energy Information Administration, Form EIA-920 Combined Heat and Power Plant Report, and predecessor forms.
Beginning with 2008 data, the Form EIA-923, Power Plant Operations Report, replaced the following: 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 Federal Energy Regulatory Commission, FERC Form 423, Monthly Report of Cost and Quality of Fuels for Electric Plants.

**Table 6.2 Stocks of Coal, Petroleum Liquids, and Petroleum Coke:
Electric Power Sector, by State, 2019 and 2018**

Census Division and State	Coal (Thousand Tons)			Petroleum Liquids (Thousand Barrels)			Petroleum Coke (Thousand Tons)		
	December 2019	December 2018	Percentage Change	December 2019	December 2018	Percentage Change	December 2019	December 2018	Percentage Change
New England	465	605	-23.2%	3,409	3,385	0.7%	0	0	--
Connecticut	W	W	W	1,202	1,227	-2.0%	0	0	--
Maine	0	0	--	231	197	17.3%	0	0	--
Massachusetts	0	0	--	1,386	1,354	2.4%	0	0	--
New Hampshire	W	W	W	345	374	-7.9%	0	0	--
Rhode Island	0	W	W	207	195	6.5%	0	0	--
Vermont	0	0	--	NM	39	NM	0	0	--
Middle Atlantic	4,612	3,511	31.4%	5,671	5,217	8.7%	0	0	--
New Jersey	W	W	W	764	644	18.6%	0	0	--
New York	W	W	W	3,504	3,234	8.3%	0	0	--
Pennsylvania	4,427	3,261	35.8%	1,404	1,338	4.9%	0	0	--
East North Central	28,377	21,289	33.3%	1,180	1,062	11.2%	116	W	W
Illinois	4,385	5,209	-15.8%	NM	69	NM	0	0	--
Indiana	8,900	6,033	47.5%	164	97	68.8%	W	W	W
Michigan	4,998	4,438	12.6%	NM	291	NM	W	W	W
Ohio	6,697	2,797	139.4%	480	411	16.8%	W	0	W
Wisconsin	3,397	2,812	20.8%	NM	194	NM	W	W	W
West North Central	22,810	21,125	8.0%	844	895	-5.6%	0	0	--
Iowa	4,659	3,798	22.7%	NM	130	NM	0	0	--
Kansas	3,227	3,465	-6.9%	110	119	-7.1%	0	0	--
Minnesota	3,743	2,748	36.2%	NM	103	NM	0	0	--
Missouri	7,070	7,177	-1.5%	326	366	-10.8%	0	0	--
Nebraska	2,597	2,218	17.1%	NM	105	NM	0	0	--
North Dakota	W	W	W	NM	27	NM	0	0	--
South Dakota	W	W	W	NM	46	NM	0	0	--
South Atlantic	23,185	16,726	38.6%	10,401	11,044	-5.8%	W	W	W
Delaware	W	W	W	524	550	-4.6%	0	0	--
District of Columbia	0	0	--	0	0	--	0	0	--
Florida	2,737	3,026	-9.6%	3,853	4,249	-9.3%	W	W	W
Georgia	5,045	3,194	58.0%	805	821	-2.0%	0	0	--
Maryland	1,723	1,536	12.2%	723	757	-4.5%	0	0	--
North Carolina	3,776	2,961	27.5%	1,214	1,234	-1.6%	0	0	--
South Carolina	2,398	1,850	29.6%	671	721	-6.9%	0	0	--
Virginia	W	582	W	2,456	2,573	-4.5%	0	0	--
West Virginia	6,263	W	W	154	139	10.8%	W	W	W
East South Central	12,837	9,721	32.1%	1,196	1,146	4.4%	0	0	--
Alabama	W	W	W	210	206	1.9%	0	0	--
Kentucky	6,582	4,881	34.9%	221	231	-4.5%	0	0	--
Mississippi	W	W	W	NM	33	NM	0	0	--
Tennessee	2,868	2,417	18.7%	756	675	11.9%	0	0	--
West South Central	18,248	13,146	38.8%	1,243	1,324	-6.1%	W	W	W
Arkansas	3,611	2,297	57.2%	163	168	-2.7%	0	0	--
Louisiana	2,588	1,867	38.6%	222	223	-0.4%	W	W	W
Oklahoma	2,578	2,988	-13.7%	93	95	-2.8%	0	0	--
Texas	9,471	5,994	58.0%	765	837	-8.6%	0	0	--
Mountain	16,447	15,671	5.0%	334	385	-13.3%	W	W	W
Arizona	3,325	2,525	31.7%	126	136	-7.6%	0	0	--
Colorado	3,581	3,964	-9.7%	118	127	-6.6%	0	0	--
Idaho	0	0	--	0	0	-36.8%	0	0	--
Montana	W	W	W	NM	36	NM	W	W	W
Nevada	W	W	W	2	2	21.6%	0	0	--
New Mexico	W	W	W	NM	28	NM	0	0	--
Utah	2,866	3,252	-11.9%	26	26	1.2%	0	0	--
Wyoming	4,644	3,783	22.8%	29	30	-4.1%	0	0	--
Pacific Contiguous	W	W	W	358	352	1.6%	0	0	--
California	0	0	--	177	176	0.8%	0	0	--
Oregon	W	W	W	80	80	0.2%	0	0	--
Washington	W	W	W	NM	96	NM	0	0	--
Pacific Noncontiguous	W	W	W	1,323	1,168	13.3%	0	0	--
Alaska	W	W	W	NM	245	NM	0	0	--
Hawaii	W	W	W	1,103	923	19.6%	0	0	--
U.S. Total	128,176	102,793	24.7%	25,960	25,977	-0.1%	471	539	-12.6%

Displayed values of zero may represent small values that round to zero. The Excel version of this table provides additional precision which may be accessed by selecting individual cells.

NM = Not meaningful due to large relative standard error or excessive percentage change.

Notes: See Glossary for definitions. Values are final. See Technical Notes for a discussion of the sample design for the Form EIA-923.

Negative generation denotes that electric power consumed for plant use exceeds gross generation.

Totals may not equal sum of components because of independent rounding. Percentage change is calculated before rounding.

Source: U.S. Energy Information Administration, Form EIA-923, Power Plant Operations Report.

**Table 6.3 Stocks of Coal, Petroleum Liquids, and Petroleum Coke:
Electric Power Sector, by Census Divison, 2019 and 2018**

	Electric Power Sector			Electric Utilities		Independent Power Producers	
Census Division	December 2019	December 2018	Percentage Change	December 2019	December 2018	December 2019	December 2018
Coal (Thousand Tons)							
New England	465	605	-23.2%	W	W	W	W
Middle Atlantic	4,612	3,511	31.4%	0	0	4,612	3,511
East North Central	28,377	21,289	33.3%	18,492	W	9,885	W
West North Central	22,810	21,125	8.0%	22,810	21,125	0	0
South Atlantic	23,185	16,726	38.6%	20,619	14,437	2,567	2,289
East South Central	12,837	9,721	32.1%	12,837	9,721	0	0
West South Central	18,248	13,146	38.8%	13,016	9,738	5,232	3,407
Mountain	16,447	15,671	5.0%	W	W	W	W
Pacific Contiguous	W	W	W	W	W	W	W
Pacific Noncontiguous	W	W	W	W	W	W	W
U.S. Total	128,176	102,793	24.7%	104,265	84,728	23,911	18,065
Petroleum Liquids (Thousand Barrels)							
New England	3,409	3,385	0.7%	497	520	2,911	2,865
Middle Atlantic	5,671	5,217	8.7%	2,138	1,833	3,534	3,384
East North Central	1,180	1,062	11.2%	717	709	463	353
West North Central	844	895	-5.6%	819	868	NM	27
South Atlantic	10,401	11,044	-5.8%	8,271	8,803	2,130	2,241
East South Central	1,196	1,146	4.4%	1,104	1,061	92	85
West South Central	1,243	1,324	-6.1%	1,025	1,026	218	297
Mountain	334	385	-13.3%	306	338	28	47
Pacific Contiguous	358	352	1.6%	278	273	79	80
Pacific Noncontiguous	1,323	1,168	13.3%	1,280	1,123	43	44
U.S. Total	25,960	25,977	-0.1%	16,435	16,553	9,525	9,423
Petroleum Coke (Thousand Tons)							
New England	0	0	--	0	0	0	0
Middle Atlantic	0	0	--	0	0	0	0
East North Central	116	W	W	W	W	W	0
West North Central	0	0	--	0	0	0	0
South Atlantic	W	W	W	W	W	W	W
East South Central	0	0	--	0	0	0	0
West South Central	W	W	W	W	W	0	0
Mountain	W	W	W	0	0	W	W
Pacific Contiguous	0	0	--	0	0	0	0
Pacific Noncontiguous	0	0	--	0	0	0	0
U.S. Total	471	539	-12.6%	428	521	43	19

W = Withheld to avoid disclosure of individual company data.

Notes: See Glossary for definitions. Values are final. See Technical Notes for a discussion of the sample design for the Form-923.

Totals may not equal sum of components because of independent rounding. Percentage change is calculated before rounding.

Source: U.S. Energy Information Administration, Form-923, 'Power Plant Operations Report.'

Table 6.4. Stocks of Coal by Coal Rank: Electric Power Sector, 2009 - 2019
(Thousand Tons)

		Electric Power Sector			
Period		Bituminous Coal	Subbituminous Coal	Lignite Coal	Total
End of Year Stocks					
	2009	91,922	92,448	5,097	189,467
	2010	81,108	86,915	6,894	174,917
	2011	82,056	85,151	5,179	172,387
	2012	86,437	93,833	4,846	185,116
	2013	73,113	69,720	5,051	147,884
	2014	72,771	72,552	6,225	151,548
	2015	82,004	108,614	4,931	195,548
	2016	67,241	90,376	4,393	162,009
	2017	56,140	77,875	3,672	137,687
	2018	41,507	58,247	3,039	102,793
	2019	54,843	69,942	3,124	128,176
Year 2017, End of Month Stocks					
	January	65,797	86,082	4,335	156,214
	February	67,752	88,326	4,424	160,502
	March	67,783	89,381	4,651	161,815
	April	68,195	90,736	5,005	163,937
	May	68,333	89,005	5,204	162,542
	June	66,591	86,722	4,701	158,014
	July	60,766	80,765	4,281	145,811
	August	59,208	77,758	4,238	141,204
	September	58,453	77,173	3,945	139,571
	October	59,122	78,821	3,519	141,463
	November	59,427	79,916	4,081	143,424
	December	56,140	77,875	3,672	137,687
Year 2018, End of Month Stocks					
	January	47,910	72,251	3,074	123,235
	February	47,658	69,960	2,909	120,526
	March	49,027	73,768	3,213	126,008
	April	50,499	74,747	3,324	128,571
	May	51,393	73,377	3,212	127,982
	June	48,411	69,439	3,191	121,041
	July	44,487	63,014	2,847	110,348
	August	42,359	58,570	2,816	103,744
	September	40,384	57,155	2,845	100,384
	October	42,588	59,252	3,016	104,855
	November	42,392	58,575	3,108	104,075
	December	41,507	58,247	3,039	102,793
Year 2019, End of Month Stocks					
	January	39,894	56,367	2,883	99,145
	February	41,235	54,664	2,738	98,637
	March	44,238	49,467	3,054	96,932
	April	48,923	55,805	3,344	108,072
	May	51,971	60,325	3,023	115,700
	June	53,689	60,294	2,551	116,861
	July	50,057	57,593	2,670	110,661
	August	49,610	57,934	2,409	110,268
	September	48,834	59,057	2,395	110,615
	October	51,573	64,046	2,590	118,566
	November	52,621	66,446	2,959	122,357
	December	54,843	69,942	3,124	128,176

Notes: See Glossary for definitions.

Values are final. See Technical Notes for a discussion of the sample design for the Form EIA-923.

and predecessor forms. Totals may not equal sum of components because of independent rounding.

Sources: U.S. Energy Information Administration, Form EIA-906, Power Plant Report; U.S. Energy Information Administration, Form EIA-920 Combined Heat and Power Plant Report, and predecessor forms. Beginning with 2008 data, the Form EIA-923, Power Plant Operations Report, replaced the following:

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

Chapter 7

Receipts, Cost, and Quality of Fossil Fuels

Table 7.1. Receipts, Average Cost, and Quality of Fossil Fuels for the Electric Power Industry, 2009 through 2019

	Coal				Petroleum				Natural Gas		All Fossil Fuels
			Average Cost				Average Cost			Average Cost	Average Cost
Period	Receipts (Thousand Tons)	Average Sulfur Percent by Weight	(Dollars per MMBtu)	(Dollars per Ton)	Receipts (Thousand Barrels)	Average Sulfur Percent by Weight	(Dollars per MMBtu)	(Dollars per Barrel)	Receipts (Thousand Mcf)	(Dollars per MMBtu)	(Dollars per MMBtu)
2009	981,477	1.01	2.21	43.74	88,951	2.14	7.02	41.64	8,118,550	4.74	3.04
2010	979,918	1.16	2.27	44.64	75,285	2.14	9.54	56.35	8,673,070	5.09	3.26
2011	956,538	1.19	2.39	46.65	66,058	2.49	12.48	73.29	9,056,164	4.72	3.29
2012	841,183	1.25	2.38	46.09	40,364	3.61	12.48	73.30	9,531,389	3.42	2.83
2013	823,222	1.29	2.34	45.33	43,714	3.54	11.57	68.09	8,503,424	4.33	3.09
2014	854,560	1.32	2.37	45.96	54,488	3.56	11.60	68.12	8,431,423	5.00	3.31
2015	782,929	1.29	2.22	42.86	48,804	3.38	6.74	39.51	9,842,581	3.23	2.65
2016	650,770	1.34	2.11	40.64	37,637	3.69	5.24	30.46	10,271,180	2.87	2.47
2017	642,364	1.28	2.06	39.27	32,672	3.59	7.10	41.23	9,628,733	3.37	2.65
2018	596,215	1.31	2.06	39.25	37,341	3.31	9.68	56.82	10,885,764	3.55	2.83
2019	560,153	1.31	2.02	38.70	24,556	3.03	9.07	53.55	11,693,486	2.89	2.50

* = Value is less than half of the smallest unit of measure. (e.g., for values with no decimals, the smallest unit is 1 then values under 0.5 are shown as *.)

NM = Not meaningful due to large relative standard error or excessive percentage change.

W = Withheld to avoid disclosure of individual company data.

Notes:

Beginning in January 2013, the threshold for reporting fuel receipts data was changed from 50 megawatts to 200 megawatts of nameplate capacity for plants primarily fueled by natural gas, petroleum coke, distillate fuel oil, and residual fuel oil. In addition, the requirement to report self-produced and minor fuels, i.e., blast furnace gas, other manufactured gases, kerosene, jet fuel, propane, and waste oils was eliminated. The threshold for coal plants remained at 50 megawatts. The following caveats for each fuel type should be noted:

COAL - includes anthracite, bituminous, subbituminous, lignite, waste coal, and coal-derived synthesis gas. Prior to 2011, synthesis gas was included in the category of Other Gases.

PETROLEUM - includes petroleum liquids (distillate fuel oil and residual fuel oil) and petroleum coke which includes petroleum coke-derived synthesis gas. Prior to 2011, petroleum coke-derived synthesis gas was included in Other Gases. Prior to 2013, petroleum liquids included distillate fuel oil, residual fuel oil, kerosene, jet fuel, waste oil, and, beginning in 2011, propane. Prior to 2011, propane was included in the category of Other Gases.

NATURAL GAS - includes natural gas only. Prior to 2011, includes Other Gases.

- All values are final.
- See Glossary for definitions.
- Starting in January 2013, there may have been a shift in the continuity of Chapter 7 tables due to changes in the sample design of Form EIA-923 and the imputation process.
- See the EIA-923 section of the Technical Notes for a discussion of the sample design for the Form EIA-923 and predecessor forms.
- See the Technical Notes for fuel conversion factors.
- Totals may not equal the sum of components because of independent rounding.

Sources: U.S. Energy Information Administration (EIA), Form EIA-923, "Power Plant Operations Report" and predecessor forms 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 7.2. Receipts and Quality of Coal Delivered for the Electric Power Industry, 2009 through 2019

Period	Bituminous			Subbituminous			Lignite		
	Receipts (Thousand Tons)	Average Sulfur Percent by Weight	Average Ash Percent by Weight	Receipts (Thousand Tons)	Average Sulfur Percent by Weight	Average Ash Percent by Weight	Receipts (Thousand Tons)	Average Sulfur Percent by Weight	Average Ash Percent by Weight
2009	418,688	1.77	10.5	484,007	0.34	5.8	64,966	0.95	14.0
2010	403,619	1.90	10.4	491,425	0.33	5.8	71,416	0.90	14.1
2011	380,184	2.01	10.5	488,366	0.33	5.8	75,675	0.90	14.4
2012	317,398	2.23	10.6	442,674	0.32	5.8	71,848	0.93	14.6
2013	312,821	2.33	10.5	429,283	0.32	5.8	71,191	0.92	14.3
2014	334,082	2.34	10.3	440,013	0.31	5.8	71,534	0.90	14.1
2015	289,093	2.40	10.4	421,127	0.32	5.8	65,826	0.89	14.1
2016	245,141	2.43	10.3	333,241	0.31	5.8	64,426	0.91	14.0
2017	224,500	2.45	10.3	350,580	0.31	5.6	59,665	0.96	14.0
2018	205,783	2.55	10.1	329,974	0.31	5.7	52,438	0.91	13.4
2019	198,016	2.52	10.0	309,029	0.32	5.7	46,781	0.90	13.3

* = Value is less than half of the smallest unit of measure. (e.g., for values with no decimals, the smallest unit is 1 then values under 0.5 are shown as *.)

NM = Not meaningful due to large relative standard error or excessive percentage change.

W = Withheld to avoid disclosure of individual company data.

Notes:

Bituminous coal includes anthracite and beginning in 2011, coal-derived synthesis gas. Prior to 2011 coal-derived synthesis gas was included in Other Gases.

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- See Glossary for definitions.
- Starting in January 2013, there may have been a shift in the continuity of Chapter 7 tables due to changes in the sample design of Form EIA-923 and the imputation process.
- See the EIA-923 section of the Technical Notes for a discussion of the sample design for the Form EIA-923 and predecessor forms.
- See the Technical Notes for fuel conversion factors.
- Totals may not equal the sum of components because of independent rounding.

Sources: U.S. Energy Information Administration (EIA), Form EIA-923, "Power Plant Operations Report" and predecessor forms 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 7.3. Average Quality of Fossil Fuel Receipts for the Electric Power Industry, 2009 through 2019

	Coal			Petroleum			Natural Gas
Period	Average Btu per Pound	Average Sulfur Percent by Weight	Average Ash Percent by Weight	Average Btu per Gallon	Average Sulfur Percent by Weight	Average Ash Percent by Weight	Average Btu per Cubic Foot
2009	9,902	1.01	8.9	141,321	2.14	0.2	1,025
2010	9,842	1.16	8.8	140,598	2.14	0.2	1,022
2011	9,762	1.19	8.8	139,795	2.49	0.4	1,021
2012	9,668	1.25	8.8	139,567	3.61	0.5	1,023
2013	9,661	1.29	8.7	139,671	3.54	0.5	1,026
2014	9,710	1.32	8.6	139,713	3.56	0.5	1,029
2015	9,634	1.29	8.6	139,681	3.38	0.5	1,034
2016	9,617	1.34	8.7	138,384	3.69	0.5	1,034
2017	9,544	1.28	8.4	138,324	3.59	0.4	1,034
2018	9,536	1.31	8.3	139,762	3.31	0.3	1,033
2019	9,592	1.31	8.3	140,549	3.03	0.3	1,034

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NM = Not meaningful due to large relative standard error or excessive percentage change.

W = Withheld to avoid disclosure of individual company data.

Notes:

Beginning in January 2013, the threshold for reporting fuel receipts data was changed from 50 megawatts to 200 megawatts of nameplate capacity for plants primarily fueled by natural gas, petroleum coke, distillate fuel oil, and residual fuel oil. In addition, the requirement to report self-produced and minor fuels, i.e., blast furnace gas, other manufactured gases, kerosene, jet fuel, propane, and waste oils was eliminated. The threshold for coal plants remained at 50 megawatts. The following caveats for each fuel type should be noted:

COAL - includes anthracite, bituminous, subbituminous, lignite, waste coal, and coal-derived synthesis gas. Prior to 2011, synthesis gas was included in the category of Other Gases.

PETROLEUM - includes petroleum liquids (distillate fuel oil and residual fuel oil) and petroleum coke which includes petroleum coke-derived synthesis gas. Prior to 2011, petroleum coke-derived synthesis gas was included in Other Gases. Prior to 2013, petroleum liquids included distillate fuel oil, residual fuel oil, kerosene, jet fuel, waste oil, and, beginning in 2011, propane. Prior to 2011, propane was included in the category of Other Gases.

NATURAL GAS - includes natural gas only. Prior to 2011, includes Other Gases.

- All values are final.

- See Glossary for definitions.

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- See the EIA-923 section of the Technical Notes for a discussion of the sample design for the Form EIA-923 and predecessor forms.

- See the Technical Notes for fuel conversion factors.

- Totals may not equal the sum of components because of independent rounding.

Sources: U.S. Energy Information Administration (EIA), Form EIA-923, "Power Plant Operations Report" and predecessor forms 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 7.4. Weighted Average Cost of Fossil Fuels for the Electric Power Industry, 2009 through 2019

	Coal								Petroleum		Natural Gas		Total Fossil	
	Bituminous		Subbituminous		Lignite		All Coal Ranks							
Period	Receipts (Trillion Btu)	Average Cost (Dollars per MMBtu)	Receipts (Trillion Btu)	Average Cost (Dollars per MMBtu)	Receipts (Trillion Btu)	Average Cost (Dollars per MMBtu)	Receipts (Trillion Btu)	Average Cost (Dollars per MMBtu)	Receipts (Trillion Btu)	Average Cost (Dollars per MMBtu)	Receipts (Trillion Btu)	Average Cost (Dollars per MMBtu)	Receipts (Trillion Btu)	Average Cost (Dollars per MMBtu)
2009	10,010	2.75	8,421	1.64	835	1.58	19,438	2.21	528	7.02	8,319	4.74	28,285	3.04
2010	9,652	2.81	8,545	1.73	925	1.62	19,290	2.27	445	9.54	8,867	5.09	28,602	3.26
2011	9,040	2.94	8,498	1.91	986	1.62	18,676	2.39	388	12.48	9,251	4.72	28,314	3.29
2012	7,502	2.89	7,722	1.97	931	1.80	16,266	2.38	237	12.48	9,747	3.42	26,249	2.83
2013	7,351	2.77	7,511	2.00	927	1.78	15,907	2.34	256	11.57	8,721	4.33	24,884	3.09
2014	7,883	2.74	7,681	2.06	934	1.77	16,595	2.37	320	11.60	8,679	5.00	25,594	3.31
2015	6,797	2.58	7,353	1.94	855	1.92	15,086	2.22	286	6.74	10,174	3.23	25,546	2.65
2016	5,770	2.40	5,818	1.89	840	1.74	12,516	2.11	219	5.24	10,619	2.87	23,354	2.47
2017	5,279	2.31	6,123	1.90	773	1.66	12,261	2.06	190	7.10	9,952	3.37	22,403	2.65
2018	4,838	2.31	5,765	1.90	677	1.71	11,371	2.06	219	9.68	11,244	3.55	22,834	2.83
2019	4,670	2.26	5,401	1.86	601	1.68	10,746	2.02	145	9.07	12,093	2.89	22,984	2.50

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Notes:

Beginning in January 2013, the threshold for reporting fuel receipts data was changed from 50 megawatts to 200 megawatts of nameplate capacity for plants primarily fueled by natural gas, petroleum coke, distillate fuel oil, and residual fuel oil. In addition, the requirement to report self-produced and minor fuels, i.e., blast furnace gas, other manufactured gases, kerosene, jet fuel, propane, and waste oils was eliminated. The threshold for coal plants remained at 50 megawatts. The following caveats for each fuel type should be noted:

COAL - All coal ranks subtotal includes anthracite, bituminous, subbituminous, lignite, waste coal, and coal-derived synthesis gas. Prior to 2011, synthesis gas was included in the category of Other Gases.

Bituminous coal includes anthracite coal and beginning in 2011, coal-derived synthesis gas.

PETROLEUM - includes petroleum liquids (distillate fuel oil and residual fuel oil) and petroleum coke which includes petroleum coke-derived synthesis gas. Prior to 2011, petroleum coke-derived synthesis gas was included in Other Gases. Prior to 2013, petroleum liquids included distillate fuel oil, residual fuel oil, kerosene, jet fuel, waste oil, and, beginning in 2011, propane. Prior to 2011, propane was included in the category of Other Gases.

NATURAL GAS - includes natural gas only. Prior to 2011, includes Other Gases.

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Sources: U.S. Energy Information Administration (EIA), Form EIA-923, "Power Plant Operations Report" and predecessor forms 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 7.5. Receipts, Average Cost, and Quality of Fossil Fuels: Electric Utilities, 2009 - 2019

	Coal						Petroleum Liquids					
	Receipts		Average Cost				Receipts		Average Cost			
Period	(Billion Btu)	(Thousand Tons)	(Dollars per MMBtu)	(Dollars per Ton)	Sulfur Percent by Weight	Percentage of Consumption	(Billion Btu)	(Thousand Barrels)	(Dollars per MMBtu)	(Dollars per Barrel)	Sulfur Percent by Weight	Percentage of Consumption
Annual Totals												
2009	14,402,019	719,253	2.22	44.47	0.99	103.4	202,598	32,959	10.44	64.18	0.51	103.5
2010	14,226,995	713,094	2.27	45.33	1.14	98.8	189,790	31,099	13.94	85.07	0.48	101.0
2011	13,871,559	699,353	2.40	47.67	1.16	101.5	144,255	23,859	20.30	122.72	0.53	114.5
2012	11,939,543	609,445	2.43	47.51	1.18	99.0	86,030	14,252	22.11	133.44	0.41	81.3
2013	11,595,328	592,772	2.38	46.51	1.23	92.9	78,101	12,814	21.09	128.57	0.43	76.2
2014	12,064,810	614,728	2.39	46.95	1.21	98.3	98,357	16,161	19.90	121.14	0.44	82.0
2015	11,088,631	571,707	2.25	43.71	1.17	105.8	90,041	14,747	11.32	69.13	0.46	79.2
2016	9,256,878	476,207	2.16	42.01	1.21	95.4	73,294	11,985	9.16	56.02	0.45	74.0
2017	9,011,629	467,595	2.12	40.81	1.16	96.0	70,422	11,640	11.60	70.19	0.47	74.4
2018	8,351,036	435,964	2.11	40.35	1.18	91.6	84,050	13,896	14.39	87.09	0.37	75.3
2019	7,970,069	413,915	2.08	39.99	1.18	103.1	66,789	11,010	13.40	81.29	0.46	69.9
Year 2017												
January	797,433	41,477	2.14	41.15	1.14	88.2	6,680	1,100	11.15	67.71	0.44	77.4
February	737,614	38,372	2.11	40.53	1.20	107.5	4,658	770	11.60	70.11	0.46	67.3
March	706,986	36,570	2.12	41.05	1.20	101.9	10,582	1,778	11.59	68.99	0.53	132.1
April	650,562	33,339	2.14	41.82	1.22	105.4	4,760	788	11.41	68.97	0.46	67.0
May	702,581	36,058	2.16	42.07	1.21	95.9	4,694	778	11.40	68.79	0.45	60.4
June	786,845	40,393	2.13	41.51	1.20	91.9	5,771	951	10.93	66.29	0.47	73.1
July	821,488	42,591	2.11	40.78	1.11	81.6	4,826	803	10.96	65.87	0.45	67.9
August	890,849	46,092	2.11	40.79	1.18	93.7	5,210	855	11.12	67.72	0.46	67.7
September	741,814	38,857	2.08	39.69	1.10	98.1	4,823	792	11.80	71.87	0.48	65.5
October	733,109	38,175	2.09	40.12	1.15	104.8	5,030	825	12.05	73.47	0.49	62.1
November	726,042	38,128	2.11	40.23	1.13	105.8	7,044	1,156	12.00	73.12	0.41	97.4
December	716,306	37,543	2.11	40.20	1.11	89.5	6,345	1,043	12.93	78.67	0.42	58.3
Year 2018												
January	689,121	36,230	2.08	39.57	1.11	75.5	16,449	2,762	14.38	85.73	0.43	61.0
February	637,294	33,294	2.10	40.18	1.17	97.3	8,657	1,413	12.58	77.10	0.46	126.0
March	696,264	36,224	2.09	40.20	1.18	111.4	5,472	906	13.38	80.86	0.36	82.4
April	600,033	31,096	2.12	40.93	1.23	101.8	5,321	875	13.78	83.81	0.36	74.7
May	654,477	33,757	2.09	40.57	1.24	95.3	6,739	1,108	14.37	87.44	0.29	82.5
June	689,040	35,857	2.10	40.33	1.21	84.0	6,566	1,085	14.63	88.49	0.28	78.5
July	738,864	38,675	2.10	40.13	1.15	79.8	5,620	920	14.34	87.60	0.27	75.5
August	802,045	41,889	2.11	40.43	1.19	87.2	5,016	826	15.26	92.68	0.34	63.6
September	695,648	36,530	2.12	40.31	1.15	90.3	5,665	940	15.53	93.63	0.35	66.8
October	713,410	37,228	2.10	40.20	1.21	104.3	6,170	1,011	15.78	96.34	0.39	73.6
November	691,145	36,346	2.10	39.90	1.17	95.3	5,383	896	15.89	95.50	0.41	69.8
December	743,694	38,838	2.17	41.48	1.17	93.2	6,991	1,155	13.83	83.69	0.44	94.7
Year 2019												
January	738,951	38,447	2.16	41.50	1.17	92.6	6,257	1,035	12.58	76.07	0.42	61.2
February	631,870	33,072	2.14	40.80	1.15	98.6	6,768	1,106	13.06	79.89	0.46	99.9
March	588,088	30,001	2.14	41.91	1.36	94.2	6,258	1,034	14.36	86.91	0.42	88.8
April	646,989	33,355	2.13	41.31	1.20	135.4	5,460	901	14.73	89.26	0.47	85.9
May	664,887	34,246	2.12	41.12	1.21	112.6	5,038	832	14.15	85.71	0.48	63.5
June	651,381	33,621	2.10	40.75	1.19	99.7	5,247	869	13.31	80.39	0.47	63.3
July	723,359	37,713	2.08	39.90	1.15	88.8	4,455	740	13.30	80.10	0.46	55.6
August	746,495	38,909	2.06	39.56	1.14	97.4	3,921	656	13.65	81.53	0.48	44.4
September	676,927	35,149	2.01	38.79	1.17	98.7	6,831	1,119	12.41	75.70	0.45	85.5
October	643,227	33,488	2.01	38.57	1.13	122.6	4,958	815	13.28	80.79	0.47	62.2
November	624,023	32,728	2.01	38.36	1.14	106.9	6,206	1,013	12.83	78.61	0.48	82.2
December	633,871	33,185	1.95	37.30	1.12	110.8	5,390	891	13.65	82.59	0.47	63.9

Displayed values of zero may represent small values that round to zero.
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Notes:
Beginning in January 2013, the threshold for reporting fuel receipts data was changed from 50 megawatts to 200 megawatts of nameplate capacity for plants primarily fueled by natural gas, petroleum coke, distillate fuel oil, and residual fuel oil. In addition, the requirement to report self-produced and minor fuels, i.e., blast furnace gas, other manufactured gases, kerosene, jet fuel, propane, and waste oils was eliminated. The threshold for coal plants remained at 50 megawatts. The following caveats for each fuel type should be noted:
COAL - includes anthracite, bituminous, subbituminous, lignite, waste coal, and coal-derived synthesis gas. Prior to 2011, synthesis gas was included in the category of Other Gases.
PETROLEUM LIQUIDS - includes distillate fuel oil and residual fuel oil. Prior to 2013, petroleum liquids included distillate fuel oil, residual fuel oil, kerosene, jet fuel, waste oil, and, beginning in 2011, propane. Prior to 2011, propane was included in the category of Other Gases.

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Table 7.6. Receipts, Average Cost, and Quality of Fossil Fuels: Electric Utilities, 2009 - 2019 (continued)

	Petroleum Coke						Natural Gas						All Fossil Fuels
	Receipts		Average Cost				Receipts		Average Cost			Average Cost	
	(Billion Btu)	(Thousand Tons)	(Dollars per MMBtu)	(Dollars per Ton)	Average Sulfur Percent by Weight	Percentage of Consumption	(Billion Btu)	(Thousand Mcf)	(Dollars per MMBtu)	(Dollars per Mcf)	Percentage of Consumption	(Dollars per MMBtu)	
Annual Totals													
2009	109,126	3,833	1.68	47.84	5.02	138.8	3,033,133	2,962,640	5.50	5.63	101.8	2.87	
2010	103,152	3,628	2.38	67.65	5.03	109.1	3,395,962	3,327,919	5.43	5.54	101.1	2.99	
2011	99,208	3,445	3.08	88.73	5.17	99.9	3,571,348	3,507,613	5.00	5.09	101.8	3.08	
2012	72,782	2,521	2.30	66.40	5.46	119.8	4,083,579	4,003,457	3.74	3.81	97.6	2.86	
2013	99,088	3,463	2.11	60.30	5.34	101.6	3,939,408	3,851,241	4.49	4.59	97.0	2.99	
2014	123,793	4,349	1.89	53.77	5.56	126.3	3,876,549	3,772,596	5.17	5.31	96.7	3.16	
2015	115,929	4,069	1.77	50.44	5.23	130.1	4,717,748	4,565,040	3.52	3.64	96.0	2.67	
2016	99,706	3,538	1.52	42.85	5.38	103.1	5,075,337	4,907,538	3.15	3.26	97.0	2.54	
2017	90,481	3,224	2.15	60.31	5.55	117.6	4,794,383	4,640,827	3.62	3.74	96.8	2.68	
2018	83,211	2,940	2.56	72.34	5.74	106.8	5,553,558	5,379,459	3.68	3.80	96.2	2.80	
2019	54,266	1,896	1.92	54.88	5.50	91.0	6,026,974	5,831,134	3.03	3.13	97.0	2.53	
Year 2017													
January	7,058	251	2.14	60.16	5.67	83.3	337,934	326,650	4.31	4.46	95.7	2.82	
February	7,593	271	2.00	56.03	5.85	124.3	294,739	285,524	3.80	3.92	96.7	2.62	
March	8,628	309	2.06	57.51	5.29	143.9	355,327	344,045	3.53	3.64	97.0	2.67	
April	5,835	208	2.00	55.96	5.34	188.7	337,897	327,119	3.52	3.63	97.7	2.65	
May	6,776	242	2.05	57.46	5.57	91.5	383,048	371,448	3.68	3.80	98.5	2.73	
June	8,386	298	2.14	60.07	5.55	105.5	441,947	428,006	3.55	3.66	97.6	2.67	
July	8,245	292	2.11	59.61	5.49	107.5	554,753	536,355	3.45	3.57	96.5	2.68	
August	7,676	273	2.11	59.17	5.45	119.8	519,869	502,857	3.42	3.53	96.7	2.62	
September	7,658	274	2.12	59.07	5.42	130.2	434,880	420,328	3.54	3.66	96.4	2.65	
October	7,454	265	2.37	66.84	5.58	154.2	389,164	376,992	3.55	3.66	97.1	2.63	
November	7,084	252	2.52	70.93	5.66	107.1	342,125	331,573	3.64	3.76	96.6	2.66	
December	8,088	287	2.17	60.99	5.74	123.5	402,703	389,931	3.71	3.83	95.6	2.74	
Year 2018													
January	7,009	248	2.38	67.41	5.31	83.4	423,606	410,310	5.20	5.37	95.5	3.41	
February	7,769	277	2.43	68.09	5.49	117.9	359,760	348,729	3.81	3.93	95.0	2.79	
March	7,841	281	2.54	70.89	5.54	141.5	397,572	384,900	3.46	3.57	96.4	2.64	
April	6,564	232	2.56	72.38	6.09	119.0	377,302	365,948	3.30	3.40	97.5	2.63	
May	4,344	152	2.41	68.58	6.09	108.3	452,870	438,567	3.24	3.35	94.8	2.63	
June	7,382	260	2.73	77.61	5.97	96.2	525,751	509,192	3.28	3.39	97.2	2.67	
July	8,147	287	2.73	77.48	5.73	100.4	632,132	612,044	3.27	3.38	95.1	2.69	
August	8,183	288	2.82	80.03	5.67	105.4	607,246	588,293	3.33	3.44	96.5	2.68	
September	7,493	263	3.05	86.74	5.59	101.2	535,618	518,216	3.28	3.39	97.0	2.68	
October	5,415	191	2.55	72.24	5.80	120.4	464,777	450,302	3.57	3.68	97.8	2.74	
November	6,524	229	2.23	63.55	5.88	116.4	390,167	378,446	4.26	4.39	94.9	2.93	
December	6,541	232	2.04	57.52	5.91	96.0	386,756	374,513	4.92	5.08	96.2	3.16	
Year 2019													
January	5,447	192	2.08	59.13	5.93	73.8	446,581	432,740	4.13	4.26	97.1	2.94	
February	4,486	155	2.27	65.75	5.78	69.4	414,367	398,782	3.76	3.90	95.9	2.84	
March	3,725	130	2.43	69.63	6.15	66.9	432,758	419,315	3.63	3.74	96.3	2.84	
April	3,159	111	2.71	76.93	5.65	101.5	401,329	388,531	3.05	3.15	96.7	2.55	
May	4,631	162	2.24	63.78	5.41	73.8	471,417	457,391	2.92	3.01	99.1	2.50	
June	3,740	130	2.18	62.61	5.15	85.7	546,353	529,347	2.73	2.82	97.6	2.43	
July	5,723	199	2.01	57.76	5.22	86.8	662,600	640,466	2.63	2.72	96.8	2.38	
August	6,693	235	1.72	48.82	5.15	115.7	680,091	657,152	2.52	2.61	96.6	2.31	
September	3,034	105	1.68	48.71	5.58	56.6	577,988	559,208	2.75	2.84	97.0	2.40	
October	1,738	60	1.51	43.76	5.45	92.3	496,610	480,428	2.69	2.78	96.7	2.35	
November	6,654	232	1.46	41.78	5.38	227.7	427,761	413,977	3.13	3.24	97.0	2.52	
December	5,236	183	1.14	32.50	5.44	132.2	469,120	453,799	3.12	3.22	96.9	2.50	

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Notes:
Beginning in January 2013, the threshold for reporting fuel receipts data was changed from 50 megawatts to 200 megawatts of nameplate capacity for plants primarily fueled by natural gas, petroleum coke, distillate fuel oil, and residual fuel oil. In addition, the requirement to report self-produced and minor fuels, i.e., blast furnace gas, other manufactured gases, kerosene, jet fuel, propane, and waste oils was eliminated. The threshold for coal plants remained at 50 megawatts. The following caveats for each fuel type should be noted:
PETROLEUM COKE - includes petroleum coke-derived synthesis gas. Prior to 2011, petroleum coke-derived synthesis gas was included in Other Gases.
NATURAL GAS - includes natural gas only. Prior to 2011, includes Other Gases.

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- See the Technical Notes for fuel conversion factors.
- Totals may not equal the sum of components because of independent rounding.

Sources: U.S. Energy Information Administration (EIA), Form EIA-923, "Power Plant Operations Report" and predecessor forms 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 7.7 Receipts, Average Cost, and Quality of Fossil Fuels: Independent Power Producers, 2009 - 2019

	Coal						Petroleum Liquids					
	Receipts		Average Cost				Receipts		Average Cost			
Period	(Billion Btu)	(Thousand Tons)	(Dollars per MMBtu)	(Dollars per Ton)	Average Sulfur Percent by Weight	Percentage of Consumption	(Billion Btu)	(Thousand Barrels)	(Dollars per MMBtu)	(Dollars per Barrel)	Average Sulfur Percent by Weight	Percentage of Consumption
Annual Totals												
2009	4,563,080	240,687	2.11	39.94	1.06	101.1	68,030	11,408	10.02	59.76	0.37	102.0
2010	4,555,898	243,585	2.20	41.15	1.21	96.0	49,598	8,420	14.80	87.19	0.35	89.9
2011	4,292,284	233,295	2.28	41.95	1.25	95.9	41,599	7,096	20.30	119.01	0.50	106.9
2012	4,036,436	218,341	2.21	40.92	1.42	104.9	23,922	4,073	22.34	131.28	0.44	79.8
2013	4,032,431	217,572	2.20	40.95	1.48	99.1	43,432	7,205	19.71	118.88	0.45	110.1
2014	4,243,949	226,600	2.25	42.20	1.61	100.1	71,774	11,980	19.90	119.36	0.45	101.0
2015	3,731,508	198,982	2.10	39.39	1.66	100.5	55,248	9,189	11.69	70.36	0.46	86.5
2016	3,047,358	164,648	1.93	35.69	1.73	91.8	25,975	4,410	9.93	58.56	0.48	75.1
2017	3,056,215	165,567	1.85	34.19	1.64	93.1	24,704	4,190	12.67	74.73	0.46	73.8
2018	2,849,062	152,015	1.89	35.41	1.70	94.2	47,699	8,022	14.52	86.39	0.44	81.7
2019	2,629,405	139,141	1.81	34.16	1.74	101.6	20,188	3,425	14.40	84.89	0.50	73.0
Year 2017												
January	297,849	16,042	1.92	35.75	1.59	96.7	2,862	488	13.96	82.04	0.47	105.5
February	254,381	13,690	1.88	34.92	1.59	110.9	1,514	254	11.89	70.84	0.50	69.9
March	251,712	13,439	1.88	35.27	1.75	103.1	1,436	247	11.97	69.71	0.44	85.2
April	235,324	12,633	1.85	34.48	1.66	99.2	1,436	242	12.28	72.85	0.44	81.4
May	238,355	12,976	1.86	34.11	1.67	97.1	1,790	306	11.55	67.69	0.45	78.7
June	239,687	13,070	1.86	34.15	1.67	87.3	1,559	267	10.88	63.53	0.42	65.0
July	257,789	14,218	1.85	33.64	1.55	80.5	1,775	303	10.73	62.88	0.48	79.1
August	279,845	15,249	1.83	33.52	1.64	91.5	1,702	289	11.16	65.68	0.43	72.0
September	258,366	13,963	1.82	33.65	1.63	92.0	1,543	267	11.35	65.70	0.42	67.7
October	250,339	13,545	1.83	33.87	1.60	99.0	2,399	406	11.71	69.17	0.50	118.1
November	243,578	13,224	1.79	33.00	1.64	88.3	2,544	434	13.15	77.15	0.56	110.2
December	248,991	13,519	1.83	33.70	1.68	81.5	4,145	688	15.82	95.35	0.43	44.3
Year 2018												
January	250,209	13,549	1.99	36.82	1.60	79.9	19,101	3,180	13.71	82.73	0.46	63.7
February	200,760	10,859	1.93	35.69	1.58	93.0	3,249	550	13.53	79.99	0.43	195.1
March	229,355	11,974	1.84	35.33	1.83	99.4	2,273	388	14.17	82.79	0.43	107.3
April	202,887	10,815	1.88	35.20	1.61	107.5	1,427	242	14.45	84.93	0.44	61.3
May	223,521	11,725	1.87	35.68	1.78	98.4	2,731	459	14.46	86.28	0.46	95.4
June	227,121	12,009	1.84	34.83	1.84	89.2	2,614	444	15.89	93.43	0.40	92.9
July	235,760	12,666	1.87	34.83	1.73	82.1	1,775	301	16.08	94.43	0.45	64.8
August	260,087	13,942	1.86	34.73	1.68	88.4	1,864	315	15.92	93.84	0.42	59.8
September	235,579	12,761	1.82	33.63	1.56	94.5	2,082	351	15.17	89.90	0.39	82.5
October	274,139	14,529	1.89	35.60	1.72	113.8	3,039	517	15.83	92.93	0.41	127.4
November	248,768	13,265	1.92	35.95	1.73	97.0	3,328	566	15.95	93.64	0.42	119.9
December	260,878	13,920	1.94	36.42	1.68	99.1	4,215	709	14.20	84.15	0.46	132.8
Year 2019												
January	258,502	13,732	1.91	35.91	1.75	94.9	2,550	426	12.15	72.73	0.50	53.5
February	208,595	11,136	1.83	34.30	1.66	96.1	2,052	344	13.83	82.61	0.46	98.6
March	225,693	11,804	1.88	35.97	1.87	96.4	1,312	223	14.97	88.25	0.54	79.1
April	215,930	11,232	1.84	35.44	1.89	127.7	1,400	238	15.72	92.48	0.51	72.3
May	219,210	11,432	1.83	35.06	1.91	118.6	1,628	278	15.67	91.68	0.49	76.9
June	210,718	11,178	1.76	33.24	1.84	105.7	1,505	255	15.10	89.08	0.48	74.1
July	210,437	11,271	1.79	33.38	1.69	83.9	1,409	240	15.49	90.87	0.48	53.7
August	228,948	12,067	1.78	33.72	1.69	96.5	1,184	203	16.40	95.62	0.49	57.7
September	207,547	11,127	1.75	32.61	1.59	95.7	1,361	232	13.79	81.01	0.56	72.0
October	219,896	11,624	1.77	33.58	1.69	114.0	1,713	292	15.05	88.23	0.52	80.0
November	214,440	11,469	1.77	33.22	1.61	101.1	1,652	281	13.67	80.52	0.49	78.7
December	209,490	11,070	1.75	33.07	1.66	104.6	2,423	414	13.65	79.88	0.50	107.5

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Notes:
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COAL - includes anthracite, bituminous, subbituminous, lignite, waste coal, and coal-derived synthesis gas. Prior to 2011, synthesis gas was included in the category of Other Gases.
PETROLEUM LIQUIDS - includes distillate fuel oil and residual fuel oil. Prior to 2013, petroleum liquids included distillate fuel oil, residual fuel oil, kerosene, jet fuel, waste oil, and, beginning in 2011, propane. Prior to 2011, propane was included in the category of Other Gases.

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Table 7.8. Receipts, Average Cost, and Quality of Fossil Fuels: Independent Power Producers, 2009 - 2019 (continued)

	Petroleum Coke						Natural Gas					All Fossil Fuels
	Receipts		Average Cost				Receipts		Average Cost			Average Cost
Period	(Billion Btu)	(Thousand Tons)	(Dollars per MMBtu)	(Dollars per Ton)	Average Sulfur Percent by Weight	Percentage of Consumption	(Billion Btu)	(Thousand Mcf)	(Dollars per MMBtu)	(Dollars per Mcf)	Percentage of Consumption	(Dollars per MMBtu)
Annual Totals												
2009	49,619	1,732	1.31	37.63	3.87	93.6	4,087,573	3,987,721	4.30	4.41	100.7	3.18
2010	30,079	1,050	1.74	49.80	3.84	72.3	4,212,611	4,119,103	4.94	5.05	100.6	3.57
2011	33,643	1,175	2.54	72.85	4.55	84.6	4,252,040	4,158,617	4.62	4.72	100.8	3.52
2012	23,024	801	0.82	23.98	5.49	92.1	4,810,553	4,696,637	3.17	3.25	93.8	2.74
2013	16,150	575	W	W	5.39	65.6	4,025,263	3,917,898	4.25	4.36	92.8	W
2014	13,781	488	2.48	70.31	5.33	70.9	4,054,540	3,934,672	4.90	5.05	92.7	3.52
2015	14,550	524	2.45	68.22	5.26	67.3	4,683,291	4,530,195	2.94	3.04	93.2	2.57
2016	13,573	492	2.50	68.88	5.44	69.9	4,791,729	4,634,518	2.54	2.63	94.0	2.29
2017	0	0	--	--	--	0.0	4,346,156	4,201,573	3.08	3.19	94.0	2.54
2018	0	0	--	--	--	0.0	4,889,212	4,727,692	3.40	3.52	94.6	2.84
2019	0	0	--	--	--	0.0	5,242,547	5,062,877	2.70	2.80	96.0	2.40
Year 2017												
January	0	0	--	--	--	0.0	308,468	297,985	3.99	4.13	93.5	2.92
February	0	0	--	--	--	0.0	266,924	258,124	3.34	3.46	94.2	2.58
March	0	0	--	--	--	0.0	309,192	299,108	3.22	3.33	94.1	2.58
April	0	0	--	--	--	0.0	284,438	275,168	3.20	3.31	94.1	2.55
May	0	0	--	--	--	0.0	315,966	305,806	3.21	3.32	94.8	2.58
June	0	0	--	--	--	0.0	401,399	388,239	2.92	3.02	94.2	2.49
July	0	0	--	--	--	0.0	510,043	492,821	2.88	2.98	93.8	2.50
August	0	0	--	--	--	0.0	490,650	474,187	2.74	2.84	94.5	2.37
September	0	0	--	--	--	0.0	410,946	396,673	2.66	2.75	93.9	2.30
October	0	0	--	--	--	0.0	370,533	358,357	2.60	2.69	93.3	2.29
November	0	0	--	--	--	0.0	310,914	300,784	3.03	3.13	93.1	2.47
December	0	0	--	--	--	0.0	366,682	354,320	3.64	3.77	94.0	2.91
Year 2018												
January	0	0	--	--	--	0.0	343,077	331,644	5.21	5.39	93.1	3.99
February	0	0	--	--	--	0.0	312,835	302,657	3.38	3.49	93.7	2.80
March	0	0	--	--	--	0.0	346,290	334,497	2.87	2.97	93.6	2.46
April	0	0	--	--	--	0.0	319,774	309,352	2.96	3.06	94.1	2.51
May	0	0	--	--	--	0.0	377,388	365,397	2.79	2.89	94.8	2.46
June	0	0	--	--	--	0.0	422,237	408,330	2.89	2.98	95.3	2.53
July	0	0	--	--	--	0.0	570,783	552,360	3.21	3.32	95.3	2.79
August	0	0	--	--	--	0.0	565,773	547,533	3.22	3.33	95.1	2.76
September	0	0	--	--	--	0.0	489,149	472,958	2.90	3.00	95.4	2.54
October	0	0	--	--	--	0.0	419,722	405,657	3.20	3.31	94.9	2.68
November	0	0	--	--	--	0.0	355,192	343,013	4.12	4.27	94.1	3.19
December	0	0	--	--	--	0.0	366,993	354,294	4.49	4.65	95.0	3.39
Year 2019												
January	0	0	--	--	--	0.0	398,896	385,014	3.88	4.02	95.6	3.05
February	0	0	--	--	--	0.0	357,555	345,530	3.49	3.61	95.0	2.85
March	0	0	--	--	--	0.0	371,920	359,394	3.30	3.41	95.0	2.73
April	0	0	--	--	--	0.0	333,598	322,802	2.65	2.74	95.5	2.33
May	0	0	--	--	--	0.0	372,853	360,800	2.53	2.61	96.4	2.28
June	0	0	--	--	--	0.0	446,512	432,051	2.35	2.43	96.4	2.17
July	0	0	--	--	--	0.0	592,358	572,083	2.43	2.51	96.4	2.26
August	0	0	--	--	--	0.0	597,443	576,291	2.27	2.35	96.5	2.13
September	0	0	--	--	--	0.0	504,061	486,741	2.38	2.47	96.5	2.19
October	0	0	--	--	--	0.0	438,101	422,965	2.22	2.30	96.1	2.09
November	0	0	--	--	--	0.0	388,489	374,471	2.77	2.88	95.5	2.41
December	0	0	--	--	--	0.0	440,761	424,737	2.69	2.79	95.8	2.39

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PETROLEUM COKE - includes petroleum coke-derived synthesis gas. Prior to 2011, petroleum coke-derived synthesis gas was included in Other Gases.
NATURAL GAS - includes natural gas only. Prior to 2011, includes Other Gases.

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Table 7.9. Receipts, Average Cost, and Quality of Fossil Fuels: Commercial Sector, 2009 - 2019

	Coal						Petroleum Liquids					
	Receipts		Average Cost				Receipts		Average Cost			
Period	(Billion Btu)	(Thousand Tons)	(Dollars per MMBtu)	(Dollars per Ton)	Average Sulfur Percent by Weight	Percentage of Consumption	(Billion Btu)	(Thousand Barrels)	(Dollars per MMBtu)	(Dollars per Barrel)	Average Sulfur Percent by Weight	Percentage of Consumption
Annual Totals												
2009	41,182	1,876	2.90	63.68	1.67	104.3	3,517	583	10.82	65.26	0.45	122.1
2010	37,778	1,747	2.82	61.06	1.77	101.6	2,395	400	15.24	91.25	0.38	106.3
2011	35,892	1,686	2.92	62.24	1.78	101.1	1,959	325	19.67	118.66	0.55	108.0
2012	4,427	192	3.41	78.71	2.75	13.2	247	43	W	W	0.00	11.0
2013	3,507	151	W	W	3.05	11.2	0	0	--	--	--	0.0
2014	4,096	182	3.12	70.30	2.50	17.1	0	0	--	--	--	0.0
2015	2,439	109	2.85	63.90	2.55	13.6	0	0	--	--	--	0.0
2016	1,288	57	2.69	60.89	3.03	8.3	0	0	--	--	--	0.0
2017	548	24	2.78	63.31	2.99	3.9	0	0	--	--	--	0.0
2018	290	13	2.94	66.52	3.04	2.2	0	0	--	--	--	0.0
2019	193	8	2.92	66.55	3.01	1.6	0	0	--	--	--	0.0
Year 2017												
January	111	5	2.77	62.82	2.99	6.9	0	0	--	--	--	0.0
February	91	4	2.77	63.46	2.95	6.9	0	0	--	--	--	0.0
March	104	5	2.77	63.24	3.02	7.0	0	0	--	--	--	0.0
April	1	0	2.77	63.60	2.96	0.1	0	0	--	--	--	0.0
May	11	0	2.77	63.54	3.23	1.2	0	0	--	--	--	0.0
June	17	1	2.77	63.65	3.02	1.8	0	0	--	--	--	0.0
July	0	0	--	--	--	0.0	0	0	--	--	--	0.0
August	4	0	2.77	63.24	2.77	0.4	0	0	--	--	--	0.0
September	72	3	2.77	63.24	2.96	6.9	0	0	--	--	--	0.0
October	35	2	2.79	64.50	2.96	3.6	0	0	--	--	--	0.0
November	13	1	2.79	63.70	3.04	1.1	0	0	--	--	--	0.0
December	89	4	2.79	63.31	3.01	6.0	0	0	--	--	--	0.0
Year 2018												
January	95	4	2.92	66.58	3.11	5.5	0	0	--	--	--	0.0
February	31	1	2.92	66.05	3.19	2.3	0	0	--	--	--	0.0
March	5	0	2.92	66.20	3.16	0.4	0	0	--	--	--	0.0
April	0	0	--	--	--	0.0	0	0	--	--	--	0.0
May	0	0	--	--	--	0.0	0	0	--	--	--	0.0
June	0	0	--	--	--	0.0	0	0	--	--	--	0.0
July	0	0	--	--	--	0.0	0	0	--	--	--	0.0
August	0	0	--	--	--	0.0	0	0	--	--	--	0.0
September	0	0	--	--	--	0.0	0	0	--	--	--	0.0
October	52	2	2.94	66.53	2.87	5.5	0	0	--	--	--	0.0
November	62	3	2.94	66.44	2.99	5.8	0	0	--	--	--	0.0
December	46	2	2.97	66.83	3.05	4.4	0	0	--	--	--	0.0
Year 2019												
January	27	1	2.90	65.89	3.00	2.0	0	0	--	--	--	0.0
February	37	2	2.90	65.51	2.95	3.0	0	0	--	--	--	0.0
March	48	2	2.90	65.86	2.94	3.6	0	0	--	--	--	0.0
April	2	0	2.90	65.28	2.90	0.3	0	0	--	--	--	0.0
May	0	0	--	--	--	0.0	0	0	--	--	--	0.0
June	2	0	2.90	66.38	3.02	0.4	0	0	--	--	--	0.0
July	1	0	2.97	67.69	2.94	0.2	0	0	--	--	--	0.0
August	0	0	--	--	--	0.0	0	0	--	--	--	0.0
September	0	0	--	--	--	0.0	0	0	--	--	--	0.0
October	23	1	2.96	67.99	3.17	2.7	0	0	--	--	--	0.0
November	31	1	2.96	67.99	3.17	3.0	0	0	--	--	--	0.0
December	21	1	2.96	67.34	2.91	1.9	0	0	--	--	--	0.0

Displayed values of zero may represent small values that round to zero.
NM = Not meaningful due to large relative standard error or excessive percentage change.
W = Withheld to avoid disclosure of individual company data.

Notes:
Beginning in January 2013, the threshold for reporting fuel receipts data was changed from 50 megawatts to 200 megawatts of nameplate capacity for plants primarily fueled by natural gas, petroleum coke, distillate fuel oil, and residual fuel oil. In addition, the requirement to report self-produced and minor fuels, i.e., blast furnace gas, other manufactured gases, kerosene, jet fuel, propane, and waste oils was eliminated. The threshold for coal plants remained at 50 megawatts. The following caveats for each fuel type should be noted:
COAL - includes anthracite, bituminous, subbituminous, lignite, waste coal, and coal-derived synthesis gas. Prior to 2011, synthesis gas was included in the category of Other Gases.
PETROLEUM LIQUIDS - includes distillate fuel oil and residual fuel oil. Prior to 2013, petroleum liquids included distillate fuel oil, residual fuel oil, kerosene, jet fuel, waste oil, and, beginning in 2011, propane. Prior to 2011, propane was included in the category of Other Gases.

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- See the EIA-923 section of the Technical Notes for a discussion of the sample design for the Form EIA-923 and predecessor forms.
- See the Technical Notes for fuel conversion factors.
- Totals may not equal the sum of components because of independent rounding.

Sources: U.S. Energy Information Administration (EIA), Form EIA-923, "Power Plant Operations Report" and predecessor forms 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 7.10. Receipts, Average Cost, and Quality of Fossil Fuels: Commerical Sector, 2009 - 2019 (continued)

	Petroleum Coke						Natural Gas					All Fossil Fuels
	Receipts		Average Cost				Receipts		Average Cost			Average Cost
Period	(Billion Btu)	(Thousand Tons)	(Dollars per MMBtu)	(Dollars per Ton)	Average Sulfur Percent by Weight	Percentage of Consumption	(Billion Btu)	(Thousand Mcf)	(Dollars per MMBtu)	(Dollars per Mcf)	Percentage of Consumption	(Dollars per MMBtu)
Annual Totals												
2009	252	9	1.65	46.54	5.11	102.8	81,134	79,308	5.18	5.30	105.0	4.58
2010	410	15	2.19	60.59	5.67	122.5	92,055	90,130	5.39	5.51	105.1	4.83
2011	268	9	W	W	5.46	147.4	95,287	93,306	5.20	5.31	107.2	W
2012	0	0	--	--	--	0.0	18,315	18,008	5.88	5.98	16.2	W
2013	0	0	--	--	--	0.0	5,497	5,450	W	W	4.6	W
2014	0	0	--	--	--	0.0	5,849	5,795	5.42	5.47	4.9	4.47
2015	0	0	--	--	--	0.0	6,499	6,371	4.11	4.19	5.5	3.76
2016	0	0	--	--	--	0.0	8,005	7,766	3.85	3.97	6.1	3.69
2017	0	0	--	--	--	0.0	7,841	7,593	3.82	3.95	4.9	3.75
2018	0	0	--	--	--	0.0	9,090	8,823	3.49	3.59	6.6	3.47
2019	0	0	--	--	--	0.0	9,429	9,087	3.26	3.39	6.7	3.26
Year 2017												
January	0	0	--	--	--	0.0	662	639	4.02	4.17	4.5	3.84
February	0	0	--	--	--	0.0	646	624	4.01	4.15	5.1	3.86
March	0	0	--	--	--	0.0	680	662	3.96	4.06	5.4	3.80
April	0	0	--	--	--	0.0	502	490	3.90	3.99	4.7	3.89
May	0	0	--	--	--	0.0	497	483	3.92	4.04	4.4	3.90
June	0	0	--	--	--	0.0	615	595	3.82	3.95	4.7	3.79
July	0	0	--	--	--	0.0	636	613	3.64	3.77	4.1	3.64
August	0	0	--	--	--	0.0	809	778	3.70	3.85	5.3	3.70
September	0	0	--	--	--	0.0	707	685	3.72	3.84	5.2	3.63
October	0	0	--	--	--	0.0	605	588	3.77	3.88	4.6	3.72
November	0	0	--	--	--	0.0	749	725	3.72	3.84	6.0	3.70
December	0	0	--	--	--	0.0	734	711	3.77	3.89	5.2	3.67
Year 2018												
January	0	0	--	--	--	0.0	844	818	3.63	3.74	7.1	3.56
February	0	0	--	--	--	0.0	709	688	3.72	3.84	6.5	3.69
March	0	0	--	--	--	0.0	768	746	3.59	3.69	6.8	3.58
April	0	0	--	--	--	0.0	732	713	3.49	3.58	7.3	3.49
May	0	0	--	--	--	0.0	776	758	3.47	3.55	7.4	3.47
June	0	0	--	--	--	0.0	670	650	3.57	3.67	5.8	3.57
July	0	0	--	--	--	0.0	790	760	3.39	3.52	5.8	3.39
August	0	0	--	--	--	0.0	786	764	3.42	3.52	5.8	3.42
September	0	0	--	--	--	0.0	744	723	3.38	3.48	6.3	3.38
October	0	0	--	--	--	0.0	792	770	3.36	3.45	7.2	3.33
November	0	0	--	--	--	0.0	723	701	3.41	3.52	6.6	3.37
December	0	0	--	--	--	0.0	756	732	3.41	3.52	6.6	3.39
Year 2019												
January	0	0	--	--	--	0.0	778	751	3.40	3.52	6.3	3.38
February	0	0	--	--	--	0.0	772	745	3.37	3.50	6.8	3.35
March	0	0	--	--	--	0.0	839	812	3.36	3.47	7.3	3.33
April	0	0	--	--	--	0.0	775	748	3.30	3.41	7.3	3.29
May	0	0	--	--	--	0.0	811	782	3.26	3.38	7.9	3.26
June	0	0	--	--	--	0.0	807	776	3.23	3.36	7.2	3.22
July	0	0	--	--	--	0.0	721	701	3.17	3.26	5.4	3.17
August	0	0	--	--	--	0.0	838	808	3.13	3.25	6.5	3.13
September	0	0	--	--	--	0.0	747	717	3.15	3.28	6.4	3.15
October	0	0	--	--	--	0.0	766	734	3.24	3.38	7.0	3.23
November	0	0	--	--	--	0.0	743	713	3.30	3.43	6.6	3.28
December	0	0	--	--	--	0.0	832	801	3.26	3.39	6.6	3.25

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Notes:
Beginning in January 2013, the threshold for reporting fuel receipts data was changed from 50 megawatts to 200 megawatts of nameplate capacity for plants primarily fueled by natural gas, petroleum coke, distillate fuel oil, and residual fuel oil. In addition, the requirement to report self-produced and minor fuels, i.e., blast furnace gas, other manufactured gases, kerosene, jet fuel, propane, and waste oils was eliminated. The threshold for coal plants remained at 50 megawatts. The following caveats for each fuel type should be noted:
PETROLEUM COKE - includes petroleum coke-derived synthesis gas. Prior to 2011, petroleum coke-derived synthesis gas was included in Other Gases.
NATURAL GAS - includes natural gas only. Prior to 2011, includes Other Gases.

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- See the Technical Notes for fuel conversion factors.
- Totals may not equal the sum of components because of independent rounding.

Sources: U.S. Energy Information Administration (EIA), Form EIA-923, "Power Plant Operations Report" and predecessor forms 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 7.11. Receipts, Average Cost, and Quality of Fossil Fuels: Industrial Sector, 2009 - 2019

	Coal						Petroleum Liquids					
	Receipts		Average Cost				Receipts		Average Cost			
Period	(Billion Btu)	(Thousand Tons)	(Dollars per MMBtu)	(Dollars per Ton)	Sulfur Percent by Weight	Percentage of Consumption	(Billion Btu)	(Thousand Barrels)	(Dollars per MMBtu)	(Dollars per Barrel)	Sulfur Percent by Weight	Percentage of Consumption
Annual Totals												
2009	431,686	19,661	2.81	61.68	1.22	99.5	55,899	9,232	9.83	59.52	0.83	112.8
2010	468,991	21,492	2.75	60.08	1.26	87.2	33,276	5,554	13.21	79.15	0.93	125.6
2011	476,108	22,204	2.93	62.86	1.33	99.5	28,939	4,878	17.67	104.83	1.08	144.8
2012	285,172	13,206	3.02	65.24	1.33	65.8	6,739	1,095	W	W	1.52	40.8
2013	275,543	12,727	W	W	1.32	64.4	2,431	394	18.20	112.29	1.43	15.8
2014	281,867	13,050	2.97	64.15	1.33	68.4	2,290	373	17.91	109.99	1.43	15.6
2015	263,630	12,132	2.72	59.17	1.35	71.4	2,359	385	13.45	82.47	1.42	16.9
2016	210,749	9,859	2.67	57.01	1.30	67.0	2,541	412	10.51	64.79	1.27	18.3
2017	192,637	9,178	2.49	52.29	1.35	70.7	1,850	297	11.18	69.57	1.42	15.2
2018	170,730	8,224	2.47	51.38	1.30	67.2	2,319	372	13.46	83.97	1.35	15.9
2019	146,324	7,088	2.55	52.69	1.19	65.1	1,684	275	13.19	80.82	1.47	14.5
Year 2017												
January	15,758	742	2.51	53.37	1.38	58.7	128	21	11.64	72.27	1.06	13.0
February	15,865	744	2.57	54.74	1.18	69.1	121	19	11.56	72.24	1.36	15.2
March	17,861	858	2.48	51.66	1.34	75.2	178	29	10.66	66.36	1.22	18.9
April	16,089	759	2.62	55.59	1.23	75.4	160	26	11.82	74.12	1.27	16.6
May	16,329	796	2.44	50.13	1.16	76.3	155	25	11.19	69.26	1.21	17.6
June	15,911	757	2.41	50.55	1.37	72.5	142	23	10.34	64.95	1.11	17.7
July	15,852	763	2.46	51.07	1.30	73.2	95	15	10.75	66.88	1.30	12.4
August	16,644	784	2.51	53.36	1.36	74.6	110	18	10.55	65.94	1.55	14.0
September	14,897	715	2.52	52.38	1.17	72.3	151	24	11.07	69.03	1.51	17.2
October	15,687	741	2.52	53.40	1.36	67.5	149	24	11.43	71.09	1.58	15.9
November	15,335	734	2.46	51.43	1.43	68.1	199	32	11.67	72.03	1.71	13.2
December	16,408	785	2.40	50.09	1.89	68.9	263	42	11.14	69.14	1.79	13.5
Year 2018												
January	15,751	758	2.46	51.13	1.18	61.0	408	65	12.64	79.32	1.32	13.7
February	14,274	683	2.48	51.82	1.32	60.9	187	30	11.38	71.32	1.20	15.9
March	15,612	747	2.51	52.40	1.31	67.4	234	38	12.59	78.52	1.32	23.5
April	13,476	643	2.52	52.79	1.35	67.0	153	24	13.24	83.77	1.23	17.6
May	14,544	704	2.51	51.92	1.24	71.9	149	24	14.33	87.27	1.47	16.1
June	14,489	697	2.49	51.65	1.28	71.9	107	17	13.54	84.39	1.48	10.5
July	14,900	724	2.41	49.69	1.32	75.3	138	22	14.64	89.87	1.42	13.2
August	13,930	668	2.48	51.76	1.31	70.4	135	22	14.45	89.97	1.39	15.5
September	12,593	600	2.53	53.10	1.35	63.7	155	25	14.38	89.73	1.12	19.7
October	12,410	598	2.47	51.18	1.38	67.1	180	29	14.50	91.01	1.37	14.9
November	14,259	701	2.50	50.92	1.15	69.1	206	33	14.01	87.74	1.58	15.0
December	14,492	701	2.35	48.52	1.47	64.1	268	43	13.75	85.58	1.46	19.7
Year 2019												
January	12,678	629	2.49	50.14	1.13	56.2	154	25	12.98	80.23	1.24	7.5
February	12,842	617	2.61	54.43	1.16	61.4	199	33	13.77	82.99	1.45	18.7
March	13,424	629	2.68	57.20	1.49	67.5	126	21	13.43	82.27	1.63	14.2
April	11,765	561	2.64	55.30	1.25	62.8	223	36	12.89	79.74	1.54	24.0
May	12,720	623	2.51	51.21	0.97	71.3	92	15	14.12	86.68	1.48	12.6
June	11,705	567	2.49	51.38	1.22	67.2	131	21	13.04	79.96	1.55	18.3
July	11,385	551	2.45	50.57	1.32	65.1	80	13	11.99	74.33	1.41	12.7
August	10,876	530	2.39	49.14	1.23	62.0	112	18	12.56	77.49	1.66	15.4
September	11,131	539	2.48	51.28	1.24	66.3	154	25	13.15	80.17	1.58	20.8
October	11,889	586	2.59	52.47	1.21	68.4	136	22	13.01	79.34	1.42	17.2
November	13,255	645	2.59	53.19	1.05	71.3	137	22	13.67	83.44	1.46	9.7
December	12,654	612	2.67	55.16	1.07	64.4	141	23	13.33	81.47	1.25	15.8

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Notes:
Beginning in January 2013, the threshold for reporting fuel receipts data was changed from 50 megawatts to 200 megawatts of nameplate capacity for plants primarily fueled by natural gas, petroleum coke, distillate fuel oil, and residual fuel oil. In addition, the requirement to report self-produced and minor fuels, i.e., blast furnace gas, other manufactured gases, kerosene, jet fuel, propane, and waste oils was eliminated. The threshold for coal plants remained at 50 megawatts. The following caveats for each fuel type should be noted:
COAL - includes anthracite, bituminous, subbituminous, lignite, waste coal, and coal-derived synthesis gas. Prior to 2011, synthesis gas was included in the category of Other Gases.
PETROLEUM LIQUIDS - includes distillate fuel oil and residual fuel oil. Prior to 2013, petroleum liquids included distillate fuel oil, residual fuel oil, kerosene, jet fuel, waste oil, and, beginning in 2011, propane. Prior to 2011, propane was included in the category of Other Gases.

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Table 7.12. Receipts, Average Cost, and Quality of Fossil Fuels: Industrial Sector, 2009 - 2019 (continued)

	Petroleum Coke						Natural Gas						All Fossil Fuels
	Receipts		Average Cost				Receipts		Average Cost			Average Cost	
Period	(Billion Btu)	(Thousand Tons)	(Dollars per MMBtu)	(Dollars per Ton)	Average Sulfur Percent by Weight	Percentage of Consumption	(Billion Btu)	(Thousand Mcf)	(Dollars per MMBtu)	(Dollars per Mcf)	Percentage of Consumption	(Dollars per MMBtu)	
Annual Totals													
2009	38,924	1,381	1.80	50.82	4.51	114.2	1,117,489	1,088,880	4.27	4.38	110.0	4.02	
2010	35,866	1,269	2.46	69.38	4.90	100.5	1,166,768	1,135,917	4.64	4.77	110.4	4.24	
2011	37,981	1,351	W	W	5.03	108.3	1,331,977	1,296,628	4.28	4.40	122.0	W	
2012	23,861	858	2.62	72.96	5.86	42.2	834,245	813,288	2.97	3.05	70.8	W	
2013	17,236	623	W	W	5.82	30.5	750,946	728,835	W	W	62.3	W	
2014	9,736	358	2.56	69.67	5.83	23.2	742,347	718,360	4.54	4.69	62.7	4.12	
2015	8,189	304	1.73	46.72	5.50	24.1	765,964	740,975	2.83	2.93	60.6	2.82	
2016	3,664	135	2.00	54.12	5.84	11.2	744,034	721,358	2.65	2.74	59.6	2.68	
2017	2,356	85	1.59	44.08	5.84	8.1	803,435	778,741	3.18	3.28	62.0	3.06	
2018	1,911	71	1.75	47.47	5.74	7.1	792,297	769,790	3.39	3.49	58.6	3.25	
2019	2,028	73	1.69	46.99	5.81	8.1	814,483	790,388	2.82	2.91	57.5	2.80	
Year 2017													
January	0	0	--	--	--	0.0	69,097	66,861	3.62	3.75	62.2	3.43	
February	0	0	--	--	--	0.0	66,943	64,869	3.19	3.29	66.9	3.08	
March	0	0	--	--	--	0.0	69,912	67,776	2.90	3.00	65.7	2.83	
April	0	0	--	--	--	0.0	66,465	64,429	3.26	3.36	65.1	3.15	
May	0	0	--	--	--	0.0	66,784	64,714	3.30	3.41	64.0	3.15	
June	271	9	1.25	35.84	5.75	9.5	66,326	64,294	3.26	3.36	61.8	3.10	
July	253	9	1.25	34.50	5.85	9.4	67,649	65,606	3.21	3.31	58.9	3.07	
August	296	11	1.25	34.50	5.85	10.9	65,687	63,678	3.08	3.17	58.8	2.97	
September	257	9	1.77	48.91	5.85	11.7	62,978	61,019	3.10	3.20	59.5	3.00	
October	893	32	1.77	48.91	5.85	35.4	63,059	61,210	3.08	3.17	58.8	2.97	
November	386	14	1.77	48.91	5.85	16.1	66,896	64,844	3.01	3.11	62.4	2.93	
December	0	0	--	--	--	0.0	71,639	69,441	3.11	3.21	60.5	3.00	
Year 2018													
January	0	0	--	--	--	0.0	69,164	67,045	3.59	3.70	58.1	3.42	
February	0	0	--	--	--	0.0	60,810	58,990	3.41	3.52	58.6	3.26	
March	0	0	--	--	--	0.0	61,164	59,423	2.85	2.94	56.5	2.81	
April	0	0	--	--	--	0.0	61,184	59,457	2.92	3.01	58.4	2.87	
May	0	0	--	--	--	0.0	63,410	61,557	2.99	3.08	58.8	2.92	
June	0	0	--	--	--	0.0	65,879	64,032	3.14	3.23	59.8	3.03	
July	160	6	1.70	45.10	5.83	6.8	68,296	66,523	3.03	3.11	57.4	2.93	
August	260	10	1.78	46.99	5.55	12.2	69,386	67,341	3.12	3.21	58.1	3.03	
September	664	25	1.78	47.54	6.02	31.0	67,825	66,022	3.12	3.20	60.1	3.04	
October	477	17	1.76	48.96	5.45	20.6	66,419	64,687	3.75	3.85	59.0	3.56	
November	172	6	1.69	46.62	5.85	8.4	71,469	69,556	3.97	4.08	61.6	3.75	
December	178	6	1.70	47.00	5.53	7.3	67,289	65,157	4.70	4.85	56.6	4.31	
Year 2019													
January	0	0	--	--	--	0.0	73,583	71,442	3.76	3.87	59.0	3.59	
February	0	0	--	--	--	0.0	64,847	62,775	3.44	3.56	58.1	3.33	
March	0	0	--	--	--	0.0	66,748	64,830	3.13	3.22	57.6	3.07	
April	0	0	--	--	--	0.0	64,259	62,480	2.85	2.93	59.7	2.85	
May	0	0	--	--	--	0.0	66,202	64,348	2.75	2.83	57.8	2.73	
June	0	0	--	--	--	0.0	64,540	62,725	2.63	2.70	56.5	2.62	
July	43	2	1.71	46.96	5.81	1.7	69,836	67,819	2.49	2.56	57.3	2.49	
August	615	23	1.75	46.99	5.75	30.2	70,509	68,322	2.37	2.45	57.1	2.39	
September	743	26	1.63	47.00	5.56	30.6	66,121	64,014	2.56	2.65	56.0	2.57	
October	627	23	1.72	47.00	6.17	30.1	65,572	63,624	2.46	2.54	55.7	2.49	
November	0	0	--	--	--	0.0	69,632	67,560	2.77	2.86	57.8	2.76	
December	0	0	--	--	--	0.0	72,635	70,448	2.62	2.70	57.8	2.64	

Displayed values of zero may represent small values that round to zero.
NM = Not meaningful due to large relative standard error or excessive percentage change.
W = Withheld to avoid disclosure of individual company data.

Notes:
Beginning in January 2013, the threshold for reporting fuel receipts data was changed from 50 megawatts to 200 megawatts of nameplate capacity for plants primarily fueled by natural gas, petroleum coke, distillate fuel oil, and residual fuel oil. In addition, the requirement to report self-produced and minor fuels, i.e., blast furnace gas, other manufactured gases, kerosene, jet fuel, propane, and waste oils was eliminated. The threshold for coal plants remained at 50 megawatts. The following caveats for each fuel type should be noted:
PETROLEUM COKE - includes petroleum coke-derived synthesis gas. Prior to 2011, petroleum coke-derived synthesis gas was included in Other Gases.
NATURAL GAS - includes natural gas only. Prior to 2011, includes Other Gases.

- Values are final.
- See Glossary for definitions.
- Starting in January 2013, there may have been a shift in the continuity of Chapter 7 tables due to changes in the sample design of Form EIA-923 and the imputation process.
- See the EIA-923 section of the Technical Notes for a discussion of the sample design for the Form EIA-923 and predecessor forms.
- See the Technical Notes for fuel conversion factors.
- Totals may not equal the sum of components because of independent rounding.

Sources: U.S. Energy Information Administration (EIA), Form EIA-923, "Power Plant Operations Report" and predecessor forms 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 7.13. Receipts of Coal Delivered for Electricity Generation by State, 2019 and 2018
(Thousand Tons)

Census Division and State	Electric Power Sector										
	All Sectors			Electric Utilities		Independent Power Producers		Commercial Sector		Industrial Sector	
	Year 2019	Year 2018	Percentage Change	Year 2019	Year 2018	Year 2019	Year 2018	Year 2019	Year 2018	Year 2019	Year 2018
New England	159	276	-42.0%	90	94	69	182	0	0	0	0
Connecticut	0	105	-100.0%	0	0	0	105	0	0	0	0
Maine	69	62	11.0%	0	0	69	62	0	0	0	0
Massachusetts	0	0	--	0	0	0	0	0	0	0	0
New Hampshire	90	94	-4.2%	90	94	0	0	0	0	0	0
Rhode Island	0	15	-100.0%	0	0	0	15	0	0	0	0
Vermont	0	0	--	0	0	0	0	0	0	0	0
Middle Atlantic	19,758	22,115	-11.0%	0	0	19,682	22,007	0	0	76	108
New Jersey	562	603	-6.8%	0	0	562	603	0	0	0	0
New York	105	356	-70.0%	0	0	105	347	0	0	0	9
Pennsylvania	19,091	21,156	-9.8%	0	0	19,015	21,057	0	0	76	99
East North Central	121,130	135,418	-11.0%	70,966	79,529	48,299	53,644	0	0	1,865	2,244
Illinois	34,332	42,205	-19.0%	6,705	7,544	25,845	32,505	0	0	1,781	2,156
Indiana	28,275	29,773	-5.0%	26,185	27,733	2,091	2,040	0	0	0	0
Michigan	21,214	22,395	-5.3%	20,965	22,146	247	241	0	0	2	9
Ohio	22,722	22,772	-0.2%	2,606	3,914	20,117	18,858	0	0	0	0
Wisconsin	14,587	18,272	-20.0%	14,505	18,193	0	0	0	0	82	80
West North Central	106,926	115,190	-7.2%	103,914	111,951	0	0	8	13	3,004	3,226
Iowa	15,988	15,309	4.4%	13,745	13,080	0	0	0	0	2,242	2,228
Kansas	11,291	12,592	-10.0%	11,291	12,592	0	0	0	0	0	0
Minnesota	11,460	12,904	-11.0%	11,460	12,725	0	0	0	0	0	178
Missouri	31,097	35,275	-12.0%	31,088	35,262	0	0	8	13	0	0
Nebraska	13,430	13,527	-0.7%	12,669	12,708	0	0	0	0	761	819
North Dakota	21,882	24,023	-8.9%	21,882	24,023	0	0	0	0	0	0
South Dakota	1,778	1,560	14.0%	1,778	1,560	0	0	0	0	0	0
South Atlantic	76,973	79,146	-2.7%	67,945	66,966	8,259	11,281	0	0	768	899
Delaware	71	35	100.0%	0	0	71	35	0	0	0	0
District of Columbia	0	0	--	0	0	0	0	0	0	0	0
Florida	9,218	11,702	-21.0%	9,166	11,625	0	0	0	0	53	77
Georgia	15,353	14,953	2.7%	15,217	14,814	0	0	0	0	136	139
Maryland	2,881	4,637	-38.0%	0	0	2,788	4,450	0	0	92	188
North Carolina	12,803	11,130	15.0%	12,535	10,761	55	119	0	0	213	251
South Carolina	7,317	6,077	20.0%	7,099	6,067	198	0	0	0	19	11
Virginia	2,617	4,705	-44.0%	2,071	3,760	292	710	0	0	255	235
West Virginia	26,712	25,906	3.1%	21,857	19,939	4,855	5,967	0	0	0	0
East South Central	55,572	57,134	-2.7%	52,421	53,298	2,561	2,993	0	0	590	843
Alabama	15,107	14,648	3.1%	15,107	14,648	0	0	0	0	0	0
Kentucky	29,987	32,038	-6.4%	29,987	32,038	0	0	0	0	0	0
Mississippi	4,124	4,600	-10.0%	1,563	1,607	2,561	2,993	0	0	0	0
Tennessee	6,354	5,848	8.6%	5,763	5,005	0	0	0	0	590	843
West South Central	91,089	98,713	-7.7%	46,260	49,892	44,600	48,517	0	0	229	304
Arkansas	14,098	16,843	-16.0%	11,854	14,003	2,184	2,762	0	0	61	78
Louisiana	5,843	7,252	-19.0%	4,456	4,736	1,387	2,515	0	0	0	0
Oklahoma	4,833	8,774	-45.0%	4,665	7,436	0	1,112	0	0	169	226
Texas	66,315	65,845	0.7%	25,286	23,717	41,029	42,128	0	0	0	0
Mountain	80,585	82,404	-2.2%	70,392	73,210	10,192	9,194	0	0	0	0
Arizona	13,396	16,162	-17.0%	13,396	16,162	0	0	0	0	0	0
Colorado	13,935	14,505	-3.9%	13,935	14,505	0	0	0	0	0	0
Idaho	0	0	--	0	0	0	0	0	0	0	0
Montana	8,917	7,971	12.0%	256	239	8,661	7,731	0	0	0	0
Nevada	1,697	1,167	45.0%	1,093	582	604	585	0	0	0	0
New Mexico	8,495	7,520	13.0%	8,495	7,520	0	0	0	0	0	0
Utah	11,481	10,975	4.6%	11,079	10,570	402	405	0	0	0	0
Wyoming	22,663	24,104	-6.0%	22,138	23,632	525	472	0	0	0	0
Pacific Contiguous	6,950	4,833	44.0%	1,599	764	4,795	3,469	0	0	555	600
California	555	600	-7.4%	0	0	0	0	0	0	555	600
Oregon	1,599	764	109.0%	1,599	764	0	0	0	0	0	0
Washington	4,795	3,469	38.0%	0	0	4,795	3,469	0	0	0	0
Pacific Noncontiguous	1,011	987	2.4%	327	260	683	727	0	0	0	0
Alaska	327	260	26.0%	327	260	0	0	0	0	0	0
Hawaii	683	727	-6.0%	0	0	683	727	0	0	0	0
U.S. Total	560,153	596,215	-6.0%	413,915	435,964	139,141	152,015	8	13	7,088	8,224

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Notes:
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Totals may not equal sum of components because of independent rounding. Percentage change is calculated before rounding.
Coal includes anthracite, bituminous, subbituminous, lignite, waste coal, and coal-derived synthesis gas.

Source: U.S. Energy Information Administration, Form EIA-923, "Power Plant Operations Report."

Table 7.14. Receipts of Petroleum Liquids Delivered for Electricity Generation by State, 2019 and 2018
(Thousand Barrels)

Census Division and State	Electric Power Sector										
	All Sectors			Electric Utilities		Independent Power Producers		Commercial Sector		Industrial Sector	
	Year 2019	Year 2018	Percentage Change	Year 2019	Year 2018	Year 2019	Year 2018	Year 2019	Year 2018	Year 2019	Year 2018
New England	357	1,724	-79.0%	21	238	336	1,486	0	0	0	0
Connecticut	10	395	-98.0%	0	0	10	395	0	0	0	0
Maine	152	298	-49.0%	0	0	152	298	0	0	0	0
Massachusetts	155	487	-68.0%	8	33	147	454	0	0	0	0
New Hampshire	13	365	-96.0%	13	206	0	160	0	0	0	0
Rhode Island	28	179	-85.0%	0	0	28	179	0	0	0	0
Vermont	0	0	--	0	0	0	0	0	0	0	0
Middle Atlantic	1,293	3,888	-67.0%	653	1,041	567	2,751	0	0	73	96
New Jersey	77	264	-71.0%	0	0	77	264	0	0	0	0
New York	823	2,437	-66.0%	653	1,041	168	1,375	0	0	1	21
Pennsylvania	393	1,187	-67.0%	0	0	321	1,112	0	0	72	75
East North Central	901	875	3.1%	555	497	313	347	0	0	33	30
Illinois	90	98	-8.6%	4	6	86	92	0	0	0	0
Indiana	215	208	3.0%	215	207	0	1	0	0	0	0
Michigan	153	159	-3.9%	140	151	0	0	0	0	13	8
Ohio	393	323	22.0%	153	58	220	244	0	0	20	21
Wisconsin	51	86	-40.0%	44	76	8	11	0	0	0	0
West North Central	617	575	7.2%	614	572	3	3	0	0	0	0
Iowa	115	117	-1.8%	115	117	0	0	0	0	0	0
Kansas	146	105	40.0%	146	105	0	0	0	0	0	0
Minnesota	76	51	49.0%	73	48	3	3	0	0	0	0
Missouri	177	206	-14.0%	177	206	0	0	0	0	0	0
Nebraska	19	9	112.0%	19	9	0	0	0	0	0	0
North Dakota	71	77	-8.1%	71	77	0	0	0	0	0	0
South Dakota	13	11	13.0%	13	11	0	0	0	0	0	0
South Atlantic	1,699	5,402	-69.0%	1,315	3,750	221	1,410	0	0	163	242
Delaware	7	331	-98.0%	0	0	7	331	0	0	0	0
District of Columbia	0	0	--	0	0	0	0	0	0	0	0
Florida	423	495	-15.0%	387	445	0	0	0	0	36	51
Georgia	234	458	-49.0%	156	325	4	72	0	0	73	61
Maryland	186	628	-70.0%	0	0	186	628	0	0	0	0
North Carolina	243	1,130	-78.0%	207	1,023	4	48	0	0	32	59
South Carolina	110	623	-82.0%	99	580	2	0	0	0	9	43
Virginia	247	1,439	-83.0%	218	1,123	18	288	0	0	12	28
West Virginia	248	299	-17.0%	248	254	0	44	0	0	0	0
East South Central	287	511	-44.0%	267	427	14	79	0	0	7	5
Alabama	32	144	-78.0%	18	65	14	79	0	0	0	0
Kentucky	142	147	-3.2%	142	147	0	0	0	0	0	0
Mississippi	23	37	-38.0%	23	37	0	0	0	0	0	0
Tennessee	90	183	-51.0%	84	178	0	0	0	0	7	5
West South Central	230	188	22.0%	184	151	46	36	0	0	0	0
Arkansas	75	48	56.0%	53	35	22	13	0	0	0	0
Louisiana	37	27	36.0%	37	27	0	0	0	0	0	0
Oklahoma	35	30	14.0%	35	30	0	0	0	0	0	0
Texas	83	82	1.1%	59	59	24	23	0	0	0	0
Mountain	362	298	21.0%	337	266	25	32	0	0	0	0
Arizona	124	94	32.0%	124	94	0	0	0	0	0	0
Colorado	5	14	-62.0%	5	14	0	0	0	0	0	0
Idaho	0	0	--	0	0	0	0	0	0	0	0
Montana	18	25	-26.0%	0	0	18	25	0	0	0	0
Nevada	25	20	23.0%	20	15	5	5	0	0	0	0
New Mexico	48	34	42.0%	48	34	0	0	0	0	0	0
Utah	69	56	24.0%	66	54	2	2	0	0	0	0
Wyoming	72	55	30.0%	72	55	0	0	0	0	0	0
Pacific Contiguous	28	20	41.0%	11	5	17	15	0	0	0	0
California	0	0	--	0	0	0	0	0	0	0	0
Oregon	4	0	--	4	0	0	0	0	0	0	0
Washington	23	20	18.0%	6	5	17	15	0	0	0	0
Pacific Noncontiguous	8,937	8,810	1.4%	7,054	6,948	1,883	1,862	0	0	0	0
Alaska	27	14	94.0%	27	14	0	0	0	0	0	0
Hawaii	8,910	8,796	1.3%	7,027	6,935	1,883	1,862	0	0	0	0
U.S. Total	14,711	22,290	-34.0%	11,010	13,896	3,425	8,022	0	0	275	372

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Notes:
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Totals may not equal sum of components because of independent rounding. Percentage change is calculated before rounding.
Petroleum Liquids includes distillate and residual fuel oils.
See the Technical Notes for fuel conversion factors.

Source: U.S. Energy Information Administration, Form EIA-923, "Power Plant Operations Report."

Table 7.15. Receipts of Petroleum Coke Delivered for Electricity Generation by State, 2019 and 2018
(Thousand Tons)

Census Division and State	Electric Power Sector										
	All Sectors			Electric Utilities		Independent Power Producers		Commercial Sector		Industrial Sector	
	Year 2019	Year 2018	Percentage Change	Year 2019	Year 2018	Year 2019	Year 2018	Year 2019	Year 2018	Year 2019	Year 2018
New England	0	0	--	0	0	0	0	0	0	0	0
Connecticut	0	0	--	0	0	0	0	0	0	0	0
Maine	0	0	--	0	0	0	0	0	0	0	0
Massachusetts	0	0	--	0	0	0	0	0	0	0	0
New Hampshire	0	0	--	0	0	0	0	0	0	0	0
Rhode Island	0	0	--	0	0	0	0	0	0	0	0
Vermont	0	0	--	0	0	0	0	0	0	0	0
Middle Atlantic	0	0	--	0	0	0	0	0	0	0	0
New Jersey	0	0	--	0	0	0	0	0	0	0	0
New York	0	0	--	0	0	0	0	0	0	0	0
Pennsylvania	0	0	--	0	0	0	0	0	0	0	0
East North Central	325	599	-46.0%	325	599	0	0	0	0	0	0
Illinois	0	0	--	0	0	0	0	0	0	0	0
Indiana	0	0	--	0	0	0	0	0	0	0	0
Michigan	280	539	-48.0%	280	539	0	0	0	0	0	0
Ohio	0	0	--	0	0	0	0	0	0	0	0
Wisconsin	45	60	-25.0%	45	60	0	0	0	0	0	0
West North Central	73	71	3.5%	0	0	0	0	0	0	73	71
Iowa	73	71	3.5%	0	0	0	0	0	0	73	71
Kansas	0	0	--	0	0	0	0	0	0	0	0
Minnesota	0	0	--	0	0	0	0	0	0	0	0
Missouri	0	0	--	0	0	0	0	0	0	0	0
Nebraska	0	0	--	0	0	0	0	0	0	0	0
North Dakota	0	0	--	0	0	0	0	0	0	0	0
South Dakota	0	0	--	0	0	0	0	0	0	0	0
South Atlantic	429	784	-45.0%	429	784	0	0	0	0	0	0
Delaware	0	0	--	0	0	0	0	0	0	0	0
District of Columbia	0	0	--	0	0	0	0	0	0	0	0
Florida	429	784	-45.0%	429	784	0	0	0	0	0	0
Georgia	0	0	--	0	0	0	0	0	0	0	0
Maryland	0	0	--	0	0	0	0	0	0	0	0
North Carolina	0	0	--	0	0	0	0	0	0	0	0
South Carolina	0	0	--	0	0	0	0	0	0	0	0
Virginia	0	0	--	0	0	0	0	0	0	0	0
West Virginia	0	0	--	0	0	0	0	0	0	0	0
East South Central	0	0	--	0	0	0	0	0	0	0	0
Alabama	0	0	--	0	0	0	0	0	0	0	0
Kentucky	0	0	--	0	0	0	0	0	0	0	0
Mississippi	0	0	--	0	0	0	0	0	0	0	0
Tennessee	0	0	--	0	0	0	0	0	0	0	0
West South Central	1,142	1,557	-27.0%	1,142	1,557	0	0	0	0	0	0
Arkansas	0	0	--	0	0	0	0	0	0	0	0
Louisiana	1,142	1,557	-27.0%	1,142	1,557	0	0	0	0	0	0
Oklahoma	0	0	--	0	0	0	0	0	0	0	0
Texas	0	0	--	0	0	0	0	0	0	0	0
Mountain	0	0	--	0	0	0	0	0	0	0	0
Arizona	0	0	--	0	0	0	0	0	0	0	0
Colorado	0	0	--	0	0	0	0	0	0	0	0
Idaho	0	0	--	0	0	0	0	0	0	0	0
Montana	0	0	--	0	0	0	0	0	0	0	0
Nevada	0	0	--	0	0	0	0	0	0	0	0
New Mexico	0	0	--	0	0	0	0	0	0	0	0
Utah	0	0	--	0	0	0	0	0	0	0	0
Wyoming	0	0	--	0	0	0	0	0	0	0	0
Pacific Contiguous	0	0	--	0	0	0	0	0	0	0	0
California	0	0	--	0	0	0	0	0	0	0	0
Oregon	0	0	--	0	0	0	0	0	0	0	0
Washington	0	0	--	0	0	0	0	0	0	0	0
Pacific Noncontiguous	0	0	--	0	0	0	0	0	0	0	0
Alaska	0	0	--	0	0	0	0	0	0	0	0
Hawaii	0	0	--	0	0	0	0	0	0	0	0
U.S. Total	1,969	3,010	-35.0%	1,896	2,940	0	0	0	0	73	71

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Totals may not equal sum of components because of independent rounding. Percentage change is calculated before rounding.
Petroleum Coke includes petroleum coke-derived synthesis gas.
See the Technical Notes for fuel conversion factors.

Source: U.S. Energy Information Administration, Form EIA-923, "Power Plant Operations Report."

Table 7.16. Receipts of Natural Gas Delivered for Electricity Generation by State, 2019 and 2018
(Million Cubic Feet)

			Electric Power Sector								
Census Division and State	All Sectors			Electric Utilities		Independent Power Producers		Commercial Sector		Industrial Sector	
	Year 2019	Year 2018	Percentage Change	Year 2019	Year 2018	Year 2019	Year 2018	Year 2019	Year 2018	Year 2019	Year 2018
New England	338,041	357,295	-5.4%	646	1,348	337,395	355,948	0	0	0	0
Connecticut	140,794	132,334	6.4%	0	0	140,794	132,334	0	0	0	0
Maine	9,373	13,614	-31.0%	0	0	9,373	13,614	0	0	0	0
Massachusetts	110,879	132,566	-16.0%	567	947	110,313	131,619	0	0	0	0
New Hampshire	25,487	21,600	18.0%	79	400	25,408	21,199	0	0	0	0
Rhode Island	51,509	57,181	-9.9%	0	0	51,509	57,181	0	0	0	0
Vermont	0	0	--	0	0	0	0	0	0	0	0
Middle Atlantic	1,299,674	1,176,917	10.0%	88,480	92,273	1,201,102	1,074,141	0	0	10,092	10,503
New Jersey	285,788	278,523	2.6%	0	0	285,788	278,523	0	0	0	0
New York	358,271	382,447	-6.3%	88,480	92,273	262,557	282,569	0	0	7,234	7,605
Pennsylvania	655,615	515,948	27.0%	0	0	652,757	513,049	0	0	2,858	2,899
East North Central	1,140,342	980,851	16.0%	382,520	345,229	736,954	614,152	6,889	6,707	13,979	14,763
Illinois	159,869	128,983	24.0%	11,328	9,674	148,518	119,272	0	0	22	37
Indiana	211,990	182,600	16.0%	99,028	87,691	112,961	94,909	0	0	0	0
Michigan	258,751	231,528	12.0%	80,521	68,184	165,409	150,349	6,889	6,707	5,932	6,288
Ohio	365,929	316,263	16.0%	61,895	71,616	298,611	238,899	0	0	5,423	5,748
Wisconsin	143,803	121,477	18.0%	129,747	108,063	11,454	10,722	0	0	2,602	2,691
West North Central	267,715	225,291	19.0%	222,855	195,270	37,931	22,828	2,197	2,116	4,732	5,079
Iowa	67,408	64,610	4.3%	62,676	59,608	0	0	0	0	4,732	5,002
Kansas	23,307	23,736	-1.8%	23,307	23,736	0	0	0	0	0	0
Minnesota	83,832	55,926	50.0%	63,047	47,747	20,773	8,093	12	10	0	77
Missouri	59,690	54,787	8.9%	40,347	37,946	17,158	14,735	2,185	2,106	0	0
Nebraska	11,470	9,068	26.0%	11,470	9,068	0	0	0	0	0	0
North Dakota	14,877	9,873	51.0%	14,877	9,873	0	0	0	0	0	0
South Dakota	7,131	7,291	-2.2%	7,131	7,291	0	0	0	0	0	0
South Atlantic	2,775,146	2,622,122	5.8%	2,289,939	2,144,723	449,301	440,969	0	0	35,906	36,430
Delaware	25,354	33,332	-24.0%	0	0	25,354	33,332	0	0	0	0
District of Columbia	0	0	--	0	0	0	0	0	0	0	0
Florida	1,289,171	1,229,395	4.9%	1,243,206	1,178,822	41,287	46,251	0	0	4,677	4,322
Georgia	434,294	380,482	14.0%	328,913	284,740	96,900	86,922	0	0	8,482	8,821
Maryland	96,466	92,375	4.4%	23,002	22,077	72,313	67,520	0	0	1,151	2,778
North Carolina	308,738	331,999	-7.0%	240,733	280,625	65,194	48,593	0	0	2,812	2,781
South Carolina	178,437	169,867	5.0%	173,081	147,310	4,403	21,601	0	0	954	956
Virginia	419,047	367,368	14.0%	276,888	229,292	131,541	127,744	0	0	10,618	10,332
West Virginia	23,638	17,306	37.0%	4,117	1,858	12,309	9,007	0	0	7,212	6,440
East South Central	1,019,264	1,007,842	1.1%	737,878	685,293	256,884	302,245	0	0	24,502	20,304
Alabama	399,066	398,878	0.0%	146,717	138,322	252,349	260,556	0	0	0	0
Kentucky	113,295	112,670	0.6%	108,870	105,054	4,426	7,616	0	0	0	0
Mississippi	363,823	370,210	-1.7%	363,714	336,137	110	34,073	0	0	0	0
Tennessee	143,079	126,084	13.0%	118,577	105,779	0	0	0	0	24,502	20,304
West South Central	3,240,210	3,009,544	7.7%	1,082,072	980,145	1,485,951	1,376,247	0	0	672,187	653,152
Arkansas	158,293	150,505	5.2%	143,446	134,446	12,136	13,448	0	0	2,711	2,612
Louisiana	558,627	500,434	12.0%	289,838	256,687	43,595	34,679	0	0	225,194	209,068
Oklahoma	337,151	318,549	5.8%	220,793	204,417	110,846	109,692	0	0	5,511	4,440
Texas	2,186,139	2,040,056	7.2%	427,995	384,596	1,319,374	1,218,428	0	0	438,770	437,032
Mountain	828,014	740,594	12.0%	692,679	623,305	134,995	116,686	0	0	341	604
Arizona	348,973	278,303	25.0%	267,937	220,964	81,036	57,340	0	0	0	0
Colorado	122,200	118,141	3.4%	105,060	99,700	17,140	18,441	0	0	0	0
Idaho	25,908	19,987	30.0%	13,721	8,914	12,187	11,073	0	0	0	0
Montana	2,780	2,749	1.1%	2,749	2,737	31	12	0	0	0	0
Nevada	173,732	180,683	-3.8%	173,732	180,683	0	0	0	0	0	0
New Mexico	89,193	82,962	7.5%	64,609	53,157	24,584	29,805	0	0	0	0
Utah	62,078	55,974	11.0%	61,738	55,369	0	0	0	0	341	604
Wyoming	3,149	1,796	75.0%	3,133	1,782	16	15	0	0	0	0
Pacific Contiguous	769,534	748,670	2.8%	318,521	295,237	422,364	424,478	0	0	28,649	28,955
California	528,794	559,705	-5.5%	183,436	189,598	316,709	341,152	0	0	28,649	28,955
Oregon	143,846	123,735	16.0%	70,838	62,606	73,008	61,129	0	0	0	0
Washington	96,895	65,229	49.0%	64,247	43,033	32,648	22,197	0	0	0	0
Pacific Noncontiguous	15,546	16,636	-6.6%	15,546	16,636	0	0	0	0	0	0
Alaska	15,546	16,636	-6.6%	15,546	16,636	0	0	0	0	0	0
Hawaii	0	0	--	0	0	0	0	0	0	0	0
U.S. Total	11,693,486	10,885,764	7.4%	5,831,134	5,379,459	5,062,877	4,727,692	9,087	8,823	790,388	769,790

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Totals may not equal sum of components because of independent rounding. Percentage change is calculated before rounding.

Source: U.S. Energy Information Administration, Form EIA-923, "Power Plant Operations Report."

Table 7.17. Average Cost of Coal Delivered for Electricity Generation by State, 2019 and 2018
(Dollars per MMBtu)

Census Division and State	Electric Power Sector			Electric Utilities		Independent Power Producers	
	Year 2019	Year 2018	Percentage Change	Year 2019	Year 2018	Year 2019	Year 2018
New England	W	4.37	W	3.35	3.87	W	4.64
Connecticut	--	W	W	--	--	--	W
Maine	W	W	W	--	--	W	W
Massachusetts	--	--	--	--	--	--	--
New Hampshire	3.35	3.87	-13.0%	3.35	3.87	--	--
Rhode Island	--	W	W	--	--	--	W
Vermont	--	--	--	--	--	--	--
Middle Atlantic	1.88	2.15	-13.0%	--	--	1.88	2.15
New Jersey	W	W	W	--	--	W	W
New York	W	W	W	--	--	W	W
Pennsylvania	W	2.09	W	--	--	W	2.09
East North Central	1.98	1.99	-0.5%	2.11	2.11	1.80	1.82
Illinois	W	1.77	W	1.97	1.88	W	1.75
Indiana	W	W	W	2.12	2.11	W	W
Michigan	W	W	W	2.09	2.12	W	W
Ohio	1.79	W	W	1.82	1.77	1.79	W
Wisconsin	2.22	2.28	-2.6%	2.22	2.28	--	--
West North Central	1.63	1.71	-4.7%	1.63	1.71	--	--
Iowa	1.54	1.63	-5.5%	1.54	1.63	--	--
Kansas	1.62	1.71	-5.3%	1.62	1.71	--	--
Minnesota	2.02	2.19	-7.8%	2.02	2.19	--	--
Missouri	1.67	1.80	-7.2%	1.67	1.80	--	--
Nebraska	1.23	1.26	-2.4%	1.23	1.26	--	--
North Dakota	1.63	1.55	5.2%	1.63	1.55	--	--
South Dakota	1.78	1.87	-4.8%	1.78	1.87	--	--
South Atlantic	2.57	2.64	-2.7%	2.59	2.70	2.38	2.30
Delaware	W	W	W	--	--	W	W
District of Columbia	--	--	--	--	--	--	--
Florida	2.83	2.88	-1.7%	2.83	2.88	--	--
Georgia	2.69	2.75	-2.2%	2.69	2.75	--	--
Maryland	2.66	2.53	5.1%	--	--	2.66	2.53
North Carolina	W	3.15	W	2.80	3.15	W	3.97
South Carolina	W	3.33	W	3.20	3.33	W	--
Virginia	W	W	W	2.77	2.67	W	W
West Virginia	2.08	2.09	-0.5%	2.11	2.14	1.96	1.90
East South Central	W	W	W	2.06	2.08	W	W
Alabama	2.29	2.27	0.9%	2.29	2.27	--	--
Kentucky	1.91	1.96	-2.6%	1.91	1.96	--	--
Mississippi	W	W	W	2.94	2.69	W	W
Tennessee	2.14	2.16	-0.9%	2.14	2.16	--	--
West South Central	1.83	1.88	-2.7%	2.07	2.08	1.58	1.66
Arkansas	W	W	W	1.97	1.98	W	W
Louisiana	W	W	W	3.11	3.12	W	W
Oklahoma	1.73	W	W	1.73	1.77	--	W
Texas	W	1.76	W	1.99	2.04	W	1.60
Mountain	W	W	W	2.01	2.00	W	W
Arizona	2.56	2.43	5.3%	2.56	2.43	--	--
Colorado	1.74	1.64	6.1%	1.74	1.64	--	--
Idaho	--	--	--	--	--	--	--
Montana	W	W	W	1.95	2.01	W	W
Nevada	W	W	W	2.76	3.07	W	W
New Mexico	2.49	2.48	0.4%	2.49	2.48	--	--
Utah	1.97	2.02	-2.5%	1.97	2.02	--	--
Wyoming	W	W	W	1.63	1.68	W	W
Pacific Contiguous	W	W	W	2.27	2.34	W	W
California	--	--	--	--	--	--	--
Oregon	2.27	2.34	-3.0%	2.27	2.34	--	--
Washington	W	W	W	--	--	W	W
Pacific Noncontiguous	W	W	W	3.51	3.28	W	W
Alaska	3.51	3.28	7.0%	3.51	3.28	--	--
Hawaii	W	W	W	--	--	W	W
U.S. Total	2.01	2.05	-2.0%	2.08	2.11	1.81	1.89

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Coal includes anthracite, bituminous, subbituminous, lignite, waste coal, and coal-derived synthesis gas.

Source: U.S. Energy Information Administration, Form EIA-923, "Power Plant Operations Report."

Table 7.18. Average Cost of Petroleum Liquids Delivered for Electricity Generation by State, 2019 and 2018
(Dollars per MMBtu)

Census Division and State	Electric Power Sector			Electric Utilities		Independent Power Producers	
	Year 2019	Year 2018	Percentage Change	Year 2019	Year 2018	Year 2019	Year 2018
New England	11.62	13.08	-11.0%	16.64	11.89	11.32	13.29
Connecticut	16.68	14.91	12.0%	--	--	16.68	14.91
Maine	W	9.78	W	--	--	W	9.78
Massachusetts	11.61	12.59	-7.8%	14.70	16.01	11.45	12.31
New Hampshire	17.80	W	W	17.80	11.29	--	W
Rhode Island	W	W	W	--	--	W	W
Vermont	--	--	--	--	--	--	--
Middle Atlantic	W	14.02	W	12.01	12.12	W	14.88
New Jersey	13.81	15.71	-12.0%	--	--	13.81	15.71
New York	12.64	13.16	-4.0%	12.01	12.12	15.20	14.00
Pennsylvania	W	16.08	W	--	--	W	16.08
East North Central	15.15	W	W	14.70	16.28	15.93	W
Illinois	W	16.82	W	15.71	16.39	W	16.84
Indiana	14.86	W	W	14.86	16.34	--	W
Michigan	13.95	15.72	-11.0%	13.95	15.72	--	--
Ohio	15.44	W	W	15.44	16.36	15.44	W
Wisconsin	W	17.16	W	13.68	17.16	W	--
West North Central	14.72	16.23	-9.3%	14.72	16.23	--	--
Iowa	14.56	16.27	-11.0%	14.56	16.27	--	--
Kansas	14.92	16.50	-9.6%	14.92	16.50	--	--
Minnesota	14.83	16.47	-10.0%	14.83	16.47	--	--
Missouri	14.73	16.15	-8.8%	14.73	16.15	--	--
Nebraska	14.87	17.36	-14.0%	14.87	17.36	--	--
North Dakota	14.49	15.56	-6.9%	14.49	15.56	--	--
South Dakota	14.19	17.17	-17.0%	14.19	17.17	--	--
South Atlantic	14.52	14.88	-2.4%	14.60	15.16	14.06	13.95
Delaware	W	W	W	--	--	W	W
District of Columbia	--	--	--	--	--	--	--
Florida	15.33	16.43	-6.7%	15.33	16.43	--	--
Georgia	W	15.64	W	14.98	15.66	W	15.56
Maryland	14.20	14.01	1.4%	--	--	14.20	14.01
North Carolina	W	W	W	14.67	17.12	W	W
South Carolina	W	17.22	W	15.13	17.22	W	--
Virginia	W	W	W	11.78	11.71	W	W
West Virginia	15.51	W	W	15.51	16.62	--	W
East South Central	W	W	W	14.55	15.98	W	W
Alabama	W	W	W	15.13	16.26	W	W
Kentucky	14.68	15.67	-6.3%	14.68	15.67	--	--
Mississippi	14.35	15.64	-8.2%	14.35	15.64	--	--
Tennessee	14.27	16.21	-12.0%	14.27	16.21	--	--
West South Central	W	W	W	14.71	15.96	W	W
Arkansas	W	W	W	14.74	16.48	W	W
Louisiana	14.61	15.18	-3.8%	14.61	15.18	--	--
Oklahoma	15.28	16.20	-5.7%	15.28	16.20	--	--
Texas	W	W	W	14.41	15.89	W	W
Mountain	16.89	W	W	16.96	18.21	15.98	W
Arizona	16.89	17.24	-2.0%	16.89	17.24	--	--
Colorado	17.67	16.41	7.7%	17.67	16.41	--	--
Idaho	--	--	--	--	--	--	--
Montana	W	W	W	--	--	W	W
Nevada	W	W	W	16.25	18.47	W	W
New Mexico	19.01	19.37	-1.9%	19.01	19.37	--	--
Utah	W	W	W	16.75	19.21	W	W
Wyoming	16.08	18.53	-13.0%	16.08	18.53	--	--
Pacific Contiguous	W	W	W	14.80	17.24	W	W
California	--	--	--	--	--	--	--
Oregon	12.45	--	--	12.45	--	--	--
Washington	W	W	W	16.52	17.24	W	W
Pacific Noncontiguous	W	W	W	12.87	13.91	W	W
Alaska	15.74	17.76	-11.0%	15.74	17.76	--	--
Hawaii	W	W	W	12.86	13.90	W	W
U.S. Total	13.63	14.44	-5.6%	13.40	14.39	14.40	14.52

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Petroleum Liquids includes distillate and residual fuel oils.
See the Technical Notes for fuel conversion factors.

Source: U.S. Energy Information Administration, Form EIA-923, "Power Plant Operations Report."

Table 7.19. Average Cost of Petroleum Coke Delivered for Electricity Generation by State, 2019 and 2018
(Dollars per MMBtu)

Census Division and State	Electric Power Sector			Electric Utilities		Independent Power Producers	
	Year 2019	Year 2018	Percentage Change	Year 2019	Year 2018	Year 2019	Year 2018
New England	--	--	--	--	--	--	--
Connecticut	--	--	--	--	--	--	--
Maine	--	--	--	--	--	--	--
Massachusetts	--	--	--	--	--	--	--
New Hampshire	--	--	--	--	--	--	--
Rhode Island	--	--	--	--	--	--	--
Vermont	--	--	--	--	--	--	--
Middle Atlantic	--	--	--	--	--	--	--
New Jersey	--	--	--	--	--	--	--
New York	--	--	--	--	--	--	--
Pennsylvania	--	--	--	--	--	--	--
East North Central	1.58	1.51	4.6%	1.58	1.51	--	--
Illinois	--	--	--	--	--	--	--
Indiana	--	--	--	--	--	--	--
Michigan	1.54	1.48	4.1%	1.54	1.48	--	--
Ohio	--	--	--	--	--	--	--
Wisconsin	1.86	1.79	3.9%	1.86	1.79	--	--
West North Central	--	--	--	--	--	--	--
Iowa	--	--	--	--	--	--	--
Kansas	--	--	--	--	--	--	--
Minnesota	--	--	--	--	--	--	--
Missouri	--	--	--	--	--	--	--
Nebraska	--	--	--	--	--	--	--
North Dakota	--	--	--	--	--	--	--
South Dakota	--	--	--	--	--	--	--
South Atlantic	2.52	3.14	-20.0%	2.52	3.14	--	--
Delaware	--	--	--	--	--	--	--
District of Columbia	--	--	--	--	--	--	--
Florida	2.52	3.14	-20.0%	2.52	3.14	--	--
Georgia	--	--	--	--	--	--	--
Maryland	--	--	--	--	--	--	--
North Carolina	--	--	--	--	--	--	--
South Carolina	--	--	--	--	--	--	--
Virginia	--	--	--	--	--	--	--
West Virginia	--	--	--	--	--	--	--
East South Central	--	--	--	--	--	--	--
Alabama	--	--	--	--	--	--	--
Kentucky	--	--	--	--	--	--	--
Mississippi	--	--	--	--	--	--	--
Tennessee	--	--	--	--	--	--	--
West South Central	1.79	2.65	-32.0%	1.79	2.65	--	--
Arkansas	--	--	--	--	--	--	--
Louisiana	1.79	2.65	-32.0%	1.79	2.65	--	--
Oklahoma	--	--	--	--	--	--	--
Texas	--	--	--	--	--	--	--
Mountain	--	--	--	--	--	--	--
Arizona	--	--	--	--	--	--	--
Colorado	--	--	--	--	--	--	--
Idaho	--	--	--	--	--	--	--
Montana	--	--	--	--	--	--	--
Nevada	--	--	--	--	--	--	--
New Mexico	--	--	--	--	--	--	--
Utah	--	--	--	--	--	--	--
Wyoming	--	--	--	--	--	--	--
Pacific Contiguous	--	--	--	--	--	--	--
California	--	--	--	--	--	--	--
Oregon	--	--	--	--	--	--	--
Washington	--	--	--	--	--	--	--
Pacific Noncontiguous	--	--	--	--	--	--	--
Alaska	--	--	--	--	--	--	--
Hawaii	--	--	--	--	--	--	--
U.S. Total	1.92	2.56	-25.0%	1.92	2.56	--	--

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Petroleum Coke includes petroleum coke-derived synthesis gas.
See the Technical Notes for fuel conversion factors.

Source: U.S. Energy Information Administration, Form EIA-923, "Power Plant Operations Report."

Table 7.20. Average Cost of Natural Gas Delivered for Electricity Generation by State, 2019 and 2018
(Dollars per MMBtu)

Census Division and State	Electric Power Sector			Electric Utilities		Independent Power Producers	
	Year 2019	Year 2018	Percentage Change	Year 2019	Year 2018	Year 2019	Year 2018
New England	W	4.62	W	3.84	4.76	W	4.62
Connecticut	3.51	4.67	-25.0%	--	--	3.51	4.67
Maine	W	W	W	--	--	W	W
Massachusetts	4.37	4.75	-8.0%	3.32	4.26	4.38	4.76
New Hampshire	W	W	W	7.51	5.95	W	W
Rhode Island	3.22	4.10	-21.0%	--	--	3.22	4.10
Vermont	--	--	--	--	--	--	--
Middle Atlantic	2.61	3.29	-21.0%	3.23	4.11	2.56	3.20
New Jersey	2.80	3.07	-8.8%	--	--	2.80	3.07
New York	2.96	3.76	-21.0%	3.23	4.11	2.85	3.62
Pennsylvania	2.35	3.06	-23.0%	--	--	2.35	3.06
East North Central	2.62	3.22	-19.0%	2.70	3.30	2.58	3.18
Illinois	W	3.37	W	2.94	3.61	W	3.35
Indiana	2.59	3.27	-21.0%	2.71	3.38	2.49	3.18
Michigan	2.60	3.25	-20.0%	2.72	3.48	2.55	3.15
Ohio	2.44	3.12	-22.0%	2.55	3.17	2.41	3.11
Wisconsin	W	3.19	W	2.74	3.19	W	--
West North Central	W	W	W	2.70	3.18	W	W
Iowa	2.48	2.93	-15.0%	2.48	2.93	--	--
Kansas	2.78	3.22	-14.0%	2.78	3.22	--	--
Minnesota	W	W	W	2.92	3.47	W	W
Missouri	W	W	W	2.47	3.30	W	W
Nebraska	2.93	3.54	-17.0%	2.93	3.54	--	--
North Dakota	3.07	2.83	8.5%	3.07	2.83	--	--
South Dakota	2.54	2.81	-9.6%	2.54	2.81	--	--
South Atlantic	3.42	4.22	-19.0%	3.52	4.32	2.79	3.53
Delaware	--	--	--	--	--	--	--
District of Columbia	--	--	--	--	--	--	--
Florida	3.72	W	W	3.73	4.38	3.40	W
Georgia	2.88	3.90	-26.0%	2.87	4.00	2.91	3.53
Maryland	3.11	3.86	-19.0%	3.54	3.64	2.98	3.93
North Carolina	3.58	4.31	-17.0%	3.79	4.41	2.79	3.73
South Carolina	3.17	4.17	-24.0%	3.17	4.17	--	--
Virginia	3.15	4.14	-24.0%	3.37	4.52	2.47	3.15
West Virginia	2.20	W	W	2.19	3.22	2.20	W
East South Central	2.84	3.31	-14.0%	2.85	3.30	2.80	3.34
Alabama	W	W	W	2.88	3.40	W	W
Kentucky	W	W	W	3.22	3.59	W	W
Mississippi	W	W	W	2.73	3.21	W	W
Tennessee	2.85	3.17	-10.0%	2.85	3.17	--	--
West South Central	2.40	3.09	-22.0%	2.38	3.07	2.42	3.11
Arkansas	W	W	W	2.61	3.30	W	W
Louisiana	W	W	W	2.70	3.31	W	W
Oklahoma	W	W	W	2.39	2.76	W	W
Texas	2.33	3.09	-25.0%	2.09	2.98	2.43	3.13
Mountain	2.62	W	W	2.58	3.08	3.02	W
Arizona	W	2.96	W	2.14	2.90	W	3.33
Colorado	W	W	W	3.07	3.62	W	W
Idaho	4.09	3.59	14.0%	4.09	3.59	--	--
Montana	W	W	W	1.59	1.30	W	W
Nevada	3.06	3.16	-3.2%	3.06	3.16	--	--
New Mexico	1.26	2.42	-48.0%	1.26	2.42	--	--
Utah	3.07	3.11	-1.3%	3.07	3.11	--	--
Wyoming	W	W	W	3.07	3.77	W	W
Pacific Contiguous	3.45	3.94	-12.0%	3.47	3.69	3.43	4.19
California	3.76	4.50	-16.0%	4.10	4.44	3.50	4.55
Oregon	W	W	W	2.21	2.23	W	W
Washington	W	W	W	3.32	2.94	W	W
Pacific Noncontiguous	6.95	6.72	3.4%	6.95	6.72	--	--
Alaska	6.95	6.72	3.4%	6.95	6.72	--	--
Hawaii	--	--	--	--	--	--	--
U.S. Total	2.89	3.56	-19.0%	3.03	3.68	2.70	3.40

Displayed values of zero may represent small values that round to zero.
NM = Not meaningful due to large relative standard error or excessive percentage change.
W = Withheld to avoid disclosure of individual company data.

Notes:
See Glossary for definitions. Values are final.
See Technical Notes for a discussion of the sample design for the Form EIA-923.
Totals may not equal sum of components because of independent rounding. Percentage change is calculated before rounding.

Source: U.S. Energy Information Administration, Form EIA-923, "Power Plant Operations Report."

**Table 7.21. Receipts and Quality of Coal by Rank Delivered for Electricity Generation:
Total (All Sectors) by State, 2019**

Census Division and State	Bituminous			Subbituminous			Lignite		
	Receipts (Thousand Tons)	Average Sulfur Percent by Weight	Average Ash Percent by Weight	Receipts (Thousand Tons)	Average Sulfur Percent by Weight	Average Ash Percent by Weight	Receipts (Thousand Tons)	Average Sulfur Percent by Weight	Average Ash Percent by Weight
New England	159	1.36	7.4	0	--	--	0	--	--
Connecticut	0	--	--	0	--	--	0	--	--
Maine	69	0.77	7.9	0	--	--	0	--	--
Massachusetts	0	--	--	0	--	--	0	--	--
New Hampshire	90	1.84	7.0	0	--	--	0	--	--
Rhode Island	0	--	--	0	--	--	0	--	--
Vermont	0	--	--	0	--	--	0	--	--
Middle Atlantic	14,879	2.72	9.2	0	--	--	0	--	--
New Jersey	562	1.73	7.7	0	--	--	0	--	--
New York	105	2.85	8.4	0	--	--	0	--	--
Pennsylvania	14,212	2.75	9.3	0	--	--	0	--	--
East North Central	60,981	3.23	10.3	60,149	0.24	4.7	0	--	--
Illinois	9,941	3.31	19.1	24,390	0.21	4.6	0	--	--
Indiana	25,962	2.86	9.0	2,313	0.22	4.5	0	--	--
Michigan	1,829	2.33	7.6	19,385	0.26	4.7	0	--	--
Ohio	22,655	3.67	9.1	68	0.29	5.2	0	--	--
Wisconsin	594	2.39	8.2	13,993	0.24	4.8	0	--	--
West North Central	1,060	3.04	9.2	83,985	0.27	5.0	21,882	0.76	9.8
Iowa	445	3.20	8.3	15,543	0.24	4.7	0	--	--
Kansas	128	3.43	12.8	11,163	0.31	5.0	0	--	--
Minnesota	0	--	--	11,460	0.34	6.0	0	--	--
Missouri	487	2.79	9.1	30,610	0.24	4.8	0	--	--
Nebraska	0	--	--	13,430	0.26	4.9	0	--	--
North Dakota	0	--	--	0	--	--	21,882	0.76	9.8
South Dakota	0	--	--	1,778	0.34	5.5	0	--	--
South Atlantic	66,998	2.36	9.6	9,047	0.32	4.7	0	--	--
Delaware	71	2.63	7.6	0	--	--	0	--	--
District of Columbia	0	--	--	0	--	--	0	--	--
Florida	9,218	2.41	8.3	0	--	--	0	--	--
Georgia	6,305	2.51	8.2	9,047	0.32	4.7	0	--	--
Maryland	2,881	2.36	10.9	0	--	--	0	--	--
North Carolina	12,803	1.74	9.7	0	--	--	0	--	--
South Carolina	7,317	1.85	9.2	0	--	--	0	--	--
Virginia	2,617	1.02	15.5	0	--	--	0	--	--
West Virginia	25,784	2.87	9.9	0	--	--	0	--	--
East South Central	33,046	2.57	9.2	19,965	0.29	5.3	2,561	0.51	13.6
Alabama	4,270	0.99	10.7	10,838	0.31	5.3	0	--	--
Kentucky	22,900	2.93	9.2	7,087	0.25	5.2	0	--	--
Mississippi	379	0.43	8.0	1,184	0.32	5.2	2,561	0.51	13.6
Tennessee	5,498	2.34	8.3	856	0.27	5.2	0	--	--
West South Central	444	2.37	11.5	68,772	0.27	5.0	21,873	1.09	17.0
Arkansas	61	0.45	9.2	14,038	0.22	4.9	0	--	--
Louisiana	334	2.92	9.3	4,308	0.28	5.0	1,200	0.60	15.8
Oklahoma	50	0.95	34.4	4,784	0.22	4.6	0	--	--
Texas	0	--	--	45,642	0.29	5.1	20,673	1.12	17.1
Mountain	19,875	0.59	12.9	60,052	0.52	8.8	256	0.53	9.0
Arizona	4,025	0.51	10.3	9,371	0.66	10.3	0	--	--
Colorado	1,236	0.46	11.1	12,699	0.32	5.6	0	--	--
Idaho	0	--	--	0	--	--	0	--	--
Montana	0	--	--	8,661	0.69	10.0	256	0.53	9.0
Nevada	646	0.41	11.0	1,051	0.38	7.0	0	--	--
New Mexico	3,128	0.87	23.8	5,367	0.84	20.4	0	--	--
Utah	10,839	0.57	11.4	240	0.91	9.0	0	--	--
Wyoming	0	--	--	22,663	0.43	6.9	0	--	--
Pacific Contiguous	555	0.45	9.4	6,394	0.35	7.6	0	--	--
California	555	0.45	9.4	0	--	--	0	--	--
Oregon	0	--	--	1,599	0.24	5.0	0	--	--
Washington	0	--	--	4,795	0.39	8.4	0	--	--
Pacific Noncontiguous	18	0.56	11.2	665	0.23	4.0	209	0.15	9.2
Alaska	0	--	--	0	--	--	209	0.15	9.2
Hawaii	18	0.56	11.2	665	0.23	4.0	0	--	--
U.S. Total	198,016	2.52	10.0	309,029	0.32	5.7	46,781	0.90	13.3

Displayed values of zero may represent small values that round to zero.
NM = Not meaningful due to large relative standard error or excessive percentage change.
W = Withheld to avoid disclosure of individual company data.

Notes:
Bituminous coal includes anthracite coal and coal-derived synthesis gas.
See Glossary for definitions. Values are final. See Technical Notes for a discussion of the sample design for the Form EIA-923.

Source: U.S. Energy Information Administration, Form EIA-923, "Power Plant Operations Report."

Table 7.22. Receipts and Quality of Coal by Rank Delivered for Electricity Generation:
Electric Utilities by State, 2019

Census Division and State	Bituminous			Subbituminous			Lignite		
	Receipts (Thousand Tons)	Average Sulfur Percent by Weight	Average Ash Percent by Weight	Receipts (Thousand Tons)	Average Sulfur Percent by Weight	Average Ash Percent by Weight	Receipts (Thousand Tons)	Average Sulfur Percent by Weight	Average Ash Percent by Weight
New England	90	1.84	7.0	0	--	--	0	--	--
Connecticut	0	--	--	0	--	--	0	--	--
Maine	0	--	--	0	--	--	0	--	--
Massachusetts	0	--	--	0	--	--	0	--	--
New Hampshire	90	1.84	7.0	0	--	--	0	--	--
Rhode Island	0	--	--	0	--	--	0	--	--
Vermont	0	--	--	0	--	--	0	--	--
Middle Atlantic	0	--	--	0	--	--	0	--	--
New Jersey	0	--	--	0	--	--	0	--	--
New York	0	--	--	0	--	--	0	--	--
Pennsylvania	0	--	--	0	--	--	0	--	--
East North Central	30,966	2.85	8.9	40,000	0.25	4.7	0	--	--
Illinois	2,404	2.53	9.4	4,301	0.21	4.5	0	--	--
Indiana	23,872	2.82	9.0	2,313	0.22	4.5	0	--	--
Michigan	1,580	2.48	7.7	19,385	0.26	4.7	0	--	--
Ohio	2,598	3.66	9.0	8	0.21	4.5	0	--	--
Wisconsin	512	2.65	7.8	13,993	0.24	4.8	0	--	--
West North Central	607	2.92	9.9	81,426	0.27	5.0	21,882	0.76	9.8
Iowa	0	--	--	13,745	0.25	4.8	0	--	--
Kansas	128	3.43	12.8	11,163	0.31	5.0	0	--	--
Minnesota	0	--	--	11,460	0.34	6.0	0	--	--
Missouri	479	2.79	9.1	30,610	0.24	4.8	0	--	--
Nebraska	0	--	--	12,669	0.26	5.0	0	--	--
North Dakota	0	--	--	0	--	--	21,882	0.76	9.8
South Dakota	0	--	--	1,778	0.34	5.5	0	--	--
South Atlantic	58,898	2.36	9.7	9,047	0.32	4.7	0	--	--
Delaware	0	--	--	0	--	--	0	--	--
District of Columbia	0	--	--	0	--	--	0	--	--
Florida	9,166	2.43	8.3	0	--	--	0	--	--
Georgia	6,170	2.55	8.1	9,047	0.32	4.7	0	--	--
Maryland	0	--	--	0	--	--	0	--	--
North Carolina	12,535	1.76	9.8	0	--	--	0	--	--
South Carolina	7,099	1.87	9.2	0	--	--	0	--	--
Virginia	2,071	1.09	18.1	0	--	--	0	--	--
West Virginia	21,857	2.87	10.1	0	--	--	0	--	--
East South Central	32,456	2.60	9.2	19,965	0.29	5.3	0	--	--
Alabama	4,270	0.99	10.7	10,838	0.31	5.3	0	--	--
Kentucky	22,900	2.93	9.2	7,087	0.25	5.2	0	--	--
Mississippi	379	0.43	8.0	1,184	0.32	5.2	0	--	--
Tennessee	4,908	2.52	8.5	856	0.27	5.2	0	--	--
West South Central	384	2.71	12.0	39,102	0.25	4.9	6,775	1.59	20.4
Arkansas	0	--	--	11,854	0.23	4.8	0	--	--
Louisiana	334	2.92	9.3	2,921	0.26	5.0	1,200	0.60	15.8
Oklahoma	50	0.95	34.4	4,615	0.22	4.6	0	--	--
Texas	0	--	--	19,711	0.27	5.1	5,575	1.84	21.6
Mountain	19,875	0.59	12.9	50,262	0.49	8.7	256	0.53	9.0
Arizona	4,025	0.51	10.3	9,371	0.66	10.3	0	--	--
Colorado	1,236	0.46	11.1	12,699	0.32	5.6	0	--	--
Idaho	0	--	--	0	--	--	0	--	--
Montana	0	--	--	0	--	--	256	0.53	9.0
Nevada	646	0.41	11.0	447	0.45	9.0	0	--	--
New Mexico	3,128	0.87	23.8	5,367	0.84	20.4	0	--	--
Utah	10,839	0.57	11.4	240	0.91	9.0	0	--	--
Wyoming	0	--	--	22,138	0.43	6.9	0	--	--
Pacific Contiguous	0	--	--	1,599	0.24	5.0	0	--	--
California	0	--	--	0	--	--	0	--	--
Oregon	0	--	--	1,599	0.24	5.0	0	--	--
Washington	0	--	--	0	--	--	0	--	--
Pacific Noncontiguous	0	--	--	0	--	--	209	0.15	9.2
Alaska	0	--	--	0	--	--	209	0.15	9.2
Hawaii	0	--	--	0	--	--	0	--	--
U.S. Total	143,275	2.29	9.8	241,401	0.31	5.7	29,122	0.93	12.1

Displayed values of zero may represent small values that round to zero.
NM = Not meaningful due to large relative standard error or excessive percentage change.
W = Withheld to avoid disclosure of individual company data.

Notes:
Bituminous coal includes anthracite coal and coal-derived synthesis gas.
See Glossary for definitions. Values are final. See Technical Notes for a discussion of the sample design for the Form EIA-923.

Source: U.S. Energy Information Administration, Form EIA-923, "Power Plant Operations Report."

**Table 7.23. Receipts and Quality of Coal by Rank Delivered for Electricity Generation:
Independent Power Producers by State, 2019**

Census Division and State	Bituminous			Subbituminous			Lignite		
	Receipts (Thousand Tons)	Average Sulfur Percent by Weight	Average Ash Percent by Weight	Receipts (Thousand Tons)	Average Sulfur Percent by Weight	Average Ash Percent by Weight	Receipts (Thousand Tons)	Average Sulfur Percent by Weight	Average Ash Percent by Weight
New England	69	0.77	7.9	0	--	--	0	--	--
Connecticut	0	--	--	0	--	--	0	--	--
Maine	69	0.77	7.9	0	--	--	0	--	--
Massachusetts	0	--	--	0	--	--	0	--	--
New Hampshire	0	--	--	0	--	--	0	--	--
Rhode Island	0	--	--	0	--	--	0	--	--
Vermont	0	--	--	0	--	--	0	--	--
Middle Atlantic	14,803	2.72	9.2	0	--	--	0	--	--
New Jersey	562	1.73	7.7	0	--	--	0	--	--
New York	105	2.85	8.4	0	--	--	0	--	--
Pennsylvania	14,136	2.76	9.3	0	--	--	0	--	--
East North Central	28,808	3.62	11.9	19,491	0.21	4.6	0	--	--
Illinois	6,413	3.64	26.2	19,432	0.21	4.6	0	--	--
Indiana	2,091	3.33	9.1	0	--	--	0	--	--
Michigan	247	1.16	6.4	0	--	--	0	--	--
Ohio	20,057	3.67	9.1	60	0.30	5.2	0	--	--
Wisconsin	0	--	--	0	--	--	0	--	--
West North Central	0	--	--	0	--	--	0	--	--
Iowa	0	--	--	0	--	--	0	--	--
Kansas	0	--	--	0	--	--	0	--	--
Minnesota	0	--	--	0	--	--	0	--	--
Missouri	0	--	--	0	--	--	0	--	--
Nebraska	0	--	--	0	--	--	0	--	--
North Dakota	0	--	--	0	--	--	0	--	--
South Dakota	0	--	--	0	--	--	0	--	--
South Atlantic	7,331	2.55	9.3	0	--	--	0	--	--
Delaware	71	2.63	7.6	0	--	--	0	--	--
District of Columbia	0	--	--	0	--	--	0	--	--
Florida	0	--	--	0	--	--	0	--	--
Georgia	0	--	--	0	--	--	0	--	--
Maryland	2,788	2.37	10.6	0	--	--	0	--	--
North Carolina	55	0.70	6.2	0	--	--	0	--	--
South Carolina	198	1.19	9.2	0	--	--	0	--	--
Virginia	292	0.84	7.6	0	--	--	0	--	--
West Virginia	3,927	2.90	8.5	0	--	--	0	--	--
East South Central	0	--	--	0	--	--	2,561	0.51	13.6
Alabama	0	--	--	0	--	--	0	--	--
Kentucky	0	--	--	0	--	--	0	--	--
Mississippi	0	--	--	0	--	--	2,561	0.51	13.6
Tennessee	0	--	--	0	--	--	0	--	--
West South Central	0	--	--	29,502	0.29	5.1	15,098	0.89	15.6
Arkansas	0	--	--	2,184	0.22	5.0	0	--	--
Louisiana	0	--	--	1,387	0.30	4.9	0	--	--
Oklahoma	0	--	--	0	--	--	0	--	--
Texas	0	--	--	25,931	0.30	5.1	15,098	0.89	15.6
Mountain	0	--	--	9,790	0.65	9.5	0	--	--
Arizona	0	--	--	0	--	--	0	--	--
Colorado	0	--	--	0	--	--	0	--	--
Idaho	0	--	--	0	--	--	0	--	--
Montana	0	--	--	8,661	0.69	10.0	0	--	--
Nevada	0	--	--	604	0.33	5.3	0	--	--
New Mexico	0	--	--	0	--	--	0	--	--
Utah	0	--	--	0	--	--	0	--	--
Wyoming	0	--	--	525	0.44	5.5	0	--	--
Pacific Contiguous	0	--	--	4,795	0.39	8.4	0	--	--
California	0	--	--	0	--	--	0	--	--
Oregon	0	--	--	0	--	--	0	--	--
Washington	0	--	--	4,795	0.39	8.4	0	--	--
Pacific Noncontiguous	18	0.56	11.2	665	0.23	4.0	0	--	--
Alaska	0	--	--	0	--	--	0	--	--
Hawaii	18	0.56	11.2	665	0.23	4.0	0	--	--
U.S. Total	51,029	3.18	10.7	64,244	0.33	5.8	17,659	0.85	15.4

Displayed values of zero may represent small values that round to zero.
NM = Not meaningful due to large relative standard error or excessive percentage change.
W = Withheld to avoid disclosure of individual company data.

Notes:
Bituminous coal includes anthracite coal and coal-derived synthesis gas.
See Glossary for definitions. Values are final. See Technical Notes for a discussion of the sample design for the Form EIA-923.

Source: U.S. Energy Information Administration, Form EIA-923, "Power Plant Operations Report."

Table 7.24. Receipts and Quality of Coal by Rank Delivered for Electricity Generation: Commercial Sector by State, 2019

Census Division and State	Bituminous			Subbituminous			Lignite		
	Receipts (Thousand Tons)	Average Sulfur Percent by Weight	Average Ash Percent by Weight	Receipts (Thousand Tons)	Average Sulfur Percent by Weight	Average Ash Percent by Weight	Receipts (Thousand Tons)	Average Sulfur Percent by Weight	Average Ash Percent by Weight
New England	0	--	--	0	--	--	0	--	--
Connecticut	0	--	--	0	--	--	0	--	--
Maine	0	--	--	0	--	--	0	--	--
Massachusetts	0	--	--	0	--	--	0	--	--
New Hampshire	0	--	--	0	--	--	0	--	--
Rhode Island	0	--	--	0	--	--	0	--	--
Vermont	0	--	--	0	--	--	0	--	--
Middle Atlantic	0	--	--	0	--	--	0	--	--
New Jersey	0	--	--	0	--	--	0	--	--
New York	0	--	--	0	--	--	0	--	--
Pennsylvania	0	--	--	0	--	--	0	--	--
East North Central	0	--	--	0	--	--	0	--	--
Illinois	0	--	--	0	--	--	0	--	--
Indiana	0	--	--	0	--	--	0	--	--
Michigan	0	--	--	0	--	--	0	--	--
Ohio	0	--	--	0	--	--	0	--	--
Wisconsin	0	--	--	0	--	--	0	--	--
West North Central	8	3.01	8.2	0	--	--	0	--	--
Iowa	0	--	--	0	--	--	0	--	--
Kansas	0	--	--	0	--	--	0	--	--
Minnesota	0	--	--	0	--	--	0	--	--
Missouri	8	3.01	8.2	0	--	--	0	--	--
Nebraska	0	--	--	0	--	--	0	--	--
North Dakota	0	--	--	0	--	--	0	--	--
South Dakota	0	--	--	0	--	--	0	--	--
South Atlantic	0	--	--	0	--	--	0	--	--
Delaware	0	--	--	0	--	--	0	--	--
District of Columbia	0	--	--	0	--	--	0	--	--
Florida	0	--	--	0	--	--	0	--	--
Georgia	0	--	--	0	--	--	0	--	--
Maryland	0	--	--	0	--	--	0	--	--
North Carolina	0	--	--	0	--	--	0	--	--
South Carolina	0	--	--	0	--	--	0	--	--
Virginia	0	--	--	0	--	--	0	--	--
West Virginia	0	--	--	0	--	--	0	--	--
East South Central	0	--	--	0	--	--	0	--	--
Alabama	0	--	--	0	--	--	0	--	--
Kentucky	0	--	--	0	--	--	0	--	--
Mississippi	0	--	--	0	--	--	0	--	--
Tennessee	0	--	--	0	--	--	0	--	--
West South Central	0	--	--	0	--	--	0	--	--
Arkansas	0	--	--	0	--	--	0	--	--
Louisiana	0	--	--	0	--	--	0	--	--
Oklahoma	0	--	--	0	--	--	0	--	--
Texas	0	--	--	0	--	--	0	--	--
Mountain	0	--	--	0	--	--	0	--	--
Arizona	0	--	--	0	--	--	0	--	--
Colorado	0	--	--	0	--	--	0	--	--
Idaho	0	--	--	0	--	--	0	--	--
Montana	0	--	--	0	--	--	0	--	--
Nevada	0	--	--	0	--	--	0	--	--
New Mexico	0	--	--	0	--	--	0	--	--
Utah	0	--	--	0	--	--	0	--	--
Wyoming	0	--	--	0	--	--	0	--	--
Pacific Contiguous	0	--	--	0	--	--	0	--	--
California	0	--	--	0	--	--	0	--	--
Oregon	0	--	--	0	--	--	0	--	--
Washington	0	--	--	0	--	--	0	--	--
Pacific Noncontiguous	0	--	--	0	--	--	0	--	--
Alaska	0	--	--	0	--	--	0	--	--
Hawaii	0	--	--	0	--	--	0	--	--
U.S. Total	8	3.01	8.2	0	--	--	0	--	--

Displayed values of zero may represent small values that round to zero.
NM = Not meaningful due to large relative standard error or excessive percentage change.
W = Withheld to avoid disclosure of individual company data.

Notes:
Bituminous coal includes anthracite coal and coal-derived synthesis gas.
See Glossary for definitions. Values are final. See Technical Notes for a discussion of the sample design for the Form EIA-923.

Source: U.S. Energy Information Administration, Form EIA-923, "Power Plant Operations Report."

**Table 7.25. Receipts and Quality of Coal by Rank Delivered for Electricity Generation:
Industrial Sector by State, 2019**

Census Division and State	Bituminous			Subbituminous			Lignite		
	Receipts (Thousand Tons)	Average Sulfur Percent by Weight	Average Ash Percent by Weight	Receipts (Thousand Tons)	Average Sulfur Percent by Weight	Average Ash Percent by Weight	Receipts (Thousand Tons)	Average Sulfur Percent by Weight	Average Ash Percent by Weight
New England	0	--	--	0	--	--	0	--	--
Connecticut	0	--	--	0	--	--	0	--	--
Maine	0	--	--	0	--	--	0	--	--
Massachusetts	0	--	--	0	--	--	0	--	--
New Hampshire	0	--	--	0	--	--	0	--	--
Rhode Island	0	--	--	0	--	--	0	--	--
Vermont	0	--	--	0	--	--	0	--	--
Middle Atlantic	76	2.28	8.1	0	--	--	0	--	--
New Jersey	0	--	--	0	--	--	0	--	--
New York	0	--	--	0	--	--	0	--	--
Pennsylvania	76	2.28	8.1	0	--	--	0	--	--
East North Central	1,208	3.31	8.8	658	0.25	5.5	0	--	--
Illinois	1,124	3.53	8.7	658	0.25	5.5	0	--	--
Indiana	0	--	--	0	--	--	0	--	--
Michigan	2	0.59	7.8	0	--	--	0	--	--
Ohio	0	--	--	0	--	--	0	--	--
Wisconsin	82	0.50	10.6	0	--	--	0	--	--
West North Central	445	3.20	8.3	2,559	0.21	4.4	0	--	--
Iowa	445	3.20	8.3	1,797	0.20	4.5	0	--	--
Kansas	0	--	--	0	--	--	0	--	--
Minnesota	0	--	--	0	--	--	0	--	--
Missouri	0	--	--	0	--	--	0	--	--
Nebraska	0	--	--	761	0.21	4.4	0	--	--
North Dakota	0	--	--	0	--	--	0	--	--
South Dakota	0	--	--	0	--	--	0	--	--
South Atlantic	768	0.89	9.1	0	--	--	0	--	--
Delaware	0	--	--	0	--	--	0	--	--
District of Columbia	0	--	--	0	--	--	0	--	--
Florida	53	0.71	6.8	0	--	--	0	--	--
Georgia	136	0.92	11.4	0	--	--	0	--	--
Maryland	92	1.73	21.9	0	--	--	0	--	--
North Carolina	213	0.81	6.7	0	--	--	0	--	--
South Carolina	19	0.69	6.7	0	--	--	0	--	--
Virginia	255	0.74	7.1	0	--	--	0	--	--
West Virginia	0	--	--	0	--	--	0	--	--
East South Central	590	1.00	7.3	0	--	--	0	--	--
Alabama	0	--	--	0	--	--	0	--	--
Kentucky	0	--	--	0	--	--	0	--	--
Mississippi	0	--	--	0	--	--	0	--	--
Tennessee	590	1.00	7.3	0	--	--	0	--	--
West South Central	61	0.45	9.2	169	0.20	4.6	0	--	--
Arkansas	61	0.45	9.2	0	--	--	0	--	--
Louisiana	0	--	--	0	--	--	0	--	--
Oklahoma	0	--	--	169	0.20	4.6	0	--	--
Texas	0	--	--	0	--	--	0	--	--
Mountain	0	--	--	0	--	--	0	--	--
Arizona	0	--	--	0	--	--	0	--	--
Colorado	0	--	--	0	--	--	0	--	--
Idaho	0	--	--	0	--	--	0	--	--
Montana	0	--	--	0	--	--	0	--	--
Nevada	0	--	--	0	--	--	0	--	--
New Mexico	0	--	--	0	--	--	0	--	--
Utah	0	--	--	0	--	--	0	--	--
Wyoming	0	--	--	0	--	--	0	--	--
Pacific Contiguous	555	0.45	9.4	0	--	--	0	--	--
California	555	0.45	9.4	0	--	--	0	--	--
Oregon	0	--	--	0	--	--	0	--	--
Washington	0	--	--	0	--	--	0	--	--
Pacific Noncontiguous	0	--	--	0	--	--	0	--	--
Alaska	0	--	--	0	--	--	0	--	--
Hawaii	0	--	--	0	--	--	0	--	--
U.S. Total	3,703	1.86	8.6	3,385	0.21	4.7	0	--	--

Displayed values of zero may represent small values that round to zero.
NM = Not meaningful due to large relative standard error or excessive percentage change.
W = Withheld to avoid disclosure of individual company data.

Notes:
Bituminous coal includes anthracite coal and coal-derived synthesis gas.
See Glossary for definitions. Values are final. See Technical Notes for a discussion of the sample design for the Form EIA-923.

Source: U.S. Energy Information Administration, Form EIA-923, "Power Plant Operations Report."

Chapter 8

Electric Power System Characteristics and Performance

**Table 8.1. Average Operating Heat Rate for Selected Energy Sources,
2009 through 2019 (Btu per Kilowatthour)**

Year	Coal	Petroleum	Natural Gas	Nuclear
2009	10,414	10,923	8,160	10,459
2010	10,415	10,984	8,185	10,452
2011	10,444	10,829	8,152	10,464
2012	10,498	10,991	8,039	10,479
2013	10,459	10,713	7,948	10,449
2014	10,428	10,814	7,907	10,459
2015	10,495	10,687	7,878	10,458
2016	10,493	10,811	7,870	10,459
2017	10,465	10,834	7,812	10,459
2018	10,481	11,095	7,821	10,455
2019	10,551	11,205	7,732	10,442

Coal includes anthracite, bituminous, subbituminous and lignite coal. Waste coal and synthetic coal are included starting in 2002.
Petroleum 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:

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 8.2. Average Tested Heat Rates by Prime Mover and Energy Source, 2009 - 2019
(Btu per Kilowatthour)

Prime Mover	Coal	Petroleum	Natural Gas	Nuclear
2009				
Steam Generator	10,150	10,349	10,427	10,459
Gas Turbine	--	13,326	11,560	--
Internal Combustion	--	10,428	9,958	--
Combined Cycle	W	10,715	7,605	--
2010				
Steam Generator	10,142	10,249	10,416	10,452
Gas Turbine	--	13,386	11,590	--
Internal Combustion	--	10,429	9,917	--
Combined Cycle	W	10,474	7,619	--
2011				
Steam Generator	10,128	10,414	10,414	10,464
Gas Turbine	--	13,637	11,569	--
Internal Combustion	--	10,428	9,923	--
Combined Cycle	W	10,650	7,603	--
2012				
Steam Generator	10,107	10,359	10,385	10,479
Gas Turbine	--	13,622	11,499	--
Internal Combustion	--	10,416	9,991	--
Combined Cycle	W	10,195	7,615	--
2013				
Steam Generator	10,089	10,334	10,354	10,449
Gas Turbine	--	13,555	11,371	--
Internal Combustion	--	10,401	9,573	--
Combined Cycle	W	9,937	7,667	--
2014				
Steam Generator	10,080	10,156	10,408	10,459
Gas Turbine	--	13,457	11,378	--
Internal Combustion	--	10,403	9,375	--
Combined Cycle	W	9,924	7,658	--
2015				
Steam Generator	10,059	10,197	10,372	10,458
Gas Turbine	--	13,550	11,302	--
Internal Combustion	--	10,379	9,322	--
Combined Cycle	W	9,676	7,655	--
2016				
Steam Generator	10,045	10,189	10,382	10,459
Gas Turbine	--	13,535	11,214	--
Internal Combustion	--	10,331	9,179	--
Combined Cycle	W	9,860	7,652	--
2017				
Steam Generator	10,043	10,199	10,353	10,459
Gas Turbine	--	13,491	11,176	--
Internal Combustion	--	10,301	9,120	--
Combined Cycle	W	9,811	7,649	--
2018				
Steam Generator	10,015	10,270	10,334	10,455
Gas Turbine	--	13,352	11,138	--
Internal Combustion	--	10,326	9,009	--
Combined Cycle	W	9,663	7,627	--
2019				
Steam Generator	10,002	10,236	10,347	10,442
Gas Turbine	--	13,315	11,098	--
Internal Combustion	--	10,325	8,899	--
Combined Cycle	W	9,662	7,633	--

Notes: W = Withheld to avoid disclosure of individual company data.

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.
Coal Combined Cycle represents integrated gasification units.

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

Table 8.3. Revenue and Expense Statistics for Major U.S. Investor-Owned Electric Utilities, 2009 through 2019 (Million Dollars)

Description	2009	2010	2011	2012	2013	2014
Utility Operating Revenues	276,124	285,512	280,520	270,912	281,901	298,430
.....Electric Utility	249,303	260,119	255,573	249,166	257,718	271,832
.....Other Utility	26,822	25,393	24,946	21,745	24,183	26,598
Utility Operating Expenses	244,243	253,022	247,118	235,694	244,316	258,936
.....Electric Utility	219,544	234,173	228,873	220,722	227,483	240,643
.....Operation	154,925	166,922	161,460	152,379	156,077	165,989
.....Production	118,816	128,831	122,520	111,714	115,046	123,366
.....Cost of Fuel	40,242	44,138	42,779	38,998	41,127	42,545
.....Purchased Power	67,630	67,284	61,447	54,570	55,529	62,066
.....Other	10,970	17,409	18,294	18,146	18,390	18,755
.....Transmission	6,742	6,948	6,876	7,183	7,881	8,902
.....Distribution	3,947	4,007	4,044	4,181	4,197	4,331
.....Customer Accounts	5,203	5,091	5,180	5,086	5,107	5,255
.....Customer Service	3,857	4,741	5,311	5,640	5,906	6,396
.....Sales	178	185	185	221	203	208
.....Administrative and General	15,991	17,120	17,343	18,353	17,738	17,532
.....Maintenance	14,092	14,957	15,772	15,489	15,505	16,801
.....Depreciation	20,095	20,951	22,555	23,677	24,723	25,919
.....Taxes and Other	29,081	31,343	29,086	29,177	31,179	31,934
.....Other Utility	24,698	18,849	18,245	14,972	16,833	18,293
Net Utility Operating Income	31,881	32,490	33,402	35,218	37,585	39,494

Description	2015	2016	2017	2018	2019
Utility Operating Revenues	282,695	282,499	286,501	293,868	293,000
.....Electric Utility	260,121	261,047	263,265	268,421	266,876
.....Other Utility	22,574	21,451	23,235	25,447	26,124
Utility Operating Expenses	242,728	239,037	240,041	253,944	250,136
.....Electric Utility	228,366	226,457	226,110	238,526	234,892
.....Operation	149,939	145,077	142,000	163,479	157,265
.....Production	107,201	100,852	98,859	104,185	99,518
.....Cost of Fuel	34,711	32,621	32,165	33,592	29,614
.....Purchased Power	52,970	49,962	49,030	53,060	50,378
.....Other	19,521	18,269	17,664	17,533	19,526
.....Transmission	9,624	10,447	10,804	11,387	11,941
.....Distribution	4,406	4,734	4,358	4,806	5,218
.....Customer Accounts	5,184	5,077	4,789	4,969	4,978
.....Customer Service	6,445	6,187	5,961	6,019	6,156
.....Sales	201	205	213	203	204
.....Administrative and General	16,878	17,575	17,016	31,911	29,248
.....Maintenance	16,392	16,982	17,996	17,786	19,898
.....Depreciation	26,847	30,097	30,323	32,125	34,883
.....Taxes and Other	35,188	34,301	35,791	25,136	22,846
.....Other Utility	14,362	12,579	13,931	15,418	15,245
Net Utility Operating Income	39,968	43,462	46,460	39,924	42,864

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

Total may not equal sum of components due to independent rounding.

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

Table 8.4. Average Power Plant Operating Expenses for Major U.S. Investor-Owned

Electric Utilities, 2009 through 2019 (Mills per Kilowatthour)

	Operation				Maintenance			
Year	Nuclear	Fossil Steam	Hydro-electric	Gas Turbine and Small Scale	Nuclear	Fossil Steam	Hydro-electric	Gas Turbine and Small Scale
2009	10.00	4.23	4.88	3.05	6.34	3.96	3.50	2.58
2010	10.50	4.04	5.33	2.79	6.80	3.99	3.81	2.73
2011	10.89	4.02	5.13	2.81	6.80	3.99	3.74	2.93
2012	12.49	4.38	6.71	2.46	7.32	4.48	4.63	2.76
2013	12.51	4.57	6.56	2.56	6.64	4.41	4.32	2.80
2014	12.41	4.55	7.30	2.63	6.67	5.11	4.59	2.90
2015	11.17	5.16	8.37	2.34	7.06	5.41	5.06	2.68
2016	10.90	5.05	6.65	2.49	7.01	5.53	4.34	2.74
2017	10.27	5.01	6.33	2.45	6.63	5.13	3.96	2.83
2018	10.78	5.19	6.69	2.37	5.93	5.27	3.96	2.71
2019	10.63	5.52	6.86	2.58	6.29	6.85	3.94	2.64

	Fuel				Total			
Year	Nuclear	Fossil Steam	Hydro-electric	Gas Turbine and Small Scale	Nuclear	Fossil Steam	Hydro-electric	Gas Turbine and Small Scale
2009	5.35	32.30	--	51.93	21.69	40.48	8.38	57.55
2010	6.68	27.73	--	43.21	23.98	35.76	9.15	48.74
2011	7.01	27.08	--	38.80	24.70	35.09	8.88	44.54
2012	7.61	28.34	--	30.45	27.42	37.20	11.34	35.67
2013	8.14	28.94	--	32.56	27.29	37.92	10.88	37.92
2014	7.71	29.39	--	37.06	26.79	39.04	11.90	42.60
2015	7.48	26.70	--	28.22	25.71	37.26	13.42	33.24
2016	7.45	25.50	--	24.97	25.36	36.08	10.98	30.19
2017	7.47	25.27	--	26.48	24.38	35.41	10.29	31.76
2018	7.15	25.40	--	27.35	23.86	35.86	10.65	32.43
2019	6.81	24.28	--	23.11	23.73	36.66	10.80	28.33

Hydroelectric category consists of both conventional hydroelectric and pumped storage.

Gas Turbine and Small Scale category consists of 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).

Total may not equal sum of components due to independent rounding.

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

Chapter 9

Environmental Data

Table 9.1. Emissions from Energy Consumption at Conventional Power Plants and Combined-Heat-and-Power Plants 2009 through 2019 (Thousand Metric Tons)

Year	Carbon Dioxide (CO ₂)	Sulfur Dioxide (SO ₂)	Nitrogen Oxides (NO _x)
2009	2,269,508	5,970	2,395
2010	2,388,596	5,400	2,491
2011	2,287,071	4,845	2,406
2012	2,156,875	3,704	2,148
2013	2,173,806	3,609	2,163
2014	2,168,284	3,454	2,100
2015	2,031,452	2,548	1,824
2016	1,928,401	1,807	1,630
2017	1,849,750	1,657	1,506
2018	1,874,346	1,571	1,485
2019	1,724,396	1,267	1,342

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.

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

Table 9.2. Quantity and Net Summer Capacity of Operable Environmental Equipment, 2009 - 2019

	Flue Gas Desulfurization Systems		Electrostatic Precipitators		Baghouses		Select Catalytic and Non-Catalytic Reduction Systems		Activated Carbon Injection Systems		Direct Sorbent Injection Systems	
Year	Quantity	Associated Net Summer Capacity (MW)	Quantity	Associated Net Summer Capacity (MW)	Quantity	Associated Net Summer Capacity (MW)	Quantity	Associated Net Summer Capacity (MW)	Quantity	Associated Net Summer Capacity (MW)	Quantity	Associated Net Summer Capacity (MW)
2009	678	174,801	1,456	314,356	597	73,863	1,323	300,007	227	39,546	65	8,242
2010	717	201,079	1,410	310,486	610	83,407	1,360	315,222	262	54,183	66	8,721
2011	731	211,781	1,368	307,043	633	98,507	1,408	331,242	274	59,057	75	8,977
2012	727	219,359	1,291	298,425	629	101,593	1,453	345,257	287	63,709	83	10,618
2013	705	219,359	1,218	289,182	637	104,331	1,458	351,233	262	61,215	97	12,985
2014	702	223,835	1,172	283,940	621	105,990	1,472	358,426	280	69,287	104	16,777
2015	693	224,143	1,037	264,905	623	110,820	1,480	359,885	364	106,450	122	23,307
2016	696	228,504	943	252,904	613	112,581	1,484	362,522	482	153,800	125	26,679
2017	681	222,513	886	244,087	601	109,495	1,492	365,878	477	151,208	126	25,762
2018	662	214,082	840	229,403	582	105,282	1,484	364,743	455	143,471	119	26,261
2019	617	203,035	781	217,328	535	101,839	1,455	361,767	431	136,597	114	25,461

Note:

'Associated Net Summer Capacity' is defined as the net summer capacity of the generators that are associated with the operation of this environmental equipment.

In some cases respondents have reported equipment late. Counts and capacity may have changed from prior publications of this table because of late reporting.

Data for 2005 and earlier are based primarily on Form EIA-767 data. In 2006, the Form EIA-767 was suspended. Data for 2007 and later are based primarily on Form EIA-860 data. All data for 2006 are inferred based on submissions from subsequent years. Beginning in 2013 environmental data was collected at a more detailed level, which increases its accuracy and in some cases reduces the equipment counts.

Source: U.S. Energy Information Administration, Forms EIA-767, "Steam-Electric Plant Operation and Design Report" and Form EIA-860, "Annual Electric Generator Report."

Table 9.3. Quantity and Net Summer Capacity of Operable Cooling Systems, by Energy Source and Cooling System Type, 2009 - 2019

	Once-Through Cooling Systems		Recirculating Cooling Systems		Cooling Ponds		Dry Cooling Systems		Hybrid Wet and Dry Cooling Systems		Other Cooling System Types	
Energy Source	Quantity	Associated Net Summer Capacity (MW)	Quantity	Associated Net Summer Capacity (MW)	Quantity	Associated Net Summer Capacity (MW)	Quantity	Associated Net Summer Capacity (MW)	Quantity	Associated Net Summer Capacity (MW)	Quantity	Associated Net Summer Capacity (MW)
2009												
Coal	445	129,350	370	161,312	100	47,960	1	335	--	--	8	3,036
Natural Gas	192	48,737	431	83,932	58	23,062	51	12,338	3	482	3	1,175
Petroleum	81	22,111	18	6,575	3	4,104	--	--	--	--	2	2,022
Other	16	1,160	25	2,316	2	344	4	356	--	--	1	33
2010												
Coal	437	129,554	371	162,953	101	48,929	2	435	1	766	9	3,086
Natural Gas	180	48,398	427	83,120	58	22,786	54	13,078	3	542	3	1,172
Nuclear	49	51,465	39	43,363	13	14,996	--	--	--	--	7	7,901
Petroleum	80	21,232	17	5,513	3	4,064	--	--	--	--	2	2,022
Other	17	1,190	26	2,546	2	344	4	356	--	--	2	63
2011												
Coal	415	127,412	369	165,958	104	50,476	3	840	1	766	9	3,090
Natural Gas	176	48,361	442	87,168	59	21,984	57	13,471	3	542	2	870
Nuclear	49	51,642	39	43,422	13	15,011	--	--	--	--	8	8,890
Petroleum	70	17,454	17	5,443	4	4,692	--	--	--	--	2	2,022
Other	18	1,318	20	1,641	--	--	1	26	--	--	2	63
2012												
Coal	372	124,589	366	166,915	88	39,933	4	1,412	1	766	15	6,918
Natural Gas	172	52,020	448	92,518	55	18,573	59	13,813	4	637	2	499
Nuclear	49	51,846	38	39,561	13	15,105	--	--	--	--	8	8,900
Petroleum	63	15,326	17	4,046	4	4,692	--	--	--	--	2	2,022
Other	15	1,258	27	2,167	--	--	1	53	--	--	2	63
2013												
Coal	345	120,340	357	164,826	77	39,482	4	1,422	1	750	11	4,797
Natural Gas	159	51,291	428	88,707	58	18,883	58	12,828	4	637	4	2,481
Nuclear	45	50,266	38	40,013	13	15,251	--	--	--	--	8	11,181
Petroleum	49	11,910	11	3,481	4	4,692	--	--	--	--	--	--
Solar Thermal	--	--	2	591	--	--	4	516	--	--	--	--
Other	15	1,301	31	2,561	1	66	--	--	--	--	1	128
2014												
Coal	328	115,930	340	160,534	74	38,906	4	1,422	1	750	22	8,322
Natural Gas	161	50,985	420	84,984	56	20,294	58	11,878	4	637	3	2,419
Nuclear	44	49,586	35	37,650	13	15,237	--	--	--	--	9	11,886
Petroleum	40	10,043	11	3,473	4	4,691	--	--	--	--	--	--
Solar Thermal	--	--	4	841	--	--	5	900	--	--	--	--
Other	16	1,332	31	2,756	1	66	1	72	--	--	1	128
2015												
Coal	259	93,180	313	153,917	77	45,026	4	1,422	1	750	25	9,883
Natural Gas	160	49,219	437	88,982	59	22,351	59	12,038	3	475	3	2,410
Nuclear	43	47,268	35	37,610	14	17,663	--	--	--	--	9	12,062
Petroleum	27	8,254	9	2,308	4	4,299	--	--	--	--	--	--
Solar Thermal	--	--	4	866	--	--	5	900	1	110	--	--
Other	18	1,676	26	2,104	1	66	1	72	--	--	1	128
2016												
Coal	210	82,047	294	149,187	79	44,702	4	1,422	1	750	22	10,148
Natural Gas	168	49,664	440	88,509	58	21,970	64	14,128	3	475	3	2,359
Nuclear	42	47,029	35	38,745	14	17,660	--	--	--	--	9	13,298
Petroleum	25	7,771	8	2,222	3	3,904	--	--	--	--	--	--
Solar Thermal	--	--	4	866	--	--	5	900	1	110	--	--
Other	18	1,689	24	2,035	1	66	1	72	--	--	1	128
2017												
Coal	197	76,492	281	142,578	75	44,341	4	1,422	1	750	19	9,581
Natural Gas	172	50,053	439	91,217	59	21,677	66	15,271	4	801	6	3,772
Nuclear	42	47,013	35	38,784	14	17,700	--	--	--	--	9	13,298
Petroleum	26	8,174	8	1,844	4	3,965	--	--	--	--	--	--
Solar Thermal	--	--	4	866	--	--	5	900	1	110	--	--
Other	17	1,582	26	2,464	2	97	2	245	--	--	1	128
2018												
Coal	180	70,659	273	138,632	67	39,593	4	1,422	1	750	16	8,089
Natural Gas	161	47,653	445	92,897	59	21,549	77	18,613	4	801	7	4,478
Nuclear	41	46,723	35	38,805	14	17,759	--	--	--	--	9	13,608
Petroleum	27	8,575	8	1,844	3	2,304	--	--	--	--	--	--
Solar Thermal	--	--	4	866	--	--	5	900	1	110	--	--
Other	17	1,931	25	2,161	1	31	1	72	--	--	1	128
2019												
Coal	163	67,142	246	129,998	63	37,807	4	1,432	1	750	14	7,629
Natural Gas	150	45,079	446	95,407	56	21,279	77	18,615	4	801	7	4,058
Nuclear	40	46,244	34	37,970	14	17,759	--	--	--	--	10	14,927
Petroleum	26	8,147	7	1,684	3	2,302	--	--	--	--	--	--
Solar Thermal	--	--	4	866	--	--	5	900	1	110	--	--
Other	18	1,962	25	2,161	--	--	1	72	--	--	1	128

Notes:

'Associated Net Summer Capacity' is defined as the net summer capacity of the generators that are associated with the operation of this environmental equipment.

In some cases respondents have reported equipment late. Counts and capacity may have changed from prior publications of this table because of late reporting.

Coal includes anthracite, bituminous, subbituminous, lignite, and waste coal; coal synfuel and refined coal; and beginning in 2011, coal-derived synthesis gas. Prior to 2011 coal-derived synthesis gas was included in Other Gases.

Petroleum Liquids includes distillate and residual fuel oils, jet fuel, kerosene, waste oil, and beginning in 2011, propane. Prior to 2011 propane was included in Other Gases.

Petroleum Coke includes petroleum coke-derived synthesis gas. Prior to 2011, petroleum coke-derived synthesis gas was included in Other Gases.

EIA did not collect cooling system data for nuclear units before 2010.

Other Energy Sources consists of wood and wood waste products, biomass, blast furnace gas and other gases.

Data for 2005 and earlier are based primarily on Form EIA-767 data. In 2006, the Form EIA-767 was suspended. Data for 2007 and later are based primarily on Form EIA-860 data. All data for 2006 are inferred based on submissions from subsequent years.

Source: U.S. Energy Information Administration, Forms EIA-767, "Steam-Electric Plant Operation and Design Report" and Form EIA-860, "Annual Electric Generator Report."

**Table 9.4. Average Costs of Existing Flue Gas Desulfurization Units
Operating in Electric Power Sector, 2009 - 2019**

Year	Average Operation and Maintenance Costs (Dollars per Megawatthour)	Average Installed Capital Costs (Dollars per Kilowatt)
2009	1.44	345.85
2010	1.52	340.18
2011	1.79	335.16
2012	1.87	266.40
2013	1.74	255.86
2014	1.84	186.45
2015	2.03	157.83
2016	1.96	303.32
2017	2.15	246.61
2018	2.08	--
2019	2.11	454.98

Notes: Average Installed Capital Costs reflect units which began operating in the specified year. Prior publications of this table reported the average installation cost of all units that were operating during each year; the new metric is intended to portray a more accurate understanding of how installation costs have changed over time.

Years in which no new Flue Gas Desulfurization units were installed a '--' is indicated in the Average Installed Capital Cost column.

Average Operation and Maintenance Costs are based on all units in operation during the specified year regardless of installation year.

Commercial and industrial facilities had significantly different costs than units used in the electric power sector. In order to give a more accurate reflection of the electric power sector, commercial and industrial facilities have been excluded from this publication table; prior publications of this table included commercial and industrial facilities when calculating average costs.

Sources:

U.S. Energy Information Administration, Form EIA-860, 'Annual Electric Generator Report'

Table 9.5. Emissions from Energy Consumption at Conventional Power Plants and Combined-Heat-and-Power Plants, by State, 2018 and 2019 (Thousand Metric Tons)

Census Division and State	Carbon Dioxide (CO2)		Sulfur Dioxide (SO2)		Nitrogen Oxides (NOx)	
	Year 2019	Year 2018	Year 2019	Year 2018	Year 2019	Year 2018
New England	24,813	27,317	10	12	23	25
Connecticut	9,517	9,591	0	1	5	6
Maine	1,823	2,202	7	7	5	6
Massachusetts	8,519	9,976	2	3	8	8
New Hampshire	1,952	2,191	1	1	2	3
Rhode Island	2,996	3,348	0	0	2	2
Vermont	7	10	0	0	1	0
Middle Atlantic	121,032	123,879	62	81	82	86
New Jersey	18,869	18,912	3	3	10	10
New York	24,807	27,936	8	11	26	29
Pennsylvania	77,357	77,031	51	67	45	47
East North Central	301,403	345,080	309	346	218	251
Illinois	63,036	72,261	86	80	33	37
Indiana	77,844	91,554	44	63	62	75
Michigan	57,232	61,435	74	74	51	52
Ohio	68,113	78,051	88	106	50	61
Wisconsin	35,179	41,779	16	23	22	26
West North Central	188,298	213,156	202	249	153	176
Iowa	28,989	34,253	27	34	24	29
Kansas	20,884	23,748	4	5	15	17
Minnesota	25,291	29,805	16	24	21	27
Missouri	57,516	65,623	81	94	42	48
Nebraska	23,660	25,525	42	54	20	22
North Dakota	28,668	31,282	31	37	29	32
South Dakota	3,289	2,921	1	1	1	1
South Atlantic	325,159	355,895	203	235	215	245
Delaware	2,650	3,193	0	1	1	2
District of Columbia	110	43	0	0	1	0
Florida	98,945	107,792	40	53	51	59
Georgia	51,074	54,803	48	48	40	43
Maryland	13,109	17,839	9	18	7	12
North Carolina	47,372	49,642	37	37	46	49
South Carolina	25,110	28,874	21	18	13	15
Virginia	29,965	33,504	13	18	22	28
West Virginia	56,823	60,203	35	42	34	37
East South Central	161,993	177,867	115	129	93	104
Alabama	50,842	56,140	32	37	26	32
Kentucky	58,805	66,267	48	53	40	45
Mississippi	25,018	26,157	12	12	16	15
Tennessee	27,328	29,303	23	27	12	12
West South Central	326,425	353,672	237	401	262	297
Arkansas	32,514	38,349	48	59	22	26
Louisiana	48,116	50,770	37	106	59	76
Oklahoma	28,239	34,476	9	32	19	24
Texas	217,556	230,076	143	203	163	171
Mountain	197,936	203,854	80	83	163	172
Arizona	43,562	46,757	11	15	34	38
Colorado	33,912	34,713	10	11	20	19
Idaho	2,293	1,766	4	4	5	4
Montana	16,348	15,614	12	11	17	16
Nevada	13,921	14,005	4	3	11	10
New Mexico	20,386	18,442	4	3	15	16
Utah	28,316	28,544	8	8	31	31
Wyoming	39,199	44,014	26	28	32	37
Pacific Contiguous	66,530	63,039	27	18	95	93
California	40,874	43,579	1	1	63	67
Oregon	11,029	8,800	7	6	15	12
Washington	14,628	10,661	19	11	16	14
Pacific Noncontiguous	10,807	10,587	21	18	37	35
Alaska	3,470	3,390	3	3	20	19
Hawaii	7,337	7,197	18	15	17	16
U.S. Total	1,724,396	1,874,346	1,267	1,571	1,342	1,485

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.

Displayed values of zero may represent small values that round to zero. The Excel version of this table provides additional precision which may be accessed by selecting individual cells.

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

Chapter 10

Demand-Side Management and Advanced Metering

Table 10.1. Demand-Side Management Program Annual Effects by Program Category, 2009 through 2012

	Energy Efficiency		Load Management			Total	
Year	Energy Savings (Thousand MWh)	Actual Peak Load Reduction (MW)	Energy Savings (Thousand MWh)	Potential Peak Load Reduction (MW)	Actual Peak Load Reduction (MW)	Energy Savings (Thousand MWh)	Actual Peak Load Reduction (MW)
2009	76,912	19,761	1,027	26,310	11,972	77,939	31,732
2010	86,914	20,828	447	26,100	12,536	87,361	33,364
2011	120,659	26,314	556	26,596	12,126	121,214	38,439
2012	138,525	28,924	712	28,503	13,200	139,237	42,124

2012 was the last year this data was collected.

Previously, annual effects were reported for large respondents only. Now the annual effects include large and small respondents, combined.

Non-Utility DSM Administrators are included in the 2011 data. See technical notes for list.

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 10.2. Demand-Side Management Program Annual Effects by Program

Category, by Sector, 2009 through 2012 (Table Discontinued)

Year	Residential	Commercial	Industrial	Transportation	Total
Energy Efficiency - Energy Savings (Thousand MWh)					
2009	27,395	34,831	14,610	76	76,912
2010	32,150	37,416	17,259	89	86,914
2011	46,790	50,732	23,061	76	120,659
2012	54,516	58,894	25,023	92	138,525
Energy Efficiency - Actual Peak Load Reduction (MW)					
2009	8,724	7,954	3,074	9	19,761
2010	9,404	8,046	3,368	10	20,828
2011	11,391	10,422	4,490	11	26,314
2012	12,821	11,743	4,348	12	28,924
Load Management - Energy Savings (Thousand MWh)					
2009	436	197	394	--	1,027
2010	215	113	118	--	447
2011	237	194	125	--	556
2012	257	368	87	--	712
Load Management - Potential Peak Load Reduction (MW)					
2009	7,308	6,460	12,462	81	26,310
2010	7,998	6,080	11,750	272	26,100
2011	7,882	6,023	12,380	311	26,596
2012	8,600	6,462	13,261	180	28,503
Load Management - Actual Peak Load Reduction (MW)					
2009	3,899	3,464	4,606	3	11,972
2010	4,726	2,854	4,819	137	12,536
2011	4,105	2,808	5,108	105	12,126
2012	4,152	3,208	5,732	108	13,200

2012 was the last year this data was collected.

Transportation data is not available before 2003.

Previously, annual data included only large respondents. Now it includes large and small respondents, combined.

Non-Utility DSM Administrators are included in the 2011 data. See technical notes for list.

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 10.3. Demand-Side Management Program Incremental Effects by Program Category, 2009 through 2012 (Table Discontinued)

	Energy Efficiency		Load Management			Total	
Year	Energy Savings (Thousand MWh)	Actual Peak Load Reduction (MW)	Energy Savings (Thousand MWh)	Potential Peak Load Reduction (MW)	Actual Peak Load Reduction (MW)	Energy Savings (Thousand MWh)	Actual Peak Load Reduction (MW)
2009	12,907	3,721	65	6,042	2,224	12,972	5,945
2010	13,592	3,215	46	5,234	2,709	13,639	5,923
2011	21,421	3,974	135	4,043	2,062	21,556	6,036
2012	21,478	3,764	41	5,357	2,671	21,520	6,435

2012 was the last year this data was collected.

Previously, large and small respondents were published separately, now they are combined.

Non-Utility DSM Administrators are included in the 2011 data. See technical notes for list.

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 10.4. Demand-Side Management Program Incremental Effects by Program

Category, by Sector, 2009 through 2012 (Table Discontinued)

Year	Residential	Commercial	Industrial	Transportation	Total
Energy Efficiency - Energy Savings (Thousand MWh)					
2009	5,030	4,959	2,918	1	12,907
2010	6,492	5,325	1,771	5	13,592
2011	9,989	8,166	3,261	6	21,421
2012	9,531	8,924	3,019	4	21,478
Energy Efficiency - Actual Peak Load Reduction (MW)					
2009	1,849	1,044	827	1	3,721
2010	1,378	1,053	783	1	3,215
2011	1,628	1,545	800	1	3,974
2012	1,775	1,562	426	1	3,764
Load Management - Energy Savings (Thousand MWh)					
2009	34	21	10	--	65
2010	13	21	12	--	46
2011	29	86	21	--	135
2012	20	14	7	--	41
Load Management - Potential Peak Load Reduction (MW)					
2009	1,922	1,971	2,127	22	6,042
2010	1,976	1,171	2,087	--	5,234
2011	1,324	1,327	1,392	--	4,043
2012	1,369	1,155	2,833	1	5,357
Load Management - Actual Peak Load Reduction (MW)					
2009	793	781	648	3	2,224
2010	666	948	1,095	--	2,709
2011	817	619	625	--	2,062
2012	686	737	1,248	*	2,671

2012 was the last year this data was collected.

Transportation data is not available before 2003.

Previously, large and small respondents were published separately, now they are combined.

Non-Utility DSM Administrators are included in the 2011 data. See technical notes for list.

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 10.5. Demand-Side Management Program Direct and Indirect Costs,

2009 through 2012 (Thousand Dollars) (Table Discontinued)

Year	Energy Efficiency	Load Management	Direct Cost	Indirect Cost	Total Cost
2009	2,221,480	944,261	3,165,741	394,193	3,607,076
2010	2,906,906	1,048,356	3,955,262	275,158	4,230,420
2011	4,002,672	1,213,102	5,215,774	328,622	5,544,396
2012	4,397,635	1,270,391	5,668,026	332,440	6,000,466

2012 was the last year this data was collected.

Direct Costs reflect electric utility costs incurred during the year that are identified with Energy Efficiency and Load Management. Total Costs are the sum of Direct and Indirect Costs.

Previously, this table included only large respondents. Now it includes large and small respondents, combined.

For the total cost data, prior to 2010, both large and small respondents reported total costs, however small respondents did not break out the costs into direct and indirect. The direct and indirect costs were reported for large respondents only.

Therefore, prior to 2010 the total cost does not equal the sum of the direct and indirect costs.

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

Non-Utility DSM Administrators are included in the 2011 data. See technical notes for list.

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

**Table 10.6. Energy Efficiency
Category, by Sector, 2013 through 2019**

Year	Residential	Commercial	Industrial	Transportation	Total
Incremental Annual Savings - Energy Savings (MWh)					
2013	11,020,468	10,461,718	3,141,044	29,894	24,653,124
2014	11,443,087	11,928,798	3,074,819	19,316	26,466,020
2015	11,012,627	12,285,000	2,818,448	13,414	26,129,489
2016	11,712,873	13,348,029	2,425,175	14,147	27,500,224
2017	13,199,995	14,095,101	2,592,155	11,776	29,899,028
2018	12,459,323	13,350,203	2,565,238	40,273	28,415,037
2019	13,283,024	12,706,234	2,538,169	35,103	28,562,529
Incremental Annual Savings - Peak Demand Savings (MW)					
2013	3,642	5,974	1,458	5	11,078
2014	3,000	2,889	563	2	6,453
2015	2,654	2,891	407	--	5,952
2016	2,698	2,556	401	3	5,658
2017	2,790	2,739	540	1	6,071
2018	2,775	3,072	459	4	6,309
2019	3,402	3,116	614	4	7,135
Incremental Costs - Customer Incentive (thousand dollars)					
2013	1,251,703	1,274,284	345,662	5	2,871,654
2014	1,522,205	1,561,358	327,227	64	3,410,854
2015	1,488,651	1,616,843	342,773	20	3,448,286
2016	1,541,458	1,733,170	296,321	--	3,570,950
2017	1,657,086	1,713,295	294,026	--	3,664,407
2018	1,602,723	1,608,369	273,676	--	3,484,767
2019	1,712,243	1,659,591	285,643	--	3,657,477
Incremental Costs - All Other Costs (thousand dollars)					
2013	1,015,135	749,710	179,719	33	1,944,597
2014	1,088,914	911,967	208,095	122	2,209,098
2015	1,152,224	938,021	193,015	40	2,283,300
2016	1,387,122	959,160	176,560	12	2,522,854
2017	1,221,072	900,291	176,585	10	2,297,957
2018	1,127,692	874,427	163,783	78	2,165,981
2019	1,209,389	910,039	168,567	33	2,288,028

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

Table 10.7. Energy Efficiency - Life Cycle Category, by Sector, 2013 through 2019

Year	Residential	Commercial	Industrial	Transportation	Total
Life Cycle Savings - Energy Savings (MWh)					
2013	83,729,903	127,269,038	38,493,282	448,421	249,940,645
2014	105,870,642	156,171,166	39,626,390	287,925	301,956,123
2015	99,512,487	160,045,443	36,589,144	199,328	296,346,403
2016	134,003,597	186,654,713	33,477,182	212,200	354,347,692
2017	137,297,599	204,102,657	33,249,999	176,636	374,826,892
2018	129,572,460	195,288,558	33,981,062	604,095	359,446,175
2019	134,474,216	186,931,400	33,284,347	526,549	355,216,512
Life Cycle Savings - Peak Demand Savings (MW)					
2013	3,782	5,876	1,293	6	10,956
2014	4,058	3,308	672	2	8,040
2015	3,492	3,104	500		7,096
2016	3,408	3,132	507	3	7,050
2017	2,668	2,698	584	1	5,951
2018	2,649	2,987	436	4	6,075
2019	3,322	2,993	613	4	6,931
Life Cycle Costs - Customer Incentive (thousand dollars)					
2013	2,698,135	2,875,483	455,343	5	6,028,810
2014	1,748,893	1,912,277	346,218	64	4,007,452
2015	1,844,246	1,997,677	413,416	30	4,255,368
2016	1,704,458	2,079,373	342,927		4,126,758
2017	2,194,049	2,359,255	296,498		4,849,803
2018	1,808,354	2,093,170	276,381		4,177,905
2019	1,911,197	2,000,492	440,237		4,351,926
Life Cycle Costs - All Other Costs (thousand dollars)					
2013	2,134,225	1,626,069	234,577	33	3,994,889
2014	1,555,433	1,348,672	216,673	122	3,120,898
2015	2,086,543	1,407,658	216,226	40	3,710,453
2016	1,964,832	1,265,765	202,112	12	3,432,717
2017	1,649,863	1,335,176	177,945	10	3,162,995
2018	2,605,135	1,409,483	164,623	78	4,179,320
2019	1,884,678	1,527,461	243,435	33	3,655,607

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

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

**Table 10.8. Demand Response - Yearly Energy and Demand Savings
Category, by Sector, 2013 through 2019**

Year	Residential	Commercial	Industrial	Transportation	Total
Number of Customers Enrolled					
2013	8,419,233	611,826	155,893	398	9,187,350
2014	8,603,402	605,094	57,129	4	9,265,629
2015	8,140,688	890,284	63,163	3	9,094,138
2016	8,739,535	1,033,649	66,170	1	9,839,355
2017	8,287,913	1,084,392	68,630	3	9,440,938
2018	8,700,669	986,816	64,753	--	9,752,238
2019	10,447,335	432,669	52,841	--	10,932,845
Energy Savings (MWh)					
2013	799,743	486,348	115,895	1	1,401,987
2014	881,563	462,337	92,549	--	1,436,449
2015	855,017	273,089	122,900	--	1,251,006
2016	1,005,144	225,174	105,818	--	1,336,136
2017	948,037	244,603	118,230	--	1,310,862
2018	1,099,179	221,502	105,536	--	1,426,211
2019	1,075,567	306,832	80,336	--	1,462,735
Potential Peak Demand Savings (MW)					
2013	7,003	5,124	14,800	168	27,095
2014	8,118	6,215	16,505	353	31,191
2015	8,703	6,989	17,169	14	32,875
2016	10,518	11,053	14,339	14	35,924
2017	8,996	6,995	15,512	5	31,508
2018	8,539	7,021	15,335	--	30,895
2019	8,867	6,907	15,246	--	31,020
Actual Peak Demand Savings (MW)					
2013	3,381	2,548	5,805	149	11,883
2014	3,147	2,652	6,883	1	12,683
2015	3,430	3,047	6,546	13	13,036
2016	3,608	3,598	4,632	4	11,841
2017	3,960	2,743	5,546	--	12,248
2018	3,788	2,694	6,040	--	12,522
2019	3,426	2,403	5,505	--	11,334

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

**Table 10.9. Demand Response - Program Costs
Category, by Sector, 2013 through 2019**

Year	Residential	Commercial	Industrial	Transportation	Total
Customer Incentives (thousand dollars)					
2013	398,598	286,057	421,208	6,919	1,112,782
2014	345,894	345,435	514,751	11,716	1,217,796
2015	320,683	338,153	461,271	339	1,120,446
2016	306,635	448,332	284,584	339	1,039,890
2017	292,443	345,226	365,451	--	1,003,124
2018	310,892	347,235	531,157	--	1,189,284
2019	306,152	322,611	490,119	--	1,118,882
All Other Costs (thousand dollars)					
2013	338,353	95,748	50,982	50	485,133
2014	301,389	101,127	45,028	115	447,659
2015	256,519	78,758	46,613	28	381,918
2016	253,180	66,084	60,443	--	379,707
2017	245,231	68,251	57,221	--	370,700
2018	235,159	66,024	59,534	--	360,718
2019	223,129	49,407	70,677	--	343,214

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

Table 10.10. Advanced Metering Count by Technology Type, 2010 through 2019

Year	Residential	Commercial	Industrial	Transportation	Total
Automated Meter Reading (AMR)					
2010	43,913,225	4,611,877	159,315	626	48,685,043
2011	41,451,888	4,341,105	172,692	77	45,965,762
2012	43,455,437	4,691,018	185,862	125	48,330,822
2013	42,491,242	4,632,744	196,132	1,202	47,321,320
2014	41,830,781	4,781,167	216,459	1,252	46,829,659
2015	42,326,302	5,049,978	226,908	1,023	47,604,211
2016	41,508,261	5,074,877	223,584	971	46,807,693
2017	39,325,014	4,813,029	230,099	707	44,368,849
2018	36,365,339	4,591,398	213,108	712	41,170,557
2019	32,750,506	4,160,628	207,286	861	37,119,281
Advanced Metering Infrastructure (AMI)					
2010	18,369,908	1,904,983	59,567	67	20,334,525
2011	33,453,548	3,682,159	154,659	7	37,290,373
2012	38,524,639	4,461,350	179,159	35	43,165,183
2013	47,321,995	5,770,067	248,515	845	53,341,422
2014	51,710,725	6,563,614	270,683	916	58,545,938
2015	57,107,785	7,324,345	310,889	813	64,743,832
2016	62,360,132	8,119,223	342,766	1,345	70,823,466
2017	69,474,626	9,060,128	365,447	1,389	78,901,590
2018	76,498,388	9,932,993	411,287	1,489	86,844,157
2019	83,539,594	10,850,886	446,871	1,504	94,838,855
Standard (non-AMR/AMI) Meters					
2010	--	--	--	--	--
2011	--	--	--	--	--
2012	--	--	--	--	--
2013	32,059,522	5,104,322	244,114	132	37,408,090
2014	32,995,176	5,642,247	254,621	1,331	38,893,375
2015	32,430,105	5,744,831	290,354	432	38,465,722
2016	28,491,094	4,929,344	280,406	416	33,701,260
2017	24,351,523	4,261,918	225,949	445	28,839,835
2018	21,982,727	3,884,695	186,001	414	26,053,837
2019	20,778,995	3,734,399	175,344	478	24,689,216
Total Number of Meters					
2010	--	--	--	--	--
2011	--	--	--	--	--
2012	--	--	--	--	--
2013	121,872,759	15,507,133	688,761	2,179	138,070,832
2014	126,536,682	16,987,028	741,763	3,499	144,268,972
2015	131,864,192	18,119,154	828,151	2,268	150,813,765
2016	132,359,487	18,123,444	846,756	2,732	151,332,419
2017	133,151,163	18,135,075	821,495	2,541	152,110,274
2018	134,846,454	18,409,086	810,396	2,615	154,068,551
2019	137,069,095	18,745,913	829,501	2,843	156,647,352

Prior to 2010, the count was the number of customers, not number of meters.

Starting in 2013 Standard (Non-AMR/AMI) meter data was collected on the EIA-861.

This data is not collected on the EIA-861S.

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

Chapter 11

U.S. Territories

**Table 11.1 Puerto Rico- Number of Ultimate Customers Served:
by Sector, 2009 through 2019**

Period	Residential	Commercial	Industrial	Transportation	All Sectors
Annual Totals					
2009	1,330,507	132,620	828	--	1,463,955
2010	1,339,703	133,029	790	--	1,473,522
2011	1,341,708	132,738	750	--	1,475,196
2012	1,349,750	131,264	721	--	1,481,735
2013	1,340,989	131,034	694	--	1,472,717
2014	1,328,546	129,122	662	--	1,458,330
2015	1,326,631	127,365	647	--	1,454,643
2016	1,332,152	127,179	633	--	1,459,964
2017	1,337,756	127,065	618	--	1,465,439
2018	1,346,102	126,527	602	--	1,473,231
2019	1,341,424	124,912	588	--	1,466,924
Year 2017					
January	1,336,481	127,251	627	--	1,464,359
February	1,337,101	127,229	626	--	1,464,956
March	1,335,413	127,147	620	--	1,463,180
April	1,337,164	127,086	620	--	1,464,870
May	1,337,956	127,048	618	--	1,465,622
June	1,339,373	127,119	616	--	1,467,108
July	1,338,891	127,049	614	--	1,466,554
August	1,337,758	127,026	615	--	1,465,399
September	1,338,973	127,056	615	--	1,466,644
October	1,337,261	126,948	615	--	1,464,824
November	1,338,117	126,941	613	--	1,465,671
December	1,338,583	126,877	612	--	1,466,072
Year 2018					
January	1,343,369	126,955	605	--	1,470,929
February	1,342,510	126,695	606	--	1,469,811
March	1,343,914	126,640	607	--	1,471,161
April	1,344,684	126,489	606	--	1,471,779
May	1,344,960	126,396	604	--	1,471,960
June	1,344,798	126,278	604	--	1,471,680
July	1,345,450	126,221	601	--	1,472,272
August	1,346,380	126,283	598	--	1,473,261
September	1,347,298	126,375	599	--	1,474,272
October	1,348,855	126,492	597	--	1,475,944
November	1,349,924	126,702	595	--	1,477,221
December	1,351,082	126,800	596	--	1,478,478
Year 2019					
January	1,343,649	125,945	594	--	1,470,188
February	1,344,627	125,872	593	--	1,471,092
March	1,345,398	125,610	595	--	1,471,603
April	1,344,357	125,225	590	--	1,470,172
May	1,343,442	125,067	589	--	1,469,098
June	1,341,453	124,798	588	--	1,466,839
July	1,341,100	124,692	588	--	1,466,380
August	1,339,811	124,550	587	--	1,464,948
September	1,338,804	124,409	584	--	1,463,797
October	1,338,280	124,254	583	--	1,463,117
November	1,338,174	124,157	582	--	1,462,913
December	1,337,987	124,366	581	--	1,462,934

Sources: U.S. Energy Information Administration, Form EIA-861M (formerly EIA-826), Monthly Electric Industry Power Report.
Form EIA-826, Monthly Electric Sales and Revenue Report with State Distributions Report;
Form EIA-861, Annual Electric Power Industry Report

**Table 11.2 Puerto Rico- Sales of Electricity to Ultimate Customers:
by Sector, 2009 through 2019 (Megawatthours)**

Period	Residential	Commercial	Industrial	Transportation	All Sectors
Annual Totals					
2009	6,673,185	8,936,576	3,094,188	--	18,703,949
2010	6,975,149	9,041,424	2,967,817	--	18,984,390
2011	6,586,877	8,832,355	2,832,127	--	18,251,359
2012	6,770,865	8,879,105	2,500,360	--	18,150,330
2013	6,319,746	8,968,572	2,504,182	--	17,792,500
2014	6,218,352	8,761,182	2,376,022	--	17,355,556
2015	6,313,615	8,586,457	2,355,385	--	17,255,457
2016	6,524,304	8,568,874	2,251,095	--	17,344,273
2017	5,045,346	6,819,591	1,746,554	--	13,611,491
2018	6,102,980	8,202,893	2,128,354	--	16,434,227
2019	6,205,152	7,905,084	2,048,192	--	16,158,428
Year 2017					
January	507,862	649,624	159,232	--	1,316,718
February	395,440	575,493	153,949	--	1,124,883
March	490,439	697,879	191,188	--	1,379,507
April	494,072	628,330	184,098	--	1,306,500
May	525,030	675,349	181,797	--	1,382,176
June	595,232	692,079	184,358	--	1,471,669
July	590,447	709,863	200,197	--	1,500,507
August	631,851	718,603	186,937	--	1,537,392
September	519,910	372,458	127,184	--	1,019,551
October	16,339	224,180	11,110	--	251,630
November	41,829	569,484	28,062	--	639,375
December	236,894	306,249	138,441	--	681,584
Year 2018					
January	389,090	558,621	141,787	--	1,089,498
February	393,230	760,068	174,720	--	1,328,018
March	450,083	531,455	98,406	--	1,079,945
April	466,218	784,445	273,377	--	1,524,040
May	565,759	801,950	165,300	--	1,533,009
June	507,497	591,959	208,432	--	1,307,888
July	577,748	680,752	145,339	--	1,403,840
August	577,416	688,524	209,353	--	1,475,293
September	527,390	722,248	186,217	--	1,435,855
October	697,731	847,420	191,078	--	1,736,230
November	456,854	593,194	172,051	--	1,222,099
December	493,964	642,258	162,293	--	1,298,515
Year 2019					
January	446,630	572,906	154,093	--	1,173,629
February	367,258	487,108	145,670	--	1,000,036
March	448,373	650,652	179,999	--	1,279,023
April	465,255	681,472	164,587	--	1,311,314
May	512,020	655,330	188,520	--	1,355,870
June	567,550	692,815	170,676	--	1,431,041
July	618,052	687,926	181,218	--	1,487,197
August	594,230	718,690	175,077	--	1,487,997
September	585,897	712,800	165,757	--	1,464,454
October	587,379	712,597	195,722	--	1,495,698
November	503,846	677,555	161,844	--	1,343,245
December	508,662	655,234	165,029	--	1,328,925

Sources: U.S. Energy Information Administration, Form EIA-861M (formerly EIA-826), Monthly Electric Industry Power Report.
Form EIA-826, Monthly Electric Sales and Revenue Report with State Distributions Report;
Form EIA-861, Annual Electric Power Industry Report

**Table 11.3 Puerto Rico- Revenue from Sales of Electricity to Ultimate Customers:
by Sector, 2009 through 2019 (Thousand Dollars)**

Period	Residential	Commercial	Industrial	Transportation	All Sectors
Annual Totals					
2009	1,313,102	1,868,381	517,578	--	3,699,061
2010	1,520,584	2,102,942	564,218	--	4,187,744
2011	1,748,433	2,483,175	662,537	--	4,894,145
2012	1,689,700	2,604,712	647,414	--	4,941,826
2013	1,633,328	2,474,088	570,210	--	4,677,626
2014	1,636,166	2,394,155	550,673	--	4,580,994
2015	1,282,008	1,850,101	417,158	--	3,549,267
2016	1,169,715	1,677,209	356,310	--	3,203,233
2017	1,123,005	1,549,337	344,034	--	3,016,376
2018	1,265,179	1,893,330	405,173	--	3,563,682
2019	1,329,706	1,810,611	420,178	--	3,560,495
Year 2017					
January	112,261	142,225	29,890	--	284,375
February	99,221	142,975	31,523	--	273,719
March	105,243	151,375	33,960	--	290,577
April	109,465	143,850	33,925	--	287,239
May	118,971	157,160	34,597	--	310,728
June	129,095	151,630	33,508	--	314,233
July	129,968	160,590	36,898	--	327,456
August	142,908	166,467	35,351	--	344,726
September	100,645	74,126	20,797	--	195,568
October	6,083	45,705	4,476	--	56,264
November	19,236	115,412	14,884	--	149,531
December	49,911	97,824	34,226	--	181,961
Year 2018					
January	86,018	159,397	31,640	--	277,056
February	75,989	170,895	32,231	--	279,115
March	109,809	148,653	22,060	--	280,522
April	84,357	161,256	54,292	--	299,904
May	103,994	165,295	22,768	--	292,057
June	107,787	132,963	40,090	--	280,839
July	122,329	165,585	28,750	--	316,664
August	114,400	148,958	38,757	--	302,114
September	109,452	162,472	33,858	--	305,781
October	136,653	181,005	35,721	--	353,379
November	101,917	142,385	33,635	--	277,937
December	112,475	154,467	31,372	--	298,314
Year 2019					
January	85,157	133,940	30,481	--	249,578
February	80,236	108,862	29,331	--	218,430
March	97,926	156,348	36,593	--	290,868
April	106,476	176,783	36,066	--	319,326
May	126,532	132,306	40,714	--	299,553
June	115,587	156,609	36,290	--	308,486
July	121,856	140,238	32,435	--	294,529
August	132,042	174,002	37,054	--	343,098
September	113,409	149,848	31,382	--	294,638
October	126,261	162,497	39,071	--	327,830
November	106,555	154,101	33,426	--	294,082
December	117,668	165,076	37,334	--	320,077

Sources: U.S. Energy Information Administration, Form EIA-861M (formerly EIA-826), Monthly Electric Industry Power Report.
Form EIA-826, Monthly Electric Sales and Revenue Report with State Distributions Report;
Form EIA-861, Annual Electric Power Industry Report

**Table 11.4 Puerto Rico- Average Price of Electricity to Ultimate Customers:
by Sector, 2009 through 2019 (Cents per Kilowatthour)**

Period	Residential	Commercial	Industrial	Transportation	All Sectors
Annual Totals					
2009	19.68	20.91	16.73	--	19.78
2010	21.80	23.26	19.01	--	22.06
2011	26.54	28.11	23.39	--	26.82
2012	24.96	29.34	25.89	--	27.23
2013	25.84	27.59	22.77	--	26.29
2014	26.31	27.33	23.18	--	26.39
2015	20.31	21.55	17.71	--	20.57
2016	17.93	19.57	15.83	--	18.47
2017	22.26	22.72	19.70	--	22.16
2018	20.73	23.08	19.04	--	21.68
2019	21.43	22.90	20.51	--	22.03
Year 2017					
January	22.10	21.89	18.77	--	21.60
February	25.09	24.84	20.48	--	24.33
March	21.46	21.69	17.76	--	21.06
April	22.16	22.89	18.43	--	21.99
May	22.66	23.27	19.03	--	22.48
June	21.69	21.91	18.18	--	21.35
July	22.01	22.62	18.43	--	21.82
August	22.62	23.17	18.91	--	22.42
September	19.36	19.90	16.35	--	19.18
October	37.23	20.39	40.29	--	22.36
November	45.99	20.27	53.04	--	23.39
December	21.07	31.94	24.72	--	26.70
Year 2018					
January	22.11	28.53	22.32	--	25.43
February	19.32	22.48	18.45	--	21.02
March	24.40	27.97	22.42	--	25.98
April	18.09	20.56	19.86	--	19.68
May	18.38	20.61	13.77	--	19.05
June	21.24	22.46	19.23	--	21.47
July	21.17	24.32	19.78	--	22.56
August	19.81	21.63	18.51	--	20.48
September	20.75	22.50	18.18	--	21.30
October	19.59	21.36	18.69	--	20.35
November	22.31	24.00	19.55	--	22.74
December	22.77	24.05	19.33	--	22.97
Year 2019					
January	19.07	23.38	19.78	--	21.27
February	21.85	22.35	20.14	--	21.84
March	21.84	24.03	20.33	--	22.74
April	22.89	25.94	21.91	--	24.35
May	24.71	20.19	21.60	--	22.09
June	20.37	22.60	21.26	--	21.56
July	19.72	20.39	17.90	--	19.80
August	22.22	24.21	21.16	--	23.06
September	19.36	21.02	18.93	--	20.12
October	21.50	22.80	19.96	--	21.92
November	21.15	22.74	20.65	--	21.89
December	23.13	25.19	22.62	--	24.09

Sources: U.S. Energy Information Administration, Form EIA-861M (formerly EIA-826), Monthly Electric Industry Power Report.
Form EIA-826, Monthly Electric Sales and Revenue Report with State Distributions Report;
Form EIA-861, Annual Electric Power Industry Report

**Table 11.5. American Samoa
By Sector, 2009 through 2019**

Year	Residential	Commercial	Industrial	Transportation	Total
Number of Ultimate Customers					
2009	10,453	1,418	9	--	11,880
2010	10,475	1,404	5	--	11,884
2011	10,616	1,447	4	--	12,067
2012	10,736	1,437	4	--	12,177
2013	10,945	1,411	4	--	12,360
2014	11,561	1,386	4	--	12,951
2015	11,023	1,356	4	--	12,383
2016	10,916	1,363	6	--	12,285
2017	10,930	1,386	4	--	12,320
2018	10,866	1,395	4	--	12,265
2019	10,762	1,450	4	--	12,216
Sales of Electricity to Ultimate Customers (megawatthours)					
2009	43,398	77,754	36,613	--	157,765
2010	45,269	76,014	20,587	--	141,870
2011	41,144	72,785	22,352	--	136,281
2012	39,935	71,952	22,539	--	134,426
2013	40,719	71,069	23,724	--	135,512
2014	41,029	70,598	23,142	--	134,769
2015	43,306	72,007	25,974	--	141,287
2016	46,493	69,617	32,232	--	148,342
2017	49,538	71,173	26,699	--	147,410
2018	45,621	72,185	24,546	--	142,352
2019	47,127	75,151	25,415	--	147,693
Revenue from Sales of Electricity to Ultimate Customers (thousand dollars)					
2009	13,185	23,273	9,786	--	46,244
2010	14,336	23,651	5,751	--	43,737
2011	16,459	26,981	7,457	--	50,898
2012	17,343	29,092	8,233	--	54,668
2013	15,809	27,905	8,339	--	52,053
2014	17,286	27,553	8,076	--	52,915
2015	15,035	22,981	7,695	--	45,710
2016	13,184	18,402	7,962	--	39,548
2017	15,020	20,626	7,294	--	42,940
2018	15,434	23,557	7,668	--	46,659
2019	16,617	25,328	8,211	--	50,155
Average Price of Electricity to Ultimate Customers (cents per kilowatthour)					
2009	30.38	29.93	26.73	--	29.31
2010	31.67	31.11	27.93	--	30.83
2011	40.00	37.07	33.36	--	37.35
2012	43.43	40.43	36.53	--	40.67
2013	38.82	39.26	35.15	--	38.41
2014	42.13	39.03	34.90	--	39.26
2015	34.72	31.91	29.63	--	32.35
2016	28.36	26.43	24.70	--	26.66
2017	30.32	28.98	27.32	--	29.13
2018	33.83	32.63	31.24	--	32.78
2019	35.26	33.70	32.31	--	33.96

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

Table 11.6. Guam
By Sector, 2009 through 2019

Year	Residential	Commercial	Industrial	Transportation	Total
Number of Ultimate Customers					
2009	39,863	6,625	--	--	46,488
2010	40,633	6,700	--	--	47,333
2011	41,255	6,717	--	--	47,972
2012	41,612	6,908	--	--	48,520
2013	41,708	6,890	--	--	48,598
2014	41,999	6,925	--	--	48,924
2015	42,752	6,940	--	--	49,692
2016	43,943	6,956	--	--	50,899
2017	43,756	7,087	--	--	50,843
2018	44,006	7,366	--	--	51,372
2019	44,226	7,517	--	--	51,743
Sales of Electricity to Ultimate Customers (megawatthours)					
2009	471,385	1,152,841	--	--	1,624,226
2010	486,962	1,150,700	--	--	1,637,662
2011	487,230	1,130,580	--	--	1,617,810
2012	459,499	1,103,976	--	--	1,563,475
2013	462,163	1,104,247	--	--	1,566,410
2014	457,835	1,075,511	--	--	1,533,346
2015	463,990	1,078,018	--	--	1,542,008
2016	494,842	1,087,317	--	--	1,582,159
2017	516,682	1,103,757	--	--	1,620,439
2018	510,725	1,071,705	--	--	1,582,430
2019	514,829	1,071,513	--	--	1,586,342
Revenue from Sales of Electricity to Ultimate Customers (thousand dollars)					
2009	103,972	284,032	--	--	388,004
2010	101,892	262,998	--	--	364,890
2011	112,320	279,555	--	--	391,875
2012	122,259	315,853	--	--	438,112
2013	122,463	315,369	--	--	437,832
2014	125,028	309,439	--	--	434,467
2015	106,057	260,652	--	--	366,709
2016	93,568	214,840	--	--	308,408
2017	103,327	230,472	--	--	333,799
2018	121,331	260,506	--	--	381,837
2019	128,641	275,267	--	--	403,908
Average Price of Electricity to Ultimate Customers (cents per kilowatthour)					
2009	22.06	24.64	--	--	23.89
2010	20.92	22.86	--	--	22.28
2011	23.05	24.73	--	--	24.22
2012	26.61	28.61	--	--	28.02
2013	26.50	28.56	--	--	27.95
2014	27.31	28.77	--	--	28.33
2015	22.86	24.18	--	--	23.78
2016	18.91	19.76	--	--	19.49
2017	20.00	20.88	--	--	20.60
2018	23.76	24.31	--	--	24.13
2019	24.99	25.69	--	--	25.46

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

**Table 11.7. Northern Mariana Islands
By Sector, 2011 through 2019**

Year	Residential	Commercial	Industrial	Transportation	Total
Number of Ultimate Customers					
2011	11,010	3,673	--	--	14,683
2012	10,657	3,615	--	--	14,272
2013	11,138	3,524	--	--	14,662
2014	11,045	3,651	--	--	14,696
2015	11,318	3,612	--	--	14,930
2016	11,869	3,952	--	--	15,821
2017	12,106	3,952	--	--	16,058
2018	12,323	4,243	--	--	16,566
2019	11,525	3,983	--	--	15,508
Sales of Electricity to Ultimate Customers (megawatthours)					
2011	65,962	160,389	--	--	226,351
2012	57,490	157,247	--	--	214,737
2013	54,056	154,505	--	--	208,561
2014	57,532	153,959	--	--	211,491
2015	52,928	145,170	--	--	198,098
2016	70,404	177,766	--	--	248,170
2017	80,502	193,399	--	--	273,901
2018	75,128	182,533	--	--	257,661
2019	76,795	180,421	--	--	257,216
Revenue from Sales of Electricity to Ultimate Customers (thousand dollars)					
2011	23,615	66,316	--	--	89,931
2012	20,209	66,437	--	--	86,646
2013	20,128	67,020	--	--	87,148
2014	20,714	66,034	--	--	86,749
2015	12,197	43,521	--	--	55,718
2016	12,657	42,870	--	--	55,527
2017	18,653	52,614	--	--	71,268
2018	20,530	58,788	--	--	79,318
2019	19,410	55,434	--	--	74,844
Average Price of Electricity to Ultimate Customers (cents per kilowatthour)					
2011	35.80	41.35	--	--	39.73
2012	35.15	42.25	--	--	40.35
2013	37.24	43.38	--	--	41.79
2014	36.01	42.89	--	--	41.02
2015	23.04	29.98	--	--	28.13
2016	17.98	24.12	--	--	22.37
2017	23.17	27.21	--	--	26.02
2018	27.33	32.21	--	--	30.78
2019	25.28	30.72	--	--	29.10

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

**Table 11.8. Virgin Islands
By Sector, 2009 through 2019**

Year	Residential	Commercial	Industrial	Transportation	Total
Number of Ultimate Customers					
2009	44,237	8,907	1,032	--	54,176
2010	44,711	8,320	1,038	--	54,069
2011	44,993	8,881	1,031	--	54,905
2012	44,780	8,826	1,023	--	54,629
2013	44,736	8,785	1,050	--	54,571
2014	45,066	8,808	1,043	--	54,917
2015	45,090	8,747	1,044	--	54,881
2016	49,559	9,951	1,089	--	60,599
2017	49,559	9,951	1,089	--	60,599
2018	46,721	7,491	2,238	--	56,450
2019	46,283	7,526	2,324	--	56,133
Sales of Electricity to Ultimate Customers (megawatthours)					
2009	248,227	127,325	348,725	--	724,277
2010	264,932	120,988	368,867	--	754,787
2011	266,721	151,424	337,652	--	755,797
2012	249,011	156,328	318,578	--	723,917
2013	231,148	123,234	326,158	--	680,540
2014	219,402	113,517	308,119	--	641,038
2015	211,753	109,530	299,598	--	620,881
2016	224,268	115,464	298,959	--	638,691
2017	174,208	85,273	201,822	--	461,303
2018	191,200	75,000	256,100	--	522,300
2019	217,003	87,000	257,313	--	561,316
Revenue from Sales of Electricity to Ultimate Customers (thousand dollars)					
2009	90,735	49,695	124,189	--	264,619
2010	112,891	42,486	132,097	--	287,474
2011	94,859	61,096	124,404	--	280,359
2012	109,441	57,856	150,636	--	317,932
2013	112,133	62,760	158,869	--	333,762
2014	108,204	58,361	153,232	--	319,797
2015	90,567	43,840	134,197	--	268,603
2016	76,907	45,969	101,434	--	224,310
2017	72,035	38,703	93,206	--	203,944
2018	66,093	36,220	83,192	--	185,505
2019	84,090	43,842	95,311	--	223,243
Average Price of Electricity to Ultimate Customers (cents per kilowatthour)					
2009	36.55	39.03	35.61	--	36.54
2010	42.61	35.12	35.81	--	38.09
2011	35.56	40.35	36.84	--	37.09
2012	43.95	37.01	47.28	--	43.92
2013	48.51	50.93	48.71	--	49.04
2014	49.32	51.41	49.73	--	49.89
2015	42.77	40.03	44.79	--	43.26
2016	34.29	39.81	33.93	--	35.12
2017	41.35	45.39	46.18	--	44.21
2018	34.57	48.29	32.48	--	35.52
2019	38.75	50.39	37.04	--	39.77

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

Appendix

Table A.1. Sulfur Dioxide Uncontrolled Emission Factors

Fuel, Code, Source and Emission Units				Combustion System Type / Firing Configuration						
Fuel	EIA Fuel Code	Source and Tables (As Appropriate)	Emissions Units Lbs = Pounds MMCF = Million Cubic Feet MG = Thousand Gallons	Cyclone Firing Boiler	Fluidized Bed Firing Boiler	Stoker Boiler	Tangential Firing Boiler	All Other Boiler Types	Combustion Turbine	Internal Combustion Engine
Distillate Fuel Oil*	DFO	Source: 2, Table 3.1-2a, 3.4-1 & 1.3-1	Lbs per MG	142.00	14.20	142.00	142.00	142.00	140.00	140.00
Jet Fuel*	JF	Assumed to have emissions similar to DFO.	Lbs per MG	142.00	14.20	142.00	142.00	142.00	140.00	140.00
Kerosene*	KER	Assumed to have emissions similar to DFO.	Lbs per MG	142.00	14.20	142.00	142.00	142.00	140.00	140.00
Other Biomass Liquids*	OBL	Source: 1 (including footnotes 3 and 16 within source)	Lbs per MG	142.00	14.20	142.00	142.00	142.00	140.00	140.00
Residual Fuel Oil*	RFO	Source: 2, Table 1.3-1; Combustion turbines and internal combustion engines assumed to have emissions similar to DFO.	Lbs per MG	157.00	15.70	157.00	157.00	157.00	140.00	140.00
Wood Waste Liquids*	WDL	Source: 1 (including footnotes 3 and 16 within source)	Lbs per MG	142.00	14.20	142.00	142.00	142.00	140.00	140.00
Waste Oil*	WO	Source: 2, Table 1.11-2; Combustion turbines and internal combustion engines assumed to have emissions similar to DFO.	Lbs per MG	147.00	14.70	147.00	147.00	147.00	140.00	140.00
Blast Furnace Gas	BFG	Sources: 1 (including footnote 7 within source); 2, Table 1.4-2 (including footnote d within source)	Lbs per MMCF	0.60	0.06	0.60	0.60	0.60	0.60	0.60
Landfill Gas	LFG	Sources: 1 (including footnote 7 within source); 2, Table 1.4-2 (including footnote d within source)	Lbs per MMCF	0.60	0.06	0.60	0.60	0.60	0.60	0.60
Natural Gas	NG	Sources: 1 (including footnote 7 within source); 2, Table 1.4-2 (including footnote d within source)	Lbs per MMCF	0.60	0.06	0.60	0.60	0.60	0.60	0.60
Other Biomass Gas	OBG	Sources: 1 (including footnote 7 within source); 2, Table 1.4-2 (including footnote d within source)	Lbs per MMCF	0.60	0.06	0.60	0.60	0.60	0.60	0.60
Other Gases	OG	Source: 1 (including footnote 7 within source)	Lbs per MMCF	0.60	0.06	0.60	0.60	0.60	0.60	0.60
Other	OTH	Assumed to have emissions similar to Natural Gas.	Lbs per MMCF	0.60	0.06	0.60	0.60	0.60	0.60	0.60
Propane Gas	PG	Sources: 1 (including footnote 7 within source); 2, Table 1.4-2 (including footnote d within source)	Lbs per MMCF	0.60	0.06	0.60	0.60	0.60	0.60	0.60
Coal-Derived Synthesis Gas	SGC	Assumed to have emissions similar to Natural Gas	Lbs per MMCF	0.60	0.06	0.60	0.60	0.60	0.60	0.60
Synthesis Gas from Petroleum Coke	SGP	Assumed to have emissions similar to Natural Gas	Lbs per MMCF	0.60	0.06	0.60	0.60	0.60	0.60	0.60
Agricultural Byproducts	AB	Source: 1	Lbs per ton	0.08	0.01	0.08	0.08	0.08	N/A	N/A
Bituminous Coal*	BIT	Source: 2, Table 1.1-3	Lbs per ton	38.00	3.80	38.00	38.00	38.00	N/A	N/A
Lignite Coal*	LIG	Source: 2, Table 1.7-1	Lbs per ton	30.00	3.00	30.00	30.00	30.00	N/A	N/A
Municipal Solid Waste	MSW	Source: 1	Lbs per ton	1.70	0.17	1.70	1.70	1.70	N/A	N/A
Other Biomass Solids	OBS	Source: 1 (including footnote 11 within source)	Lbs per ton	0.23	0.02	0.23	0.23	0.23	N/A	N/A
Petroleum Coke*	PC	Source: 1	Lbs per ton	39.00	3.90	39.00	39.00	39.00	N/A	N/A
Refined Coal*	RC	Assumed to have the emissions similar to Bituminous Coal.	Lbs per ton	38.00	3.80	38.00	38.00	38.00	N/A	N/A
Subbituminous Coal*	SUB	Source: 2, Table 1.1-3	Lbs per ton	35.00	3.50	35.00	35.00	35.00	N/A	N/A
Tire-Derived Fuel*	TDF	Source: 1 (including footnote 13 within source)	Lbs per ton	38.00	3.80	38.00	38.00	38.00	N/A	N/A
Waste Coal*	WC	Source: 1 (including footnote 20 within source)	Lbs per ton	30.00	3.00	30.00	30.00	30.00	N/A	N/A
Wood Waste Solids	WDS	Source: 1	Lbs per ton	0.29	0.08	0.08	0.29	0.29	N/A	N/A
Black Liquor	BLQ	Source: 1	Lbs per ton **	7.00	0.70	7.00	7.00	7.00	N/A	N/A
Sludge Waste	SLW	Source: 1 (including footnote 11 within source)	Lbs per ton **	2.80	0.28	2.80	2.80	2.80	N/A	N/A

Notes:

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

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

Sources:

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

Table A.2. Nitrogen Oxides Uncontrolled Emission Factors

Fuel, Code, Source and Emission Units				Combustion System Type / Firing Configuration								
							Tangential Boiler		All Other Boiler Types			
Fuel	EIA Fuel Code	Source and Tables (As Appropriate)	Emissions Units Lbs = Pounds MMCF = Million Cubic Feet MG = Thousand Gallons	Cyclone Firing Boiler	Fluidized Bed Firing Boiler	Stoker Boiler	Dry-Bottom Boilers	Wet-Bottom Boilers	Dry-Bottom Boilers	Wet-Bottom Boilers	Combustion Turbine	Internal Combustion Engine
Distillate Fuel Oil	DFO	Source: 2, Tables 1.3-1, 3.1-1, & 3.4-1	Lbs per MG	24.00	24.00	24.00	24.00	24.00	24.00	24.00	122.00	443.80
Jet Fuel	JF	Source: 2, Tables 1.3-1, 3.1-1, & 3.4-1	Lbs per MG	24.00	24.00	24.00	24.00	24.00	24.00	24.00	118.80	432.00
Kerosene	KER	Source: 2, Tables 1.3-1, 3.1-1, & 3.4-1	Lbs per MG	24.00	24.00	24.00	24.00	24.00	24.00	24.00	118.80	432.00
Other Biomass Liquids	OBL	Source: 1 (including footnote 3 within source); EIA estimates	Lbs per MG	19.00	19.00	19.00	19.00	19.00	19.00	19.00	112.30	408.30
Residual Fuel Oil	RFO	Source: 2, Table 1.3-1; EIA estimates	Lbs per MG	47.00	47.00	47.00	32.00	32.00	47.00	47.00	131.70	479.00
Wood Waste Liquids	WDL	Source: 1 (including footnote 16 within source); EIA estimates	Lbs per MG	5.43	5.43	5.43	5.43	5.43	5.43	5.43	230.50	838.10
Waste Oil	WO	Source: 2, Table 1.11-2; EIA estimates	Lbs per MG	19.00	19.00	19.00	19.00	19.00	19.00	19.00	92.20	335.20
Blast Furnace Gas	BFG	Sources: 1 (including footnote 7 within source); EIA estimates	Lbs per MMCF	15.40	15.40	15.40	15.40	15.40	15.40	15.40	30.40	256.55
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	72.44	144.00	1,215.22
Natural Gas	NG	Source: 2, Tables 1.4-1, 3.1-1, and 3.4-1	Lbs per MMCF	280.00	280.00	280.00	170.00	170.00	280.00	280.00	328.00	2,768.00
Other Biomass Gas	OBG	Sources: 1 (including footnote 7 within source); EIA estimates	Lbs per MMCF	112.83	112.83	112.83	112.83	112.83	112.83	112.83	313.60	2,646.48
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	152.82	263.82	2,226.41
Other	OTH	Assumed to have emissions similar to Natural Gas.	Lbs per MMCF	280.00	280.00	280.00	170.00	170.00	280.00	280.00	328.00	2,768.00
Propane Gas	PG	Sources: 3; EIA estimates	Lbs per MMCF	522.26	522.26	522.26	522.26	522.26	522.26	522.26	803.36	6,779.57
Synthesis Gas from Petroleum Coke	SGC	Assumed to have emissions similar to Natural Gas	Lbs per MMCF	280.00	280.00	280.00	170.00	170.00	280.00	280.00	328.00	2,768.00
Coal-Derived Synthesis Gas	SGP	Assumed to have emissions similar to Natural Gas	Lbs per MMCF	280.00	280.00	280.00	170.00	170.00	280.00	280.00	328.00	2,768.00
Agricultural Byproducts	AB	Source: 1	Lbs per ton	1.20	1.20	1.20	1.20	1.20	1.20	1.20	N/A	N/A
Bituminous Coal	BIT	Source: 2, Table 1.1-3	Lbs per ton	33.00	5.00	11.00	10.00	14.00	12.00	31.00	N/A	N/A
Lignite Coal	LIG	Source: 2, Table 1.7-1	Lbs per ton	15.00	3.60	5.80	7.10	7.10	6.30	6.30	N/A	N/A
Municipal Solid Waste	MSW	Source: 1	Lbs per ton	5.00	5.00	5.00	5.00	5.00	5.00	5.00	N/A	N/A
Other Biomass Solids	OBS	Source: 1 (including footnote 11 within source)	Lbs per ton	2.00	2.00	2.00	2.00	2.00	2.00	2.00	N/A	N/A
Petroleum Coke	PC	Source: 1 (including footnote 8 within source)	Lbs per ton	21.00	5.00	21.00	21.00	21.00	21.00	21.00	N/A	N/A
Refined Coal	RC	Assumed to have the emissions similar to Bituminous Coal.	Lbs per ton	33.00	5.00	11.00	10.00	14.00	12.00	31.00	N/A	N/A
Subbituminous Coal	SUB	Source: 2, Table 1.1-3	Lbs per ton	17.00	5.00	8.80	7.20	7.20	7.40	24.00	N/A	N/A
Tire-Derived Fuel	TDF	Source: 1 (including footnote 13 within source)	Lbs per ton	33.00	5.00	11.00	10.00	14.00	12.00	31.00	N/A	N/A
Waste Coal	WC	Source: 1 (including footnote 20 within source)	Lbs per ton	15.00	3.60	5.80	7.10	7.10	6.30	6.30	N/A	N/A
Wood Waste Solids	WDS	Source: 1	Lbs per ton	2.51	2.00	1.50	2.51	2.51	2.51	2.51	N/A	N/A
Black Liquor	BLQ	Source: 1	Lbs per ton **	1.50	1.50	1.50	1.50	1.50	1.50	1.50	N/A	N/A
Sludge Waste	SLW	Source: 1 (including footnote 11 within source)	Lbs per ton **	5.00	5.00	5.00	5.00	5.00	5.00	5.00	N/A	N/A

Notes:
** 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/>
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 A.3. Carbon Dioxide Uncontrolled Emission Factors

Fuel	EIA Fuel Code	Factor (Kilograms of CO2 Per Million Btu)**	Notes
Bituminous Coal	BIT	93.30	
Distillate Fuel Oil	DFO	73.16	
Geothermal	GEO	7.71	
Jet Fuel	JF	70.90	
Kerosene	KER	72.30	
Lignite Coal	LIG	97.70	
Municipal Solid Waste	MSW	41.69	
Natural Gas	NG	53.07	
Petroleum Coke	PC	102.10	
Propane Gas	PG	63.07	
Refined Coal	RC	93.30	Assumed to have emissions similar to Bituminous Coal.
Residual Fuel Oil	RFO	78.79	
Synthesis Gas Derived from Coal	SGC		* Factor is based on the fuel source used to produce the synthesis gas
Synthesis Gas Derived from Petroleum Coke	SGP		* Factor is based on the fuel source used to produce the synthesis gas
Subbituminous Coal	SUB	97.20	
Tire-Derived Fuel	TDF	85.97	
Waste Coal	WC	93.30	Assumed to have emissions similar to Bituminous Coal.
Waste Oil	WO	95.25	

Notes:

* Factors for synthesis gas derived from coal and synthesis gas derived from petroleum coke are based on the fuel source used to produce the synthesis gas.

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

Source: Energy Information Administration estimates:
http://www.eia.gov/environment/emissions/co2_vol_mass.cfm

Table A.4. Nitrogen Oxides Control Technology Emissions Reduction Factors

		Reduction Factor							
Nitrogen Oxides Control Technology	EIA Code	Coal	Residual Fuel Oil and Distallate Fuel Oil	Natural Gas	Wood	Other Solids	Other Liquids	Other Gases	Other Fuels
Burner Out of Service	BO	15.00%	15.00%	15.00%	15.00%	15.00%	15.00%	15.00%	15.00%
Low Excess Air	LA	15.00%	15.00%	15.00%	15.00%	15.00%	15.00%	15.00%	15.00%
Biased Firing (Alternative Burners)	BF	15.00%	15.00%	15.00%	15.00%	15.00%	15.00%	15.00%	15.00%
Overfire Air	OV	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%
Advanced Overfire Air	AA	30.00%	30.00%	30.00%	30.00%	30.00%	30.00%	30.00%	30.00%
Low NOx Burners	LN	45.00%	45.00%	50.00%	45.00%	45.00%	45.00%	50.00%	45.00%
Fuel Reburning	FU	55.00%	55.00%	55.00%	55.00%	55.00%	55.00%	55.00%	55.00%
Selective Noncatalytic Reduction	SN	45.00%	32.50%	32.50%	55.00%	45.00%	32.50%	32.50%	45.00%
Selective Catalytic Reduction	SR	80.00%	80.00%	85.00%	80.00%	80.00%	80.00%	85.00%	80.00%
Ammonia Injection	NH3	62.50%	56.25%	58.75%	67.50%	62.50%	56.25%	58.75%	62.50%
Flue Gas Recirculation	FR	45.00%	45.00%	45.00%	45.00%	45.00%	45.00%	45.00%	45.00%
Water Injection	H2O	15.00%	15.00%	15.00%	15.00%	15.00%	15.00%	15.00%	15.00%
Steam Injection	STM	15.00%	15.00%	15.00%	15.00%	15.00%	15.00%	15.00%	15.00%
Other	OT	15.00%	15.00%	15.00%	15.00%	15.00%	15.00%	15.00%	15.00%

		Source of Selected Reduction Factor							
Nitrogen Oxides Control Technology	EIA Code	Coal	Residual Fuel Oil and Distallate Fuel Oil	Natural Gas	Wood	Other Solids	Other Liquids	Other Gases	Other Fuels
Burner Out of Service	BO	Source: 1	Source: 2	Source: 9	Source: 9	Source: 9	Source: 10	Source: 11	Source: 9
Low Excess Air	LA	Source: 1	Source: 2	Source: 9	Source: 9	Source: 9	Source: 10	Source: 11	Source: 9
Biased Firing (Alternative Burners)	BF	Source: 1	Source: 2	Source: 9	Source: 9	Source: 9	Source: 10	Source: 11	Source: 9
Overfire Air	OV	Source: 1	Source: 9	Source: 9	Source: 9	Source: 9	Source: 10	Source: 11	Source: 9
Advanced Overfire Air	AA	Source: 1	Source: 9	Source: 9	Source: 9	Source: 9	Source: 10	Source: 11	Source: 9
Low NOx Burners	LN	Source: 1	Source: 2	Source: 3	Source: 9	Source: 9	Source: 10	Source: 11	Source: 9
Fuel Reburning	FU	Source: 1	Source: 9	Source: 9	Source: 9	Source: 9	Source: 10	Source: 11	Source: 9
Selective Noncatalytic Reduction	SN	Source: 1	Source: 2	Source: 4	Source: 5	Source: 9	Source: 10	Source: 11	Source: 9
Selective Catalytic Reduction	SR	Source: 1	Source: 2	Source: 4	Source: 9	Source: 9	Source: 10	Source: 11	Source: 9
Ammonia Injection	NH3	Source: 6	Source: 6	Source: 6	Source: 6	Source: 9	Source: 10	Source: 11	Source: 9
Flue Gas Recirculation	FR	Source: 10	Source: 2	Source: 10	Source: 10	Source: 9	Source: 10	Source: 11	Source: 9
Water Injection	H2O	Source: 8	Source: 8	Source: 8	Source: 8	Source: 9	Source: 10	Source: 11	Source: 9
Steam Injection	STM	Source: 8	Source: 8	Source: 8	Source: 8	Source: 9	Source: 10	Source: 11	Source: 9
Other	OT	Source: 7	Source: 7	Source: 7	Source: 7	Source: 9	Source: 10	Source: 11	Source: 9

Source: 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/>

- Source 1: AP-42, Table 1.1-2
Source 2: AP-42, Section 1.3.4.3 Text
Source 3: AP-42, Table 1.4-1
Source 4: AP-42, Section 1.4.4 Text
Source 5: AP-42, Section 1.6.4 Text
Source 6: Average of Selective Catalytic Reductiona and Selective Noncatalytic Reduction
Source 7: Minimum of other technologies for fuel group
Source 8: Matches Other selection
Source 9: Assumed to have reduction similar to coal
Source 10: Assumed to have reduction similar to Residual Fuel Oil and Distallate Fuel Oil
Source 11: Assumed to have reduction similar to natural gas

Notes:
Coal reduction factors are applied to Bituminous Coal, Subbituminous Coal, Lignite Coal, and Waste Coal.
Wood reduction factors are applied to Wood Waste Solids, Black Liquor, and Wood Waste Liquids.
Other Solids reduction factors are applied to Petroleum Coke, Mincipal Solid Waste, Tire-Derived Fuels, Sludge Waste, Agricultural Biproducts, and Other Biomass Solids.
Other Liquids reduction factors are applied to Jet Fuel, Kerosene, Waste Oil, and Other Biomass Liquids.
Other Gases reduction factors are applied to Blast Furnace Gas, Landfill Gas, Propane Gas, Coal-Derived Synthesis Gas, Synthesis Gas from Petroleum Coke, Other Biomass Gas, and Other Gas.

Table A.5. Unit of Measure Equivalents

Unit	Equivalent
Kilowatt (kW)	1,000 (One Thousand) Watts
Megawatt (MW)	1,000,000 (One Million) Watts
Gigawatt (GW)	1,000,000,000 (One Billion) Watts
Terawatt (TW)	1,000,000,000,000 (One Trillion) Watts
Gigawatt	1,000,000 (One Million) Kilowatts
Thousand Gigawatts	1,000,000,000 (One Billion) Kilowatts
Kilowatthours (kWh)	1,000 (One Thousand) Watthours
Megawatthours (MWh)	1,000,000 (One Million) Watthours
Gigawatthours (GWh)	1,000,000,000 (One Billion) Watthours
Terawatthours (TWh)	1,000,000,000,000 (One Trillion) Watthours
Gigawatthours	1,000,000 (One Million) Kilowatthours
Thousand Gigawatthours	1,000,000,000(One Billion Kilowatthours
U.S. Dollar	1,000 (One Thousand) Mills
U.S. Cent	10 (Ten) Mills
Barrel of Oil	42 Gallons

Source: U.S. Energy Information Administration

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 n th digit if the $(n+1)$ digit is 5 or larger and keep the n th 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 changes:

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

where $x(t_1)$ and $x(t_2)$ denote the quantity at 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-861M, "Monthly Electric Power Industry Report;"
- Form EIA-861S, "Annual Electric Power Industry Report (Short Form);"
- 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:

- 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-826, “Monthly Electric Utility Sales and Revenues with State Distributions 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.
- W Withheld to avoid disclosure of individual company data.
- 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 are 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 not 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 ReliabilityFirst 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),
- ReliabilityFirst Corporation (RFC),
- Southeastern Electric Reliability Council (SERC),

- Southwest Power Pool (SPP),
- Texas Regional Entity (TRE), and
- Western Energy 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 include 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-423² 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 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-861M (Formerly the EIA-826)

The Form EIA 861M, "Monthly Electric Power Industry Report," is a monthly collection of data from a sample of approximately 520 of the largest electric utilities (primarily investor and publicly owned) as well as a census of energy service providers with sales to ultimate consumers in deregulated States. Form EIA-861 (see below), with approximately 3,300 respondents, serves as a frame from which the Form 826 sample is drawn. Based on this sample, a model is used to estimate for the entire universe of U.S. electric utilities on a monthly basis.

Instrument and design history: The collection of electric power sales data and related information began in the early 1940's and was established as FPC Form 5 by FPC Order 141 in 1947. In 1980, the report was revised with only selected income items remaining and became the FERC Form 5. The Form

EIA 826, “Electric Utility Company Monthly Statement,” replaced the FERC Form 5 in January 1983. In January 1987, the “Electric Utility Company Monthly Statement” was changed to the “Monthly Electric Utility Sales and Revenue Report with State Distributions.” The title was changed again in January 2002 to “Monthly Electric Utility Sales and Revenues with State Distributions Report” to become consistent with other EIA report titles. The Form EIA 826 was revised in January 1990, and some data elements were eliminated.

In 1993, EIA for the first time used a model sample for the Form EIA 826. A stratified random sample, employing auxiliary data, was used for each of the four previous years. The sample for the Form EIA 826 was designed to obtain estimates of electricity sales and average retail price of electricity at the State level by end use sector.

Starting with data for January 2001, the restructuring of the electric power industry was taken into account by forming three schedules on the Form EIA-826. Schedule 1, Part A is for full service utilities that operate as in the past. Schedule 1, Part B is for electric service providers only, and Schedule 1, Part C is for those utilities providing distribution service for those on Schedule 1, Part B. In addition, Schedule 1 Part D is for those retail energy providers or power marketers that provide bundled service. Also, the Form EIA-826 frame was modified to include all investor-owned electric utilities and a sample of companies from other ownership classes. A new method of estimation was implemented at this same time. (See Electric Power Monthly, April 2001, p.1.)

With the October 2004 issue of the Electric Power Monthly (EPM), EIA published for the first time preliminary electricity sales data for the Transportation Sector. These data are for electricity delivered to and consumed by local, regional, and metropolitan transportation systems. The data being published for the first time in the October EPM included July 2004 data as well as year-to-date. EIA’s efforts to develop these new data have identified anomalies in several States and the District of Columbia. Some of these anomalies are caused by issues such as: 1) Some respondents have classified themselves as outside the realm of the survey. The Form EIA-826 collects retail data from those respondents providing electricity and other services to the ultimate end users. EIA has experienced specific situations where, although the respondents’ customers are the ultimate end users, particular end users qualify under wholesale rate schedules. 2) The Form EIA-826 is a cutoff sample and not intended to be a census.

Data processing and data system editing: Monthly Form EIA-861M submission is available via an Internet Data Collection (IDC) system. The completed data are due to EIA by the last calendar day of the month following the reporting month. Nonrespondents are contacted to obtain the data. The data are edited and additional checks are completed. Following verification, imputation is run, and tables and text of the aggregated data are produced for inclusion in the EPM.

Imputation: Regression prediction, or imputation, is done for entities not in the monthly sample and for any nonrespondents. Regressor data for Schedule 1, Part A is the average monthly sales or revenue from the most recent finalized data from survey Form EIA-861. Beginning with January 2008 data and the finalized 2007 data, the regressor data for Schedule 1 Parts B and C is the prior month’s data.

Formulas and methodologies: The Form EIA 861M data are collected by end-use sector (residential, commercial, industrial, and transportation) and State. Form EIA 861 (see below) data are used as the

frame from which the sample is selected and in some instances also as regressor data. Updates are made to the frame to reflect mergers that affect data processing.

With the revised definitions for the commercial and industrial sectors to include all data previously reported as 'other' data except transportation, and a separate transportation sector, all responses that would formerly have been reported under the "other" sector are now to be reported under one of the sectors that currently exist. This means there is probably a lower correlation, in general, between, say, commercial Form EIA-826 data for 2004 and commercial Form EIA-861 data for 2003 than there was between commercial Form EIA-826 data for 2003 and commercial Form EIA-861 data for 2002 or earlier years, although commercial and industrial definitions have always been somewhat nebulous due to power companies not having complete information on all customers.

Data submitted for January 2004 represent the first time respondents were to provide data specifically for the transportation end-use sector.

During 2003 transportation data were collected annually through Form EIA-861. Beginning in 2004 the transportation data were collected on a monthly basis via Form EIA-826. In order to develop an estimate of the monthly transportation data for 2003, values for both sales of electricity to ultimate customers and revenue from sales of electricity to ultimate customers were estimated using the 2004 monthly profile for the sales and revenues from the data collected via Form EIA-826. All monthly non-transportation data for 2003 (i.e. street lighting, etc.), which were previously reported in the "other" end-use sector on the Form EIA-826 have been prorated into the Commercial and Industrial end-use sectors based on the 2003 Form EIA-861 profile.

A monthly distribution factor was developed for the monthly data collected in 2004 (for the months of January through November). The transportation sales and revenues for December 2004 were assumed to be equivalent to the transportation sales and revenues for November 2004. The monthly distribution factors for January through November were applied to the annual values for transportation sales and revenues collected via Form EIA-861 to develop corresponding 2003 monthly values. The eleven month estimated totals from January through November 2003 were subtracted from the annual values obtained from Form EIA-861 in order to obtain the December 2003 values.

Data from the Form EIA-861M are used to determine estimates by sector at the State, Census division, and national level. State level sales and revenues estimates are first calculated. Then the ratio of revenue divided by sales is calculated to estimate retail price of electricity at the State level. The estimates are accumulated separately to produce the Census division and U.S. level estimates³.

Some electric utilities provide service in more than one State. To facilitate the estimation, the State service area is actually used as the sampling unit. For each State served by each utility, there is a utility State part, or "State service area." This approach allows for an explicit calculation of estimates for sales, revenue, and average retail price of electricity by end use sector at State, Census division, and national level. Estimation procedures include imputation to account for nonresponse. Non-sampling error must also be considered. The non-sampling error is not estimated directly, although attempts are made to minimize the non-sampling error.

Average retail price of electricity 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 utility. Operating revenue includes energy charges, demand charges, consumer service charges, environmental surcharges, fuel adjustments, and other miscellaneous charges. Electric utility operating revenues also include State and Federal income taxes and taxes other than income taxes paid by the utility.

The average retail price of electricity reported in this publication by sector represents a weighted average of consumer revenue and sales within sectors and across sectors for all consumers, and does not reflect the per kWh rate charged by the electric utility to the individual consumers. Electric utilities typically employ a number of rate schedules within a single sector. These alternative rate schedules reflect the varying consumption levels and patterns of consumers and their associated impact on the costs to the electric utility for providing electrical service.

Adjusting monthly data to annual data: As a final adjustment based on our most complete data, use is made of final Form EIA-861 data, when available. The annual totals for Form EIA-826 data by State and end-use sector are compared to the corresponding Form EIA-861 values for sales and revenue. The ratio of these two values in each case is then used to adjust each corresponding monthly value.

Sensitive data: Most of the data collected on the Form EIA-861M are not considered business sensitive. However, monthly revenue, sales, and customer data collected from energy service providers (Schedule 1, Part B), which do not also provide energy delivery, are considered business sensitive and must adhere to EIA's "Policy on the Disclosure of Individually Identifiable Energy Information in the Possession of the EIA" (45Federal Register 59812 (1980)).

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 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: No imputation was required for EIA-860 data.

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.

Prime Movers: The Form EIA-860 sometimes represents a generator's prime mover by using the abbreviations in the table below.

Prime Mover Code	Prime Mover Description
BA	Energy Storage, Battery
CE	Energy Storage, Compressed Air
CP	Energy Storage, Concentrated Solar Power
FW	Energy Storage, Flywheel
PS	Energy Storage, Reversible Hydraulic Turbine (Pumped Storage)
ES	Energy Storage, Other
ST	Steam Turbine, including nuclear, geothermal and solar steam (does not include combined cycle)
GT	Combustion (Gas) Turbine (including jet engine design)
IC	Internal Combustion Engine (diesel, piston, reciprocating)
CA	Combined Cycle Steam Part
CT	Combined Cycle Combustion Turbine Part
CS	Combined Cycle Single Shaft
CC	Combined Cycle Total Unit
HA	Hydrokinetic, Axial Flow Turbine
HB	Hydrokinetic, Wave Buoy
HK	Hydrokinetic, Other
HY	Hydroelectric Turbine (including turbines associated with delivery of water by pipeline)
BT	Turbines Used in a Binary Cycle (including those used for geothermal applications)
PV	Photovoltaic
WT	Wind Turbine, Onshore
WS	Wind Turbine, Offshore
FC	Fuel Cell
OT	Other

Energy Sources: The Form EIA-860 sometimes represents the energy sources associated with generators by using the abbreviations and/or groupings in the table below.

Energy Source Grouping	Energy Source	
	Code	Energy Source Description
Coal	ANT	Anthracite Coal
	BIT	Bituminous Coal
	LIG	Lignite Coal
	SUB	Subbituminous Coal
	SGC	Coal-Derived Synthesis Gas
	WC	Waste/Other Coal (including anthracite culm, bituminous gob, fine coal, lignite waste, waste coal)
Petroleum Products	DFO	Distillate Fuel Oil (including diesel, No. 1, No. 2, and No. 4 fuel oils)
	JF	Jet Fuel
	KER	Kerosene
	PC	Petroleum Coke
	PG	Gaseous Propane
	RFO	Residual Fuel Oil (including No. 5, and No. 6 fuel oils, and bunker C fuel oil)
	SG	Synthesis Gas from Petroleum Coke
	WO	Waste/Other Oil (including crude oil, liquid butane, liquid propane, naphtha, oil waste, re-refined motor oil, sludge oil, tar oil, or other petroleum-based liquid wastes)
Natural Gas and Other Gases	BFG	Blast Furnace Gas
	NG	Natural Gas
	OG	Other Gas
Nuclear	NUC	Nuclear (including Uranium, Plutonium, and Thorium)
Hydroelectric Conventional	WAT (Prime Mover = HY)	Water at a Conventional Hydroelectric Turbine, and water used in Wave Buoy Hydrokinetic Technology, Current Hydrokinetic Technology, and Tidal Hydrokinetic Technology
Hydroelectric Pumped Storage	WAT (Prime Mover = PS)	Pumping Energy for Reversible (Pumped Storage) Hydroelectric Turbine
Wood and Wood-Derived Fuels	WDS	Wood/Wood Waste Solids (including paper pellets, railroad ties, utility poles, wood chips, bark, and wood waste solids)
	WDL	Wood Waste Liquids (excluding Black Liquor but including red liquor, sludge wood, spent sulfite liquor, and other wood-based liquids)
	BLQ	Black Liquor
Other Biomass	AB	Agricultural By-Products
	MSW	Municipal Solid Waste
	OBG	Other Biomass Gas (including digester gas, methane, and other biomass gases)
	OBL	Other Biomass Liquids
	OBS	Other Biomass Solids
	LFG	Landfill Gas
	SLW	Sludge Waste
	SUN	Solar (including solar thermal)
Other Renewable Energy Sources	WND	Wind
Other Energy Sources	GEO	Geothermal
	PUR	Purchased Steam
	WH	Waste heat not directly attributed to a fuel source
	TDF	Tire-Derived Fuels
	MWH	Electricity used for energy storage
	OTH	Other

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. Prior to data year 2012, the survey was used to collect information on power sales and revenue data from approximately 3,300 respondents. About 3,100 are electric utilities, and the remainders are nontraditional entities such as energy service providers or the unregulated subsidiaries of electric utilities and power marketers.

For data year 2012 and forward, EIA modified the frame of the Form EIA-861, “Annual Electric Power Industry Report,” from a census to a sample, and EIA is using model-based methods to estimate the sales, revenues, and customer counts by sector and state for those respondents that have been removed from the frame. EIA created a new Form EIA-861S, “Annual Electric Power Industry Report (Short Form),” for the respondents that have been removed from the Form EIA-861 frame. Respondents removed from the EIA-861 frame and placed on the EIA-861S tend to be smaller utilities with annual sales volumes not exceeding 100,000 megawatthours (MWhs). Form EIA-861S with fewer data elements compared to the EIA-861, collects limited data on total sales, revenues, and customer counts by state. Every eighth data year, EIA-861S respondents are required to fill out the full EIA-861 form. For data year 2019, EIA-861S respondents were required to complete the full EIA-861 form.

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 and public street lighting. 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.

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 Electric Power Annual reports total sales volumes (megawatthours) of electricity to ultimate consumers 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 sales of electricity to ultimate consumers 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 average 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.

Net-Metering: This section was expanded in 2011. Previously, customer count by sector was the only data collected and published. In 2010, the EIA-861 started collecting the capacity of the net-metered installations by sector and technology. The technology types are: photovoltaic (PV), wind and other.

Starting with the 2016 data collection year, storage and virtual net metering were added to the PV section.

Demand-Side Management (DSM): Prior to 2011, DSM data was separated into two categories, large and small utilities. Some tables contained data for just large utilities and others contained both categories, published separately. Starting in 2011, there is no longer a division in the data. All tables now include all DSM data from utilities; this change is also reflected in the historical data.

Starting in 2011, a new category of respondents were added to the EIA-861, non-utility DSM administrators: Efficiency Maine Trust, Energy trust of Oregon, Focus on Energy, NYSERDA and Vermont Energy Investment Corporation.

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 the potential peak load reduction that may occur if all demand response is called and/or participates.

Advanced Metering: New in 2011, Automated Meter Reading (AMR) and Advanced Metering Infrastructure (AMI), including historical data back to 2007. From 2007-2009, the count by sector is for number of customers, for 2010-2011, the count is the actual number of meters. For example; if an industrial customer had 12 meters, in 2007-2009 the count would have been 1, in 2010-2011, the count would be 12.

In 2013, the number of standard meters (non AMR/AMI) was added to this schedule.

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, nonutility source and disposition of electricity, combustion by-product collection and disposal, and cooling systems, as well as operational data for flue gas desulfurization, particulates, and nitrous oxide controls. Data are collected from a monthly sample of approximately 2,150 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, at combined heat and power (CHP) plants, useful thermal output. At the end of the year, the monthly respondents report their annual source and disposition of electric power (nonutilities only), operational data for air emissions controls and cooling systems, and the collection and disposal of combustion by-products on the Form EIA-923 Supplemental Form (Schedules 6, 7, and 8A to 8F). Approximately 7,800 plants, representing all generators not included in the monthly sample and with a nameplate capacity of 1 MW or more, report applicable 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. Operational data for air emissions equipment are collected annually from facilities that have a steam turbine capacity of at least 10 megawatts, and operational data on cooling systems and data on the collection and disposal of combustion by-products are collected from facilities that have a steam turbine capacity of at least 100 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). Approximately 0.02 percent of the national total generation for is imputed, although this will vary by State and energy source.

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

Net Generation = (Factor) x Gross Generation
<u>Prime Movers:</u>
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
<u>Environmental Equipment:</u>
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. Power plants include independent power producers, electric utilities, and commercial and industrial CHP facilities with a total fossil-fueled nameplate capacity of 50 megawatts or more. The data on cost and quality of fuel shipments are 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, thousand cubic feet (Mcf) and million Btu per thousand cubic feet.

Net and Gross Generation and Fuel Consumption and Stocks: Generation data are collected in megawatthours from all power plants with a sum of nameplate capacity at least 1 MW. The fuels consumed are collected in tons (solids), barrels (liquids) and thousand cubic feet (gases). Fuels are grouped into coal, petroleum liquids, petroleum coke, natural gas, other gases, and other miscellaneous fuels. Energy consumption is not collected for nuclear, wind, solar, geothermal or other plants that do not burn fuels. For information on fuel groupings, see the instructions to the Form EIA-923 at http://www.eia.gov/survey/form/eia_923/instructions.pdf. **Combustion By-Product Collection and Disposal:** Data are collected in thousand tons. Associated financial data for by-products (O&M and capital expenses and revenue) are collected in thousand dollars.

Air Emissions Equipment: Operational efficiencies and emission rates are collected for flue gas desulfurization, particulate matter, and nitrous oxide control equipment for steam-electric units with at least 10 MW nameplate capacity.

Cooling Systems: Operational data on water use is collected from steam-electric plants, including nuclear plants, with at least 100 MW nameplate capacity.

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 consumed 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.

In 2011, the components of MSW as a percentage of the total were updated. The updated values were applied to final 2011 data and to preliminary 2012 and 2013 data. Although updated component percentages for 2006 through 2010 were available, historical EIA data series for consumption of MSW and net generation were not revised for 2005 to 2010. The tables below are the percentages applied to the EIA data for each year.

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

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

Table 1. Btu consumption for biogenic and non-biogenic municipal solid waste (percent)

	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
Biogenic	57	56	55	55	56	56	56	56	56	56	51
Non-biogenic	43	44	45	45	44	44	44	44	44	44	49

Table 2. Tonnage consumption for biogenic and non-biogenic municipal solid waste (percent)

	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
Biogenic	77	77	76	76	75	75	75	75	75	75	64
Non-biogenic	23	23	24	24	25	25	25	25	25	25	36

Useful Thermal Output (UTO): With the implementation of the Form EIA-923, “Power Plant Operations Report,” in 2008, combined heat and power (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.

Beginning with 2016 Form EIA-923 data, reported efficiency factors by survey respondents replaced the previously EIA estimated efficiency factors used in the fuel allocation process. For the processing of 2016 CHP data, EIA used for each plant an average of the efficiency factors reported by the CHP plants on the 2013, 2014, and 2015 Form EIA-923, “Power Plant Operations Report” surveys. An average was used to smooth out variations in any one year’s data. Once efficiency of each plant was established, the value was input into the above methodology to allocate the consumption of fuel between electric power and UTO. This update applies to the 2016 data and going forward but was not retroactively applied to previous years.

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 Electric Power Annual (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.

Capacity Factors and Usage Factors

This section describes the methodology for calculating capacity factors and usages factors by fuel and technology type for operating electric power plants. Capacity factor is a measure (expressed as a percent) of how often an electric generator operates over a specific period of time, using a ratio of the actual output to the maximum possible output over that time period.

The monthly capacity factor calculation includes all operating electric generators which operated for the entire month using the net generation reported on the Form EIA-923 and the net summer capacity reported on the Form EIA-860. The capacity factor for a particular fuel/technology type is given by:

$$capacity\ factor = \frac{\sum_{x,m} net\ generation_{x,m}}{\sum_{x,m} capacity_{x,m} * hours\ in\ month_m}$$

where x represents generators of that fuel/technology combination and m represents individual months. Net generation and capacity are specific to a generator, and the generator is categorized by its primary fuel type as reported on the EIA-860. All generation from that generator is included, regardless of other fuels consumed. Net generation and capacity for a generator is excluded from the summations during the month that the generator initially began operation and if applicable during the month that the generator retired. Therefore, these published capacity factors will differ from a simple calculation using annual generation and capacity totals from the appropriate tables in this publication.

Usage factors are calculated for energy storage technologies using gross generation instead of net generation:

$$usage\ factor = \frac{\sum_{x,m} gross\ generation_{x,m}}{\sum_{x,m} capacity_{x,m} * hours\ in\ month_m}$$

Air Emissions

This section describes the methodology for calculating estimated emissions of carbon dioxide (CO₂) from electric generating plants for 1989 through the present, as well as the estimated emissions of sulfur dioxide (SO₂) and nitrogen oxides (NO_x) from electric generating plants for 2001 through the present. For a description of the methodology used for other years, see the technical notes to the EPA 2003.

Methodology Overview: Initial estimates of uncontrolled SO₂ 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:

$$Emissions = Quantity\ of\ Fuel\ Consumed \times Emission\ Factor$$

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 SO₂ emissions. As discussed below, physical quantities are converted to millions of Btus for calculating CO₂ emissions.

For some fuels, the calculation of SO₂ 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:

$$Emissions = Quantity\ of\ Fuel\ Consumed \times Emission\ Factor \times Sulfur\ Content$$

The fuels that require the percent sulfur as part of the emissions calculation are indicated in Table A.1., which lists the SO₂ emission factors used for this report.

In the case of SO₂ 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 A.1. and A.2.

For SO₂ 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 SO₂ is the fluidized bed boiler, in which the sulfur removal process is integral with the operation of the boiler. The SO₂ emission factors shown in Table A.1. for fluidized bed boilers already account for 90 percent removal of SO₂ since, in effect, the plant has no uncontrolled emissions of this pollutant.

Although SO₂ 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 CO₂ are incomplete and are not used in this report.) The CEMS data account for the bulk of SO₂ and NO_x emissions from the electric power industry. For those plants for which CEMS data are available, the EIA estimates of SO₂ 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 Electric Power Annual 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.

CO₂ Emissions: CO₂ 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 CO₂ emissions, the fuel-specific emission factor from Table A.3. is multiplied by the fuel consumption in MMBtu.

The estimation procedure calculates uncontrolled CO₂ emissions. CO₂ control technologies are currently in the early stages of research and there are no commercial systems installed. Therefore, no estimates of controlled CO₂ emissions are made.

SO₂ and NO_x Emissions: To comply with environmental regulations controlling SO₂ 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 A.4.). 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 fuels⁷ 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 SO₂ and NO_x emissions:

- For steam electric plants, uncontrolled emissions are estimated using the emission factors shown in Tables A.1. and A.2. 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 SO₂, 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 A.4. 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 A.1. and Table A.2. 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 A.1.⁸
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 SO₂ 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 Factors for Propane, Petroleum Coke, and Synthesis Gases.

The quantity conversion for petroleum coke is 5 barrels (of 42 U.S. gallons each) per short ton (2,000 pounds), propane is 1.53 thousand cubic feet per barrel, coal-derived synthesis gas is 98.06 thousand cubic feet per ton, and petroleum coke-derived synthesis gas is 107.31 thousand cubic feet per ton.

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 Electric Power Annual and other data products, classifies nonutility power producers into the following categories:

- **Electric Utility (Sector 1):** All regulated plants with a primary purpose of selling electricity in the public markets (NAICS = 22).
- **Independent Power Producers (Sector 2):** All non-regulated plants with a primary purpose of electric power generation and a primary purpose of selling electricity in the public markets (NAICS = 22) with no ability to cogenerate heat and power.
- **Electric Power, Combined Heat and Power (Sector 3):** All non-regulated plants with a primary purpose of electric power generation and a primary purpose of selling electricity in the public markets (NAICS = 22) with the ability to cogenerate heat and power.
- **Commercial, Non-Combined Heat and Power (Sector 4):** All plants with a commercial primary purpose with no ability to cogenerate heat and power.

- **Commercial, Combined Heat and Power (Sector 5):** All plants with a commercial primary purpose with the ability to cogenerate heat and power.
- **Industrial, Non-Combined Heat and Power (Sector 6):** All plants with an industrial primary purpose with no ability to cogenerate heat and power.
- **Industrial, Combined Heat and Power (Sector 7):** All plants with an industrial primary purpose with the ability to cogenerate heat and power.

The following is a list of the North American Industry Classification System (NAICS) classifications used by EIA.

	Agriculture, Forestry, Fishing and Hunting
111	Crop Production
112	Animal Production
113	Forestry and Logging
114	Fishing, Hunting and Trapping
115	Support Activities for Agriculture and Forestry
	Mining, Quarrying, and Oil and Gas Extraction
211	Oil and Gas Extraction
2121	Coal Mining
2122	Metal Ore Mining
2123	Nonmetallic Mineral Mining and Quarrying
	Utilities
22	Electric Power Generation, Transmission and Distribution (other than 2212, 2213, 22131, 22132 or 22133)
2212	Natural Gas Distribution
22131	Water Supply and Irrigation Systems
22132	Sewage Treatment Facilities
22133	Steam and Air-Conditioning Supply
	Manufacturing
311	Food Manufacturing
312	Beverage and Tobacco Product Manufacturing
313	Textile Mills (Fiber, Yarn, Thread, Fabric, and Textiles)
314	Textile Product Mills
315	Apparel Manufacturing
316	Leather and Allied Product Manufacturing
321	Wood Product Manufacturing
322	Paper Manufacturing (other than 322122 or 32213)
322122	Newsprint Mills
32213	Paperboard Mills
323	Printing and Related Support Activities
324	Petroleum and Coal Products Manufacturing (other than 32411)
32411	Petroleum Refineries
325	Chemical Manufacturing (other than 32511, 32512, 325193, 325188, 3252 325211, 3253 or 325311)
32511	Petrochemical Manufacturing
32512	Industrial Gas Manufacturing
325193	Ethyl Alcohol Manufacturing (including Ethanol)
325188	Industrial Inorganic Chemicals

3252	Resin, Synthetic Rubber, and Artificial Synthetic Fibers and Filaments Manufacturing (other than 325211)
325211	Plastics Material and Resin Manufacturing
3253	Pesticide, Fertilizer, and Other Agricultural Chemical Manufacturing (other than 325311)
325311	Nitrogenous Fertilizer Manufacturing
326	Plastics and Rubber Products Manufacturing
327	Nonmetallic Mineral Product Manufacturing (other than 32731)
32731	Cement Manufacturing
331	Primary Metal Manufacturing (other than 331111 or 331312)
331111	Iron and Steel Mills
331312	Primary Aluminum Production
332	Fabricated Metal Product Manufacturing
333	Machinery Manufacturing
334	Computer and Electronic Product Manufacturing
335	Electrical Equipment, Appliance, and Component Manufacturing
336	Transportation Equipment Manufacturing
337	Furniture and Related Product Manufacturing
339	Miscellaneous Manufacturing
421	Wholesale Trade
441	Retail Trade
	Transportation and Warehousing
481	Air Transportation
482	Rail Transportation
483	Water Transportation
484	Truck Transportation
485	Transit and Ground Passenger Transportation
486	Pipeline Transportation
487	Scenic and Sightseeing Transportation
488	Support Activities for Transportation (other than 4881, 4882, 4883 or 4884)
4881	Support Activities for Air Transportation (including Airports)
4882	Support Activities for Rail Transportation (including Rail Stations)
4883	Support Activities for Water Transportation (including Marinas)
4884	Support Activities for Road Transportation
491	Postal Service
492	Couriers and Messengers
493	Warehousing and Storage
	Information
511	Publishing Industries (except Internet)
512	Motion Picture and Sound Recording Industries
515	Broadcasting (except Internet)
517	Telecommunications
518	Data Processing, Hosting, and Related Services
519	Other Information Services
521	Finance and Insurance
53	Real Estate and Rental and Leasing (including Convention Centers and Office Buildings)
541	Professional, Scientific, and Technical Services

55	Management of Companies and Enterprises
	Administrative and Support and Waste Management and Remediation Services
561	Administrative and Support Services
562	Waste Management and Remediation Services (other than 562212 or 562213)
562212	Solid Waste Landfill
562213	Solid Waste Combustors and Incinerators
611	Educational Services
	Health Care and Social Assistance
621	Ambulatory Health Care Services
622	Hospitals
623	Nursing and Residential Care Facilities
624	Social Assistance
	Arts, Entertainment, and Recreation
711	Performing Arts, Spectator Sports, and Related Industries
712	Museums, Historical Sites, and Similar Institutions
713	Amusement, Gambling, and Recreation Industries
	Accommodation and Food Services
721	Accommodation
722	Food Services and Drinking Places
	Other Services (except Public Administration)
811	Repair and Maintenance
812	Personal and Laundry Services
813	Religious, Grantmaking, Civic, Professional, and Similar Organizations
814	Private Households
92	Public Administration (other than 921, 922, 92214 or 928)
921	Executive, Legislative, and Other General Government Services
922	Justice, Public Order and Safety Activities (other than 92214)
92214	Correctional Facilities
928	National Security and International Affairs (including Military Bases)

Multiple Survey Programs- Small Scale PV Solar Estimation of Generation

Monthly generation from small scale PV solar resources is an estimation of the generation produced from PV solar resources and not the results of a data collection effort for generation directly, with the exception of “Third Party Owned” or (TPO) solar installations which has direct data collection. TPO data however is not comprehensive. TPOs do not operate in every state, TPO collected data is not a large portion of the estimated amount, and the data has been collected for limited period of time. The generation estimate is based on data collected for PV solar capacity.

Capacity of PV solar resources is collected directly from respondents. These data are collected on several EIA forms and from several types of respondents. Monthly data for net-metered PV solar capacity is reported on the Form EIA-826. Form EIA-826 is a cutoff sample drawn from the annual survey Form EIA-861 which collects this data from all respondents. Using data from both of these surveys we have a regression model to impute for the non-sampled monthly capacity.

The survey instruments collect solar net metering capacity from reporting utilities by state and customer class. There are four customer classes: residential, commercial, industrial and transportation. However, the estimation process included only the residential, commercial and industrial customers.¹ Data for these customer classes were further classified by U.S. Census Regions, to ensure adequate number of customer observations in for each estimation group.

Estimation Model: The total PV capacity reported by utilities in the annual EIA-861 survey is the single primary input (regressor) to the monthly estimation of PV capacity by state. The model tested for each Census Region was of the form:

$$y_{i_{2015,m}} = \beta_1 x_{i_{2013}} + w_i^{-1/2} e_i, \text{ where}$$

$x_{i_{2013}}$ is the i^{th} utility's 2013 (or the last published year) solar PV capacity

$y_{i_{2015,m}}$ is the i^{th} utility's month m , 2015 (or the current year) reported solar PV capacity

w_i is the weight factor, which is the inverse of $x_{i_{2013}}$

β_1 is effectively the growth rate of reported month m solar PV capacity

e_i is the error term

The model checks for outliers and removes them from the regression equation inputs. The model calculates RSEs by sector, state, census region, and US total. Once we have imputed for all of the monthly net-metered PV solar capacity we add to total net metered capacity, the PV solar capacity collected on the Form EIA-861 for distributed and dispersed resources that are not net metered.

We use a second model to estimate the generation using this capacity as an input. The original methodology was developed for the "Annual Energy Outlook" based on our "NEMS" modelled projections several years ago. The original method underwent a calibration project designed to develop PV production levels for the NEMS projections consistent with simulations of a National Renewable Energy Laboratory model called PVWatts, which is itself embedded in PC software under the umbrella of the NREL's System Advisor Model (SAM).

The PVWatts simulations require, panel azimuth orientations and tilts, something that the NEMS projections do not include. Call the combinations of azimuths and tilts "orientations." The orientation and solar insolation (specific to a location) have a direct effect on the PV production level. The calibration project selected the 100 largest population Metropolitan Statistical Areas (MSAs) and relied on weights derived from orientation data from California Solar Initiative dataset to develop typical outputs for each of the 100 MSAs. It then was expanded from an annual estimate to a monthly estimate. A further description of this model is located here. A listing of the MSAs are included in Appendix 1.

Using Form EIA-861 data for service territories, which lists the counties that each electric distribution company (EDC) provides service, and NREL solar insolation data by county a simple average of insolation values by EDC is calculated.

Using the estimation model, we produce by utility, by state and by sector an estimate of generation. All the utilities' capacity and generation estimates are summed by state and sector and a KWh/KW rate by state and sector is calculated.

Capacity from the Form EIA-860 that is net metered is subtracted from the total capacity by state and sector as well as the capacity reported on the EIA-826 from TPOs, resulting in a new "net" capacity amount. This capacity amount is multiplied by the KWh/KW rate to produce the non-TPO generation estimate and then it is added to the TPO reported sales to ultimate customers from the EIA-826 to obtain a final estimate for generation and a blended KWh/KW rate is calculated. The estimate for generation is aggregated by US census regions and US totals. The RSEs for capacity are checked for level of error and if they pass, the summary data by state, US census region and US total are reported in the EPM.

Appendix 2 contains a flow diagram of the data inputs, data quality control checks and data analysis required to perform this estimation.

Appendix 1- MSAs

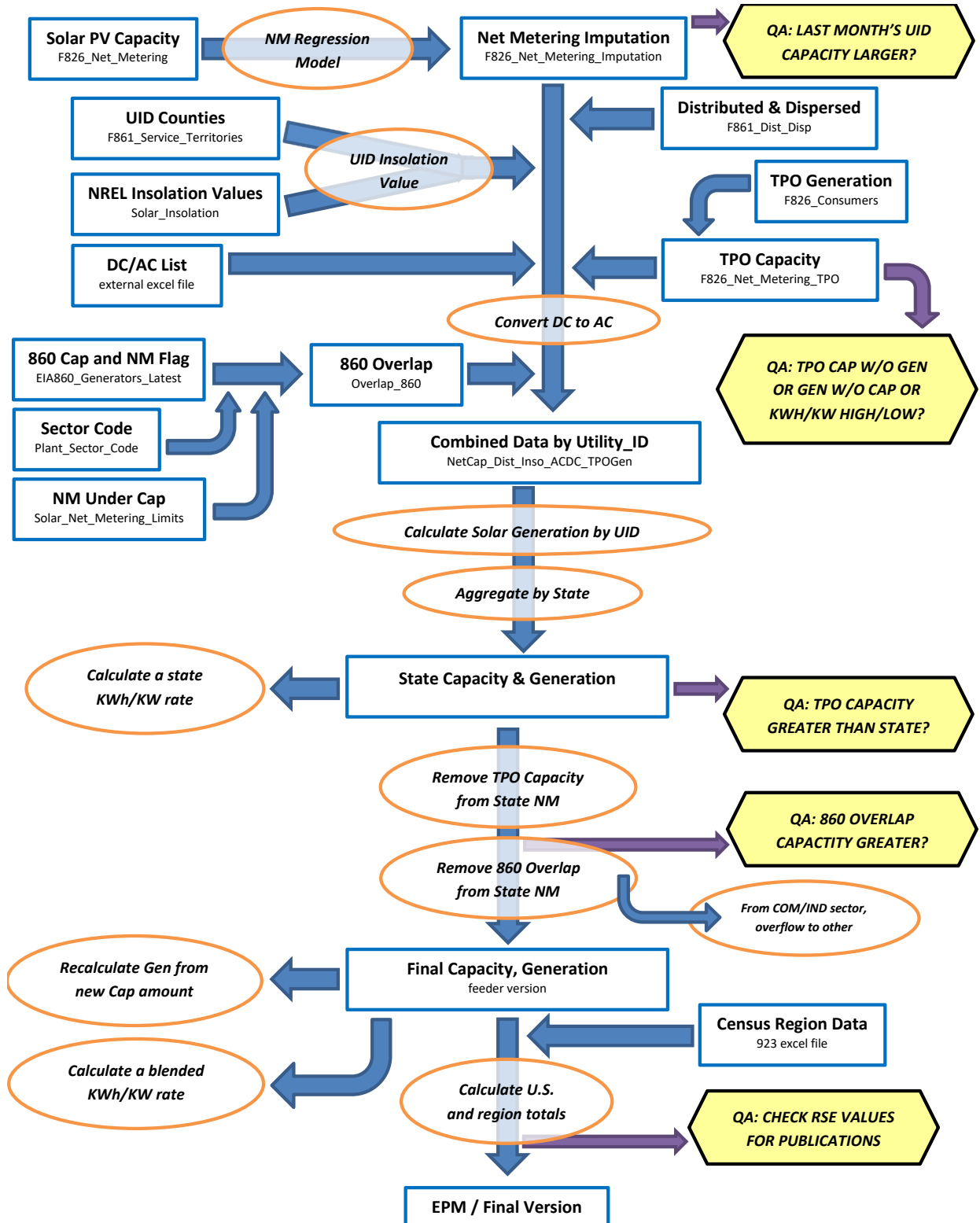
TMY3 (1991-2005) Weather Stations by MSA

Site	Weather Location	MSA
1	USA NY New York Central Park Obs.	New York-Newark-Jersey City, NY-NJ-PA MSA
2	USA CA Los Angeles Intl Airport	Los Angeles-Long Beach-Anaheim, CA MSA
3	USA IL Chicago Midway Airport	Chicago-Naperville-Elgin, IL-IN-WI MSA
4	USA TX Dallas-fort Worth Intl Airport	Dallas-Fort Worth-Arlington, TX MSA
5	USA TX Houston Bush Intercontinental	Houston-The Woodlands-Sugar Land, TX MSA
6	USA PA Philadelphia Int'l Airport	Philadelphia-Camden-Wilmington, PA-NJ-DE-MD MSA
7	USA VA Washington Dc Reagan Airport	Washington-Arlington-Alexandria, DC-VA-MD-WV MSA
8	USA FL Miami Intl Airport	Miami-Fort Lauderdale-West Palm Beach, FL MSA
9	USA GA Atlanta Hartsfield Intl Airport	Atlanta-Sandy Springs-Roswell, GA MSA
10	USA MA Boston Logan Int'l Airport	Boston-Cambridge-Newton, MA-NH MSA
11	USA CA San Francisco Intl Airport	San Francisco-Oakland-Hayward, CA MSA
12	USA AZ Phoenix Sky Harbor Intl Airport	Phoenix-Mesa-Scottsdale, AZ MSA
13	USA CA Riverside Municipal Airport	Riverside-San Bernardino-Ontario, CA MSA
14	USA MI Detroit City Airport	Detroit-Warren-Dearborn, MI MSA
15	USA WA Seattle Seattle-Tacoma Intl Airport	Seattle-Tacoma-Bellevue, WA MSA
16	USA MN Minneapolis-St. Paul Int'l Arp	Minneapolis-St. Paul-Bloomington, MN-WI MSA
17	USA CA San Diego Lindbergh Field	San Diego-Carlsbad, CA MSA
18	USA FL Tampa Int'l Airport	Tampa-St. Petersburg-Clearwater, FL MSA
19	USA MO St Louis Lambert Int'l Airport	St. Louis, MO-IL MSA
20	USA MD Baltimore-Washington Int'l Airport	Baltimore-Columbia-Towson, MD MSA
21	USA CO Denver Centennial [Golden - NREL]	Denver-Aurora-Lakewood, CO MSA
22	USA PA Pittsburgh Allegheny Co Airport	Pittsburgh, PA MSA
23	USA NC Charlotte Douglas Intl Airport	Charlotte-Concord-Gastonia, NC-SC MSA
24	USA OR Portland Hillsboro	Portland-Vancouver-Hillsboro, OR-WA MSA
25	USA TX San Antonio Intl Airport	San Antonio-New Braunfels, TX MSA
26	USA FL Orlando Intl Airport	Orlando-Kissimmee-Sanford, FL MSA
27	USA CA Sacramento Executive Airport	Sacramento-Roseville-Arden-Arcade, CA MSA
28	USA OH Cincinnati Municipal Airport	Cincinnati, OH-KY-IN MSA
29	USA OH Cleveland Hopkins Intl Airport	Cleveland-Elyria, OH MSA
30	USA MO Kansas City Int'l Airport	Kansas City, MO-KS MSA
31	USA NV Las Vegas McCarran Intl Airport	Las Vegas-Henderson-Paradise, NV MSA
32	USA OH Columbus Port Columbus Intl A	Columbus, OH MSA
33	USA IN Indianapolis Intl Airport	Indianapolis-Carmel-Anderson, IN MSA
34	USA CA San Jose Intl Airport	San Jose-Sunnyvale-Santa Clara, CA MSA
35	USA TX Austin Mueller Municipal Airport	Austin-Round Rock, TX MSA
36	USA TN Nashville Int'l Airport	Nashville-Davidson-Murfreesboro-Franklin, TN MSA

37	USA VA Norfolk Int'l Airport	Virginia Beach-Norfolk-Newport News, VA-NC MSA
38	USA RI Providence T F Green State	Providence-Warwick, RI-MA MSA
39	USA WI Milwaukee Mitchell Intl Airport	Milwaukee-Waukesha-West Allis, WI MSA
40	USA FL Jacksonville Craig	Jacksonville, FL MSA
41	USA TN Memphis Int'l Airport	Memphis, TN-MS-AR MSA
42	USA OK Oklahoma City Will Rogers	Oklahoma City, OK MSA
43	USA KY Louisville Bowman Field	Louisville/Jefferson County, KY-IN MSA
44	USA VA Richmond Int'l Airport	Richmond, VA MSA
45	USA LA New Orleans Alvin Callender	New Orleans-Metairie, LA MSA
46	USA CT Hartford Bradley Intl Airport	Hartford-West Hartford-East Hartford, CT MSA
47	USA NC Raleigh Durham Int'l	Raleigh, NC MSA
48	USA UT Salt Lake City Int'l Airport	Salt Lake City, UT MSA
49	USA AL Birmingham Municipal Airport	Birmingham-Hoover, AL MSA
50	USA NY Buffalo Niagara Intl Airport	Buffalo-Cheektowaga-Niagara Falls, NY MSA
51	USA NY Rochester Greater Rochester	Rochester, NY MSA
52	USA MI Grand Rapids Kent County Int'l Airport	Grand Rapids-Wyoming, MI MSA
53	USA AZ Tucson Int'l Airport	Tucson, AZ MSA
54	USA HI Honolulu Intl Airport	Urban Honolulu, HI MSA
55	USA OK Tulsa Int'l Airport	Tulsa, OK MSA
56	USA CA Fresno Yosemite Intl Airport	Fresno, CA MSA
57	USA CT Bridgeport Sikorsky Memorial	Bridgeport-Stamford-Norwalk, CT MSA
58	USA MA Worcester Regional Airport	Worcester, MA-CT MSA
59	USA NM Albuquerque Intl Airport	Albuquerque, NM MSA
60	USA NE Omaha Eppley Airfield	Omaha-Council Bluffs, NE-IA MSA
61	USA NY Albany County Airport	Albany-Schenectady-Troy, NY MSA
62	USA CA Bakersfield Meadows Field	Bakersfield, CA MSA
63	USA CT New Haven Tweed Airport	New Haven-Milford, CT MSA
64	USA TN Knoxville McGhee Tyson Airport	Knoxville, TN MSA
65	USA SC Greenville Downtown Airport	Greenville-Anderson-Mauldin, SC MSA
66	USA CA Oxnard Airport	Oxnard-Thousand Oaks-Ventura, CA MSA
67	USA TX El Paso Int'l Airport	El Paso, TX MSA
68	USA PA Allentown Lehigh Valley Intl	Allentown-Bethlehem-Easton, PA-NJ MSA
69	USA LA Baton Rouge Ryan Airport	Baton Rouge, LA MSA
70	USA TX McAllen Miller Intl Airport	McAllen-Edinburg-Mission, TX MSA
71	USA OH Dayton Int'l Airport	Dayton, OH MSA
72	USA SC Columbia Metro Airport	Columbia, SC MSA
73	USA NC Greensboro Piedmont Triad Int'l Airport	Greensboro-High Point, NC MSA
74	USA FL Sarasota Bradenton	North Port-Sarasota-Bradenton, FL MSA
75	USA AR Little Rock Adams Field	Little Rock-North Little Rock-Conway, AR MSA
76	USA SC Charleston Intl Airport	Charleston-North Charleston, SC MSA
77	USA OH Akron Akron-canton Reg. Airport	Akron, OH MSA
78	USA CA Stockton Metropolitan Airport	Stockton-Lodi, CA MSA

79	USA CO Colorado Springs Muni Airport	Colorado Springs, CO MSA
80	USA NY Syracuse Hancock Int'l Airport	Syracuse, NY MSA
81	USA FL Fort Myers Page Field	Cape Coral-Fort Myers, FL MSA
82	USA NC Winston-Salem Reynolds Airport	Winston-Salem, NC MSA
83	USA ID Boise Air Terminal	Boise City, ID MSA
84	USA KS Wichita Mid-continent Airport	Wichita, KS MSA
85	USA WI Madison Dane Co Regional Airport	Madison, WI MSA
86	USA MA Worcester Regional Airport	Springfield, MA MSA
87	USA FL Lakeland Linder Regional Airport	Lakeland-Winter Haven, FL MSA
88	USA UT Ogden Hinkley Airport	Ogden-Clearfield, UT MSA
89	USA OH Toledo Express Airport	Toledo, OH MSA
90	USA FL Daytona Beach Intl Airport	Deltona-Daytona Beach-Ormond Beach, FL MSA
91	USA IA Des Moines Intl Airport	Des Moines-West Des Moines, IA MSA
92	USA GA Augusta Bush Field	Augusta-Richmond County, GA-SC MSA
93	USA MS Jackson Int'l Airport	Jackson, MS MSA
94	USA UT Provo Muni	Provo-Orem, UT MSA
95	USA PA Wilkes-Barre Scranton Intl Airport	Scranton-Wilkes-Barre-Hazleton, PA MSA
96	USA PA Harrisburg Capital City Airport	Harrisburg-Carlisle, PA MSA
97	USA OH Youngstown Regional Airport	Youngstown-Warren-Boardman, OH-PA MSA
98	USA FL Melbourne Regional Airport	Palm Bay-Melbourne-Titusville, FL MSA
99	USA TN Chattanooga Lovell Field Airport	Chattanooga, TN-GA MSA
100	USA WA Spokane Int'l Airport	Spokane-Spokane Valley, WA MSA

Appendix 2 – Flow diagram of data sources and analysis



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.

³ 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/>.

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

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/survey/form/eia_767/instructions_form.pdf.

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c))
Emergency Order: Tri-State)
Generation and Transmission)
Association, Platte River Power)
Authority, Salt River Project,)
PacifiCorp, and Xcel Energy)

Order No. 202-25-14

Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
Public Interest Organizations

Filed January 28, 2026

Exhibit 1-108:
UT Austin Article



The University of Texas at Austin

energy institute

The Full Cost of Electricity (FCe-)



The History and Evolution of the U.S. Electricity Industry

PART OF A SERIES OF WHITE PAPERS



TEXAS

The University of Texas at Austin



THE FULL COST OF ELECTRICITY is an interdisciplinary initiative of the Energy Institute of the University of Texas to identify and quantify the full-system cost of electric power generation and delivery – from the power plant to the wall socket. The purpose is to inform public policy discourse with comprehensive, rigorous and impartial analysis.

The generation of electric power and the infrastructure that delivers it is in the midst of dramatic and rapid change. Since 2000, declining renewable energy costs, stringent emissions standards, low-priced natural gas (post-2008), competitive electricity markets, and a host of technological innovations promise to forever change the landscape of an industry that has remained static for decades. Heightened awareness of newfound options available to consumers has injected yet another element to the policy debate surrounding these transformative changes, moving it beyond utility boardrooms and legislative hearing rooms to everyday living rooms.

The Full Cost of Electricity (FLe-) study employs a holistic approach to thoroughly examine the key factors affecting the *total direct and indirect costs* of generating and delivering electricity. As an interdisciplinary project, the FLe- synthesizes the expert analysis and different perspectives of faculty across the UT Austin campus, from engineering, economics, law, and policy. In addition to producing authoritative white papers that provide comprehensive assessment and analysis of various electric power system options, the study team developed online calculators that allow policymakers and other stakeholders, including the public, to estimate the cost implications of potential policy actions. A framework of the research initiative, and a list of research participants and project sponsors are also available on the Energy Institute website: energy.utexas.edu

This paper is one in a series of Full Cost of Electricity white papers that examine particular aspects of the electricity system.

Other white papers produced through the study can be accessed at the University of Texas Energy Institute website: energy.utexas.edu

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The History and Evolution of the U.S. Electricity Industry



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EXECUTIVE SUMMARY

Universally available, reliable, and affordable electricity is associated with a nation's improvements in quality of life for its citizens, increased productivity, and competitive advantage. The structure of the electricity industry – of generation, delivery, and use of electricity – over the past century has evolved significantly. For decades, scale economies associated with large centralized generation technologies encouraged vertical integration and drove down the cost of electricity, fostered universal access, and provided for reliable electric service delivered by a single utility in a given region. Starting in the 1970s, higher fuel prices, environmental concerns, technological innovations and a desire for more economic efficiency led to the rethinking of this vertically-integrated, regional monopoly model.

Following the restructuring of the telecommunications industry and the natural gas industry, policy makers began to rethink the notion that power generation and sales are (or should be) a natural monopoly. In the 1980s policy makers chose to break up the telephone monopoly in the U.S., unleashing competitive and technological forces that have transformed the communications sector. In the late 1970s and 1980s a series of government decisions deregulating wellhead prices and the pipeline industry unleashed powerful market forces in the natural gas industry, ultimately making both natural gas and gas-fired power much less expensive. The increased competition from merchant generators encouraged restructuring of the electric power industry in many states, breaking down the vertical integration model.

During the same timeframe, innovations in finance were created that complemented these new technologies to help make them more cost competitive. An important example is the Power Purchase Agreement (PPA) for independent natural gas plant electricity production and, later, wind and solar plants. These agreements played a key role in financing non-utility owned

generating assets by enabling their owners, known as independent power producers (IPPs), to raise investment capital, employ tax-exempt bond financing, and capture Federal tax credits, enabling IPPs to provide renewable power at attractive long-term fixed prices to utilities. By the mid-1990s, policy makers began to restructure the electricity system, seeking to take advantage of these same technological and competitive forces in order to promote innovation and reduce electricity costs.

At the same time, policymakers incentivized alternative technologies, such as wind power. Both the federal and state governments implemented environmental regulations, tax credits, and other support programs for renewables. Solar technology, initially much more expensive than wind, did not benefit from these policies until the late 2000s and early 2010s when some states instituted programs that specifically supported solar installations. For both wind and solar, foreign government support for manufacturing has also been critical (e.g., Denmark for wind in its early days, and China for solar PV more recently). These technologies also enabled some customers to start generating some of their own electricity, competing with their local utility or competitive generators, and threatening the traditional utility business model as well as the competitive market structure as they exist today.

Several technologies will combine to drive changes in the electric industry: increasingly cost competitive wind and solar PV, inexpensive natural gas combined with flexible and efficient combined cycle gas plants, and electricity energy storage and demand response systems with progressively lower costs. These and other technological changes will continue to encourage the industry to adopt new technology and business models, policy makers to consider alternative regulatory and electricity market structures, and electricity customers to pursue self-generation that competes with traditional utilities in ways that may further de-stabilize the existing order. ■

1 | INTRODUCTION

The basic functions of the electric power industry, as historically structured, are electricity generation (production), transmission and distribution (T&D) to deliver electricity from the point of generation to the point of consumption, and customer relationship management.

There are various regulatory approaches for arranging the relationship between electricity generation and end-use consumption. Historically, a vertically integrated utility in the U.S. was an investor-owned utility (IOU) and was regulated by an independent public entity typically known as a public utility commission (PUC) or public service commission (PSC) (see Figure 3, Model 1). State-owned utilities in most of the world tended to also be vertically integrated (see Figure 4, Model 5). The customer relationship, where it mattered (primarily the U.S.) consisted primarily of monthly billing, outage management and advertising to encourage either conservation or consumption growth, depending on the situation.

The goal of this document is to summarize the history of the U.S. electric power industry, describe how the utility business model came to fruition, and introduce the more recent drivers

for changing that model. In many cases, the historical business structures and regulatory models have become challenged across the United States over the past few decades. Thus, with the background in this document, the reader can contextualize the drivers for recent and future changes within the electricity industry.

The rest of this document is organized as follows. Section 2 provides a history of the interplay between technology, finance, and regulation that formed the traditional regulated electric utility business model. Section 3 describes the major ownership (for-profit and non-profit), management, and regulatory models of modern electricity grids. Section 4 provides some future perspectives and technological drivers for continued regulatory and consumer changes before Section 5 provides a brief conclusion. ■

2 | FORMATION OF THE ELECTRIC UTILITY MODEL

OVERVIEW

The dominant model for delivering electricity to consumers was, and remains, large-scale, central generation facilities, and transmission and distribution networks at regulated prices (rates) (see Figure 3, Model 1). The traditional utility business model formed within the interplay of technology, finance, and regulation.

The business structure was created in the early 20th century as the industry pioneers like Samuel Insull realized that **technology** allowed for power plants to become larger (especially, using steam turbines) and to reach **economies of scale** that reduced the unit cost of power. Insull and other early electricity providers also realized that they could make money selling electricity to a more diverse set of customers throughout the day, rather than simply serving evening electricity demand (or “load”), which was the basis of the early electric systems. This realization led them to acquire more customers and to grow their service territories. These large power plants and networks necessitated **financing mechanisms**, via holding companies with multiple investors or later, access to low-cost financing via the debt markets. These progressively more advanced methods of equity and debt financing enabled new infrastructure (power plants, transmission and distribution lines) to be built and paid for over time, but without all the risk falling on a single company or investor. **Regulation** was considered necessary to allow electric companies to operate as monopolies to avoid waste of capital resources in duplicate infrastructure, create a regulatory compact that included an obligation to serve within the monopoly service area, stabilize the cost of capital by reducing risk, and provide affordable electricity service. To protect customers from monopolistic prices, electricity rates started to be regulated first by municipal, then by state governments. Federal regulation became relevant when grids grew larger across state borders, thus generating interstate commerce.

The traditional vertically integrated system persisted into the 1990s, when the federal government and some states decided to restructure the electricity industry, breaking vertically integrated utilities into generation and wires businesses, and introducing competition in the generation sector. In the late 1980s, Chile and the UK initiated a restructuring of their traditional vertically integrated electric power monopolies to introduce competition primarily at the wholesale or “bulk power” level where generators compete in a market. These efforts provided some guidance for restructuring in the U.S. Changes to the traditional model were also precipitated by a series of laws passed by the Congress between 1978 and 1992, which laid the foundation for the introduction of independent power producers (IPPs) into the market, the shift to market pricing of power, and the unbundling of electricity delivery from electricity sales. Today, the roles of both federal and state regulators in states with restructured electricity markets are more complex as they attempt to maintain grid reliability by managing robust and maturing competitive markets with more participants, increased integration of new sources of electricity generation, and increased demand-side participation into the system.

TECHNOLOGY

The modern electric utility industry in America began with Thomas Edison’s invention of the first practical light bulb in 1879. Within three years, Edison built the first “centralized” fossil fuel driven power plant at Pearl Street in New York City’s financial district. Adoption quickly followed in homes, factories, and in transportation to maximize the usefulness of this energy source. Entrepreneurs recognized the potential for electricity to revolutionize every aspect of American life from the home

to the factory, and they engaged government first at the local or municipal level to facilitate the construction of infrastructure.

Thomas Edison's original system design was based upon direct current (dc) and low voltages. Because of high dissipative power losses in wires, this limited the transmission distance from power plant to end use point for electric power, which in turn restricted interactions with government to the local level. The power was generated and consumed within only a few miles. However, technological advances soon extended the scale and reach of electricity generation, and simultaneously necessitated an expanded role for government.

The most significant technological advance was alternating current (ac) electricity. By 1896, in the famous "power wars", Westinghouse Electric (with the help from inventor Nikola Tesla) had introduced ac electricity, expanding the reach of power plants to dozens of miles (1000s of miles today) from the point of electric load. The shift from dc to ac technology made larger scale (e.g., larger power plants) systems possible. This shift was largely due to the fact that ac permitted the power to be transmitted at high voltage and low current, substantially reducing power losses relative to dc systems. In turn, the use of ac transmission permitted the *exploitation of the economies of scale* for power plants, reducing the unit cost of electricity, and making electricity progressively more affordable and available to ever more customers.

After this dc-to-ac transition, for decades the technology evolved along the lines of what has become the traditional electricity utility model: large scale centralized generation sending ac electricity over transmission and distribution lines to consumers. While the vast majority of transmission is high voltage ac, modern high voltage dc transmission lines have been selectively used primarily for point-to-point long distance connections to transfer large amounts of power with enhanced stability over an ac connection.

For the past century, scale economies associated with large centralized generation technologies encouraged vertical integration and drove

down the cost of electricity, fostered universal access, and provided for reliable electric service delivered by a single utility in a given region.

The initial loads on these early power systems were mostly lighting, followed closely by electric motors, loads that were well suited for ac power. However, over the past few decades the explosion in the number of computers, microprocessors, and telecommunications systems provided loads that are inherently suited to dc. These devices require better power quality than lights and motors, while the rectifiers (that convert ac to dc) in the systems often produce power quality challenges. At the same time, distributed energy resources such as solar photovoltaic (PV) panels and batteries provide energy sources that are also inherently dc. In order to avoid losing the competition to serve this new kind of load, utilities may need to adapt by offering new energy delivery models, such as dc microgrid overlays on top of their existing ac distribution systems. Legislatures and utility regulators play an important, if not essential, role in redefining the regulatory environment that defines the incentives and structure for utility business models. The traditional vertically integrated structures that were appropriate for the 20th century may inhibit desired incentives, investments, or innovation of utilities.

FINANCING

During the very early years of distributing electricity, grids were local, and used small neighborhood power plants (combustion engines) to generate power. The amount of capital required was relatively modest and then-available financing resources were adequate. With the transition to large ac systems (e.g., 100+ MW thermal and hydroelectric power plants), however, it was obvious that larger-scale financing was required. Electric companies could issue bonds to build these plants, but the risk was becoming too great for the investors that participated in the debt market of the era.

To reduce both risk and financing costs, the concept of a **holding company** was developed to blend the bonds from existing as well as new power

plants and to also provide cash flow from one of the associated firms to finance further growth in another one of the held firms. Samuel Insull, a franchisee of Thomas Edison, recognized the potential for economies of scale and the role for the natural monopoly in electricity. He invested heavily in centralized power plants. By 1907, Insull had acquired twenty companies and formed Commonwealth Edison, beginning a cycle of centralization in the electric utility industry [1].

Despite growing state regulation (discussed in the next section), consolidation and private expansion continued in the electric sector through the 1910s and 20s, often using the financial innovation of holding companies. Applying this tool, Samuel Insull controlled businesses in 32 states with more than \$500 million in assets in 1930. By 1932, eight holding companies controlled three-fourths of the IOUs, with most of their operations exempt from state regulation due to the crossing of state lines [2].

Financial product innovations served to fuel the growth of the U.S. power system with minimal problems until the last quarter of the 20th century, when fuel prices increased and some utilities began losing money when regulators refused to allow them to charge rates that reflected these cost increases. Unprofitable operations, in turn, inhibited some utilities' ability to raise financing for new plants. Moreover, the scale of the new plants could sometimes be so large relative to the size of the utilities' assets or revenue that some smaller utilities could not afford to own and build a new large power plant without partners; meanwhile, regulators would not allow smaller utilities to take the risks associated with building such large facilities without historical precedent in their jurisdiction. This was particularly true with new nuclear construction and the reason why some nuclear power plants were owned by multiple companies in the 1970s and 80s.

Today, there is a corresponding struggle to finance large coal and nuclear power facilities (with capital costs of several billions of dollars each) in competitive wholesale markets. The vast majority of new generation capacity is relatively smaller natural gas, wind, and PV facilities (with capital costs of \$100s of millions). Today, the ability to add new generation capacity in smaller

sized increments can be attractive for utilities in an era of low load growth; it helps them to better manage cash flows, reduce capital demands and risk, and to simplify the project development, ownership, and operation structures.

REGULATION

In terms of the chronological development of electricity regulation, the electric power industry generally evolved from being unregulated, to being regulated first by municipalities, then states, and then the federal government. Today in the U.S., the states typically regulate the retail sale of electricity, while federal law authorizes the Federal Energy Regulatory Commission (FERC) to regulate wholesale markets that involve interstate commerce and interstate transmission of electricity.¹

The first progressive reformers in New York and Wisconsin expanded regulation of the industry to the state level at around the same time Samuel Insull was consolidating electric companies into what would become Commonwealth Edison. In 1905, Wisconsin's Governor Robert LaFollete established a state-level railroad commission to regulate railroad rates, schedules, service, and operations. Two years later, the Wisconsin legislature extended regulation to the state's electric companies, and New York State regulated its electric industry in the same year. Following the Progressives' lead, 45 states had established government oversight of electric utilities by 1914 [3].

The Federal Power Commission & Federal Energy Regulatory Commission

Congress first established the Federal Power Commission (FPC) by the Federal Water Power Act in 1920 to license hydroelectric dams on navigable waters or lands owned by the Federal Government. It later designated that the commission be comprised of five members, serving staggered terms, with no more than three from the same political party. This structure

¹ The ERCOT market in Texas does not include ac transmission of power across state lines, so it is mostly exempt from Federal Power Act regulation.

remains in place today within the Federal Energy Regulatory Commission (FERC), the subsequent federal agency that subsumed the FPC. Since the Federal Power Act of 1935, the FPC and now FERC has been charged with ensuring that wholesale power sales and transmission service be offered at rates that are “just and reasonable, and nondiscriminatory.” During the early decades of the FPC, the commission’s power to regulate interstate commerce in electricity and natural gas were further expanded or clarified.

After the Great Depression Progressive reformers began to warn of the dangers of monopolies combined with lax regulation, and to see electricity as an essential public good. Campaigning for President in 1932, Franklin Roosevelt (FDR) vowed to fight “the Ishmaels and Insulls, whose hand is against everyman’s [4].” Subsequent New Deal reforms established new regulatory frameworks for the electric industry as well as programs designed to bring electricity to rural America.

Electrification was seen to be an important technology to combat poverty and improve the quality of Americans’ lives. The formation of the Tennessee Valley Authority (TVA) in 1933 introduced public energy policy as a tool to fight rural poverty in America. By the 1930s, ninety-percent of urban households had electricity compared with only ten percent in rural areas. Private industry demonstrated little interest in serving rural America due to the high construction costs, low population density, and perceived lack of ability for customers (e.g., poor farmers) to pay for the electricity. In response, FDR followed TVA with an executive order establishing the Rural Electrification Administration in 1935 prior to Congress enacting the Rural Electrification Act (REA) in 1936. These federal actions stimulated the introduction of electric service in rural areas, substantially improving quality of life for Americans, and encouraging business to enter and drive further economic development.

By 1939, the REA had helped to establish 417 electric cooperatives in rural areas, serving 25% of rural households in America. At the time of FDR’s death in 1945, an estimated 90% of rural farms were electrified [5]. Rural electrification in the

period increased from 13% to 94% [6]. TVA then created the Electric Home and Farm Authority (EHFA) to increase the supply of electric ranges, refrigerators, and water heaters to rural areas and to provide low-cost financing for farmers to afford them. The REA and TVA made a significant contribution to the reduction in poverty in the U.S. In addition to rural co-ops, investor owned utilities have shown to be effective providing more than half of the electricity in the US.

The Public Utility Holding Company Act of 1935 (PUHCA) also had a lasting influence on the electric utility industry in America. Congress passed the PUHCA to facilitate the regulation of the electric utility sector by either confining their operations to a single state or limiting operations that cross state lines to a contiguous geographic service area, easing regulation. PUHCA also outlawed the highly leveraged and opaque multi-level pyramids of holding companies that contributed to the economic collapse during the Great Depression. Remaining interstate holding companies and most companies that delivered a substantial amount of electricity were forced to register with the new Securities and Exchange Commission (1935). Along with other public companies, these utility companies were now required to follow the more strict Securities and Exchange Commission (SEC) rules for financial reporting and to obtain approval to issue stock and bond securities [7]. ***In effect, PUHCA of 1935 established the framework for the traditional electric utility industry.***

National Electric Reform

The traditional regulated utility model, first formalized by the Public Utility Holding Company Act of 1935 and governed as a natural and technical monopoly, remained mostly unchanged until the energy shocks in the 1970s. The energy price spike following the 1973 Arab Oil Embargo set the expectation among utilities and regulators that energy prices would continue to increase in the decades to come. Utilities also expected continued growth of electricity demand driven by a growing population, the need to switch away from more expensive petroleum fuels for heating and power

generation, and continued supply disruptions from oil-exporting Arab nations or more specifically from the Organization of Petroleum Exporting Countries (OPEC). As a result of these expectations and the belief that natural gas supplies were limited, utilities developed ambitious plans for power plants based on coal and large-scale nuclear technologies, which turned out to have construction costs much higher than historic averages [8]. Some of these utility plans were influenced by the Power plant and Industrial Fuel Use Act (PIFUA) of 1978 (repealed in 1987) that, among other fuel use restrictions, prevented the use of natural gas by regulated utilities in power plants (except where it was necessary to reduce air pollution associated with burning coal or oil). By restricting the use of natural gas for electricity generation by utilities, PIFUA stimulated a large build-out of coal power plants during the 1970's and 1980's. While these coal plants contribute a significant portion of the emissions of the entire power generation sector, many of them are now uneconomic and being retired given low natural gas prices from the surge in gas supplies from hydraulic fracturing techniques, efficient combined-cycle gas plants, declining costs of wind and solar generation, in addition to implemented or proposed environmental regulations.

The perception of future energy shortfalls also created an opportunity for smaller scale plants such as small hydropower sites, industrial co-generation, burning of municipal waste, and renewable resources such as geothermal energy, wood, wind, and solar. With the traditional utilities mainly focused on large-scale and capital-intensive projects, the development of these new smaller and/or renewable resources was contingent upon the purchase of their output by utilities at favorable terms. To encourage the development of these new resources and to diversify the domestic electric power base, Congress passed the Public Utility Regulatory Policies Act of 1978 (PURPA). Section 210 of this federal legislation created a new legal category of power plants known as qualifying facilities (QFs), with specific size and other characteristics, that enabled new market entrants such as non-utility generators, or NUGs (e.g., power producers that

BOX 1:

The Role of Natural Gas Industry Restructuring in Driving Changes in the Electric Power Industry

The Natural Gas Act of 1938 gave the FPC the power to regulate the sale and transportation of natural gas in interstate commerce. In 1940, amendments to the Natural Gas Act enabled the FPC to certify and regulate natural gas facilities, and the 1954 court ruling *Phillips Petroleum Co. v. Wisconsin* required the FPC to begin regulating natural gas wellhead prices. This action proved to be poorly conceived in that it eventually constrained gas exploration, and supply as well as technology innovation along the natural gas supply chain and by end-users. As part of the energy sector reforms in 1978, the Natural Gas Policy Act was passed along with PIFUA and PURPA that started the process of phasing out gas wellhead price regulation. Within a decade, rising market prices fostered new drilling and the development of new exploration and production techniques that led to significant new supplies and price declines.

Several orders by FERC in the 1980s and early 1990s, were designed to increase competition in the natural gas sector. The 1985 FERC Order No. 436 required that natural gas pipelines provide open access to transportation services, enabling gas consumers to negotiate prices directly with producers and contract separately for transportation. In 1992 FERC issued Order No. 636 (The Restructuring Rule) that mandated unbundling of sales services from transportation services, provided customers with a full choice of providers, and opened these markets to competition. In 2000, FERC Order No. 637 further addressed inefficiencies in the capacity release market. Together with PURPA and PIFUA, these changes in the natural gas industry fueled the emergence of the IPP sector, facilitating wholesale electricity competition.

There are many parallels between natural gas and electricity regulation. Both systems need to connect producers, via transmission and distribution infrastructure, to end-use consumers. The restructuring of the natural gas markets with the unbundling of services and open access to transmission provided a model for the subsequent restructuring of the electricity market.

were not utilities and did not own transmission lines) [9]. PURPA required local investor-owned utilities to purchase the output from QFs, at full avoided-cost (the cost utilities would incur if they were to generate the same amount themselves or purchase it from another source). Some states enacted laws and regulations specifying avoided-cost rates for power purchases from QFs. Initially, some states established avoided-cost rates that exceeded utilities' actual avoided-costs, until the Supreme Court struck down those laws in 1984.²

Congress responded to the 1970s' energy crises by reorganizing the FPC into the Federal Energy Regulatory Commission (FERC) in 1978 to streamline regulations, encourage greater energy security, and contain the increases in energy costs. An important aspect of these efforts was to wean U.S. power generation from oil (particularly imported oil) to domestic sources of energy.

Subsequently, in the 1980s and 1990s FERC finalized orders that significantly restructured natural gas markets (see Box 1). These orders enabled merchant developers of electricity generation plants to bypass local natural gas distribution companies and reduce their fuel costs by buying natural gas in the wholesale market and connecting to transmission pipelines directly.

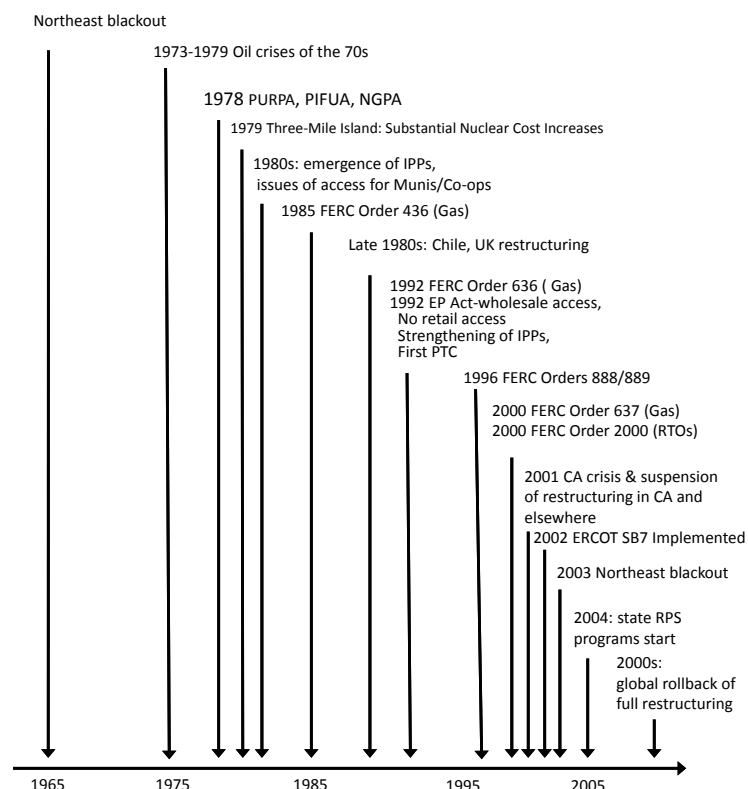
Wholesale electricity competition was further strengthened by the 1992 Energy Policy Act that authorized FERC to order "wheeling" (the transport of) of third party power over utility lines. This act also more broadly authorized new non-utility generation facilities to sell their electricity to utilities at market prices. Wholesale competition would not have been possible at the same pace and scale without the confluence of these laws and actions that allowed natural gas fired generation to become a key player from non-utility co-generation and CHP power plants. These non-utility generators sold their excess power to the utilities that could not legally burn natural gas in their own plants. Nowadays, these non-utility generators are commonly known as merchant

² Deregulation of the wellhead price of natural gas after 1978 rapidly increased gas supplies. Many of the QFs and NUGs built in the 1980s were gas-fired combined heat and power (CHP) facilities, sometimes also referred to as co-generation plants

FIGURE 1:

Milestones in U.S. electricity restructuring

Key Milestones in U.S. Electricity Restructuring

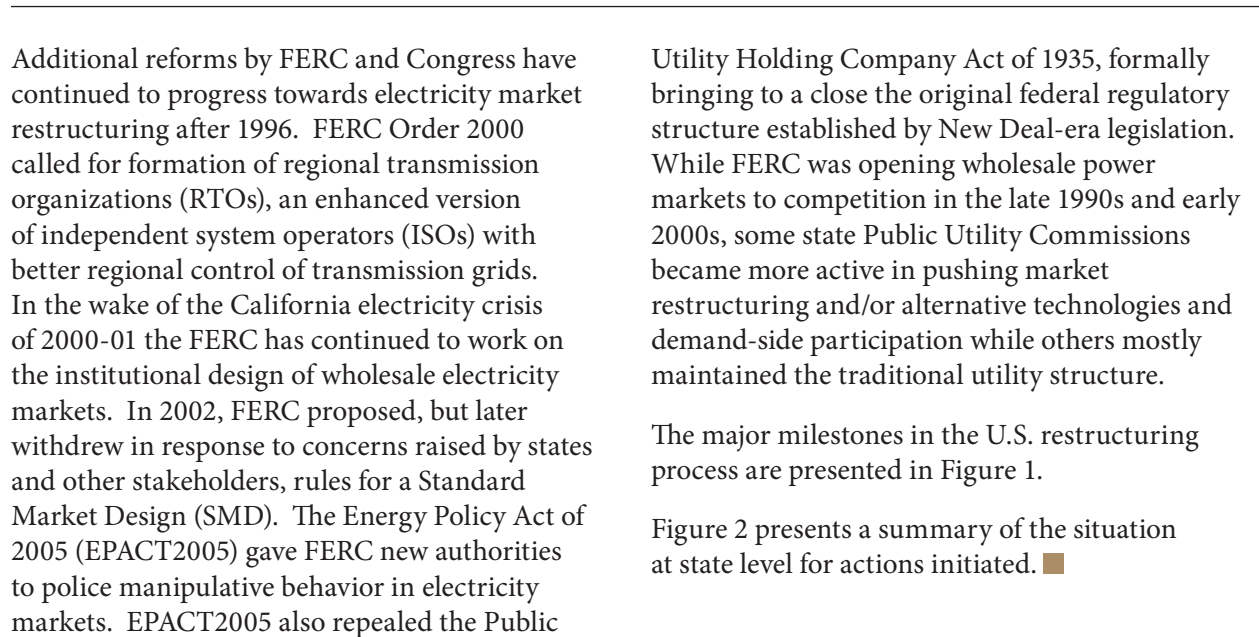


plants or independent power producers, or IPPs.

Using many of the concepts and lessons from the restructuring of the natural gas industry in the 1980s, FERC also pursued similar reforms in the electricity sector; Orders 888 and 889, issued on April 24, 1996, were particularly significant. These orders:

- Require transmission owners to offer nondiscriminatory, comparable transmission service to others seeking such services over its own facilities. This often is referred to as the "open access" rule;
- Ensure that potential suppliers of electricity have equal access to the market; and
- Encourage the creation of a separate Price Exchange to reveal market-clearing prices for electricity in the new competitive market [10].

Electricity Restructuring by state (Source EIA [11]). Restructuring implies that a monopoly system of electric utilities has been replaced with competing sellers.



3 | ELECTRICITY INDUSTRY ORGANIZATIONAL STRUCTURES

Now that we have provided an overview of the historical interplay of technology, finance, and regulation that has shaped the electricity industry, we now represent the various electric grid regulatory structures via a framework of six simplified models.

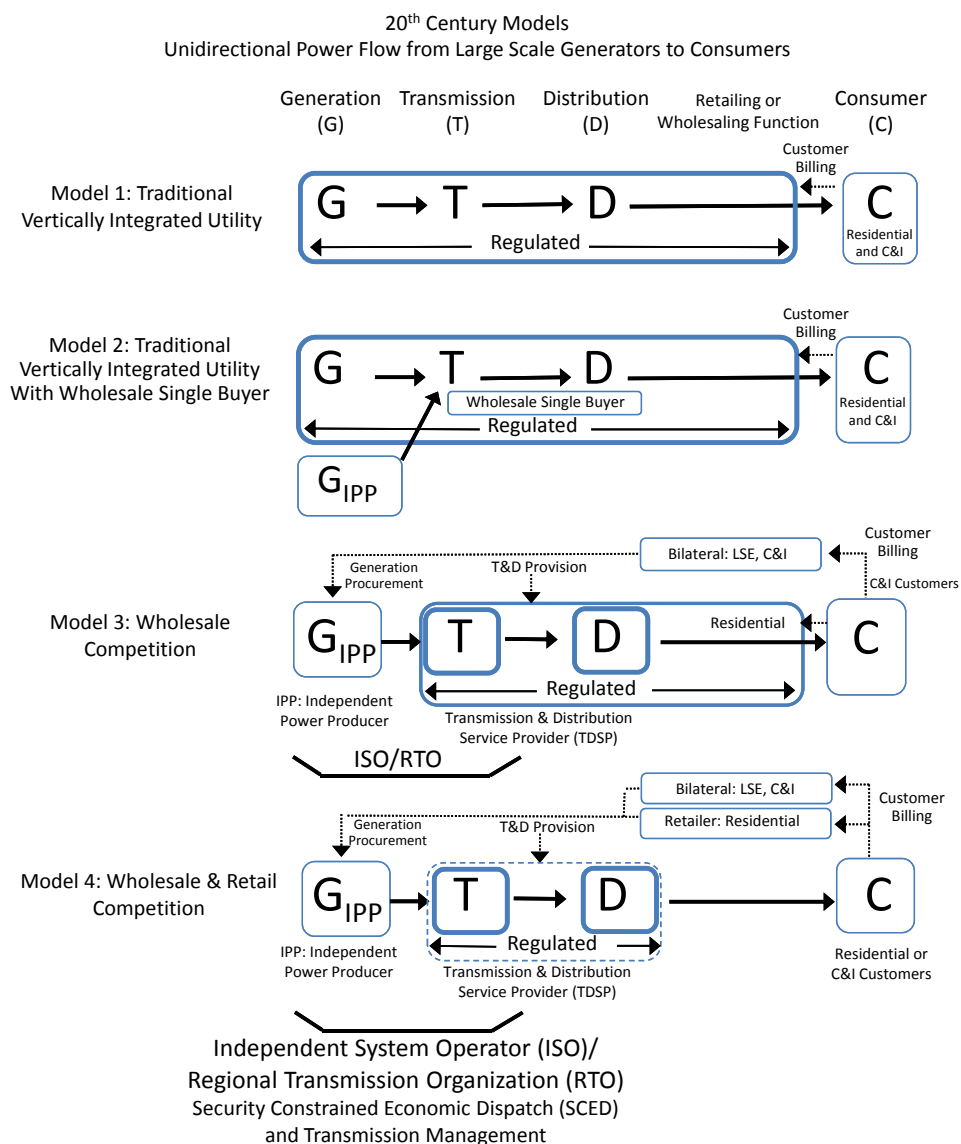
INVESTOR-OWNED UTILITIES (FOR PROFIT OWNERSHIP)

There are many ways to categorize the organization of electric utilities. From the point of view of investor owned utilities (IOUs) there are four

FIGURE 3:

Typical Investor Owned Utility (IOU) Electricity Market Structures

Different Structures of Electricity Markets



main ways of structuring the industry, although there are many possible variations on each.

Representations of each of these models are presented in Figure 3.

In the case of restructuring to competitive markets, the operation and control of the transmission (T) and distribution (D) system (in essence the grid) is still viewed as a natural monopoly, because of the requirement of central dispatch and the difficulty in building competing T&D systems given the costs and right-of-way barriers to entry. As such, the grid operations and T&D infrastructure have remained monopolies in almost all jurisdictions that experienced restructuring. Management of the grid to maintain reliability is handled by such entities as independent system operators (ISOs) or regional transmission organizations (RTOs), with oversight by regulators and other stakeholders.

Model 1 – Vertically Integrated (monopoly at all levels)

This is the traditional vertically integrated utility model. A single monopoly company handles the production of electricity and its delivery over its own transmission and distribution network to final consumers. Generation is not subject to competition and no commercial and industrial (C&I) or residential consumer has any choice of supplier (with the exception of self-generation).

State-owned electric companies around the world and many traditional IOUs fit this model. The state-owned utilities do not have the inherent conflict between owners and consumers since the consumers “own” the company (at least, in theory). For IOUs, there can be a conflict as the utility owners or debt holders (e.g., stock and bond holders) are not necessarily the utility’s customers. Even in restructured markets, one can find examples of this vertically integrated model with a monopoly service area (such as a municipally owned utility) selling electricity to its customers. There are more than 2,000 publicly owned utilities in the U.S., serving about 15% of the customers.

Model 2 – Single Buyer (limited competitive generation)

In restructured markets, different arrangements have been pursued to facilitate wholesale competition. One approach allows a single buyer, the purchasing agency, to choose from a number of different generators. Direct procurement of transmission service from competing generators to final customers is not permitted. The purchasing agency has a monopoly on transmission networks and sales to final consumers. This model allows for the integrated utility to introduce competition from independent power producers, or IPPs, that own power generation facilities. The Single Buyer model is most commonly associated with jurisdictions where a vertically integrated utility remains (often state-owned).

Model 3 – Wholesale Competition of Generation

Many countries prefer the model of Wholesale Competition to the single buyer model. This model allows Discos³ or load serving entities (LSEs) to buy wholesale electricity⁴ directly from competing producers on the transmission network and deliver this electricity over a distribution network to customers. Discos or LSEs may still have a monopoly over final consumers. There is open access to transmission lines for delivery of energy from any generator to carry power to any customer. A system operator manages the transmission system and generator dispatch. This system operator is independent of the other major market participants (generators, Discos, LSEs, and customers).

3 A “Disco” is a company that both owns the distribution wires and retails electricity. In Model 3, Discos continue to serve their captive customers at regulated rates. In Model 4, a retailer is a merchant who sells electricity to final customers, but does not own the wires over which the electricity is transported; this is the purest form of retail competition. In some regions, Discos are allowed to continue to serve as retailers in competition with non-wires retailers often driven by the problems of non-technical losses (i.e. theft). Sometimes, a retailer will be created as a separate company affiliated with a Disco, which is not ideal even if there are strong requirements for the two companies to not share information.

4 Wholesale electricity is the electricity after the point of generation, as it exists on the transmission network, before the electricity reaches final customers.

Model 3 is close to the UK system as it operated immediately after it was restructured in 1990, as well as some places in the U.S. and other restructured markets in Australia, New Zealand, Asia, and Latin America. It is probably the most common restructuring approach but with variations to reflect certain local political, socioeconomic, or technical peculiarities.

Model 4 – Retail and Wholesale Competition

This electricity market model allows all customers to choose their electricity supplier. There is open access to transmission and distribution wires, and as in the case of the Wholesale Competition model, transmission and distribution companies are usually still regulated as separate Transmission Service Providers (TSPs) and Distribution Service Provider (DSPs) or an integrated “Wires and Poles” Transmission and Distribution Service Provider (TDSP). Thus, the distribution (delivery) is separate from the retail activity, and the latter is competitive. A retailer is a merchant who sells electricity to final consumers but does not own any distribution wires.

The UK, Norway, Chile, Australia, and some U.S. states have systems that approximate to this

model, or are in a phased transition. The retail choice program in Electric Reliability Council of Texas (ERCOT) represents arguably the most competitive retail electricity market in the U.S. The market has been open since 2002, allowing even the residential customers to choose their electricity providers. However, municipally owned utilities and cooperatives have decided not to participate in retail choice. Still, there are tens of retail electricity providers (REPs) offering several hundred rate plans. In this model there are many possibilities. In the UK, most retailers sell bundled natural gas and electricity. Customers can choose and change retailers as contracts expire. This model is also expected to facilitate deployment of smart grid (e.g., smart thermostats, remote control of appliances, time-of-use pricing). However, the REPs in the ERCOT market have been slow to incorporate these technologies into their offers presumably because of uncertainty of return on investment.

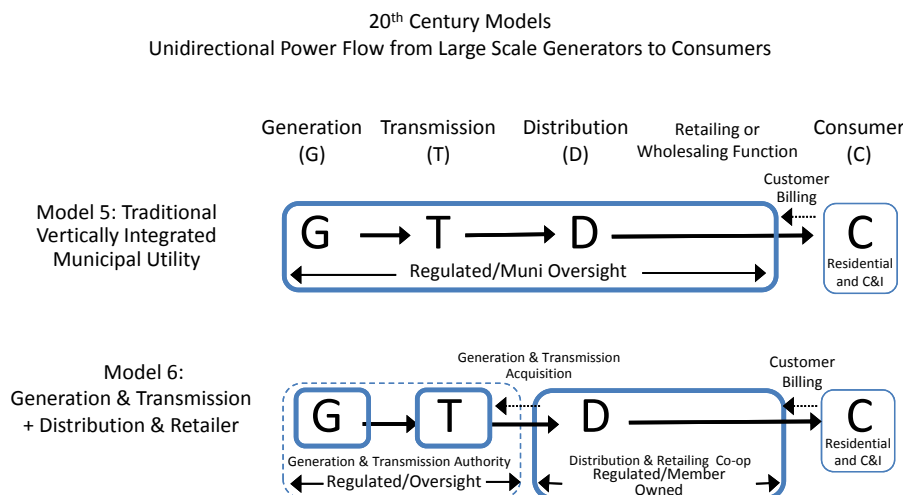
PUBLICLY-OWNED UTILITIES (NON-PROFIT OWNERSHIP)

Electric grid assets can be owned by non-profit entities, such as municipal and federal governments or member owned cooperatives

FIGURE 4:

Not-for-Profit Municipal Utilities, Generation & Transmission Authorities, Distribution & Retailing Co-ops

Different Structures of Electricity Markets



(see Figure 4). In these cases, the structure of the grid is similar to those models representing grids with for-profit ownership. In some cases, there is a mix of for-profit and non-profit ownership of assets on a single synchronized grid.

Model 5 – Vertically Integrated Municipally Owned Utilities

Some cities own their own electric utility. The municipally owned utility structure (Model 5) in Figure 4 is similar to the investor-owned, fully-integrated vertical Model 1, where the residential, commercial, or industrial consumer have no choice of supplier (with the exception of self-generation). Advantages to the electricity consumer can include the elimination of corporate income and property taxes that would be included in the cost of IOU-provided electricity service, a source of income for the municipal government, and local control. Disadvantages can include a lack of scale that may increase costs.

Model 6 – Administrations, Authorities, and Cooperatives (Co-Ops)

Figure 4 also shows the model successfully deployed in areas that did not have sufficient population density to attract service by investor or

nearby municipally owned utilities. These areas were without power until rural electrification efforts began in the 1930's. A few of these organizations also experienced significant growth in capacity to provide massive amounts of energy for critical World War II projects. Generation and transmission services can be provided by Federal Power Marketing Administrations (such as the Bonneville Power Administration), agencies such as the Tennessee Valley Authority (TVA), state created non-profit firms (e.g. Lower Colorado River Authority), or generation & transmission (G&T) co-ops. These G&T entities generate and transmit bulk power to rural co-ops or municipal utilities. Even with the separation of generation and transmission from distribution, the consumer has no choice of supplier (again, with the exception of self-generation) but possibly has the ability to influence investment decisions (e.g., as a co-owner of a cooperative or citizen of a city that owns its municipal utility). ■

4 | PERSPECTIVES ON THE FUTURE

A fundamental assumption that led to the initial regulatory model of the electric industry was that the provision of electricity was most economically achieved through scale economies that favored vertical integration and centralized generation. Accordingly, the regulatory model was based on the notion that regulatory commissions need to ensure that the consumers pay as little as possible for reliable and pervasively available electricity service. In order to achieve that main goal, regulators have sought to oversee the utilities to ensure that the utilities are investing in available technology to keep current prices low, allow the utilities to make sufficient profits so they can raise necessary funding in the capital markets, and monitor to ensure the utilities are operating in a manner that does not cause undue harm to public health and welfare. When it works well this is a political process that appropriately allocates costs and benefits in a complex, rapidly changing environment. When the structure does not function well, customers can suffer from increased costs and poor service.

The restructuring of the electricity industry has led to competition in wholesale markets, and, in some cases, retail markets. More efficient generation technologies, such as combined-cycle-gas-turbines, have benefited from and supported wholesale electricity competition. In most jurisdictions, including both restructured and traditionally regulated, policymakers have also been increasingly pursuing environmental goals. However, maximizing environmental performance and maximizing economic efficiency are distinct goals, and are sometimes in tension with one another.

Tax policies (federal and state), state renewable portfolio standards (RPS) programs, and environmental (air, land, water, climate) regulations have introduced technologies that compete with existing thermal generators. These include wind, solar (both distributed rooftop, and utility-scale PV, concentrated solar thermal), demand side management (energy efficiency,

demand response), and storage (batteries, flywheels, compressed air). Some communities promote these technologies for social and environmental reasons as well as reliability (e.g., community solar). It is interesting to note that RPS programs can be partially driven by state economic development goals as well as environmental considerations. State regulators have modified their rules to accommodate these technologies.

These trends pose continuing challenges for grid operators. Distributed resources and demand side participation can be particularly challenging with retail competition. The retail market structure may not encourage the investment required to exploit load that may be flexible. The relative ease for end-consumers to switch retail electricity providers can create disincentives for investments in intelligent distributed resources. The trend toward distributed energy resources represents an important departure from historical practice.

TECHNOLOGICAL CHANGE CONTINUES

Intermittent renewable electricity generation technologies do introduce some challenges for utilities, ISOs, and regulators. In competitive markets renewables enjoy certain advantages. The zero fuel costs, low operating costs, and low life-cycle emissions encourage deployment. However, the intermittency of these sources is forcing the grid operators to depend upon (and value) more flexible generation sources elsewhere on the grid to compliment the intermittent renewables in order to maintain reliable electric service. It is important to note that baseload power generation (e.g. nuclear and coal) with more constant output typically also needs to be complimented with flexible dispatchable generation to adjust the total power supply to match the constantly varying demand. Wind power fits the existing traditional electricity model fairly well because it is generally implemented as large-scale wind farms remote from the load, a typical scenario for a modern ac power system. The major challenge anticipated

in system dispatch by the grid system operator is to maintain stability and reliability by “firming” the renewable generation by simultaneously varying the output of traditional gas, coal, or hydro generation. To date, relatively modest levels of intermittency related to wind and solar power generation within major North American grids are handled via adjustments to existing system dispatch protocols that were already in existence to handle the intermittency related to unpredictability of loads and generator trip-outs. Improvements in wind and solar generation forecasting techniques have also helped. Despite the challenges of forecasting loads and renewable generation output, some small electric grids, such as on Oahu, Hawaii, have been able to reach high percentages of wind and solar generation relatively quickly, through the deployment of new technologies and regulatory adjustments.

Many believe that eventually solar photovoltaic (PV) power will be more widely adopted than wind power. Solar generation is becoming increasingly attractive. PV can be installed in smaller distributed applications or large utility scale solar farms (30-100MW+) as an IPP. Solar PV power output is inherently dc and appears to be relatively well matched to many modern load patterns. For example, peak solar PV generation occurs during the summer daytimes when air-conditioning loads are highest, though the exact hourly timing of the peak PV and air-conditioning load usually does not precisely match. More importantly, PV shows promise of becoming cost effective from large utility-scale installations, community level systems attached to neighborhood distribution circuits, and with smaller distributed rooftop installations on the home or business. Solar PV is a technology that brings back the initial concept of neighborhood dc power, but its integration can now be made even more robust by overlaying a dc microgrid with the existing ac transmission and distribution grid for those customers with the most demanding reliability requirements.

Wind and solar power show promise to be truly disruptive, as they might become (based on current cost trends) the least expensive ways to generate electricity in some regions on a levelized cost basis, not considering system costs such as

new transmission lines and balancing generation. Incremental transmission and balancing costs may or may not be consequential. The levelized cost of electricity (LCOE) is a commonly used metric for comparing different generation types. Typically expressed on a \$/kWh basis, it combines capital and operating costs to estimate the amount of money that it takes for a particular electricity generation plant to produce a kWh of electricity over its expected lifetime [12].

The impact of renewables is even more pronounced in dispatch decisions and spot markets for electricity, where the marginal cost of providing the next kWh is what matters. Since its marginal costs are effectively zero, wind can be dispatched at prices lower than conventional resources, even at negative prices at times, owing to federal tax credits and renewable energy trading credits. Such prices, driven by out-of-market subsidies provided to these generation technologies, can undermine energy price signals in competitive electricity markets. However, many of these subsidies expire over time. Renewable energy proponents sometimes argue that the competitive markets themselves are not complete since they do not fully internalize many important factors, such as health impacts from air emissions. Many emissions regulations have been implemented since the 1970s, helping to internalize some of these costs.

Renewable electricity generation output is both predictably variable with such factors as the time of day and sometimes intermittent with the changing of wind and cloud patterns. Grid operators have managed to incorporate significant amounts of wind power to date with little impact on reliability. However, as far larger amounts of renewables are installed, fast ramping thermal generation, energy storage, and more flexible load are likely to become more important. The electric industry will need to balance the grid using the legacy grid assets (e.g., natural gas power plants), even more advanced forecasting techniques, and perhaps eventually increased forms of energy storage. These options, however, are not mutually exclusive, and these technology changes are driving changes in both regulation, wholesale market structure, and financing of the electric sector.

Demand that is responsive to price signals (e.g., lower when prices are high) can reduce generator or utility revenues. Energy storage can be deployed in a number of places on the grid, including on the customer site that might enhance the level of demand response. Only a few of these storage configurations are financially attractive at this time. As storage prices decline, more regionally specific market applications for grid storage may become economic for various grid needs. Storage can be co-located near intermittent renewable generation to “firm” its output. Large-scale storage such as CAES, pumped hydro, or thermal storage could be attached to the transmission system. Local storage such as batteries could be installed at various interconnection points with the distribution network. “Behind the Meter” storage can be co-located with a customer’s load to reduce utility demand and energy charges.

There are other technologies that might impact the future of the electricity grid. Some have been around a long time but technology improvements and recent changes in market rules might render them more attractive. For example, micro-turbines that burn natural gas to generate electricity might make sense in some places as a distributed resource. Combined heat and power (CHP), which is one of the most efficient ways to utilize fuels, in large commercial and industrial applications may prove to be attractive for communities or municipalities. Batteries are not new either, but new material compositions may bring lower battery costs, in which case their deployment can be accelerated. Other technologies are relatively newer with a relatively small number of units deployed. Storage options such as compressed air energy storage (CAES) or thermal storage can find larger applications if they can be optimized to reduce costs. The storage of CO₂ through carbon capture and sequestration (CCS) might allow some traditional thermal capacity to remain as part of grids that might need to operate with lower CO₂ emissions. Small modular nuclear reactor (SMRs), the first “commercial” site of which might be built in the next few years, can be a game-changer if they prove to substantially reduce costs. Finally, there is significant activity in energy efficiency, conservation, and

flexible loads that can alter load profiles, and, hence, the way grids operate by changing the relevance of demand-side participation.

FINANCIAL CHALLENGES FOR UTILITIES

Utilities face increased affordability of distributed generation, particularly rooftop photovoltaic (PV) panels, and stagnant or declining electricity demand in the U.S. since 2007. These trends can lead to the underutilization of large, costly, and long-lived fixed utility assets (e.g., power plants, transmission, or distribution assets) compared to the expected utilization rates that were used in the original investment decision-making and regulatory approval. Thus, these assets are at risk of becoming a “stranded cost” or a cost that cannot be fully recovered. When markets were being restructured, utilities were concerned that their investments recently approved by the regulators would not recover their costs if the energy prices declined rapidly as a result of competition or new technology. Finding this concern legitimate in certain cases, policymakers granted ways to recover these stranded costs.

In restructured markets, new technologies can make large and long-lasting investments economically obsolete relatively quickly. The electric system includes transformers, transmission lines and power plants that are 50 years old or more, for example. The financial markets are reluctant to make these longer-term investments in an uncertain environment, at least not without a significant premium to cover the risk or without assurance that stranded costs will be recovered. The regulatory response can be to identify stranded costs that will be recovered independent of system evolution. Stranded cost recovery can in some circumstances shift the risk from the utility investors to the consumers by increasing the cost of electricity to customers. For example, if a utility is able to charge its customers for stranded assets (e.g., those retired early due to lack of economic operation), then the customers’ electric rates (e.g., \$/kWh charged on their bill) or fixed charges may increase even while the fuel costs of electricity generation decrease creating a customer backlash that may be of concern to regulators.

The issue of declining revenues, due to distributed generation and lower demand more generally, impacts the ability of electric utilities to access less expensive capital to fund new investments. As noted by Peter Kind in his report to the Edison Electric Institute, “Since practically all utilities have an ongoing need for capital to fund their capital expenditure programs, the industry has developed financial policies intended to support the access to relatively low-cost capital in (practically) all market environments. Under traditional cost-of-service ratemaking, customers benefit through lower cost of service and, therefore, lower rates” [13]. If future revenues become more in doubt for utilities, then they are pressured to raise their rates (e.g., \$/kWh charges) to pay existing debts, and future capital might come at a higher cost, again putting upward pressure on electricity rates. These upward pressures on electricity rates only enhance the incentives for further electricity conservation (or load defection to distributed generation) by consumers, a trend described as the “utility death spiral.” The extent to which this death spiral will play out is uncertain, but it is one of the many important motivations for understanding the Full Cost of Electricity. One of the policies that have been helpful to the expansion of rooftop solar PV around the country, net metering, has been under pressure. Utilities observed that there was a loss of revenues resulting from the expansion of rooftop solar while they are required to maintain the same infrastructure under rates approved by regulators for larger loads. At the time of writing, a couple of state utilities have revised their rules to address this concern deeming it legitimate from a ratemaking perspective. Other states and utilities are evaluating similar policies.

CUSTOMER ELECTRICITY COSTS

A customer’s electricity bill consists of different charges. In jurisdictions without competition, the rate will generally reflect generation and T&D costs but be set by the regulator or the government. In competitive markets, the regulated T&D charges are fixed over a relatively long period of time. These rates are fixed because the assets are long-lived (measured in decades) capital investments generally financed with long term debt and amortized over 20 to 30 years. The unregulated

cost of electricity (energy charges) will vary along with the wholesale price that varies over the course of days, seasons, or longer commodity price or technology cycle periods, but utility economists have become more expert at achieving an average cost due to the predictability of the average (not instantaneous) cost and load. The proportion of fixed charge related to long-term capital asset investments and variable energy generation related charges in a customer bill have varied over time and across jurisdictions.

In some states, ratemaking policies allow for some cross-subsidies between residential and larger commercial and industrial consumers. Block rates can be pursued to encourage conservation and efficiency (e.g., much higher rates above a certain level of consumption) despite sometimes-lower fixed cost amortization costs with higher volumetric energy sales. Fixed charges can increase meaningfully if new transmission and distribution investments are mandated by the regulator or the legislature to accommodate remote resources such as wind or solar (e.g., Competitive Renewable Energy Zone transmission lines in ERCOT). These increases in fixed charges may or may not be offset by decreased generation costs.

Historically, reliability has been an important objective of all electricity systems. In some competitive regions, generators are compensated for the capacity they make available to the grid via long-term capacity markets in addition to energy they sell into the energy markets every hour. These capacity charges are also fixed in customer bills for extended periods of time. As such, changes in customer bills can arise from regulated infrastructure charges or capacity charges as well as market-based energy charges. In recent years, given that the low price of natural gas has kept wholesale electricity prices very low, increases in customer bills in competitive jurisdictions are most likely the result of investment in new T&D and/or generation infrastructure.

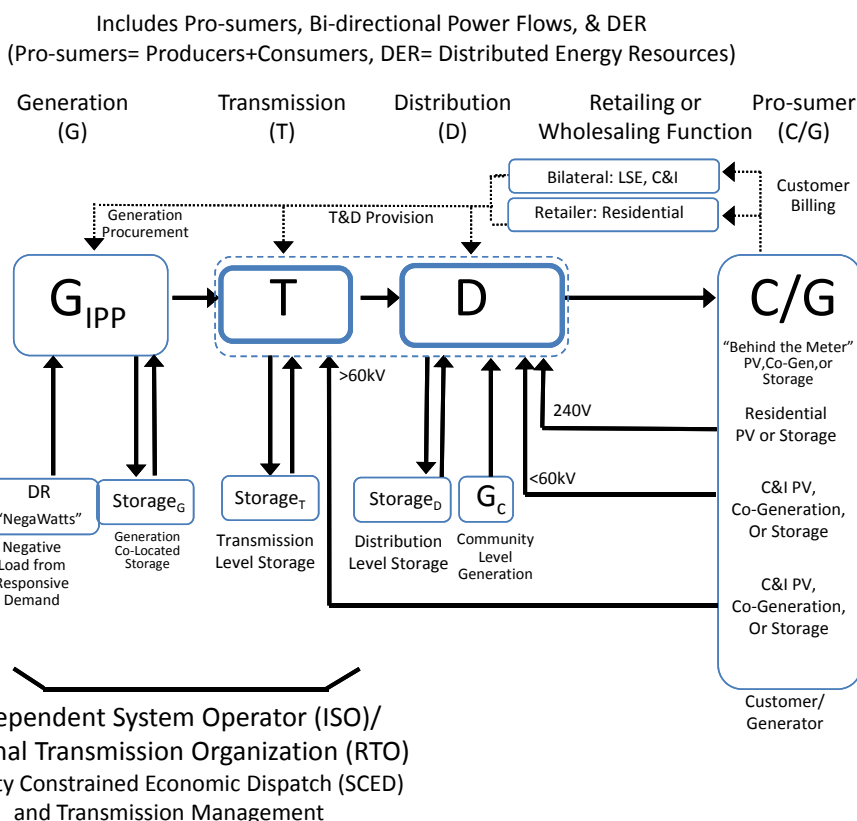
EVOLVING ELECTRIC GRID ORGANIZATIONAL STRUCTURES

Technological progress and cost reductions have introduced additional complexity and challenges to the previously described utility models of Figures

FIGURE 5:

Disruptive Technologies to the Existing Utility Model

21st Century Electricity Market Example



3 and 4. These changes are fostering even more complex business and regulatory models where customers can increasingly purchase electricity services from multiple vendors for multiple purposes (e.g., demand response (DR), distributed generation, energy storage) and in multiple ways (see Figure 5). Storage and generation systems can technically be located on multiple parts of the grid depending upon capabilities and needs.

Community level solar systems connected to the distribution system can reduce transmission loading and allow distribution companies or cooperatives to own small-scale generation for the first time or provide unique customer ownership opportunities for those who cannot install rooftop PV on their residences. Rooftop PV or cogeneration systems at homes and businesses can be a utility-owned distributed generation resource or customer-owned generation that reduces utility revenue. All of these configurations can provide an opportunity to improve (or complicate) the utility model, their finances, and in some cases the

technical operation of the grid. The emergence of distributed energy resources (DERs) either on the utility side of the meter, or behind the customer meter, may become a transformative force to the utility industry. While the discussions of such concepts as “transactive energy” and the models of distributed system platforms (DSP) or independent distribution system operators (DSOs) are beyond the scope of this paper, these concepts are part of ongoing restructuring efforts in a number of states. These efforts are attempts to accommodate new technology alternatives, associated business structures, market design, and the supporting regulatory structure to meet stakeholder objectives for their 21st century energy systems [14][15][16][17].

There will also likely be an increased demand for newer and more customer-centric regulatory frameworks that allow an increased number of technologies to be owned and operated by a larger number of players that serve more diverse customers. ■

5 | CONCLUSION

For a century, the scale economies associated with large centralized generation technologies encouraged vertical integration, drove down the cost of electricity, fostered universal access that improved citizens' quality of life, and provided for reliable electric service. The structure of the electricity industry started to evolve significantly starting in the 1970s. Higher fuel prices, environmental concerns, technological innovations and efforts to improve the economic efficiency of electricity service led to the rethinking of the traditional vertically-integrated, regional monopoly model. In the late 1970's and 1980's a series of government decisions deregulating wellhead natural gas prices and the pipeline industry made natural gas-fired electric power much less expensive. These efficient non-utility co-generation/CHP gas powered generators were some of the first disruptive technologies and firms that threatened the traditional vertically integrated utility model.

By the mid-1990s, policy makers began to restructure the electricity system, seeking to promote innovation and reduce electricity costs while incorporating policies that addressed environmental concerns. Federal

and state governments implemented environmental regulations, tax credits, and other programs that encouraged deployment of renewables such as wind and solar.

Continuing declines in the cost of wind and solar PV, inexpensive natural gas combined with flexible and efficient combined cycle gas plants, micro grids, and energy storage and demand response systems with progressively lower costs continue to provide opportunities to improve the traditional utility business model. These technology developments are strongly encouraging the industry to consider new technology and business models, policy makers to consider alternative regulatory and electricity market structures, and electricity customers to pursue self-generation, storage, or responsive demand capabilities that have the potential to significantly reduce utility revenues and profitability. With so many moving pieces, the policy and investment environment can be uncertain. The companion papers of the FCE- project and related research by team members offer more insights into the technologies, trends, or considerations that lead to disruptive changes and uncertainty. ■

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BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c)	)	
Emergency Order: Tri-State	)	Order No. 202-25-14
Generation and Transmission	)	
Association, Platte River Power	)	
Authority, Salt River Project,	)	
<u>PacifiCorp, and Xcel Energy</u>	)	

Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
Public Interest Organizations

Filed January 28, 2026

Exhibit 1-109:
PacifiCorp 2025 Oregon RFP



825 NE Multnomah Street, Suite 2000
Portland, Oregon 97232

October 15, 2025

VIA ELECTRONIC FILING

Public Utility Commission of Oregon
Attn: Filing Center
201 High Street SE, Suite 100
Salem, OR 97301-3398

Re: UM 2383—PacifiCorp's Informational Filing

PacifiCorp d/b/a Pacific Power encloses for filing in the above-referenced docket its informational filing to provide notice that the 2025 Oregon Situs Request for Proposals (RFP) has been issued to market. PacifiCorp provides the following RFP, which has been informed by conversations with the Oregon Public Utility Commission Staff and the Independent Evaluator.

If you have any questions about this filing, please contact Amira Thompson, State Regulatory Affairs Manager, at (503) 260-4420.

Sincerely,

A handwritten signature in dark ink, appearing to read "Robert Meredith", with a stylized flourish at the end.

Robert Meredith
Director, Regulation

Enclosures



**2025 Oregon Situs
Request for Proposals
(2025 OR Situs RFP)**

**ISSUED: October 13, 2025
BIDS DUE: November 18, 2025**

**PacifiCorp
2025 OR Situs RFP
Resource & Commercial Strategy
2025ORSitusRFP@pacificorp.com**



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SECTION 1. OVERVIEW

A. PURPOSE AND SCOPE OF RFP

The PacifiCorp 2025 Integrated Resource Plan (IRP) established an action item to initiate a Request for Proposals (RFP) to procure resources for its Oregon customers that are aligned with the 2025 IRP preferred portfolio and that can achieve commercial operations by the end of December 2029.¹ The 2025 IRP calls for 1,570 megawatts of utility scale solar resources, 1,400 megawatts of utility-scale wind resources, and 320 megawatts of small-scale solar resources by the end of 2029. The 2025 IRP also calls for energy storage resources, including 509 megawatts of lithium-ion batteries with four-hour duration, and 272 megawatts of iron-air storage with 100-hour duration by the end of 2029. This RFP is seeking resources that are agnostic to both duration and technology type.

Consistent with these identified needs, the 2025 OR Situs RFP will accept and evaluate cost-competitive bids for resources with the following characteristics:

1. Minimum nameplate capacity of 1 megawatt;
2. Generates electricity from wind, photovoltaic (PV) solar, wave, geothermal, hydroelectric, biomass, or other sources of energy that support compliance with Oregon's House Bill 2021 emissions reduction requirements.
3. Storage resources (e.g., battery);²
4. Have a guaranteed commercial operation date (GCOD) on or before December 31, 2029;³
5. For Renewable Portfolio Standard (RPS)-eligible resources, the resources must be approved or certified by the Oregon Department of Energy as RPS-eligible generation resources (RPS Certification) within 90 days of commercial operation date (COD), and will maintain RPS Certification throughout the duration of any agreement with PacifiCorp;⁴
6. The bids submitted reflect firm pricing at the time of bid and pricing is held firm through June 22, 2026; and
7. The bids meet the minimum eligibility requirements of this RFP listed in Section 3.G Minimum Eligibility Requirements for Bidders, and otherwise complies with the requirements of this RFP.

¹ PacifiCorp 2025 Integrated Resource Plan, Chapter 1, Action Item 2b.

² For bids including storage, additional criteria are in Appendix C-2 Bid Summary and Pricing Input Sheet.

³ E.g., Section 11.1.2 in each of the two pro forma power purchase agreements. Commercial operation dates prior to December 31, 2029, must have a contract term that terminates no earlier than December 31, 2034.

⁴ OAR 860-091-0030(1) Projects used to comply with the standard in ORS 469A.210(2) must be an Oregon Renewable Portfolio Standard-approved generator.



Questions about minimum eligibility requirements or any other questions concerning the information presented in this RFP issuance may be submitted to PacifiCorp at: 2025ORSitusRFP@pacificorp.com for clarification.

This document outlines the 2025 OR Situs RFP process and requirements. **PACIFICORP IS NOT BOUND TO ACCEPT ANY BIDS AND MAY CANCEL OR SUSPEND THIS SOLICITATION AT ANY TIME AND AT ITS OWN DISCRETION.**

B. INTERCONNECTION REQUIREMENTS

Bidders submitting resources into the 2025 OR Situs RFP must demonstrate the ability of the bid resources to interconnect to a transmission or distribution system by providing one of the following: 1) a completed interconnection system impact study and/or facilities study, or, 2) for bids indicating interconnection service to PacifiCorp Transmission's system (on system bids), confirmation from PacifiCorp Transmission that bidder's proposed interconnection request has passed the screens as part of the Initial Review process or Supplemental Review process in the Fast Track Process for small generation interconnection service⁵, or 3) a signed interconnection agreement. An informational interconnection study is not sufficient interconnection documentation to be considered eligible for the 2025 OR Situs RFP.

For any bid that is proposing to interconnect to a third-party transmission system and secure transmission service to deliver the output of the resource to PacifiCorp at PACE or PACW, the bidder must provide 1) a completed system impact and/or facilities study by the third-party transmission provider, confirming ability to interconnect to the third party's transmission or distribution system, if such study or agreement is completed, and 2) satisfactory evidence⁶ that long-term, firm, point-to-point transmission rights or Bonneville Power Administration's conditional firm bridge transmission rights, are already secured in bidder or project owner's name or readily obtainable by bidder to deliver the full output of the resource to PacifiCorp on or before December 31, 2029.

⁵ "Fast Track Process", "screens", "Initial Review" and "Supplemental Review" are all described in PacifiCorp Transmission's Open Access Transmission Tariff (OATT).

⁶ Transmission service documentation demonstrating ability to deliver to PacifiCorp's system is two-fold: first, long-term, firm transmission service or Bonneville Power Administration's conditional firm bridge transmission service, is available from a third-party transmission provider and second, the bidder has made a request to the third-party transmission provider to acquire long-term firm point-to-point transmission service or Bonneville Power Administration's conditional firm bridge transmission service, to PacifiCorp's system. Documentation must include copies of direct, dated correspondence from transmission service provider to the bidder, showing evidence of a request for transmission service, and the transmission provider indicating to the bidder that long-term, firm, uninterruptible transmission service or Bonneville Power Administration's conditional firm bridge transmission service, will be available for the bidder to procure, for a specified OATT service, and an identified MW capacity, point of receipt, point of delivery, and term. Dated correspondence must be at least within six (6) months of bid submittal.



C. TRANSACTION TYPE

PacifiCorp is accepting qualified proposals for transactions using 1) existing resources from bidders who currently own or have legally binding rights to operate existing resources, and 2) new resources from bidders with development rights to construct new resources. PacifiCorp will accept bids in the 2025 OR Situs RFP from existing operating facilities subject to the following conditions:

1. Bidders cannot terminate an existing contract with PacifiCorp to bid into the 2025 OR Situs RFP; and
2. The existing contract must expire before the required on-line date as identified in a bidder's proposal, but no later than December 31, 2029; and
3. The submitted bid must meet all other requirements in the 2025 OR Situs RFP.

PacifiCorp will consider proposals with the following transaction structures:

1. **Power Purchase Agreement (PPA)** transaction for exclusive ownership by PacifiCorp of any and all energy, capacity, ancillary services (including reactive power) and environmental attributes associated with the generation (and storage if included in the bid). PacifiCorp will consider PPA terms between 5 and 20 years. PacifiCorp provides two forms of PPA: generation-only resources and generation resources collocated with a battery energy storage system (BESS) resource. With respect to collocated resources, the term length must be the same term for both the generation and the storage resource. PacifiCorp requires full dispatch control of the collocated or standalone battery (charge and discharge) as addressed in contractual terms in the applicable appendices to this RFP.
2. **Stand-alone Energy Storage Agreement (ESA)** transaction whereby PacifiCorp controls the output of a standalone storage resource (BESS, Pumped storage hydro (PSH) or other). PacifiCorp will consider energy storage agreement terms between 5 and 20 years.

In order to provide for a transparent and fair process, the RFP will be conducted under the oversight of an Independent Evaluator (IE) as further described in Section 2.A Independent Evaluator. The IE will have been involved in the development of the RFP and will ensure the RFP process is conducted in a fair and reasonable manner. Potential bidders are invited and encouraged to contact the IE with questions or concerns. More information concerning the role of the IE is provided in **Appendix M – Role of the Independent Evaluator**.

D. OPERATING CAPABILITIES OF THE RESOURCE

All bids must have the ability to comply with technical and operating specifications for Automated Generation Control (AGC) for automated signal operation and Automatic Voltage Regulation functionality and be capable of following a four second signal. Bidders must review and understand the North America Electric Reliability Corporation (NERC)



guidelines regarding technical requirements.⁷ Additional information concerning AGC is in the pro forma PPA attached in **Appendix E-1 – PPA for Generation Only, Appendix E-2 – PPA for Generation with Storage, and Appendix E-3 for Energy Storage Agreement.**

SECTION 2. PROCEDURAL ITEMS

PacifiCorp will evaluate proposals based on the following:

1. Conformance with the RFP minimum eligibility requirements,
2. Final score and ranking for each conforming bid, per Section 6 Bid Evaluation and Selection.
3. Technical design, feasibility, and compliance with the documentation in **Appendix A – Technical Specifications and Required Submittals**,
4. Ability to provide acceptable credit security as determined per **Appendix D – Bidder’s Credit Information**, and
5. Acceptance of the standard form PPA and/or ESA contract provided in **Appendix E-1 - PPA for Generation Only, Appendix E-2 - PPA for Generation with Storage, or Appendix E-3 - ESA for Energy Storage.**

A. INDEPENDENT EVALUATOR

PacifiCorp is conducting the 2025 OR Situs RFP under the oversight of an IE. The IE will be retained by PacifiCorp on behalf of the Public Utility Commission of Oregon (Oregon Commission) as required by Oregon Administrative Rules § 860-89-200.¹ The IE will be involved in the RFP and provide oversight to ensure the RFP process is conducted in a fair and reasonable manner. Potential bidders are invited and encouraged to contact the IE with questions or concerns. More information concerning the role of the IE is provided in **Appendix M – Role of the Independent Evaluator.**

Contact information for the IE is as follows:

Independent Evaluators:
OREGON – PA Consulting Group, Inc. 2025AS_PAC_IE@paconsulting.com

B. STANDARDS OF CONDUCT; SEPARATION OF FUNCTIONS

Each bidder responding to this RFP must conduct its communications and activities in recognition of PacifiCorp’s obligation to comply with the Federal Energy Regulatory

⁷ Please refer to NERC, Improvements to Interconnection Requirements for BPS-Connected Inverter-Based Resources, September 2019.



Commission (FERC)'s Standards of Conduct for Transmission Providers in **Appendix I – Standards of Conduct; Separation of Functions**, which require the functional separation of PacifiCorp's transmission and merchant functions. Interconnection with or transmission service on PacifiCorp's system is arranged through PacifiCorp's transmission function, and not PacifiCorp's merchant function, which administers this RFP. As part of a bid submittal, bidders will be requested to execute a customer consent form provided in **Appendix J – Seller Authorization to Release Generation Data to PacifiCorp** that enables PacifiCorp's merchant function to discuss the bidder's interconnection and/or transmission service application(s) with PacifiCorp's transmission function.

C. CONFIDENTIALITY

Bidders will be required to execute a confidentiality agreement in the form provided in **Appendix G-1 – Confidentiality Agreement**. As provided in the form of confidentiality agreement, PacifiCorp will endeavor to maintain the confidentiality of all bids submitted, to the extent consistent with law or regulatory order. It is the bidder's responsibility to clearly indicate in its proposal what information it deems to be confidential and subject to the terms of the executed confidentiality agreement. Bidders may not mark an entire proposal as confidential, but bidders must mark specific information on individual pages to be confidential to receive confidential treatment for that information under the terms of the executed confidentiality agreement.

All information supplied to PacifiCorp or generated internally by PacifiCorp is and will remain the property of PacifiCorp. To the extent bidder receives information from PacifiCorp, bidder must maintain the confidentiality of such information and such information may not be provided to any third-party before, during or after this RFP process unless required by law or regulatory order.

D. PACIFICORP'S RESERVATION OF RIGHTS AND DISCLAIMERS

PacifiCorp reserves the right, without limitation or qualification and in its sole discretion, to reject any or all bids, and to terminate or suspend this RFP in whole or in part at any time. Without limiting the foregoing, PacifiCorp reserves the right to reject as non-responsive any or all bid proposals received for failure to meet any requirement of this RFP. PacifiCorp further reserves the right without qualification and in its sole discretion to decline to enter into any agreement with any bidder for any reason, including, but not limited to, change in regulations or regulatory requirements that impact PacifiCorp, and any evidence of collusive bidding or other anticompetitive behavior or conduct of bidders.

Bidders who submit bid proposals do so without recourse against PacifiCorp, its parent company, its affiliates and its subsidiaries, against any director, officer, employee, agent or representative of any of them, or against the Independent Evaluator, for any modification or withdrawal of this RFP, rejection of any bid proposal, or failure to enter into an agreement.



SECTION 3. GENERAL INFORMATION AND LOGISTICS

A. SCHEDULE

The proposed 2025 OR Situs RFP schedule is shown below and is subject to change.⁸

Event	Date
RFP issued to market and publicized	10/13/2025
Bidder workshop	10/21/2025
Last day for bidder questions to PacifiCorp and the IE	11/12/2025
Bid submissions due with pricing and issues list	11/18/2025
Staff/ IE proposals on model runs	12/2/2025
Staff hosted workshop on model runs	12/4/2025
Stakeholder comments on whether additional model runs are needed	12/18/2025
Staff/ IE final required model runs	1/6/2026
Bid evaluations, and IE review complete	4/1/2026
IE Report on final shortlist complete	4/14/2026
Commission acknowledgment	6/15/2026
Contracts finalized and executed ⁹	6/22/2026
Issuance of Second Phase of RFP	8/15/2026
Guaranteed commercial operation date (GCOD)	12/31/2029

The schedule above is subject to change. Actual dates may vary for reasons that include, but are not limited to, negotiation time, availability of key personnel, regulatory delays, due diligence, the evaluation or negotiation of any issues unique to any bid, bidder, or facility. PacifiCorp is not responsible for any costs or damages to bidders alleged to be attributable to changes in the RFP schedule stated above. PacifiCorp is not obligated to develop a shortlist of bidders, to make a final selection, or to initiate or complete negotiations on any transaction.

The schedule above also reflects the expectation from the Oregon Public Utilities Commission Order No. 25-343: “We expect PacifiCorp to engage with Staff and stakeholders on their analysis, including providing additional model runs in the list

⁸ Any schedule changes will be posted to PacifiCorp’s 2025 OR SITUS RFP website:

<https://www.pacifiCorp.com/suppliers/rfps/2025-oregon-situs-rfp.html>

⁹ This date is aspirational and contract execution may occur after this date.



development process, if necessary, and we reinforce the need for these analyses to support prudence review.”

Bidders must be available for calls and meetings with PacifiCorp regarding bid submittals and be responsive to bid deficiency questions within two (2) business days.

B. 2025 OR SITUS RFP BIDDER WORKSHOP

A bidder workshop will be scheduled and will cover the 2025 OR Situs RFP structure, deliverables, schedule, requirements, required forms and interconnection requirements. The bidder workshop will be scheduled as Microsoft Teams meetings for remote attendance. Additional details on the bidder workshop will be posted to the PacifiCorp website at <https://www.pacificorp.com/suppliers/rfps/2025-oregon-Situs-rfp.html>.

C. SUBMISSION OF QUESTIONS

Bidders may submit questions related to this solicitation by email, and PacifiCorp will respond in a timely fashion. While PacifiCorp will maintain the confidentiality of the party posing questions, all questions as well as PacifiCorp’s response to questions will be posted on the PacifiCorp website at <https://www.pacificorp.com/suppliers/rfps/2025-oregon-Situs-rfp.html>.

Bidders may submit questions to PacifiCorp and the IE by email at:

PacifiCorp: 2025ORSitusRFP@pacificorp.com and IE: 2025AS_PAC_IE@paconsulting.com

All questions submitted to PacifiCorp will be shared with the IE.

D. SUBMISSION OF BIDS

Each proposal submitted must include a cover letter signed by one or more representatives with the requisite corporate or other organizational authority to approve and submit the bidder’s proposal.¹⁰ Additionally, the cover letter must also include the following declaration, which may not be edited without the express approval of PacifiCorp:

“[Insert legal name of bidder] acknowledges receipt of PacifiCorp’s 2025 OR Situs Request for Proposal on or about [DATE]. The bidder makes the following representations to PacifiCorp:

1. All the statements and representations made in this proposal are true to the best of the bidder’s knowledge and belief.

¹⁰ If the proposal is bid under a partnership, the partnership must be fully established, including a legally binding agreement among the partners (not a letter of intent), before submission of a proposal under this RFP. Each partner must be bound to comply with the terms of this RFP and the proposal. The signature of each partner must be included on the cover letter, along with their contact information (i.e., company name, phone number, email address, etc.). The proposal must include evidence documenting the legal and binding partnership.



2. The bidder possesses ownership of, leasehold interest in, right to develop site, or valid title to property on which the resources included in this bid are located.
3. The bidder possesses or will obtain all required permits to site, construct and operate applicable facility(ies) under the bid.
4. The bidder agrees to comply with **Appendix S – Cyber Security Requirements**.
5. The bidder holds PacifiCorp harmless for all development activities related to the applicable facility(ies) under the bid.
6. With respect to any new facility(ies) sited and constructed in Oregon under the bid, the bidder understands the requirements in ORS 757.306¹¹ and will provide required attestations or Project Labor Agreements under ORS 469A.210 within 30 days of the date of construction begins.
7. The bidder agrees to report diversity representation by contractors.
8. With respect to any existing facility(ies) under the bid, the bidder has obtained RPS Certification. With respect to any new facility(ies) to be constructed under the bid, the bidder will apply for and obtain RPS Certification within 90 days of COD. In either case, the bidder agrees it will maintain the RPS Certification for the full term of the PPA.
9. Bid pricing takes into account the risk profile and other terms and conditions of the transaction documents in **Appendix E-1 PPA – for Generation Only, Appendix E-2 – PPA for Generation with Storage, or Appendix E-3 - ESA for Energy Storage**, as currently drafted without modification.
10. This proposal is a firm and binding proposal through June 22, 2026.

**PACIFICORP IS ACCEPTING ONLY ELECTRONIC COPIES OF A BID AND WILL NOT
ACCEPT HARD COPIES.**

For each individual bid, the bidder must submit one (1) electronic copy of the bid, sent to the RFP email address and IE email address specified below. The bid must include any required forms in PDF format and Microsoft Excel format, including all appendices and exhibit sheets. Hard copy submittals will not be accepted.

Each bid must be submitted as a separate document. For example, three separate bids must be sent in three separate emails.

¹¹ A person who constructs or repowers a large-scale project sited in Oregon will, at the time of contract finalization for development of the project or execution of a contract for delivery of energy from the project, provide a signed attestation or declaration stating to the best of their knowledge and belief, subject to penalty of perjury as described in ORS 162.065, that during all periods of construction all contractors and subcontractors working on the construction or repowering project will have done certain things related to apprenticeship programs, diversity hiring outreach, anti-employee harassment policies, and other required measures as required by ORS 757.306. ("Large-scale project" means a renewable energy generation, sequestration or storage facility with a capacity rating of 10 megawatts or greater.)



Submit bid(s) via email to:

PacifiCorp: 2025ORSitusRFP@pacificorp.com and IE: 2025AS_PAC_IE@paconsulting.com

Bidders must be aware of file size when delivering the electronic copy of their bids. PacifiCorp suggests limiting the size of each email with attached files to no more than 20 MB to ensure email delivery. Bidders may submit multiple emails for their bids and must label the emails accordingly (i.e. "1 of 3...", "2 of 3...", "3 of 3...").

PacifiCorp will respond with email(s) confirming receipt.

Bids will be accepted until 5:00 p.m. Pacific Prevailing Time on November 18, 2025.

PacifiCorp will not accept any late proposals. Any bids received after dates and times stated above will be deleted.

All bid proposals will have a bid validity date through 5:00 p.m. Pacific Prevailing Time, June 22, 2026.

Each bid submission must include all the requirements listed in Section 4 RFP Content and Submittal Instructions of this RFP document.

E. BID SUBMISSION FEES

Fee	Amount	Activity	Refundable/Non-Refundable
Due by bid submission due date			
Bid Submission Initial Fee	\$10,000	This initial fee covers costs associated with minimum eligibility requirements screening, bid modeling, bid evaluation and bid scoring for each distinct RFP.	Non-refundable. Due at the bid submission due date.
Bid Fee - Independent Energy Performance Report Evaluation	\$10,000	A fee of \$10,000 will be used to cover the cost associated with a forecast generation evaluation conducted by an independent consultant hired by PacifiCorp.	Non-refundable. Due at the bid submission due date.

		**This fee is not required for a standalone battery bid and will be waived for bidders for whom this Independent Energy Performance Report Evaluation has already been obtained within the last two years for this same resource.	

The Bid Fees will be used to cover the costs incurred by PacifiCorp in analyzing the proposals, including the costs of the IE and legal advisors.

Payment of Bid Submission Initial Fees.

Bid submission initial fees must be paid upon bid submission via wire transfer to PacifiCorp. Wire instructions provided upon request to parties who intend to submit bids. No cashier's checks will be accepted. As a bid requirement, when the bid is submitted, bidders must provide documentation of submitted bid submission initial fee and bid fee- independent energy performance report evaluation, such as a PDF receipt of the wire transfer or wire transfer confirmation number. The bid submission initial fee is non-refundable.

Bidders are responsible for all bid fees and all costs and expenses of any response to PacifiCorp in connection with its proposal for the 2025 OR Situs RFP. Such expenses may include but are not limited to 1) 2025 OR Situs RFP bid submission initial fees, 2) Bidder's fees paid for additional studies, 3) Bidder's cost of providing additional information, and bidder's own expenses in negotiating and reviewing any documentation. **PACIFICORP WILL HAVE NO LIABILITY OR OBLIGATION TO RETURN AMOUNTS PAID BY BIDDERS IN THE EVENT OF PACIFICORP'S REJECTION OF ANY PROPOSAL, REGARDLESS OF ANY RELIANCE BY BIDDERS ON ANY COMMUNICATION RECEIVED FROM PACIFICORP OR ANY OTHER REASON, UNDER ANY LEGAL THEORY OR PRINCIPLE OF EQUITY.**

F. BID NUMBERING AND FILE NAMING CONVENTION

Bid numbers will be self-assigned by bidders in accordance with the directives below. There is no limit to the number of bids that may be submitted, subject to having paid the applicable bid submission initial fee(s) and bid fee – independent energy performance report evaluation,) in accordance with Section 3.E Bid Submission Fees.



Different bids must be expressed as a whole number, beginning with the number 1. Each subsequent bid will have a separate sequential bid number (i.e., 2, 3, etc.). Each bid will have a corresponding bid number which must be used to identify a corresponding **Appendix C-2 – Bid Summary and Pricing Input Sheet**. For example, the first bid will be identified as “1” and subsequent bids will be identified as “2”.

File names must be kept short by using abbreviations wherever possible. All required documents must use the following naming convention:

[abbreviated bidder name]_[bid number]_[abbreviated_file_description]

G. MINIMUM ELIGIBILITY REQUIREMENTS FOR BIDDERS

Bidders may be disqualified for failure to comply with the RFP if any of the requirements outlined in this RFP are not met to the satisfaction of PacifiCorp, as determined in PacifiCorp’s sole discretion. If bids do not comply with these requirements, PacifiCorp has the option to deem the bid non-conforming and eliminate it from further evaluation. Reasons for rejection of a bidder or its bid include, but are not limited to:

1. Receipt of any bid after the bid submittal deadline.
2. Failure to submit the required bid submission initial fee and bid fee – independent energy performance report evaluation when due.
3. Failure to meet the requirements described in this RFP and provide all information requested in **Appendix C-2 – Bid Summary and Pricing Input Sheet** of this RFP.
4. For RPS-eligible resources, failure to receive RPS Certification within 90 days of COD and maintain RPS Certification throughout the duration of any agreement with PacifiCorp.
5. Bids for ineligible resources. Only bids for resources specified in Section 1.A Purpose and Scope of RFP will be accepted. All submissions must conform to the documentation in **Appendix A – Technical Specifications and Required Submittals**.
6. Failure to adequately demonstrate the viability of and a commitment to GCOD on or before December 31, 2029.
7. Failure to execute **Appendix G-1 – Confidentiality Agreement** and permit disclosure of information contained in the proposal to PacifiCorp’s agents, contractors, regulators, or non-bidding parties to regulatory proceedings consistent with terms of executed confidentiality agreement.
8. Any attempt to influence PacifiCorp in the evaluation of the proposals outside the solicitation process.
9. Failure to provide a firm proposal through the bid validity date outlined in Section 3.D Submission of Bids of this RFP.



10. Failure to disclose the commitment of any portion of the proposed resource to another entity.
11. Failure to disclose the real parties of interest in any submitted proposal.
12. Failure to clearly specify all pricing terms for each proposal.
13. For bids using on-system resources, failure to provide either 1) a completed system impact and/or facilities interconnection study, or 2) confirmation of having passed screens (see Section 1.B Interconnection Requirements), or 3) a signed generation interconnection agreement, confirming ability to interconnect to PacifiCorp's transmission or distribution system.
14. Failure to offer the product delivered to a point of interconnection or point of delivery on PacifiCorp's transmission or distribution system.
15. For any bid that is proposing to interconnect to a third-party transmission system, failure to meet the requirements in Section 1.B Interconnection Requirements.
16. Failure to demonstrate and describe in sufficient detail the bidder's ability to adequately acquire or purchase major equipment (i.e., wind turbines, solar photovoltaic panels, inverters, tracking system, generator step-up transformers, batteries) and other critical long-lead time equipment.
17. Failure to demonstrate that the bidder can meet the credit security requirements.
18. Failure to demonstrate that the bidder can meet the scheduled commercial operation date proposed.
19. Failure to submit information required by PacifiCorp to evaluate the proposal.
20. A determination by PacifiCorp that collusive bidding or any other anticompetitive behavior has occurred.
21. The bidder, or facility proposed in the bid is involved in bankruptcy proceedings.
22. Failure of the authorized officer of the bidder to sign the proposal cover letter as required in this document and without edits.
23. Any change in law or regulatory requirements that make the bidder's proposal non-conforming.
24. Failure to provide the resource performance estimate information as described in Section 5.B Facility Performance Estimate Information of the RFP.
25. Failure to provide a performance report and model output including hourly output values as identified in **Appendix C-3 – Energy Performance Report**.
26. Failure to provide **Appendix D – Bidder's Credit Information**.



27. Bid submission that includes a requirement that PacifiCorp provide credit assurances.
28. Failure to provide documentation of binding, exclusive site control for the applicable facility(ies).¹²
29. Bid submission with a facility(ies) description that is inconsistent with the facility(ies) description in existing interconnection study and/or executed generator interconnection agreement. In the event changes have been made to the proposed facility bid as compared to what is described in the current interconnection documentation, Bidder will need to provide documentation from interconnection provider that a material modification or interconnection restudy is not required that could materially impact the facility costs or estimated in-service date.
30. With respect to Oregon-sited resources, failure to agree to provide attestations or Project Labor Agreements as specified by ORS 469A.210 and in provisions in the pro forma contract agreements.
31. Failure to agree to track and report to PacifiCorp the bidder's use of diverse businesses.
32. Failure to comply with co-location/proximity requirements where the nameplate capacity rating of multiple resource bids, in the aggregate, exceeds the 80 megawatts threshold in OAR 860-089-0100(1)(c).
33. For bids representing generation co-located with storage, failure to: demonstrate the storage facility's ability to allow PacifiCorp to dispatch and charge the storage facility from the grid; and failure to provide adequate plans for (a) recycling all battery energy storage equipment, to the extent required to be in compliance with applicable laws and prudent practices, (b) fire protection with respect to the storage facility and (c) emergency response, in compliance with all applicable requirements of law and in accordance with prudent electrical practices.

SECTION 4. RFP CONTENT AND SUBMITTAL INSTRUCTIONS

A. ALL PROPOSALS

This section outlines the content and format requirements for all proposals. Bids that do not include the information requested as described in this section may, at the sole discretion of PacifiCorp, be deemed ineligible for further evaluation if the bidder does not provide information within two (2) business days of a request by PacifiCorp. PacifiCorp may deem information not relevant as determined by PacifiCorp in its sole discretion. All sections must be complete and in compliance with the RFP Section 3 General Information and Logistics for the bid to be accepted.

¹² Site control for the 2025 OR SITUS RFP requires a definitive, exclusive and binding lease or purchase agreement or option agreement.



B. GENERAL ORGANIZATION OF THE BID SUBMITTAL

Appendix B-2 – Bid Proposal Instructions and Required Information outlines the proposal instructions and requirements for submitting a bid. Each item listed in the appendix document is required unless it is specified as optional. Bids that are missing any of the required submittals identified in Appendix B-2 may be deemed ineligible for this RFP.

C. PPA AND ESA PROPOSALS

For new or existing generating and or storage facilities, PacifiCorp will consider transaction structures whereby the bidder develops the facility, assumes responsibility for construction and sells the power (and non-power attributes) and or storage services to PacifiCorp on a long-term basis, pursuant to the terms of a standard-form PPA or ESA, which will include certain performance guarantees. The bidder will be responsible for all aspects of the development and construction of the facility, including, but not limited to, permitting, engineering, procurement, construction, interconnection and long-term asset management and operational costs. Without limiting the foregoing, the bidder will be responsible for obtaining all permits, rights and resources required to construct and operate the generation facility consistent with the bidder's proposal.

Bidders must demonstrate the facility's interconnection studies and interconnection agreement are consistent with the proposed renewable resource equipment, capacity, configuration, and that the interconnection agreement scheduled commercial operation date is aligned with the bid's scheduled commercial operation date, and that no material modification¹³ or interconnection restudy will be required. PacifiCorp will consider bids where the interconnection study reflects a commercial operation date (COD) before the end of 2029, even if the COD proposed in the bid is not exactly aligned. In such cases, PacifiCorp will consult with PacifiCorp Transmission to determine whether the interconnection study adequately supports the interconnection needs of the proposed resource. However, to ensure compliance with House Bill 2021, both the COD reflected in the interconnection study and the COD proposed in the bid must fall before the end of 2029.

If a proposed resource intends to interconnect to a third-party transmission system, the bidder will be responsible under the PPA or ESA to arrange and maintain long-term firm point-to-point transmission service or Bonneville Power Administration's conditional firm bridge transmission service to deliver the full output of the PPA or ESA to a designated point of delivery on PacifiCorp's transmission or distribution system. Bidders must clearly articulate the point of delivery in their bid and include any and all third-party transmission service costs in their PPA or ESA price (see Section 3.G of Minimum Eligibility Requirements for Bidders).

The bidder's proposal must be priced to the standard-form pro forma documents supplied in **Appendix E-1 – PPA for Generation Only, Appendix E-2 – PPA for Generation with Storage, and Appendix E-3 – Energy Storage Agreement** as applicable. Note that the pro

¹³ As defined in PacifiCorp Transmission's Open Access Transmission Tariff (OATT).



forma agreements are tailored for new facilities and specific technologies; conforming changes may be required by PacifiCorp for existing facilities or other types of facilities.

Bidders are required to provide an issues list ("Issues List") and redlines to PacifiCorp and the IE by the date of bid submittal. In accordance with OAR 860-089-0250(3)(d), PacifiCorp will engage in contract negotiations that are mutually agreeable with bidders that make the final shortlist.

SECTION 5. RESOURCE INFORMATION

A. BID SUMMARY AND PRICING INPUTS

Bidders must review and follow the instructions in **Appendix B-2 Bid Proposal Instructions and Required Information**, **Appendix C-1 – Bid Summary and Pricing Input Sheet Instructions** and **Appendix C-2 – Bid Summary and Pricing Input Sheet**. Appendix C-2 is an Excel-based workbook that covers bid summary information, energy production profile, and pricing requirements.

B. RESOURCE PERFORMANCE ESTIMATE INFORMATION

Bidders are required to provide a facility performance estimate prepared by a third-party expert. PacifiCorp may accept an in-house energy performance report contingent upon PacifiCorp being able to replicate the results. The 8,760 hourly profile in **Appendix C-2 – Bid Summary and Pricing Input Sheet** is expected to be consistent with or supported by the bidder's provided facility performance estimate as part of Appendix C-3 referenced below.

Appendix C-3 – Energy Performance Report provides detailed directions for resource performance information by resource type.

C. DIRECT INTERCONNECTION TO PACIFICORP'S SYSTEM (ON SYSTEM BIDS)

All bidders are required to have met the interconnection requirements described in Section 1.B Interconnection Requirements. Any completed PacifiCorp Transmission interconnection study is to be included in **Appendix A-2 – Interconnection Studies and Agreements**. Off-system bidder requirements for interconnections are discussed in Section 5.D Transmission Service For Delivery to PacifiCorp's System (Off-System Bids) below. PacifiCorp will review the bidder's interconnection documentation to confirm it aligns with the bidder's submitted bid.

Bidders must document in their bid and otherwise provide all estimated interconnection costs identified in their interconnection studies and agreements, including direct assigned and network upgrade costs. Bid prices will include any estimated direct-assigned interconnection costs but will exclude the estimated network upgrades costs. Although the network upgrade costs are not to be included in the bid price, the network upgrade costs will be provided to PacifiCorp and included in the utility's valuation models.



D. TRANSMISSION SERVICE FOR DELIVERY TO PACIFICORP'S SYSTEM (OFF-SYSTEM BIDS)

Any off-system bid must, in addition to meeting the interconnection requirements described in Section 1.B Interconnection Requirements, meet all of the minimum eligibility requirement, including requirement #14 in Section 3.G Minimum Eligibility Requirements for Bidders. The off-system bid must reasonably demonstrate that the full proposed output of the resource, as identified in the bid, can be delivered by December 31, 2029.

Off-system bidders are responsible for any current or future third-party tariff requirements or tariff changes related to, but not limited to, any of the following: interconnection, variable energy resource, electric losses, reserves, transmission, integration, imbalance, scheduling, and ancillary service arrangements required to deliver to the bidder's selected point of delivery on PacifiCorp's transmission or distribution system. These costs will not be included in the evaluation of PPA proposals as they are assumed to be the responsibility of the bidder.

Off-system bidders must include in submitted bid prices all interconnection costs from the third-party interconnection provider, whether from a study or a signed interconnection agreement. Off-system bidders must also include in their bid price the estimated costs for all third-party transmission service.

In the event an off-system bid is awarded an agreement, such agreement will include appropriate provisions reflecting the bidder's obligation to timely arrange and maintain the necessary third-party, long-term firm, transmission service or Bonneville Power Administration's conditional firm bridge transmission service, facilitating delivery of the full output of the resource to the identified point of delivery, including associated events of default for failure to comply with such requirements.

E. PACIFICORP NETWORK TRANSMISSION SERVICE

PacifiCorp will request Designated Network Resource (DNR) service to serve PacifiCorp network load once a definitive agreement is fully executed.

F. TAX CREDITS AND/OR FACILITY INCENTIVES

Bidders bear all risks, financial and otherwise, associated with their or their facilities' eligibility to receive any state or federal energy tax credits, sales tax waivers or exemptions, payment in lieu of tax, or any other identified tax- or accounting-related, incentive, or benefit, including in the event of a change in tax law. The obligations of a bidder to perform under any executed agreement at the bid pricing resulting from this solicitation remain effective and binding regardless of whether a bidder or facility is eligible for or receives tax credits or other tax- or accounting-related incentives or benefits. Bidders must explain in their submitted **Appendix B-2 Bid Proposal Instructions and Required Information** whether a bid is dependent upon Production Tax Credits (PTC) or Investment Tax Credits (ITC).



G. ACCOUNTING

All proposals will be assessed for appropriate accounting and tax treatment. Bidders must supply all information reasonably required to make these assessments if a facility is selected to the final shortlist. According to Generally Accepted Accounting Principles, PacifiCorp will establish and maintain accounts for the revenue, expenses, assets, liabilities and owners' equity associated with all resource facilities acquired through this RFP and will ensure that all revenues and all expenses associated with the management and ownership of the resource(s) are properly recorded to these accounts. This will include expenses associated with work performed by PacifiCorp personnel. Additionally, PacifiCorp will account for the power costs associated with the resource(s) in a separate account(s).

SECTION 6. BID EVALUATION AND SELECTION

A. OVERVIEW OF THE EVALUATION PROCESS

PacifiCorp's bid evaluation and selection process is designed to identify the combination and amount of new resources that will maximize customer benefits through the selection of bids that will satisfy projected capacity and energy needs while maintaining reliability. The method for evaluating resources will be transparent, fair, and consistent with how market bids are evaluated with additional oversight by the IE.

The 2025 IRP selected individual resources and optimized a preferred portfolio from a list of generic "proxy" resources to reliably meet PacifiCorp's energy and capacity needs across its six-state service territory. The PLEXOS portfolio optimization model that PacifiCorp will use to evaluate the 2025 OR Situs RFP bids was also used to develop PacifiCorp's 2025 IRP. PacifiCorp uses PLEXOS to serve as a decision support tool that can be used to guide prudent resource acquisition paths that maintain system reliability at a reasonable cost.

At a high level, the 2025 OR Situs RFP evaluation process involves, among other considerations:

1. Bid screening based on minimum eligibility requirements.
2. Identification of interconnection network upgrades.
3. Validation of bidder's generation profile.
4. Non-Price Scoring based on **Appendix P – Non-Price Scoring Questionnaire**.
5. Price Scoring:
 - a. Bid preparation for input into PLEXOS.
 - b. PLEXOS modeling, including bid selection, portfolio optimization, reliability testing, price-policy scenario analysis, stochastic risk analysis and price scoring.
6. Combination of price and non-price scoring and ranking of preferred resources:
 - a. Price Scoring - Weighted eighty (80) percent based on the net cost of the bid; i.e., highest benefit or lowest cost.



- b. Non-Price Scoring – Weighted twenty (20) percent

- 7. Final shortlist of proposals for pursuing contract negotiation.

Additional details regarding the 2025 OR Situs RFP evaluation process and cost-ranking methodology is provided below.

Methodology for scoring bids using Bonneville Power Administration's conditional firm bridge transmission service is provided in Appendix R – Bid Scoring Modeling.

B. BID ELIGIBILITY: MINIMUM ELIGIBILITY REQUIREMENTS

Upon receipt all bids will undergo screening to assess compliance with the minimum requirements and overall conformance with the RFP. After IE review and consultation, non-conforming bids will be notified and given five (5) business days to correct the deficiencies. Failure to do so may result in removal from further consideration.

C. EVALUATION OF BIDDER'S ENERGY PERFORMANCE REPORT

An independently prepared evaluation of bidder's energy performance report will be produced for each bid.

D. NON-PRICE SCORING

Eligible bids will be evaluated based on responses to the **Appendix P - Non-Price Scoring Questionnaire**.

PacifiCorp confirms that the non-price scoring is compliant with OAR 860-089-0400(2), non-price factors. Non-price scores primarily relate to resource characteristics identified in the Company's most recent acknowledged IRP Action Plan and reflect standard form contracts. Non-price score criteria that seek to identify minimum thresholds for a successful bid have been converted into minimum bidder requirements.

E. PRICE SCORING

- a. Bid Preparation into PLEXOS and Resource Shaping

All eligible bid resources will be prepared and uploaded into PLEXOS. PacifiCorp uses its proprietary Excel models to process bid costs for input to PLEXOS modeling with oversight by the IE.

Consistent with the treatment of capital revenue requirement in PacifiCorp's IRP modeling, PacifiCorp will convert any calculated revenue requirement associated with capital costs, as applicable (i.e., return on investment, return of investment, and taxes) to first-year-real-levelized costs. Consistent with the treatment of non-capital revenue requirement in PacifiCorp's IRP modeling, all other bid costs will be summarized in nominal dollars and formatted for input into the bid evaluation models.



PacifiCorp's proprietary Excel model will calculate the delivered revenue requirement cost of each eligible bid, inclusive of any applicable carrying cost and net of tax credit benefits, all operations and maintenance expenses, property taxes, generation taxes, direct assigned interconnection costs and PacifiCorp Transmission estimated network upgrade costs, as applicable. In developing the delivered cost for each bid, PacifiCorp requires certain cost data as inputs to the bid preparation model.

Summary of Cost Components for a PPA

- i. PPA Price Schedule
- ii. Storage Costs (monthly capacity payment)
- iii. Network Upgrade Revenue Requirements

Any internal assumptions for key financial inputs (i.e., inflation, discount rates, marginal tax rates, asset lives, AFUDC rates, etc.) and PacifiCorp carrying costs (i.e., integration costs, owner's costs, etc.) will be applied consistently to all bids, as applicable, and reviewed by the IE prior to finalizing the bid preparation model for PLEXOS. Bids with different price structures and terms will be normalized prior to uploading into PLEXOS.

Upon bid submittal, PacifiCorp will engage a third-party to evaluate resource performance and degradation schedules. The third-party subject matter expert will provide data for input into the PLEXOS model, consistent with Oregon rule 860-089-0400 5(a).

b. PLEXOS Analysis: Bid Selection and Portfolio Optimization

The bid evaluation team will evaluate the bids using PLEXOS, the same production cost models used in the 2025 IRP. The PLEXOS production cost model will select the optimized portfolio of resources proposed as part of the 2025 OR Situs RFP.

PacifiCorp will summarize for the IE how the bid evaluation models function, and the IE will be provided with the inputs and outputs of PLEXOS model runs used during the evaluation process.

i. Bid Resource Portfolio Development

The PLEXOS model is used to develop an optimized portfolio of resources and candidates for the final shortlist. PacifiCorp uses PLEXOS to develop, test and evaluate the cost of multiple resource portfolios including sensitivities to understand the relative performance of portfolio and resource alternatives under certain conditions.

ii. Reliability Tests

PacifiCorp will perform a reliability assessment to ensure that the selected portfolio of resources can meet all hourly load and operating reserve requirements with sufficient margin ¹⁴ to account for other system uncertainties such as non-normal weather events. If incremental flexible resource capacity be required to maintain system reliability, the shortfall will be provided to the model to ensure it selects sufficient capacity to achieve the targeted reliability requirements.

iii. Price Policy Scenarios and Risk Analysis

PacifiCorp evaluates portfolios under a range of different environmental policy and market price scenarios (policy-price scenarios). ¹⁵ PLEXOS calculates the stochastic mean present value revenue requirement (PVR) and the risk-adjusted PVR for various policy-price scenarios to help identify whether top-performing portfolios exhibit especially poor performance under the range of scenarios. PacifiCorp summarizes and analyzes the portfolios to identify the specific bid resources that are most consistently selected among the policy-price scenarios.

In this way, PacifiCorp uses PLEXOS to optimize its selection of bid resources to identify the lowest cost, reliable portfolio under multiple scenarios for further consideration as part of the final shortlist process. PacifiCorp may select one or more 2025 OR Situs RFP resource portfolios for further scenario risk analysis.

PacifiCorp uses PLEXOS to test each portfolio and evaluate its ability to perform under dynamic weather and market conditions. PLEXOS measures the stochastic risk of each portfolio through its production cost estimates. By holding a resource portfolio fixed and using simulations of stochastic variables, including load, wholesale electricity and natural gas prices, hydro generation, wind generation, solar generation, and thermal unit outages, PLEXOS can measure the expected cost of each portfolio in an uncertain future.

iv. Price Scoring

PLEXOS will calculate the relative costs and benefits of each resource included in the model for evaluation. The operational characteristics of every bid will be included in the model so that PLEXOS will generate a value stream specific to each bid that will then be used to calculate a price score in accordance with **Appendix R - Bid Scoring and Modeling**.

¹⁴ Consistent with the reserve requirements in the 2025 IRP.

¹⁵ Policy-price scenarios will be conceptually consistent with those used in the 2025 IRP (i.e., alternative environmental policy assumptions among low, medium, and high price scenarios), but updated to reflect PacifiCorp's assessment of the most current information in consultation with the IE.



More information about bid modeling techniques and price scoring, including an example of how the bid scoring will work, may be found in **Appendix R – Bid Scoring and Modeling**.

E. FINAL SCORING AND RANKING TO RECOMMENDED FINAL SHORTLIST

Following the PLEXOS analysis to select resources and determine price scores for each of the bids, PacifiCorp will combine the price and non-price scores to generate a total final bid score and ranking for each bid. When calculating scores associated for any bids located in PacifiCorp's PACE balancing area, the capacity contribution for PacifiCorp's PACW balancing area will be reduced to zero, in consultation with the independent evaluator and OPUC Staff, and in accordance with the forthcoming capacity scoring proposal, once the capacity requirements have reached the transmission limit in the peak summer season. Furthermore, as part of the selection of a final shortlist, (a) PacifiCorp will evaluate House Bill 2021 compliance if implications arise from increases of unspecified market purchases that might occur when more PACE-sited resources produce generation that exceeds the available transmission from PACE to PACW, and (b) modeling will assess whether resource supply in or deliverable to PACW are sufficient in supporting PacifiCorp's balancing requirements as part of its California ISO Extended Day-Ahead Market (EDAM) participation.

If the ranked bids are inconsistent with the selected resources and preferred portfolio resulting from the PLEXOS performance optimization models, in coordination with the IE, PacifiCorp will investigate the discrepancy(ies) and may add or remove resources and run additional iterations of PLEXOS including, but not limited to, reliability tests and price-policy scenarios.

PacifiCorp will hold regular meetings with the IE both in the preparation process for preparing model inputs and analyses and after proposals are received during the evaluation and selection process. Before establishing a final shortlist, the IE will be provided with all bid preparation files and all of the PLEXOS outputs in order to evaluate the scoring and selection process. PacifiCorp may take into consideration, in consultation with the IE, other factors that are not expressly or adequately factored into the evaluation process outlined above, particularly any factor required by applicable law or Commission order to be considered.¹⁶

PacifiCorp will summarize and evaluate the results of its scenario risk analysis, considering PVRR results, to identify the specific least-cost, least-risk bids in combination with non-price scores. Based on these data and certain other factors as described above, and in consultation with the IE, PacifiCorp may establish a final shortlist.

After the final shortlist is established, PacifiCorp will engage with the selected bidders to initiate negotiation of their contract and prepare the contract for execution. Selection of a bid to the final shortlist does not constitute a winning bid. Only execution of a definitive

¹⁶ OAR 860-089-0400.



agreement between PacifiCorp and the bidder, on terms acceptable to PacifiCorp, in its sole and absolute discretion, will constitute a winning bid proposal.

Pursuant to Oregon Public Utility Commission order 25-343 in docket no. UM 2383, PacifiCorp acknowledges that capacity is to be scored system wide. A system wide scoring methodology is still being developed and will be supplemented after further coordination with Oregon Public Utility Staff and the Independent Evaluator.

In accordance with the Oregon Public Utility Commission's order no. 25-343 in docket No UM 2383, before the shortlist is finalized for PacifiCorp's Washington RFP, PacifiCorp will confer with the IE to determine and discuss any on-ramps to allow for Oregon to potentially participate in resources shortlisted for Washington that were also bid into the Oregon RFP.

SECTION 7. AWARDING OF CONTRACTS

A. INVITATION

This RFP presents only an opportunity for bidders to make proposals to PacifiCorp. No proposal is itself a binding contract except to the extent the parties execute a definitive agreement with complete documentation providing otherwise.

PacifiCorp may in its sole discretion do any one or more of the following:

1. Determine which proposals are eligible for consideration in response to this RFP.
2. Issue additional subsequent solicitations for information and conduct investigations with respect to the qualifications of each bidder.
3. Supplement, amend, or otherwise modify this RFP, or cancel this RFP with or without the substitution of another RFP.
4. Negotiate with bidders to amend any proposal.
5. Select and enter into agreements with the bidders who, in PacifiCorp's sole judgment, submit proposals that best satisfy the interests of PacifiCorp and its customers. In exercising its sole judgment, PacifiCorp may consider factors other than price.
6. Waive any irregularity or informality on any proposal to the extent not prohibited by law.
7. Reject any or all proposals in whole or in part at any point in time, including proposals that are on the shortlist.
8. Vary any timetable.
9. Conduct any briefing session or further RFP process on any terms and conditions.
10. Withdraw any invitation to submit a response.



B. BASIS OF REJECTION

Proposals may be rejected for any reason including but not limited to not meeting the minimum eligibility requirements identified in Section 3.G Minimum Eligibility Requirements for Bidders of this RFP.

C. NON-RELIANCE LETTER

All parties will be required to sign **Appendix G-2 – Non-Reliance Letter** if they qualify for the final shortlist.

D. POST-BID NEGOTIATION

PacifiCorp will seek to enter into a final agreement with each bidder on the final shortlist. PacifiCorp will include in its final evaluation prior to contract execution any factor that may impact the total cost of a facility and associated risks, including but not limited to all the factors used in the final shortlist cost analysis plus consideration of the terms of the final agreement and accounting treatment and potential effects due to rating agency treatment, if applicable.

SECTION 8. SECOND PHASE OF RFP

In accordance with the Oregon Public Utility Commission's order 25-343 in docket no. UM 2383, PacifiCorp will issue to market a second phase of this RFP, anticipated in 2026, which would occur after the conclusion, and contracts are executed, for the first phase of this RFP. Order No. 25-343 provides clarification that "a second phase of the RFP [should be] timed to take advantage of additional clarity on the connection between Longhorn substation and PACW, or any other way PacifiCorp connects the Boardman to Hemingway transmission project to PACW."

A second phase will comply with order 25-343, by allowing on system bidders that obtain a completed Facilities Study or Generator Interconnection Agreement, and by allowing off system bidders that may be able to progress through the interconnection and transmission service request process with a third party utility. The intent of the second phase is to provide a known entry for potential bidders that are currently in an existing PacifiCorp Cluster Study, and projects that seek to interconnect and deliver over a third party utility, contingent on a transmission project or study that will allow delivery to PacifiCorp West, including the Boardman to Hemingway transmission project.

When PacifiCorp is prepared to issue a second phase of the RFP, PacifiCorp will provide notice via the PacifiCorp website and email notification list. To be added to the notification distribution list, email 2025ORSitusRFP@pacificorp.com. Furthermore, PacifiCorp will provide notice to the Oregon Public Utility Commission by making a filing in UM 2383 following the current request for proposals, or as soon as PacifiCorp is aware of opportunities for additional interconnection and transmission service. PacifiCorp's



understanding is that it would need to seek approval of the second phase of the RFP prior to market issuance, by the Oregon Public Utilities Commission, pursuant to per OAR Chapter 860-089.

PACIFICORP HAS NO OBLIGATION TO ENTER INTO ANY AGREEMENT WITH ANY BIDDER TO THIS RFP AND PACIFICORP MAY TERMINATE OR MODIFY THIS RFP AT ANY TIME WITHOUT LIABILITY OR OBLIGATION TO ANY BIDDER. IN ADDITION, THIS RFP DOES NOT IN ANY WAY PREVENT PACIFICORP FROM ENTERING INTO ANY AGREEMENT THAT PACIFICORP DEEMS PRUDENT, IN PACIFICORP'S SOLE DISCRETION, AT ANY TIME BEFORE, DURING, OR AFTER THIS RFP PROCESS IS COMPLETE. FINALLY, PACIFICORP RESERVES THE RIGHT TO NEGOTIATE ONLY WITH THOSE ENTITIES THAT PROPOSE TRANSACTIONS THAT PACIFICORP BELIEVES IN ITS SOLE DISCRETION HAVE A REASONABLE LIKELIHOOD OF BEING EXECUTED.

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c))
Emergency Order: Tri-State)
Generation and Transmission)
Association, Platte River Power)
Authority, Salt River Project,)
PacifiCorp, and Xcel Energy)

Order No. 202-25-14

Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
Public Interest Organizations

Filed January 28, 2026

Exhibit 1-110:
PacifiCorp 2024 URC RFP

2024 Utah Renewable Communities

Request for Proposals

“2024 URC RFP”

Program Renewable Resources

ISSUED: 5/22/2025

DUE DATE: 7/10/2025

2024 URC RFP Responses:

**Energy Strategies, LLC
111 East Broadway, Suite 1200
Salt Lake City, Utah 84111
www.URC2024RFP.com**

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Each of the Appendices referenced above are available at www.URC2024RFP.com. The 2024 URC RFP is utilizing Appendices from the PacifiCorp 2022 AS RFP to streamline the process for bidders that participated in the PacifiCorp 2022 AS RFP and to ensure that the Communities and PacifiCorp receive all of the information necessary for the Communities to evaluate and score the bids and for PacifiCorp to utilize in contracting.

However, the following appendices that were included in the PacifiCorp 2022 AS RFP are intentionally omitted from this solicitation:

- Appendix B-1 series: Notice of Intent to Bid, NOI Excel Spreadsheet, Bid Fee

- Calculator Worksheet
- Appendix E-2.2: Co-located Generating Resource with Energy Storage
- Appendix E-3: Tolling Agreement Documents
- Appendix H-3: PacifiCorp Transmission: Summary of OASIS queue positions
- Appendix L: Non-Price Scoring Matrix
- Appendix M: Role of Independent Evaluator
- Appendix N: PacifiCorp's Organization for RFP Process
- Appendix O: PacifiCorp's Company Alternative (Benchmark Resource)
- Appendix Q series: 2021 Demand Response, all DR appendices
- Appendix R series: Bid Scoring and Modeling, Bid Scoring Example
- Appendix H-1: PacifiCorp IRP Preferred Portfolio Transmission Upgrade Selections (update to reflect 2023 IRP Update)
- Appendix H-2: PacifiCorp IRP Preferred Portfolio Proxy Resource Selections (update to reflect 2023 IRP Update)

The following appendices that were included in the PacifiCorp 2022 AS RFP have been updated for use in this solicitation:

- Appendix A-1.4: BTA Solar Work Specifications (updates to preferred and prohibited vendors)
- Appendix A-1.6: BTA Battery Energy Storage System Technical Specification (updates to preferred and prohibited vendors)

Additionally, the following appendices that were included in the PacifiCorp 2022 AS RFP are included in the URC 2024 RFP but contain substantively different questions, information, conditions, or signatories:

- Appendix B-2: Bid Proposal Instructions and Required Information
- Appendix C-1: Bid Summary and Pricing Input Sheet Instructions (revised)
- Appendix C-2: Bid Summary and Pricing Input Sheet (additional tabs and questions)
- Appendix E-2.1: PPA Documents – Generating Resource Only (additional conditions)
- Appendix F-2: BTA Documents (additional conditions)
- Appendix G-1: Confidentiality Agreement
- Appendix G-2: Non-Reliance Letter
- Appendix S: Cyber Security Requirements

Finally, one additional appendix that was not included in the PacifiCorp 2022 AS RFP has been added for use in this solicitation:

- Appendix W: Payment Instructions

As noted herein, the Communities are solely responsible for the administration of the 2024 URC RFP. PacifiCorp dba Rocky Mountain Power (Company) is not administering the 2024 URC RFP and the use of the PacifiCorp 2022 AS RFP is a convenience to the Communities, to Company, and to the bidders and does not signify any greater involvement from PacifiCorp than is described herein.

SECTION 1. INTRODUCTION

This 2024 Utah Renewable Communities' Request for Proposals for renewable energy resources (2024 URC RFP), is administered by the Community Renewable Energy Agency (Agency)¹ on behalf of customers that participate in the Community Clean Energy Program (Program).² The 2024 URC RFP is seeking cost-competitive bids for energy produced by wind, photovoltaic (PV) solar, geothermal, or hydroelectric resources and interconnecting with PacifiCorp's transmission system. The resources must meet the criteria developed by the Agency in conjunction with Company and set forth in this RFP. The Agency is seeking to purchase energy from renewable resources pursuant to the Community Clean Energy Act (Act (Utah Code §§ 54-17-901 to -909)) and in support of the Program created by the Act and the Utah Public Service Commission (Commission).

Proposals must demonstrate to the Agency's satisfaction, and as determined in its sole discretion, that the proposed project(s) can successfully interconnect and achieve commercial operation within the timeframe listed in Section 2. The Agency is not bound to accept any bids and may cancel this solicitation at any time and at their own discretion.

Bids must be for new generation capacity not located behind any load served by a utility or net-metered, and each project must be individually metered and remotely monitored. The project bid may be for the partial output of new generation capacity so long as all other contracted output is for customers in Rocky Mountain Power's service territory. The minimum discrete project size is 2.0 MW AC and the maximum is 300.0 MW AC, and the Agency is seeking a project or projects to meet 600,000 MWhs of average annual forecasted demand for customers participating in the Program (Participating Customers) in the project(s)' first full calendar year of operation.

The Agency will accept proposals for generation from new wind, photovoltaic (PV) solar, geothermal, or hydroelectric resource projects capable of directly interconnecting with Company's network transmission system. These resources are required to self-provide ancillary services to the grid and may be subject to curtailment to ensure sufficient self-provided ancillary service. Other resource types may be considered as required by the Commission so long as they meet the other requirements of this solicitation.

Each bid **must** include the Base Bid as described below. It may optionally include up to two add-ons and two variants, also described below.

The required "Base Bid" shall include the fixed price (in dollars per Megawatt-hour or \$/MWh) at which the bidder proposes to sell all energy generated by the project to Company over a twenty-five (25) year term. This fixed price shall also include any and all environmental attributes associated with all energy generated, which will be transferred to and exclusively owned by the Agency on behalf of Participating Customers.³ The Base Bid may not combine generation resource types and is required of all bidders.

¹ The public-facing name of the Agency is the Utah Renewable Communities (URC).

² Additional information regarding the Agency, its formation and decision-making authority, is set forth in Section 3 below.

³ "Environmental Attributes" will be a defined term in the pro forma transaction documents for this RFP.

In addition to the Base Bid, the bidder may optionally include the following two add-ons:

1. A “Storage Add-On” option specifying the price to co-locate storage with the generating resource, priced in dollars per kilowatt-month for a twenty-five (25) year term. The Storage Add-On may or may not be evaluated by the Agency for scoring purposes but may feature in contract negotiations. Should the Agency select a bid with a Storage Add-On for contract negotiation, parties will discuss whether to address the storage component with a combined generation and storage agreement (using Appendix E-2.2 from PacifiCorp’s 2022 All-Source RFP as a starting point) or with a separate tolling agreement (using Appendix E-3 from PacifiCorp’s 2022 All-Source RFP as a starting point).
2. A “Post-PPA Sale Add-On” option priced in dollars whereby the bidder proposes to sell its project rights to Company at the conclusion of the twenty-five (25) year PPA term. The Post-PPA Sale Add-On will not be evaluated by the Agency for scoring purposes but may feature in contract negotiations.

In addition to the Base Bid, the bidder may optionally include the following two bid variants:

1. A “Twenty Year Bid Variant” PPA option specifying a fixed priced (in \$ per MWh) at which the bidder proposes to sell all energy generated by the project to Company over a twenty (20) year term that meets the other requirements of the Base Bid. The Twenty Year Bid Variant will not be evaluated by the Agency for scoring purposes but may feature in contract negotiations.
2. A “BTA Bid Variant” option priced in dollars whereby the bidder develops the generation project, assumes responsibility for construction and ultimately transfers the operating asset to Company prior to the Commercial Operation Date (COD), all pursuant to the terms of a build transfer agreement (BTA). Bidder is responsible for all development, design⁴, generation equipment supply, balance of plant (BOP) equipment, construction, commissioning, and performance testing. A bidder that elects to submit the optional BTA Bid Variant must submit a price for the generation resource and may also submit a price for the generation resource plus co-located storage. These BTA prices will not be evaluated by the Agency for scoring purposes but if a Base Bid selected for contract negotiation by the Agency also includes the optional BTA Bid Variant, then Company may elect to pursue the BTA Bid Variant.

The Agency reserves the right to reject non-compliant bids. Only the Base Bid will be evaluated for Phase 2 evaluation. The Agency may elect to select a Base Bid with optional Storage Add-On for Phase 3 evaluation. During the negotiation phase described in Section 7(D), below, the Agency reserves the right to use the bid pricing to propose an equivalent

⁴ The resource design must comply with Company’s pro forma technical specification as identified in RFP Appendices.

two-phase PPA price, with a higher fixed price in the first 1-5 years and a commensurately lower fixed price for the remaining years during contract negotiations.

Importantly, a PPA signed by Company to serve a Program under the Act may contain additional conditions precedent to become effective. If a bid's price exceeds its modeled financial benefit, resulting in a net-cost, then the Program will likely need to provide a reserve fund covering a substantial share of this net-cost before the PPA can become effective. For this reason, the Phase 3 price evaluation (described in Section 6) considers both the net-cost of energy (in dollars per Megawatt-hour) and the net-cost of contract (in dollars). Bidders should be advised that, while the net-cost of energy (in dollars per Megawatt-hour) for larger projects (closer to the upper end of the 300 MW cap) may be superior to smaller projects, the net-cost of contract (in dollars) for larger projects may be inferior to smaller projects because of the reserve fund requirement described above.

While not currently reflected in **Appendix E-2.1 Power Purchase Agreement**, the Agency and PacifiCorp are exploring other potential security mechanisms for the program that may impact Appendix E-2.1, including termination provisions, should the Agency and PacifiCorp come to an agreement on a working mechanism.

For bids selected by the Agency for contract negotiation, the Agency may specify a share of the project's generation that may be separately contracted by a large energy user within Company's service territory.

Company and Agency may request from bidder (1) financial statements and/or (2) documentation from an independent engineer that supports the economic useful life of the underlying asset. Please see Section 4.C for more information related to Variable Interest Entity (VIE) accounting and tax ownership.

Pursuant to the Act and associated Commission rules, Company is required to obtain Commission approval prior to entering into any PPA or BTA selected in connection with this RFP, and execution of any such BTA or PPA is contingent on Company receiving such approval.

The Agency is not required to utilize an independent evaluator (IE) in conducting the RFP.

SECTION 2. PROCEDURAL ITEMS

Bids will be evaluated based on the following:

- Cost to Participating Customers.
- Project location.
- Project size.
- Project readiness, including site control, development status (including status for all permits), developer's experience, and demonstration that the project's commercial operation date will be achieved between January 1, 2026 and December 31, 2029.
- Transmission access and interconnection status in conformance with the 2024 URC RFP requirements outlined in Section 5.B. Direct Interconnection.

- Bidder must include Base Bid PPA pricing as described above.
- Exceptions to the pro forma PPA and BTA terms as represented in **Appendix E-2 and Appendix F-2** respectively. Note that any bids that include exceptions that significantly alter the structure of the pro forma Build-Transfer Agreement as described in Section 4.B of this RFP may be rejected as non-compliant without regard to any other evaluation factors.
- Compliance with and verification of major equipment availability defined in **Appendix A – Technical Specification**, and as outlined in **Appendices A-1 through A-10** for each type of renewable technology.
- Ability to provide acceptable credit security for the bidder's proposed obligation and conformance to the pro forma agreements attached as **Appendices E-2 and F-2** to this RFP.

Each proposal will be prepared at the sole cost and expense of the bidder and with the express understanding that there will be no claims whatsoever for reimbursement from Company or the Agency. Neither the Agency nor Company is liable for any costs incurred by bidders in responding to this RFP, and bidder shall not be entitled to recover any damages arising out of or relating to the Agency's rejection of any proposal, or bidder's reliance upon any communication received from the Agency or from Company, for any reason. Bidder shall bear all costs, expenses, and bidder fees of any response to the Agency in connection with its proposal for the 2024 URC RFP, including providing additional information, the bidder fee, and bidder's own expenses in negotiating and reviewing any documentation. Bid fees are non-refundable in all circumstances, including in the event that no bids are selected or if the 2024 URC RFP is terminated. Additionally, winning bidder(s) may be required to provide a bidder success fee in the event bidder fees do not cover RFP administration and evaluation costs.

Appendix E-1 – PPA Instructions to bidder provides additional detail on preparation of bid document deliverables.

All proposals belong to the Agency and will not be returned. Confidentiality agreements and mutual nondisclosure agreements (NDAs) will be executed with Initial Short List projects as part of this RFP. The Agency will use reasonable efforts to protect information clearly and prominently marked as proprietary and confidential on the page it appears, but the Agency reserves the right to release such information to agents or contractors to help evaluate the proposal, as well as to Company, its regulators and non-bidding parties to regulatory proceedings subject to standard protective orders or confidentiality arrangements. The Agency shall not be liable for any damages resulting from any disclosure of such information, howsoever occurring.

Each bidder must submit a non-refundable bid fee as follows:

- for project bids of 10 MW or smaller: \$5,000
- for project bids larger than 10 MW: \$15,000

This bid fee will be required for each separate Base Bid. This bid fee will cover any associated optional add-ons (Storage Add-On, Post-PPA Sale Add-on) so long as the price for generation specified in the Base Bid remains constant. The bid fee will also cover any

associated optional Twenty-Year Bid Variant so long as the only difference from the Base Bid is the price for generation and the contract end date.

All optional bid add-ons and variants may not be evaluated by the Agency for scoring purposes. However, these optional elements may be evaluated by Agency or Company and may feature in contract negotiations.

Should a bid be selected for the Initial Short List for advancement to Phase 3 evaluation, PacifiCorp will require an additional \$12,500 bid analysis fee, payable to PacifiCorp. Any variant upon the original bid will be submitted as a new bid and subject to the full bid fee of \$12,500. The bid fee in support of Phase 3 is non-refundable should negotiations fail to produce an executed power purchase agreement. The bid fee may be partially refundable up to unused amounts of the bid fee total should a bidder successfully complete execution of a power purchase agreement.

SECTION 3. LOGISTICS

A. SCHEDULE (PROVISIONAL)

Milestone	Date
RFP Submitted to UT Public Service Commission for review	11/19/2024
RFP issued to market and Q&A period begins	5/22/2025
Q&A period ends	6/10/2025
RFP Bids Due	7/10/2025
Phase 1: Consultant Completes Bid Eligibility Screening and Begins Phase 2 Evaluation	7/25/2025
Phase 2: Agency Selects Initial Short List	8/18/2025
Phase 3: PacifiCorp Begins Modeling System Benefits	9/2/2025
Phase 3: PacifiCorp Delivers System Benefit Modeling Results to Agency	11/6/2025
Phase 3: System Benefit and Indicative Costs Discussions with Agency Begins	11/21/2025
Phase 3: System Benefit and Indicative Costs Discussions with Agency Ends	12/12/2025
Phase 3: Agency Completes Final Short List (FSL) Evaluation	12/16/2025
Execute Agreements	2/6/2026

The provisional schedule above is subject to change. Actual dates may vary from the provisional schedule for reasons that include, but are not limited to, negotiation time, availability of key personnel, due diligence, the evaluation or negotiation of any issues unique to any bid, bidder, or project, bidder's willingness to agree to forms of agreements desired by Company or the Agency, and actions required by any third parties. The Agency accepts no liability to the extent the actual schedule varies from the indicative schedule. The Agency is not obligated to develop a short list of bidders, to make a final selection, or to initiate or complete negotiations on any transaction.

Bidders should note the condensed schedule and be available for calls and meetings regarding bid submittals and be responsive to questions in a timely manner. The Agency will attempt to complete the bid review and screening as efficiently as possible but may require very short turnaround times on bid clarifications in order to meet the RFP milestones and schedule.

B. SUBMISSION OF QUESTIONS

Interested parties and bidders may submit questions related to this solicitation by the date indicated in Section 3.A., and the Agency will respond in a timely fashion. Pre-bid materials, bidder questions, and responses will be found at the following website: www.URC2024RFP.com.

C. AGENCY AUTHORITY AND RFP ROLES

The Agency was created pursuant to an interlocal cooperation agreement among the following communities, each of which passed a resolution stating a goal of achieving an amount equivalent to 100% of the annual electric energy supply for Participating Customers from renewable energy resources by 2030: Town of Alta, Town of Castle Valley, Coalville City, City of Cottonwood Heights, Emigration Canyon City, Francis City, Grand County, City of Holladay, City of Kearns, Midvale, Millcreek, City of Moab, Oakley City, Ogden City, Park City, Salt Lake City, Salt Lake County, Town of Springdale, and Summit County (Participating Communities). The Agency has authority to take action on behalf of all Participating Communities to implement the Act, including with regard to resource solicitation and resource acquisition in connection with the purposes of the Act. The Agency acts through the Community Renewable Energy Board (Board), made up of individual members of the Participating Communities and with voting and decision-making authority on behalf of the Agency.

This RFP has been developed by the Agency in conjunction with Company, as required by the Act. The Agency has engaged Energy Strategies (“Consultant”) to assist with bid collection, evaluation, and scoring.

Company has no role in administering the RFP or selecting winning project bids. Company is the contracting party to any BTA or PPA that may result from this RFP and, as such, retains certain rights and authority with respect to BTA and PPA structures, and the evaluation of exceptions to the pro forma BTA and PPAs set forth in the appendices hereto. Company will also conduct analysis of bid pricing to determine the net costs and estimate emissions reductions of projects bid into the RFP. If Company submits bids into the RFP, it will maintain separation between the personnel responsible for modeling all bids and those individuals responsible for bidding resources into the RFP.

D. SUBMISSION OF BIDS

Bidders must create a user account and upload electronic documents to the following website: www.URC2024RFP.com

Bidders will receive an automatically-generated receipt email.

Bids will be accepted until 5:00 p.m. Mountain Prevailing Time (MPT) on July 10, 2025 as evidenced by the electronic timestamp recorded by the website document repository.

The Agency will not accept any late proposals.

All bid proposals shall have a bid validity date through 5:00 pm MPT, April 30, 2026.

E. BID EVALUATION FEES

Each bidder must submit a non-refundable bid fee as follows:

- for project bids of 10 MW or smaller: \$5,000
- for project bids larger than 10 MW: \$15,000

This bid fee will be required for each separate Base Bid.

Should a bid be selected for the Initial Short List for advancement to Phase 3 evaluation, Company will require an additional \$12,500 analysis fee, payable to PacifiCorp. Any variations to the original bid will be submitted as a new bid and subject to the full \$12,500 bid fee. The bid fee in support of Phase 3 is non-refundable should negotiations fail to produce an executed power purchase agreement. The bid fee may be partially refundable up to unused amounts of the bid fee total should a bidder successfully complete execution of a power purchase agreement. In addition to the Base Bid, the bidder may optionally include a Storage Add-On, a Post-PPA Sale Add-On, a Twenty-Year Bid Variant, and/or a BTA Bid Variant as described in Section 1, but these options may not be evaluated by the Agency for scoring purposes. However, these optional elements may be evaluated by the Agency and/or Company and feature in contract negotiations.

Proposals must be submitted in the legal name of the respondent who would be bound by any agreement with Company.

Payment of Bid Fees for Phases 1 and 2. Non-refundable Bid Fees shall be paid to the Agency according to the instructions in Appendix W. Bidder shall provide documentation of submitted bid fees, such as a receipt or confirmation number when bid is submitted. The Agency will not refund any bid fees associated with any bid, regardless of the success or failure of that bid, or if the RFP is cancelled.

Payment of Bid Fees for Phase 3. The Bid Fees for Phase 3 shall be paid to PacifiCorp according to the instructions for Phase 3 in Appendix W.

F. MINIMUM ELIGIBILITY REQUIREMENTS FOR BIDDERS

Bidders may be disqualified for failure to comply with the RFP if any of the requirements outlined in this RFP are not met to the satisfaction of the Agency as determined in its sole discretion. If proposals do not comply with these requirements, the Agency has the option

to deem the proposal non-conforming and eliminate it from further evaluation. Reasons for rejection of a bidder or its proposal include, but are not limited to:

1. Receipt of any proposal after the response deadline.
2. Failure to meet the requirements described in this RFP and provide all information requested in **Appendix C – Bid Summary and Pricing Input Sheet** of this RFP.
3. Failure to demonstrate a commercial operation date within the timeframe listed in Section 2.
4. Failure to permit disclosure of information contained in the proposal to the Agency’s agents or contractors, to Company or regulators, or non-bidding parties to regulatory proceedings under appropriate confidentiality agreements.
5. Any attempt to influence the Agency, Company, or contractors in the evaluation of the proposals, outside the solicitation process.
6. Failure to provide a firm offer that includes a signed attestation from an officer of the bidder’s company through the bid validity date outlined in Section 3.D. of this RFP.
7. Failure to disclose the real parties in interest in the submitted proposal.
8. Failure to clearly specify pricing for a 25-year term.
9. Failure to offer unit contingent (as generated) or system firm capacity and energy, directly interconnected with Company’s network transmission system.
10. Failure to provide all estimated interconnection costs and transmission service costs, if applicable, in the bid proposal. Costs estimates shall be performed and provided by the project if a transmission provider study has not been completed or is not available at the time of submittal.
11. Proposal presents unacceptable level of development or technology risk including multiple resource types combined under a single bid.
12. Failure to materially comply with technical specification requirements in **Appendix A**.
13. Failure to submit development and construction milestone documentation that demonstrates a process to adequately acquire or purchase major equipment (i.e., wind turbine generators and related equipment, solar photovoltaic panels, inverters, tracking system, generator step-up transformers, batteries, etc.) and other critical long lead time equipment.
14. Failure to demonstrate, to the Agency’s satisfaction, that it can meet the credit security requirements for the resource proposed.
15. Failure to submit information required by the Agency to evaluate the price and non-price factors described herein.
16. Failure to or inability to abide by the applicable safety standards.
17. Bidder submits an unacceptable contract structure, including but not limited to exceptions that significantly alter the structure of the pro forma PPA (**Appendix E-2**) as described in Section 4.B of this RFP.
18. Collusive bidding or any other anticompetitive behavior or conduct exists.
19. Bidder or proposed project being bid is involved in bankruptcy proceedings.
20. Failure of the bidder’s authorized officer to sign the proposal.
21. Misrepresentation or failure to abide by Federal Trade Commission Green guidelines.
22. Any change in regulations or regulatory requirements that make the bidder’s proposal non-conforming.

23. Any matter impairing the bidder, the specified resource or the generation of power or environmental attributes of the renewable resource.
24. Failure to provide a performance model output including hourly output values as identified in **Appendix A**.
25. Failure to provide **Exhibit D – Bidder’s Credit Information**, and **Appendix C – Form 1 – Pricing Input Sheet**.
26. Bidder’s failure to provide signed **Exhibit G-2 Non-reliance Letter**
27. Any matter impairing bidder, specified resources or the generation of power or non-power attributes therefrom.
28. Failure to provide documentation of site control for the project excluding right-of-way or easements for transmission, roads, or access to the site.
29. Bids containing energy generation types other than wind, PV solar, geothermal, and hydroelectric.
30. Failure of the project to directly interconnect with PacifiCorp’s transmission system
31. Failure to demonstrate that the project has a draft or executed generator interconnection agreement or interconnection study report (cluster study or facilities study) with PacifiCorp showing that the project can reach commercial operation by December 31, 2029.
32. Failure to submit a resume of similar generation projects developed by the bidder or bidder’s parent company that have reached commercial operation within the last five years with an explanation of any discrepancies between the original contractually agreed commercial online date (COD) and the achieved COD.
33. Failure to demonstrate that the bidder or bidder’s parent company has delivered within the last five years a project of the same generation type as the project bid
34. For wind projects, failure to submit one or more years of avian studies.
35. Failure to attain an Interconnection and Project Readiness Score of at least 70%.

If Agency rejects any bid on the grounds that it fails to meet the minimum eligibility requirements above, Agency will notify the bidder and identify the minimum eligibility requirement the bid failed to meet.

G. AGENCY AND COMPANY RESERVATION OF RIGHTS AND DISCLAIMERS

The Agency reserves the right, without limitation or qualification and in its sole discretion, to reject any or all bids, and to terminate or suspend this RFP in whole or in part at any time. Without limiting the foregoing, the Agency reserves the right to reject as non-responsive any or all bid proposals received for failure to meet any requirement of this RFP outlined herein. The Agency further reserves the right without qualification and in its sole discretion to decline to enter into any agreement with any bidder for any reason, including, but not limited to, change in regulations or regulatory requirements that impact Company, and/or any collusive bidding or other anticompetitive behavior or conduct of bidders. Bid fees are non-refundable per Section 3, part E.

Bidders who submit bid proposals do so without recourse against the Agency or Company, its consultants, its individual members, or against any director, officer, employee, agent, the Participating Customers or representative of any of them, for any modification or withdrawal of this RFP, rejection of any bid proposal, failure to enter into an agreement, or for any other reason relating to or arising out of this RFP. Bidders will be required to

execute **Appendix G - Confidentiality Agreement** after the Initial Short List is identified and **Appendix G - Non-Reliance Letter**.

H. ACCOUNTING

All proposals will be assessed by Company for appropriate accounting and tax treatment. Bidders must supply all information Company reasonably requires in order to make these assessments if a project is selected to the Initial Short List. According to Generally Accepted Accounting Principles, Company will establish and maintain accounts for the revenue, expenses, assets, liabilities and owners' equity associated with any and all renewable resources acquired through this solicitation and will ensure that all revenues and all expenses associated with the management and ownership of the resource(s) are properly recorded to these accounts. This will include expenses associated with work performed by Company personnel. Additionally, Company will account for the power costs associated with the resource(s) in a separate account(s).

I. CONFIDENTIALITY

The Agency and its consultant(s) will attempt to maintain the confidentiality of all bids submitted, to the extent consistent with law or regulatory order, as long as such confidentiality does not adversely impact a regulatory proceeding. It is the bidder's responsibility to clearly indicate in its proposal what information it deems to be confidential. Bidders may not mark an entire proposal as confidential, but must mark specific information on individual pages to be confidential in order to receive confidential treatment for that information.

In an effort to maintain the confidentiality of project bid pricing, all bids will be submitted to Consultant via the RFP website for initial scoring and evaluation on behalf of the Agency. Underlying project bid data is not expected to be possessed by any member communities of the Agency. However, because the underlying bids may ultimately be deemed subject to Utah's Government Records Access Management Act (GRAMA), the Agency recommends that every project bid be submitted with a letter asserting a claim of business confidentiality pursuant to Utah Code Section 63G-2-305(2) and in accordance with Utah Code Section 63G-2-309. This letter must contain a description of all information in the bid that the bidder asserts is confidential and a concise statement of reasons supporting the bidder's claim of business confidentiality. The bidder expressly acknowledges that the Agency's consultant may retain information submitted by the bidder in connection with this RFP until June 30, 2026. To the extent bidder receives information from the Agency or its consultants, bidder shall maintain the confidentiality of such information and such information shall not be available to any entity before, during, or after this RFP process unless required by law or regulatory order.

Only those Agency agents or employees who are directly involved in the RFP process or with the need to know for business reasons will be afforded the opportunity to view submitted bids or bidder information.

Bidders should be aware that information supplied by bidders may be requested and supplied during regulatory proceedings, subject to appropriate confidentiality provisions applicable to that particular proceeding. This means that parties to regulatory proceedings

may request and view confidential information. If such a request occurs, the Agency will attempt to prevent such confidential bidder information from being supplied to intervening parties who are also bidders, or who may be providing services to a bidder, but the Agency cannot promise success in that endeavor and accordingly cannot be held liable for any information that it is ordered to be released or that is inadvertently released.

Calculations of net costs provided by Company to Agency are considered confidential by Company and results will not be shared with bidders.

SECTION 4. RFP CONTENT

A. ALL PROPOSALS

Bidders must create a user account and upload electronic documents to the following website: www.URC2024RFP.com

Bids must include all information as described in this solicitation narrative and further detailed in **Appendix B-2: Bid Proposal Instructions and Required Information**, which contains a list of appendices to be completed for the Base Bid, optional add-ons, and optional variants, and describes what information must be included in the written proposal.

B. POWER PURCHASE AGREEMENT

Bids must contain all of the information requested in **Appendix E-1 – PPA Instructions to Bidders**. For the required Base Bid, the term of the PPA shall be twenty-five (25) years with a fixed price in dollars per Megawatt-hour (\$ per MWh).

Appendix C – Bid Summary and Pricing Input Sheet shows the form of pricing information required for the Base Bid PPA structure as well as questions and forms related to the optional bid add-ons and variants. This is an Excel-based worksheet that covers bid summary information, electrical interconnection information, 8760 energy production profile, PV degradation information, and pricing for the PPA.

In the event Company is required to consolidate the entity under variable interest entity (VIE) accounting requirements, the entity will be required to provide the financial statement information to Company throughout the term of the agreement that is necessary to consolidate the entity.

The determination of consolidation under variable interest entity accounting requirements requires a comprehensive evaluation, including an assessment as to who has the ability to direct key economic decisions of the entity and who is required to absorb the gains and losses of the entity. The entity that meets these two requirements is generally considered the primary beneficiary and is required to consolidate the entity if it is considered a variable interest entity and if the contract is a variable interest. Typically, a fixed price per unit contract would indicate that Company does not have a variable interest and does not absorb the gains and losses of the entity. In this case, it is unlikely that the entity would be

consolidated. The Agency reserves the right to request additional information in order to complete its evaluation of tax ownership for VIE accounting requirements if necessary.

Please also refer to Section 5.F of this RFP.

For the purposes of evaluating tax ownership, bidders of longer-term contract offers must be prepared to submit, at Company's request, documentation from an independent engineer that supports the economic useful life of the underlying asset that will be used by the bidder.

The bidder's proposal must contain the information requested in **Appendix E-1 PPA Instructions to bidders**. The bidder must provide documentation and information, representations, and warranties sufficient to assure the Agency and Company that any proposed project will successfully complete construction and achieve full operation within the timeframe listed in Section 2, and that any new resource will be eligible to claim, as applicable, the full or partial federal PTC/ITC as interpreted by applicable guidelines and rules of the Internal Revenue Service.

Bidders are required to include a redlined or marked up version of **Appendix E-2 Power Purchase Agreement** showing exceptions to the terms of the pro forma PPA document, unless they indicate that they will accept the PPA "as-is". Bidders objecting to terms should provide alternate language and context to the objections for the Agency and Company to evaluate the alternate language. Bidders should also submit comments to the pro forma agreement on issues that they have concerns with and identify alternatives to address the issues. Providing a redline is a requirement for eligibility; however substantive comments should also be provided to provide context to the redlined document.

BIDDERS SHOULD BE AWARE THAT, IF THEIR BID IS SELECTED, THE BIDDER WILL BE REQUIRED TO COMPLETE A QUALIFYING REPORTING ENTITY (QRE) SERVICES AGREEMENT AS PART OF THE PPA WHICH ESTABLISHES WREGIS REGISTRATION AND REPORTING OBLIGATIONS FOR PARTIES ONCE THE RESOURCE IS IN COMMERCIAL OPERATION.

C. BUILD TRANSFER AGREEMENT

Each bid may opt to include a BTA Bid Variant that includes a "Build-Transfer" transaction whereby the bidder develops the project, assumes full responsibility for construction and commissioning of the project, transfers title to the project, potentially in stages, to Company prior to mechanical completion and thereafter completes construction and commissioning of the project, all pursuant to the terms of the build transfer agreement ("BTA"). Bids including such BTA Bid Variant proposals shall provide the following information.

Appendix C – Bid Summary and Pricing Input Sheet shows the form of project information required for a "Build-Transfer" transaction. This is an Excel-based worksheet that covers bid summary information, electrical interconnection information, 8760 energy production profile, PV degradation information, and pricing and other cost assumption inputs for the BTA. The bidder's proposal must contain the information requested in **Appendix F-1 – BTA Instructions to Bidders**. The bidder must provide information, representations, and warranties sufficient to assure the Agency and Company that any

proposed project will successfully complete construction and achieve full commercial operation within the timeframe listed in Section 2. The bidder must also provide evidence that any new resource will be eligible to claim, as applicable, the full or partial federal PTC/ITC as interpreted by applicable guidelines and rules of the Internal Revenue Service. Under the BTA, the bidder will assume full responsibility for the loss of any PTC/ITC, including due to failure to achieve full commercial operation within the timeframe listed in Section 2 or to satisfy applicable guidelines and rules of the Internal Revenue Service.

The BTA pro forma documents are attached as **Appendix F-2 – Build Transfer Agreement (BTA)**. Bidders should include a redlined or marked up version of **Appendix F-2 Build Transfer Agreement** showing exceptions to the terms of the pro forma BTA document. Bidders objecting to terms should provide alternate language and context to the objections for the Agency and Company to evaluate the alternate language. **Any exceptions that represent significant modifications to the pro forma BTA may result in rejection of the bid as non-compliant. The Agency will reject as non-compliant any bid which proposes to transfer to Company the stock or membership interest (as opposed to assets) of one or more companies which own the project.**

The BTA is structured such that Company makes progress payments on an agreed-upon schedule in exchange for the developer meeting certain milestones and deliverables. All bidders in this category must complete the information requested in **Appendix C – Bid Summary and Pricing Input Sheet** (BTA tabs). The Agency will only accept BTA proposals in which Company purchases the project prior to “mechanical completion” (as further specified in the BTA) and the bidder retains full responsibility to complete construction and commissioning of the project thereafter through commercial operation.

The bidder will be responsible for, in accordance with the requirements of this RFP, all aspects of the development and construction of the facility, including, but not limited to, site control, permitting, engineering, procurement, construction, interconnection and all related costs up to achieving commercial operation. Without limiting the foregoing, the bidder will be responsible for obtaining all necessary real property interests, permits, rights and resources required to construct and provide an operational generation resource consistent with the bidder’s proposal. BTA bids must identify and provide all taxes including but not limited to property, sales and use incurred during construction and are the responsibility of the developer.

Bidders will be responsible for submitting an operation and maintenance (O&M) service proposal as part of the overall BTA bid submittal consistent with **Appendix K (BTA) Operations and Maintenance Services**. **Any proposal that does not include an O&M proposal that provides pricing, scope and other key terms will be rejected as a nonconforming proposal.**

Bidders should note that any proposal submitted in this category that proposes new construction of a resource must comply with the applicable technical and construction specifications contained in **Appendix A – 2024 Utah Renewable Project Technical Specification** and must utilize the services of a single primary contractor.

To the extent the bidder uses a contractor or a separate legal entity other than the bidder itself, this entity must be experienced with the type of facility being proposed and meet credit criteria, all as deemed acceptable to the Agency and Company.

Bidders should indicate in their bid documents whether a purchase option for a BTA has already been negotiated or is in the process of being negotiated with Company.

SECTION 5. RESOURCE INFORMATION

A. BID SUMMARY INFORMATION

Bidders must supply bid summary and pricing information using the instructions in Appendix C-1 and filling out the spreadsheet in Appendix C-2.

B. DIRECT INTERCONNECTION WITH THE PACIFICORP TRANSMISSION SYSTEM

The Agency is seeking renewable resources capable of directly interconnecting with PacifiCorp's transmission system in its PACE balancing area.⁵ The Agency prefers bids that will not face significant transmission costs or constraints between: (1) the resource's point of interconnection or the resource's delivery point on PacifiCorp's transmission system; and (2) PacifiCorp network load. Bidders are thus required to provide as much granularity and documentation as possible regarding their proposed point of interconnection. Bidders should also indicate with their bids whether their project will include any jointly owned generation tie lines or other shared facilities arrangements.

As noted above, bidders should provide evidence that the proposed project has requested a direct interconnection with PacifiCorp's transmission system and has received, at a minimum, a cluster study report with PacifiCorp's transmission function supporting commercial operation no later than December 31, 2029.

All bid proposals that will require a new electrical interconnection or an upgrade to an existing electrical interconnection must include a firm statement of the cost of interconnection (broken out between network upgrade costs and facility-specific or direct assigned interconnection costs), together with a diagram of the interconnection facilities. The interconnection costs included in the bids from all bidders will be considered by the bid evaluation team as firm costs and included in the bid evaluation. Interconnection costs should be clearly identified in the resource cost proposal and differentiate the portion of costs associated with network upgrades and that portion that are facility-specific.

Before any final transaction agreements with winning bidders are executed, the Agency will require an interconnection Facilities Study report to determine the final network upgrades and direct assigned cost for interconnection service. Bids will be evaluated based on the direct assigned interconnection costs submitted in the bids, which will be considered firm costs for the Initial Short List evaluation. Bids that are selected to the Initial Short

⁵ To further clarify, projects should interconnect directly to the PacifiCorp transmission system and be located in Idaho, Utah, or Wyoming.

List will be held to their pricing for the Final Short List evaluation. If selected to the Final Short List, bidder's agreement with Company, and any final transaction agreement, will include a condition precedent that states the Agency will compare the actual direct assigned and network upgrade costs associated with the interconnection from the most recent completed system impact/cluster study (SIS) or Facilities Study (FS) with the bidder's firm estimate provided in their best and final price. In the event the actual direct assigned SIS cost exceeds the bidder's interconnection cost in best and final pricing, bidder will be responsible for the cost above their best and final firm price. In the event the actual SIS direct assigned cost is less than the bidder's firm interconnection cost estimate, the Agency will require an adjustment of the final PPA price to reflect the reduction in interconnection costs. The Agency will examine critical study information such as: (1) whether the studies support a commercial operation date within the timeframe listed in Section 2; and (2) interconnection direct assigned and network upgrade costs.

All proposals will require firm transmission service on PacifiCorp's network transmission system and proposed resources must be able to be designated by PacifiCorp's Energy Supply Management (ESM) function as a Network Resource under the network service contract between PacifiCorp Transmission (www.oasis.pacifiCorp.com) and PacifiCorp ESM. The final transaction agreement includes a condition precedent that should designation as a Network Resource (DNR) require additional upgrades beyond those identified in the interconnection study, the bidder may be required to bear the additional cost.

C. FERC'S STANDARDS OF CONDUCT

Each bidder responding to this RFP must conduct its communications, implementation and operations in compliance with FERC's Standards of Conduct for Transmission Providers (see **Appendix I**), requiring the separation of transmission and merchant functions. Any interconnection or transmission service agreement is NOT a transmission service agreement with PacifiCorp's ESM merchant function; rather, it is with PacifiCorp's transmission function or other third-party transmission provider. As such, the bidder must follow the transmission provider's OASIS process. If requested, bidders shall execute a customer consent form (see Appendix J PacifiCorp Transmission Waiver) consistent with FERC requirements that enables PacifiCorp's ESM merchant function to discuss the bidder's interconnection and/or transmission service application(s) with the transmission interconnection or transmission service provider.

D. RESOURCE TYPES ELIGIBLE TO BID

The Agency is seeking new renewable energy resources capable of directly interconnecting to PacifiCorp's network transmission system between January 1, 2026 and December 31, 2029. The Agency is limiting the resource types to wind, PV solar, geothermal, and hydroelectric only and will not accept bids that combine these technologies with other technologies except for co-located storage resources. These resources must be capable of being interconnected with PacifiCorp's transmission system.

E. TAX CREDITS AND/OR PROJECT INCENTIVES

Bidders must bear all risks, financial and otherwise, associated with bidder's or the facility's eligibility to receive any state or federal energy tax credits, sales tax waivers or exemptions or any other identified tax credit or incentive, or qualify for accelerated depreciation for bidder's accounting, reporting or tax purposes, as applicable. The obligations of the bidder to perform under any executed agreement as a result of this solicitation shall be effective and binding regardless of whether the sale of or output from the bidder's facility under such agreement is eligible for, or receives investment tax credits, or other identified tax credits/incentives.

The Agency will require written documentation of the amount, timing and control of any and all available tax credits/incentives that the bidder's facility is eligible for, applied for, and/or received. Such documentation shall include but not be limited to ownership rights to the credit, grant or incentive, timing including expiration dates and milestones to achieve the credit, grant, or incentive.

F. ACCOUNTING AND TAX CONSIDERATIONS

All contracts proposed to be entered into as a result of this RFP will be assessed by Company for appropriate accounting and tax treatment. Bidders shall be required to supply Company with any and all information that Company reasonably requires in order to make preliminary assessments if the bid is selected to the Initial Short List. Specifically, given the term length of the PPA or BTA arrangement, accounting and tax rules may require either: (i) a contract be accounted for by Company as a finance lease or operating lease⁶ for book purposes pursuant to ASC 842, (ii) a contract be accounted for by Company as a capital lease for tax purposes⁷, or (iii) the seller or assets owned by the seller, as a result of an applicable contract, be consolidated as a VIE into Company's financial statements.⁸

G. COST ASSOCIATED WITH DIRECT OR INFERRED DEBT

The Agency will not take into account potential costs to Company associated with direct or inferred debt (described below) as part of its economic analysis in the short list evaluations. However, after completing the Final Short List and before the final resource selections are made, the Agency and Company may take direct or inferred debt into consideration. In so doing, Company may obtain a written advisory opinion from a rating agency to substantiate Company's analysis and final decision regarding direct or inferred debt.

Direct debt results when a contract is deemed to be a lease pursuant to ASC 842 and liability reflected on Company's balance sheet.

⁶ "Finance Lease" and "Operating Lease" - shall have the meaning as set forth in the Accounting Standards Codification (ASC) 842 as issued and amended from time to time by the Financial Accounting Standards Board.

⁷ See IRS Code Section 7701(e) describing the test for finance lease for tax purposes.

⁸ "Variable Interest Entity" or "VIE" - shall have the meaning as set forth in ASC 810 as issued and amended from time to time by the FASB.

Inferred debt results when credit rating agencies infer an amount of debt associated with a power supply contract and, as a result, take the added debt into account when reviewing Company's credit standing.

SECTION 6. BID EVALUATION AND SELECTION

A. OVERVIEW OF THE EVALUATION PROCESS

The Agency's bid evaluation and selection process is designed to identify the combination and amount of new renewable projects bid into the 2024 URC RFP that will cost-effectively support URC member communities' goals to achieve net-100% renewable electricity on behalf of Participating Customers by 2030. The Agency will not make any of the evaluation models available to bidders.

The bid evaluation process will occur in three phases. In the first phase, the Agency will calculate an Interconnection and Project Readiness Score (IPRS) and reject non-conforming bids. Although not a scoring element, the IPRS will be used to reject project bids scoring less than 70% and to adjust non-price scoring elements in the third phase.

In the second phase, price (expressed in \$ per MWh) and non-price scoring elements will be evaluated to develop an Initial Short List of projects consisting of up to six bids across two categories: 1) wind and solar – W&S, and 2) geothermal and hydropower (G&H).

In the third phase, PacifiCorp will model two scoring inputs for each bid selected to the Initial Short List: a financial benefit (expressed in \$ per MWh) and avoided climate pollution through 2030 (expressed in metric tons of CO₂-equivalent). Any other factors not expressly included in the formal evaluation process but required by applicable law or Commission order, will be used by the Agency to establish the Final Short List.

Representatives from the Agency, its Consultant, or Company may contact bidders to confirm and clarify information presented in each proposal.

After the Final Short List is established, Company will initiate negotiations with projects from the Final Short List that are selected by the Agency by a vote of its Board. Selection of a bid to the Final Short List does not constitute a winning bid. Only execution of a definitive agreement between Company and the bidder, on terms acceptable to the Agency and Company, in their sole and absolute discretion, will constitute a winning bid proposal. Any definitive PPA or BTA will be in the form of the PPA or BTA contracts provided in **Appendices E-2** and **F-2**, respectively. If the bidder alters the PPA or BTA, or does not use it as the underlying agreement, bid evaluation and selection can be affected. The Agency welcomes bidders, at their own discretion, to provide written comments on the PPA or BTA provided in **Appendices E-2** and **F-2** as part of their bid. Neither the Agency nor Company has a legal obligation to enter into any agreement of any kind with any bidder.

B. PHASE 1 – INTERCONNECTION AND PROJECT READINESS

Project bids that have not already been rejected as non-conforming will be evaluated using an Interconnection and Project Readiness Score (IPRS). This evaluation consists of ten questions as follows:

Interconnection and Project Readiness Score Factors	Scoring Weight
1. Does project have site control necessary to support a generation facility? (Yes = 1, No = 0)	1
2. Does project have site control necessary to support a generation-intertie ("gen-tie") needed to interconnect the project on the transmission system? (Yes = 1, No = 0)	1
3. Does project have a signed generator interconnection agreement? (Yes = 1, No = 0)	1
4. Does this project have at least one of the following: (1) it has passed fast-tracked under section 50 of PacifiCorp's OATT, (2) it has been issued an executable interconnection agreement under PacifiCorp's OATT section 51.4.3, or (3) it has a facilities study, either final or draft? (Yes = 1, No = 0) <i>Please note: OATT references are to PacifiCorp's Open Access Transmission Tariff v.2.0.0 dated April 1, 2020</i>	1
5. Has this project been studied as a Network Resource Interconnection Service (NRIS) or does it pass as fast-tracked under section 50 of PacifiCorp's OATT? (Yes = 1, No = 0)	1
6. Wetlands are either not present or mitigation plans are in place. (True = 1, False = 0)	1
7. Endangered species are either not present on site or mitigation plans are in place (True = 1, False = 0)	1
8. Cultural resources are either not present or mitigation plans are in place (True = 1, False = 0)	1
9. Site is zoned for proposed use (True = 1, False = 0)	1
10. Permitting is complete (i.e., project is shovel-ready) (True = 1, False = 0)	1

The total points will be summed and divided by 10 total possible points to develop an IPRS expressed as a percentage. Project bids with an IPRS lower than 70% will be rejected and the IPRS will be carried forward into the second phase of project bid evaluation.

C. PHASE 2 – INITIAL SHORT LIST

1. Price Evaluation (up to 70 points)

The Agency is committed to procuring least cost/least risk renewable energy through this solicitation on behalf of the Participating Customers.⁹ In phase 2, the Agency will compare the all-in cost (expressed in \$ per MWh)—inclusive of network upgrade costs associated with interconnecting the resource—among all bids that have met the threshold requirements described in phase 1. The lowest cost bid will be awarded 70 points and all other bids will be awarded a pro-rated share of 70 points based on how much more expensive they are than the lowest cost bid. This price evaluation will consider the pricing

⁹ As noted above, the Agency is under no obligation to procure resources bid into this RFP.

of the base 25-year project term. Please see Section 6.C.3 for a discussion of how wind and solar (W&S) bids will be ranked in a different list from geothermal and hydropower (G&H) bids for the purpose of selecting up to six (6) bids for the Initial Short List.

Bids must include documentation that demonstrates that the project(s) qualify for and will receive the full or partial value of the federal PTC or ITC as interpreted by applicable guidelines and rules of the Internal Revenue Service at commercial operation. The bids will be ranked to determine an initial shortlist, after also taking into account the Non-Price Evaluation.

2. Non-Price Evaluation (Up To 13 points)

The non-price scoring factors will be evaluated as follows:

NON-PRICE FACTOR WEIGHTING

Non-Price Factors	Non-Price Scoring Weight
1. Is the project located in Utah? (Yes = 3, No = 0)	3
2. If your project is located in Utah, will at least 50% of construction labor hours be supplied by in-state labor at the bid price? (Yes = 1, No = 0)	1
3. Will your project meet prevailing wage requirements for construction labor at the bid price? (Yes = 1, No = 0)	1
4. Will at least 2% of construction labor hours be supplied by registered apprenticeship labor at the bid price? (Yes = 1, No = 0)	1
5. Is your project located in a (1) 2024 Coal Closure Energy Community * or (2) disadvantaged area** as indicated on Federal maps? (Yes = 2, No = 0)	2
6. Inclusive of construction activities, how much water will your project consume in gallons per MW-hr over its operational life? (None = 2, between 0 and 20 = 1, more than 20 = 0)	2
7. By what date can your project reach commercial operation and deliver energy to the PacifiCorp transmission system, as evidenced by the most recent cluster or facilities interconnection study report or generator interconnection agreement? (by Dec 2026 = 3, between Jan and Dec 2027 = 2, between Jan and Dec 2028 = 1, between Jan and Dec 2029 = 0)	3

***2024 Coal Closure Energy Communities are light- or dark-green shaded areas in the [United States Department of Energy Community Tax Credit Bonus Map](#)**

****Disadvantaged areas are green-shaded areas in the [archived EJScreen](#) tool. Please note: to turn on the Designated Disadvantaged Communities layer, click Places > Designated Disadvantaged Communities > EPA IRA Disadvantaged Communities and in the Map Contents box, ensure that EPA IRA Data 2.0 is checked.**

3. Initial Short List Selection

The Agency will use the combined price and non-price results for valid bids to rank them in two separate lists: one list of all wind and solar bids (W&S) and a second list of all geothermal and hydropower bids (G&H). So long as there are G&H bids that meet all

screening criteria and survive Phase 1 scoring, up to three (3) top scoring bids will be selected from the G&H category; then, three (3) or more top scoring bids will be selected from the W&S category to bring the total bids selected for the Initial Short List and advancing to Phase 3 to no more than six (6) bids. Should any project bids of 10 MW or smaller size advance to Phase 2, the Agency reserves the right to select up to one (1) such bid to the Initial Short List.

In making Initial Short List selections, the Agency will consider the anticipated impact on the program rate that will be paid by Participating Customers. The total contract cost, commercial online date, and need to establish a dedicated reserve fund are all factors that may influence the program rate.

The Agency anticipates that the Initial Short List will represent approximately 500 MW of aggregate capacity. However, the Agency may establish an Initial Short List containing less or more aggregate capacity depending upon the relative total bid score among the bids and the total capacity bid into each category.

Network customers of PacifiCorp transmission, including Company, can request non-binding studies to provide an estimate of potential, high-level costs related to adding a potential designated network resource at a particular location on the system. While intervening transmission service requests or other changes on the system could impact the accuracy of the non-binding study estimates, these nevertheless provide a reasonable tool to evaluate potential transmission service costs before a final agreement is reached with a bidder. Accordingly, for all bids included in the Initial Short List, the Agency also reserves the right to request an informal study from PacifiCorp transmission to identify potential network upgrade costs that might be necessary for the bidder's facility to be designated as a network resource on PacifiCorp's transmission system. The cost of this non-binding study is to be paid by the bidder.

D. PHASE 3 – FINAL SHORT LIST

1. Price Evaluation (up to 70 points)

To be evaluated for Phase 3, Company will require an additional \$12,500 bid analysis fee for each Base Bid, variant, and/or add-on selected by the Agency to the Initial Short List and a signed Appendix G-2: Non-Reliance Letter prior to calculating a financial benefit (expressed in \$ per MWh). For clarity, Phase 3 evaluation of a bidder's Base Bid and an optional Storage Add-On will be subject to a \$25,000 bid analysis fee. If a bidder does not (a) execute this agreement with Company and (b) deliver this payment to Company by August 22, 2025, the Agency may remove that bid from the Initial Short List and replace it with a different bid.

Company will assess Initial Short List bids for the appropriate accounting and tax treatment. PPA bids will be evaluated to determine: (i) whether a contract must be accounted for by Company as a finance lease or operating lease in accordance with ASC 842 for book purposes, (ii) whether a contract must be accounted for by Company as a capital lease for tax purposes, or (iii) whether the seller or assets owned by the seller, as a result of an applicable contract, shall be consolidated as a VIE into PacifiCorp's financial

statements. Potential accounting treatment impacts will be incorporated into the bid evaluation and selection process. Please also refer to Section 5.F of this RFP.

For project bids that involve generation types other than solar, wind, and hydro, or storage types other than batteries, the bidder may be required to cover the cost for Company to hire a third party to support calculation of the financial benefits.

Net-Cost of Energy (35 points)

For each Initial Short List bid, the net-cost of energy will be calculated as the difference between the PPA fixed price (expressed in \$ per MWh) and the financial benefit (expressed in \$ per MWh).

The Agency will compare the net-cost of energy (expressed in \$ per MWh) among all Initial Short List bids. The bid with the lowest net-cost of energy (which may be negative) will be awarded 35 points. For all other project bids, the net-cost of energy will be compared to the lowest net-cost of energy. For every \$1 per MWh of net-cost of energy that a project bid exceeds the lowest net-cost of energy bid, 2 points will be deducted from the 35 possible points. For example, if the lowest net-cost of energy bid is -\$5 per MWh and another project bid's net-cost of energy is \$0 per MWh, the first project bid would receive 35 points and the second project bid would receive $(35 - 10 =) 25$ points.

Net-Cost of Contract (35 points)

For each Initial Short List bid, the net-cost of contract will be calculated as the net present value of the net-cost of energy over the 25-year term of the PPA (expressed in \$).

The Agency will compare the net-cost of contract (expressed in \$) among all Initial Short List bids. The project bid with the lowest net-cost of contract (which may be negative) will be awarded 35 points while project bids with a net-cost of contract of \$45 million or more will be awarded 0 points. All other project bids will be awarded a prorated share of 35 points based on how much more expensive they are compared to the lowest net-cost of contract.

2. Non-Price Evaluation (up to 30 points)

Commercial Online Date Confidence Score (up to 4 points)

Consultant will review interconnection studies and related documentation for every Initial Short List bid and assign a Commercial Online Date Confidence Score as shown:

- No, the document review does not support the indicated online date: 0
- No, the document review suggests the indicated online date is unlikely: 1
- Maybe, the document review suggests the indicated online date is possible: 2
- Yes, the document review suggests the indicated online date is likely: 3
- Yes, the document review suggests the indicated online date is substantially supported: 4

Adjusted CO₂ Reduction Score (up to 13 points)

PacifiCorp will model projected carbon dioxide reductions for each Initial Short List bid from the indicated commercial online date through 2030 (expressed in metric tons of CO₂). These carbon dioxide reductions result from changes in how PacifiCorp's thermal power plants are dispatched in response to new sources of generation.

The modeled CO₂ reductions through 2030 will be adjusted by the Commercial Online Date Score converted to a percentage. For example, if an Initial Short List bid receives a Commercial Online Date Score of 2 out of 4 (50%), then the bid's modeled CO₂ reduction (in metric tons) will be adjusted to 50% of its original value.

The adjusted CO₂ reduction (in metric tons) will be compared among all Initial Short List bids. The bid with the largest adjusted CO₂ reduction through 2030 will receive 13 points and all other bids will be awarded a prorated share of 13 points based on how many fewer tons of adjusted carbon dioxide pollution they will reduce compared to the project bid with the largest reduction.

Non-Price Factors Previously Scored in Phase 2 (up to 13 points)

The non-price scoring factors from phase 2 will also be included in the non-price evaluation for phase 3.

3. Other Factors: Applicable Law and Statutory Requirements

The bid methodology has been designed to capture applicable law and statutory requirements. Before establishing a final shortlist, the Agency may take into consideration other factors that are not expressly or adequately factored into the evaluation process outlined above, particularly any factor required by applicable law or Commission order to be considered.

4. Final Short List Selection

The Agency will summarize and evaluate the results of its price and non-price scores among all surviving project bids. Based on these data and certain other factors as described above the Agency may establish a Final Short List. Once the Final Short List is established and bidders notified, the Agency may select by a vote of its Board one or more project bids for contract negotiation. Should any project bids of 10 MW or smaller advance to Phase 3, the Agency reserves the right to select up to one (1) such bid for contract negotiation.

In selecting one or more project bids from the Final Short List for contract negotiation, the Agency will consider the anticipated impact on the program rate that will be paid by Participating Customers. The net-cost of energy, net-cost of contract, total contract cost, commercial online date, and need to establish a dedicated reserve fund are all factors that may influence the program rate.

Company will not enter into any agreement without Agency approval.

5. BTA Bid Evaluation

If a Base Bid that contains a BTA Bid Variant is selected to the Final Short List and is approved by the Agency's Board for contract negotiation, Company may elect to pursue a BTA with the bidder when the project proceeds to the contract negotiation phase.

SECTION 7. INVITATION TO BID

A. INVITATION

This RFP contains only an invitation to make proposals to the Agency. No proposal is itself a binding contract unless the parties execute definitive and complete documentation providing otherwise.

The Agency may in its sole discretion do any one or more of the following:

1. Determine which proposals are eligible for consideration in response to this RFP.
2. Issue additional subsequent solicitations for information and conduct investigations with respect to the qualifications of each bidder.
3. Supplement, amend, or otherwise modify this RFP, or cancel this RFP with or without the substitution of another RFP.
4. Negotiate with bidders to amend any proposal.
5. Require winning bidder(s) to provide an additional administrative fee.
6. Select and enter into agreements with the bidders who, in the Agency's sole judgment, are most responsive to the RFP and whose proposals best satisfy the interests of the Agency and the Participating Customers, and not necessarily on the basis of price alone or any other single factor.
7. Issue additional subsequent solicitations for proposals.
8. Waive any irregularity or informality on any proposal to the extent not prohibited by law.
9. Reject any or all proposals in whole or in part.
10. Vary any timetable.
11. Conduct any briefing session or further RFP process on any terms and conditions.
12. Withdraw any invitation to submit a response.

B. CONFIDENTIALITY AGREEMENT

In addition to the confidentiality provisions set forth herein, bidders should note that all parties will be required to sign **Appendix G-1 – Confidentiality Agreement** with the Agency upon bid submission, as well as a transmission voluntary consent notice to authorize the release of data to PacifiCorp's ESM Market Function from PacifiCorp Transmission.

C. NON-RELIANCE LETTER

All parties will be required to sign **Appendix G-2 - Non-Reliance Letter** if they qualify for the Initial Short List prior to the Company modeling the financial impact of the project bid.

D. POST-BID NEGOTIATION

Company will further negotiate both price and non-price factors during post-bid negotiations. The Agency will also include in its evaluation any factor that may impact the total cost of a resource, including but not limited to all of the factors used in the Final Short List cost analysis plus consideration of accounting treatment and potential effects due to rating agency treatment, if applicable. Post-bid negotiation will be based on the Agency's cost assessment. The Agency will continually update its economic and risk evaluations until Company and the bidder execute a definitive agreement acceptable to Company. The Agency must approve any contract negotiated between Company and the bidder.

Neither the Agency nor Company shall have any obligation to enter into any agreement with any bidder to this RFP and the Agency may terminate or modify this RFP at any time without liability or obligation to any bidder. In addition, this RFP shall not be construed as preventing the Agency or Company from entering into any agreement that the Agency or Company deems prudent, in each of the Agency's and Company's independent sole discretion, at any time before, during, or after this RFP process is complete. Finally, the Agency reserves the right to negotiate only with those entities that propose transactions that the Agency believes in its sole discretion to have a reasonable likelihood of being executed.

E. SUBSEQUENT REGULATORY ACTION

Unless mutually agreed between the parties or unless required by actual (or proposed) law or regulatory order, at the time of contract execution, the Agency does not intend to include a contractual clause whereby the Agency is allowed to adjust contract prices in the event that an entity that has regulatory jurisdiction over Rocky Mountain Power does not fully recognize the contract prices. As of the issuance date for this solicitation, the Agency is unaware of any such actual law or regulatory order.

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

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Emergency Order: Tri-State)
Generation and Transmission)
Association, Platte River Power)
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Public Interest Organizations

Filed January 28, 2026

Exhibit 1-111:
Western Energy Imbalance Market Webpage

WESTERN ENERGY MARKETS



The ISO's Western Energy Imbalance Market enhances grid reliability while meeting the needs of an evolving industry through collaborative efforts across the West

Western Energy Imbalance Market (WEIM)

The ISO's Western Energy Imbalance Market is a real-time energy market, the first of its kind in the western United States.

The WEIM's advanced market system automatically finds low-cost energy to serve real-time consumer demand across the west. Since its launch in 2014, the WEIM has enhanced grid reliability and generated cost savings for its participants. Besides its economic advantages, the WEIM improves the integration of renewable energy, which leads to a cleaner, greener grid.

Participants

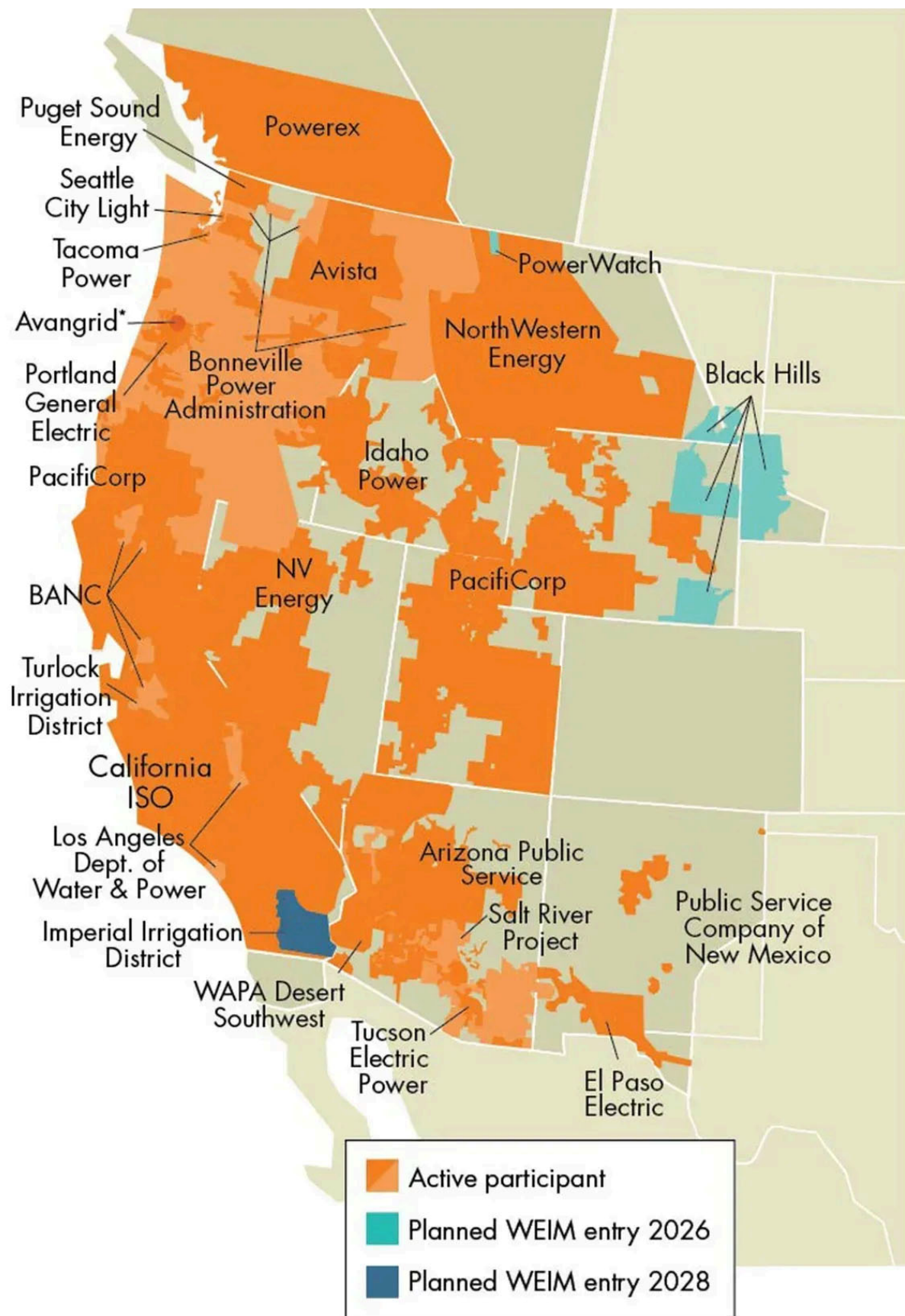
- [Imperial Irrigation District](#) – *planned entry 2028*
- [Black Hills](#) – *planned entry 2026*
- [PowerWatch \(formerly BHE Montana\)](#) – *planned entry 2026*
- [Avangrid](#) – entered 2023
- [El Paso Electric](#) – entered 2023
- [WAPA Desert Southwest Region](#) – entered 2023

Back to top

- [Bonneville Power Administration](#) – entered 2022
- [Tucson Electric Power](#) – entered 2022
- [Avista](#) – entered 2022
- [Tacoma Power](#) – entered 2022
- [NorthWestern Energy](#) – entered 2021
- [Los Angeles Department of Water & Power](#) – entered 2021
- [Public Service Company of New Mexico](#) – entered 2021
- [Turlock Irrigation District](#) – entered 2021
- [Salt River Project](#) – entered 2020
- [Seattle City Light](#) – entered 2020
- [Balancing Authority of Northern California](#) – entered 2019
- [Idaho Power Company](#) – entered 2018
- [Powerex](#) – entered 2018
- [Portland General Electric](#) – entered 2017
- [Puget Sound](#) – entered 2016
- [Arizona Public Service](#) – entered 2016
- [NV Energy](#) – entered 2015
- [PacifiCorp](#) – entered 2014
- [California ISO](#) – entered 2014

[View implementation documents for participants](#)

Participant map



**Avangrid office; generation only BAA with distribution across multiple states. Map boundaries are approximate and for illustrative purposes only. Copyright © 2025 California ISO*

[Download map](#)

See the [latest quarterly benefits report](#).

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[OASIS](#) | [MPP](#) | [WEIM Portal](#) | [Developer](#) | [Glossary](#) | [Sitemap](#) | [Privacy and Terms of use](#)

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Exhibit 1-112:
WEIS — Southwest Power Pool



WESTERN ENERGY IMBALANCE SERVICE MARKET

Quick Links

- [SPP WEIS Marketplace Protocols](#)

News Release Quick Links

- [May 12, 2021, release announcing Colorado Springs Utilities joining SPP's western market](#)
- [Dec. 23, 2020, release announcing FERC's approval of the WEIS tariff](#)
- [Nov. 12, 2020, release announcing SPP and stakeholders will consider RTO expansion to the west; study anticipates \\$49M in annual savings for current and new members](#)
- [Feb. 21, 2020, release announcing WEIS tariff filing](#)
- [Dec. 12, 2019, release announcing new participants of the WEIS](#)
- [Sept. 9, 2019, release announcing the first agreements with participants of the WEIS](#)
- [June 17, 2019, release announcing WEIS proposal and design](#)

SPP invites utilities to help build an electricity market to serve the west

SPP's Western Energy Imbalance Service market (WEIS) will balance generation and load regionally and in real time for participants in the Western Interconnection.

SPP began administering WEIS on a contract basis February 2021. Utilities do not have to be a member of the SPP regional transmission organization (RTO) to participate. The market will centrally dispatch energy from participating resources throughout the region every five minutes, enhancing both the reliability and affordability of electricity delivery from utilities to their customers.

The following are participants of the WEIS Market:

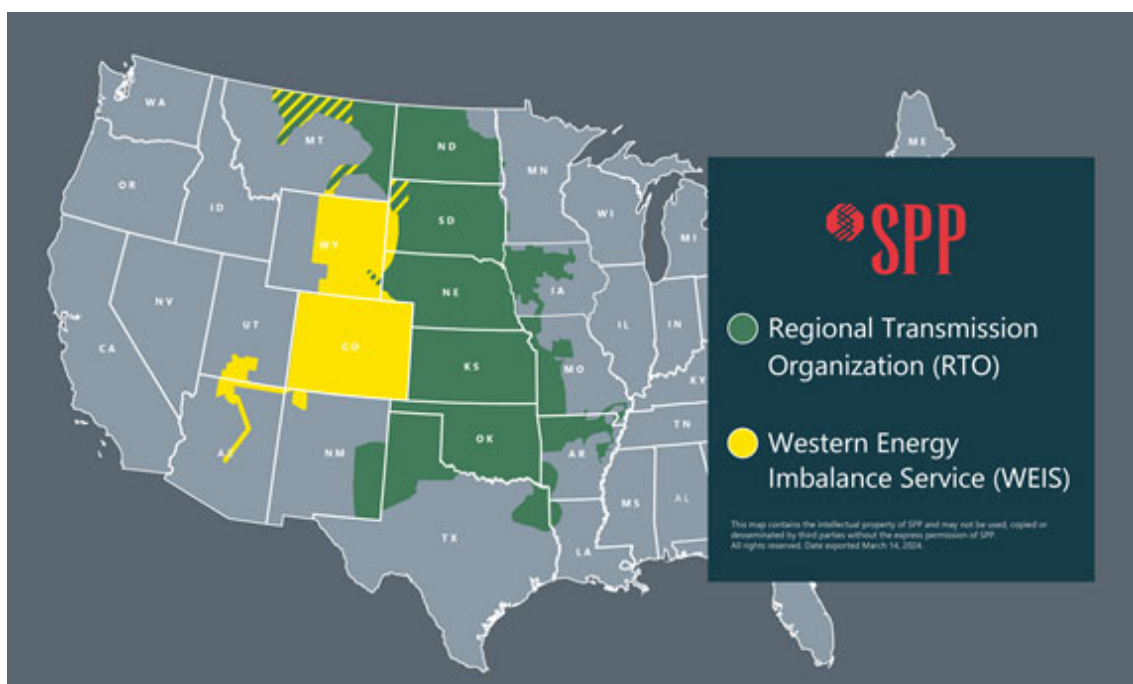
- Basin Electric Power Cooperative
- Black Hills Energy (effective April 2023)
- City of Farmington NM Electric Utility
- Colorado Springs Utilities (effective August 2022)
- Deseret Power Electric Cooperative
- Guzman Energy
- Municipal Energy Agency of Nebraska
- Platte River Power Authority (effective April 2023)
- Tri-State Generation and Transmission Association
- United Power, Inc.
- Western Area Power Administration
 - Upper Great Plains West
 - Rocky Mountain Region
 - Colorado River Storage Projects
- Xcel Energy (effective April 2023)

SPP's previous energy imbalance market went live in 2007 and provided participants with \$103 million in benefits in its first year of operation.

As the market's administrator, SPP maintains reliability of the region's transmission system and meets demand with the most cost-effective generation available, reducing wholesale electricity costs for participants. Like SPP's previous markets, the WEIS provides price transparency of wholesale energy, allows parties to trade bilaterally and hedges against costly transmission congestion.

In designing the WEIS, SPP leveraged existing constructs in the west and its experience successfully building and operating its own energy imbalance market from 2007-2014, after which the RTO introduced day-ahead unit commitment and other services in the transition to its current Integrated Marketplace.

An overview of the WEIS' proposed scope and design is available in the Related Documents menu to the right.



Governance and Stakeholder Involvement

For more than 75 years, SPP has distinguished itself as a stakeholder-driven organization that achieves its business objectives through consensus-building. While SPP's independent board of directors provides ultimate oversight of the administration of the WEIS market, an open, transparent, and inclusive stakeholder process is a hallmark of our culture and business model. This same approach has been brought to the governance of the WEIS market to provide ample opportunities for stakeholder engagement and to ensure the market remains effective, efficient and competitive.

Stakeholders can stay informed of, and participate in, WEIS Market development through the Western Markets Working Group.

SPP's **Western Markets Working Group (WMWG)** is the forum for customers of SPP's western energy imbalance service market to engage in matters of WEIS Market related governance and strategy and with other stakeholders.

Its meetings serve as an open forum for entities looking to learn about SPP or to have a say in the development of the WEIS market in the west.

Attendees may [register on SPP.org for WMWG meetings](#), which may be attended in-person or by phone. Those interested in learning more about SPP's provision of energy imbalance service in the west are encouraged to register and attend or to contact SPP's customer relations department.

To stay updated on the WEIS Market, subscribe to the [SPP WMWG Exploder](#). If you do not have an account, you may [create one](#) using the Create Account button at the top right of the page.

The [Change User Forum](#) (CUF) engages market participants and monitors market and SPP readiness for the western energy imbalance service market. The CUF makes project management and process improvement recommendations to SPP staff and/or the [Western Markets Executive Committee](#).

Want to learn more?

If you are interested in learning more about SPP's Western Energy Imbalance Service (WEIS) market, training is available. SPP provides several online self-study courses about key features of the WEIS market and participant responsibilities. If you work for an organization that is an active WEIS participant, you already have access. Register or log into the [SPP Learning Center](#). And if you need assistance logging in or are not currently a member of SPP's WEIS market, contact [SPP's Stakeholder Training Group](#).

WESTERN SERVICES

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[Western Events](#)

[Markets+](#)

[RTO Expansion](#)

[Western Resource Adequacy Program](#)

[Western RC Services](#)

[Western Interconnection Unscheduled Flow Mitigation Plan \(WIUFMP\)](#)

[WEIS](#)

- [WEIS Revision Requests](#)
-

RELATED DOCUMENTS

[Western Energy Imbalance Service Market \(WEIS\) Proposal](#)

[WMEC Charter](#)

[WEIS Implementation Milestones](#)

[WEIS Implementation Program Overview](#)

[2023 WEIS Course Catalog](#)

RELATED DOCUMENT GROUPS

 [Western Energy Imbalance Service Market \(WEIS\)](#)

Western Stakeholder Groups

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<u>PacifiCorp, and Xcel Energy</u>	)	

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Exhibit 1-113:
Craig Station, AMD data 2020 through 2024

State	Facility Name	Facility ID	Unit ID	Associated Year	Operating	Sum of the	Gross Load	Steam Load	SO2 Mass	SO2 Rate (lb/hr)	CO2 Mass	CO2 Rate (lb/hr)	NOx Mass (lb/hr)	NOx Rate (lb/hr)	Heat Input (MMBtu/hr)	Primary Fuel	Secondary Fuel	Unit Type	SO2 Control	NOx Control	PM Control	Hg Control	Program Code
CO	Craig	6021	C1	2020	8511	8490.94	2517304		560.023	0.0431	2726442	0.105	3097.992	0.2329	25995872	Coal	Pipeline N2	Dry bottom Wet Limes	Low NOx B	Baghouse			ARP, MATS
CO	Craig	6021	C1	2021	8123	8119.01	2563445		573.766	0.0439	2751844	0.105	3095.465	0.2316	26238031	Coal	Pipeline N2	Dry bottom Wet Limes	Low NOx B	Baghouse			ARP, MATS
CO	Craig	6021	C1	2022	8413	8393.53	2797335		742.279	0.0518	2917219	0.1049	3492.321	0.2465	27814864	Coal	Pipeline N2	Dry bottom Wet Limes	Low NOx B	Baghouse			ARP, MATS
CO	Craig	6021	C1	2023	8083	8072.47	2015029		526.926	0.0474	2210610	0.105	2518.031	0.2337	21077513	Coal	Pipeline N2	Dry bottom Wet Limes	Low NOx B	Baghouse			ARP, MATS
CO	Craig	6021	C1	2024	8541	8536.69	1824100		335.429	0.0325	2058659	0.105	2211.571	0.2218	19628748	Coal	Pipeline N2	Dry bottom Wet Limes	Low NOx B	Baghouse			ARP, MATS
CO	Craig	6021	C2	2020	7993	7961.83	2300379		517.033	0.0404	2562694	0.105	763.524	0.0618	24434513	Coal	Pipeline N2	Dry bottom Wet Limes	Low NOx B	Baghouse			ARP, MATS
CO	Craig	6021	C2	2021	8635	8628.91	2822038		476.124	0.0301	3177713	0.105	1014.748	0.0667	30298549	Coal	Pipeline N2	Dry bottom Wet Limes	Low NOx B	Baghouse			ARP, MATS
CO	Craig	6021	C2	2022	8427	8420.82	2629692		645.904	0.0451	2948921	0.105	987.563	0.0698	28117158	Coal	Pipeline N2	Dry bottom Wet Limes	Low NOx B	Baghouse			ARP, MATS
CO	Craig	6021	C2	2023	5582	5573.88	1245370		282.48	0.0381	1457229	0.105	401.375	0.0562	13894277	Coal	Pipeline N2	Dry bottom Wet Limes	Low NOx B	Baghouse			ARP, MATS
CO	Craig	6021	C2	2024	8405	8400.47	1801957		302.703	0.0271	2209975	0.105	625.283	0.0587	21071487	Coal	Pipeline N2	Dry bottom Wet Limes	Low NOx B	Baghouse			ARP, MATS
CO	Craig	6021	C3	2020	7811	7789.23	2821877		1644.329	0.1077	3145100	0.105	3152.793	0.2047	29987627	Coal	Pipeline N2	Dry bottom Dry Lime Fl	Low NOx B	Baghouse			ARP, MATS
CO	Craig	6021	C3	2021	7426	7415.67	2579840		1307.602	0.1058	2635046	0.1049	2731.044	0.2108	25124446	Coal	Pipeline N2	Dry bottom Dry Lime Fl	Low NOx B	Baghouse			ARP, MATS
CO	Craig	6021	C3	2022	7708	7697.91	2783361		1714.714	0.1259	2837603	0.105	2973.326	0.2122	27055733	Coal	Pipeline N2	Dry bottom Dry Lime Fl	Low NOx B	Baghouse			ARP, MATS
CO	Craig	6021	C3	2023	7624	7611.42	1981366		1195.702	0.117	2135790	0.105	2131.88	0.2023	20364134	Coal	Pipeline N2	Dry bottom Dry Lime Fl	Low NOx B	Baghouse			ARP, MATS
CO	Craig	6021	C3	2024	6146	6137.68	1441766		666.086	0.0852	1610839	0.105	1495.032	0.1898	15358887	Coal	Pipeline N2	Dry bottom Dry Lime Fl	Low NOx B	Baghouse			ARP, MATS

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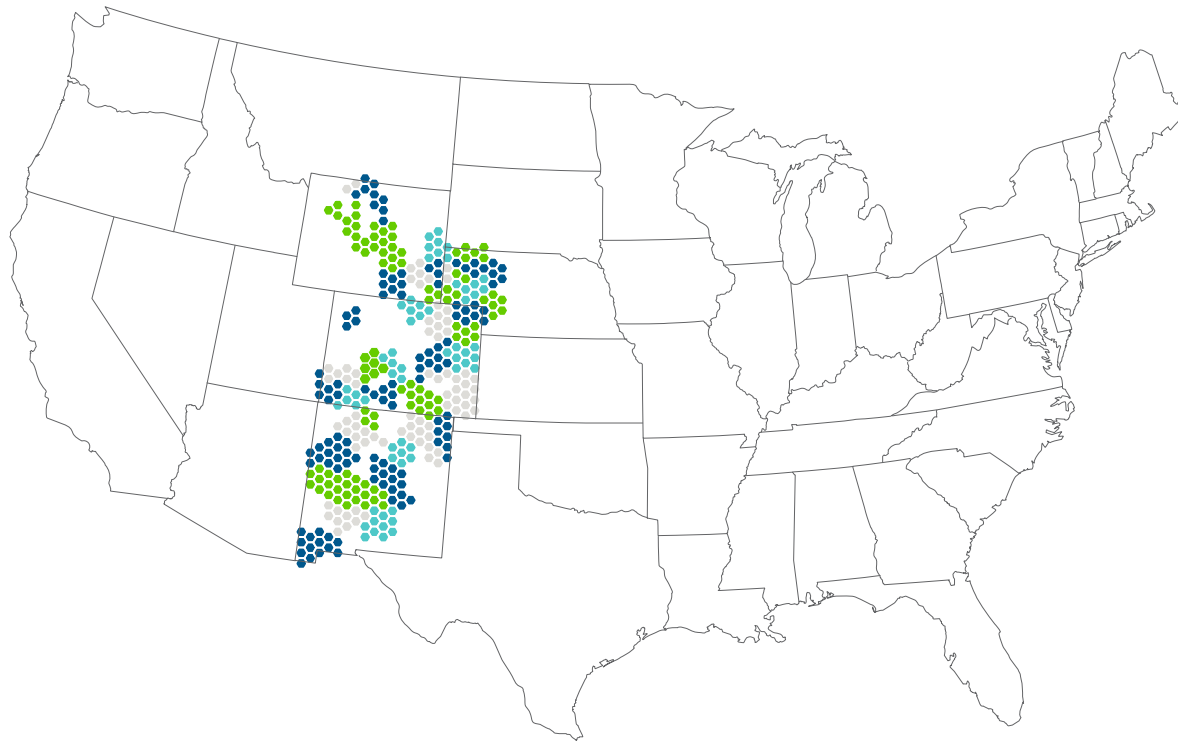
Exhibit 1-114:
Tri-State Members

[MENU](#)

What it means to be a member

Tri-State is more than just an energy provider—we're a community of member-owned utilities and businesses working together across Colorado, Nebraska, New Mexico, and Wyoming. As a cooperative, our strength comes from our members, and our board of directors reflects that diversity. These board members aren't just representatives—they're ranchers, farmers, and local business owners who live and work in the same communities served by our utilities. Their firsthand experience and deep local ties help guide the decisions that shape Tri-State's future, ensuring we stay true to our mission and values.

With our members, we supply power and services that support the rural communities they serve. That is the cooperative difference—we answer to our neighbors, not shareholders.



Member List </member-list>

70+

Tri-State was founded in 1952, which means we've been supplying electricity to the rural West for over 70 years.

1M

Together with our members, we serve nearly one million people and businesses across nearly 200,000 square miles.

5.32

We average 5.32 consumers per mile, vs. the national average of 32.4. We serve electricity to some of the most rural parts of the U.S.

Meet the board chairman at the end of the line

The son of a World War II veteran and life-long New Mexico rancher, Tri-State Board Chairman Tim Rabon has seen the powerful effect of people coming together and discusses how that is the foundation of the co-op model.



Listen to the podcast

</podcast-western-watts-cooperative-roots-tim-rabon-tri-state>



Power in numbers

Our association was formed to bring electricity to our members in the rural West when other power providers would not. Together we can capture economies of scale while sharing the costs and risks of supplying power to areas with few consumers, difficult terrain and a lot of ground to cover. Even today, some of our members serve as few as one connection per mile of distribution line.

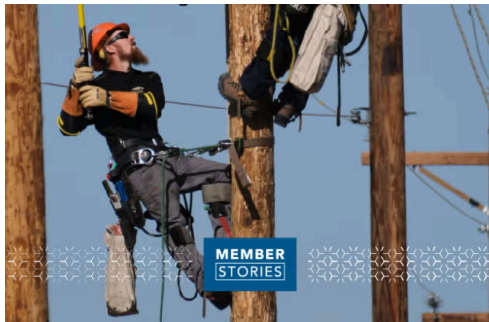
But whether they're in the desert, mountains, rural towns or plains—all our members still need reliable, affordable, responsible power. By pooling resources, collectively buying and selling power and managing the backbone of infrastructure that transports that power, we can negotiate better prices and build more efficient facilities than individual distribution cooperatives could on their own. This results in lower cost, more reliable electricity for our members.



Bridging communities through member programs

We want to help members make electrification and efficiency upgrades accessible for all so we use rebate, education and financing programs. These options and incentives benefit our members and their communities and consumers. Together, we can Electrify and Save®.

Our programs </programs>



Empowering Cooperatives: Inside Mesa Hotline School's Dedication to Excellence



</empowering-cooperatives-inside-mesa-hotline-schools-dedication-excellence>

Every May, over 500 line workers, teachers and volunteers gather in Grand Junction, Colorado at the Mesa Hotline School for the two-week annual learning event. The school attracts participants from across the United States, emphasizing safety and reliability in electrical transmission and distribution. It's an energetic and transformative learning experience with the aim of equipping people with the knowledge and skills needed to keep the lights on for the communities they serve.

[Read more > </empowering-cooperatives-inside-mesa-hotline-schools-dedication-excellence>](#)

The Power of Collaboration - Electric Engines for a Cleaner Future

</power-collaboration-electric-engines-cleaner-future>

As a cooperative, we know that when people come together, we can achieve greater results than any one of us could have done alone. Such was the case in the electrification of the Dahlia Station, a key depot along the Amarillo-to-Albuquerque pipeline managed by NuStar Energy – one of the nation's largest independent liquids terminal and pipeline operators.

[Read more > </power-collaboration-electric-engines-cleaner-future>](#)

Communities Win with Rebates: Two Business Owners Make Rebates Work for Them </communitieswin>

Cooperatives like Big Horn are always looking for ways to better serve their member-owners. One way of doing that is by offering rebates for energy-efficient home and business upgrades.

[Read more > </communitieswin>](#)

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English 

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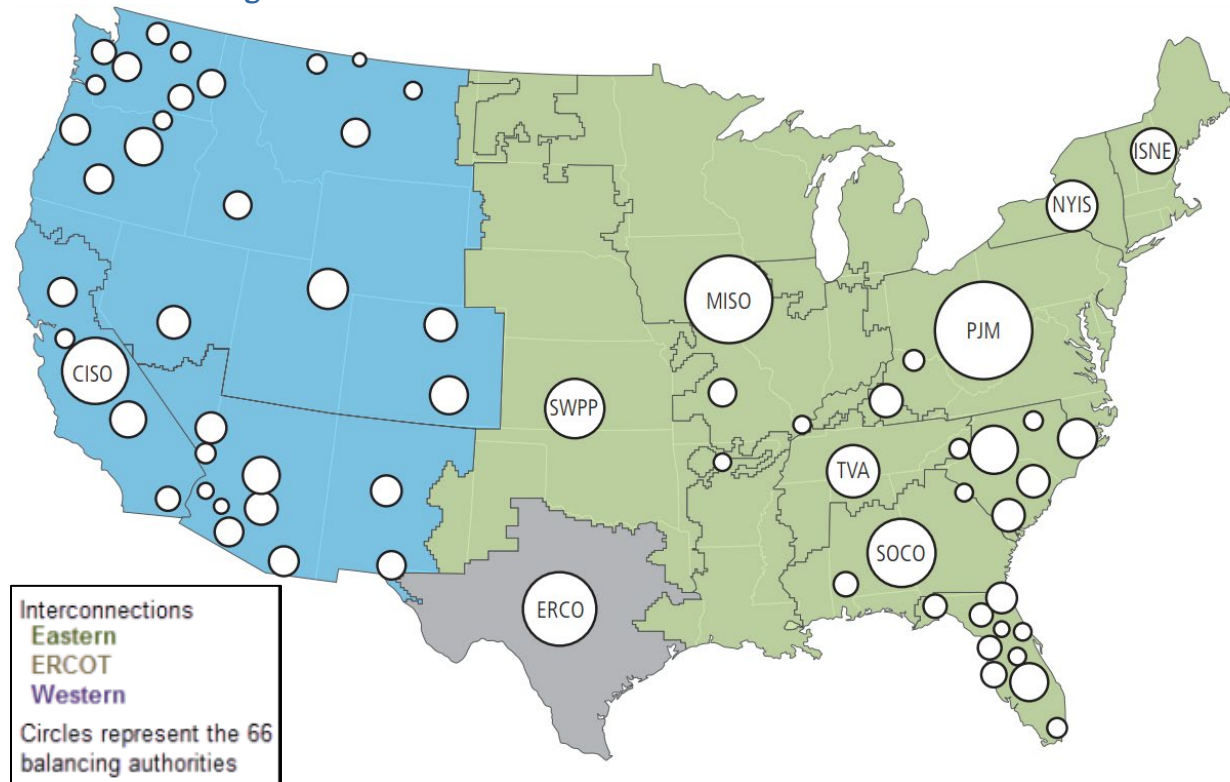
Filed January 28, 2026

Exhibit 1-115:
Department Explainer on Balancing Authorities

How it Works: The Role of a Balancing Authority

There are many key players in the electricity supply chain that work together to reliably supply power to electric customers. One key player is the balancing authority, which manages the operation of the electric system within a specific geographic area. There are more than 60 balancing authorities in the U.S., and they are typically either utilities, Power Marketing Administrations (PMAs), or a group of utilities that have formed regional entities called regional transmission organizations (RTOs) and independent system operators (ISOs).¹

Exhibit 1. Balancing Authorities Across the U.S.



Source: Quadrennial Energy Review: Transforming the Nation's Electricity System: The Second Installment of the QER (January 2017)

See EIA [Hourly Electric Grid Monitor](#) for interactive map.

A balancing authority ensures that power system demand and supply are always balanced, which maintains safe and reliable operation of the power system. If supply falls below demand, it can cause a drop in frequency below the stable system frequency, risking significant permanent physical damage to electrical equipment and prolonged grid-wide blackouts. During such situations, balancing authorities may direct utilities to “shed load” (i.e., implement rolling blackouts) to bring supply and demand into balance.

¹ U.S. Energy Information Administration Form 930

Balancing authorities also manage transfers of electricity (interchanges) with other balancing authorities and use economic dispatch to optimize the use of various generating units to minimize real-time costs. Balancing authorities are responsible for maintaining operating conditions under mandatory reliability standards issued by the North American Electric Reliability Corporation (NERC) and approved by the U.S. Federal Energy Regulatory Commission (FERC).

ISOs/RTOs

The formation of ISOs and RTOs came at the encouragement of FERC (click to read on [FERC orders](#) and [RTOs/ISOs](#)) to operate the transmission system independently of—and foster competition for electricity generation among—wholesale market participants. ISOs/RTOs do not own transmission or generation assets, nor do they directly serve or establish pricing for retail electric customers. They are not a part of any government, so they also do not have any enforcement authority over any electric generation facilities, electric transmission or distribution lines, or substations.²

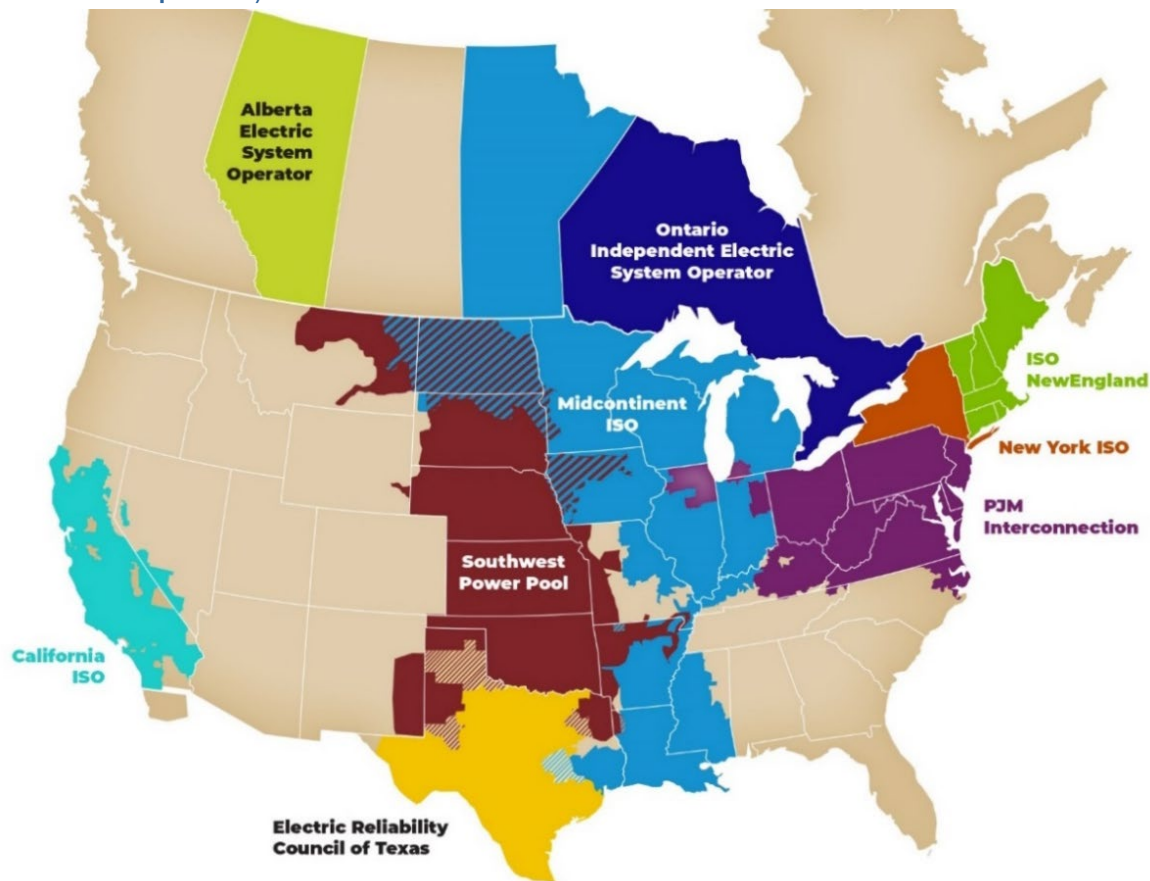
The role of ISOs and RTOs are similar, but ISOs do not meet the minimum requirements specified by FERC to hold the designation of RTO or have not applied for the status. An ISO operates the region's electricity grid, oversees the region's wholesale electricity markets, and provides reliability planning for the region's bulk electricity system. RTOs perform the same functions as the ISOs but have greater responsibility for planning near- and long-term transmission maintenance, upgrades, and expansion projects in collaboration with the actual transmission system owners. Utilities in areas where there is no RTO or ISO serve all these functions for their own territories. There are currently three ISOs and four RTOs that operate within the U.S.:

Independent System Operators (ISO)	California ISO	CAISO
	New York ISO	NYISO
	Electric Reliability Council of Texas ³	ERCOT
Regional Transmission Operator (RTO)	PJM Interconnection	PJM
	Midcontinent Independent System Operator	MISO
	Southwest Power Pool	SPP
	ISO New England	ISO-NE

Although two-thirds of the nation's electricity load is served in RTO/ISO regions (as can be seen from the map in Exhibit 2), there are large sections of the United States—particularly in the Southeast and the West—where there is no ISO or RTO. Electric utilities in these areas are still subject to the same reliability regulations under NERC/FERC.

² The North American Electric Reliability Corporation (NERC) issues and enforces reliability standards for balancing authorities, which are approved by the U.S. FERC and, in Canada, by Canadian regulators. NERC relies on [Regional Entities](#) to enforce reliability standards with bulk power system owners.

³ ERCOT does not fall under FERC authorities over interstate transmission and wholesale markets since it is entirely within the state of Texas and is not interconnected with the rest of the region. ERCOT is still subject to NERC oversight and FERC regulation for reliability.

Exhibit 2. Map of ISO/RTO Territories

Source: [ISO/RTO Council](#)

Grid Operation

Balancing authorities function as grid operators that dispatch electric generators to provide reliable power at the lowest cost. Because each generator has differing variable costs, generation is dispatched using the least costly generator first, in a way that is consistent with the relevant constraints of the transmission system and reliability requirements. Traditional utilities that are balancing authorities manage economic dispatch within their service areas, while ISOs and RTOs determine economic dispatch using bid-based markets where buyers and sellers bid for or offer generation. The dispatch process occurs in two phases: day-ahead unit commitment for the next day's dispatch, and real-time system dispatch.

- **Day-Ahead Commitment:** Balancing authorities decide which generating units should be committed to be online for each hour of the next 24-hour period. In selecting the most economic generators to commit, operators consider forecasted load requirements and each unit's physical operating characteristics, such as how quickly output can be changed, maximum and minimum output levels, and the minimum time a generator must run once it is started. Load forecasting uses mathematical models to predict demand across the balancing authority's footprint, incorporating weather/climate, past energy consumption data, typical behavioral patterns, and economic activity.
- **Real-Time System Dispatch:** Balancing authorities must decide the appropriate level at which each available resource from the day-ahead commitment should be operated, given the real-

time load and other grid conditions, so that overall production costs are minimized. Actual demand will vary from the forecasted load and the balancing authorities must adjust the actual dispatch to match. As part of real-time operations, demand, generation, and interchange (imports and exports) must be continually kept in balance to maintain the stable system frequency. This is typically done by automatic generation control to change the generation dispatch as needed.

Contingency Resources and Capacity Markets

Grid operators maintain excess contingency resources in the form of power generation capacity, inertia⁴ capacity, and electricity storage to ensure that electricity supply is always available to meet anticipated peak demand. This “reserve margin” is required to meet Federal and State reliability requirements and can be used to provide a cushion or buffer during unexpected demand spikes, or potential loss of supply or transmission resources. If reserve margins fall below specified levels, grid operators may initiate emergency procedures to use additional resources—such as ancillary services and load management measures—that are only available during scarcity conditions.

RTO/ISOs typically use capacity markets to ensure that there are sufficient resources available to serve anticipated load and meet reserve margin requirements. Capacity markets may use auctions to lock in prices for electric capacity from generation resources in advance of the need. Capacity markets can also be marketplaces for [demand response](#), in which customers reduce demand when called upon in exchange for capacity payments similar to what generators receive. Capacity prices vary by location and timing of capacity commitments, and typically not by size or fuel type. ISO-NE, PJM, MISO, and NYISO operate capacity markets, while other ISOs currently do not.

Ancillary Services

Ancillary services are intended to maintain electric reliability and support electricity transmission. They mainly include services related to frequency stability like operating reserves; services related to voltage stability like reactive power support and voltage control, and other services like black start generation. Ancillary services are becoming more important for variable energy resources—such as wind and solar power—due to their production variability and forecast uncertainty. Within ISOs/RTOs, ancillary services are typically procured through bid-based auction markets, tariff fixed or formula-based rates, or competitive solicitations.

Operating reserves are needed to quickly restore load and generation balance when a supply resource trips offline. Operating reserves are provided by dispatchable generating units increasing output or demand-side resources reducing demand to restore balance. There are three types:

1. **Spinning reserves** are provided by generators that are online (synchronized to the system frequency) with some spare capacity and capable of increasing its electricity output within a short time period (within 10 minutes).
2. **Non-spinning reserves** are provided by generating units that are not necessarily synchronized to the power grid but can be brought online within a short time period (within 10 minutes). Non-spinning reserves can also be provided by demand-side resources.
3. **Supplemental reserves** are provided by generating units that can be made available within a longer time period (between 10 to 30 minutes).

⁴ An inertia is an interconnection permitting passage of current between two or more electric utility systems

Black start generating units—primarily hydroelectric facilities and diesel generators—can transition from a shutdown condition to an operating condition and start delivering power without any outside assistance from the electric grid. These are the first facilities to start up in the event of a system failure or blackout to restore the rest of the grid.

Emergency Measures

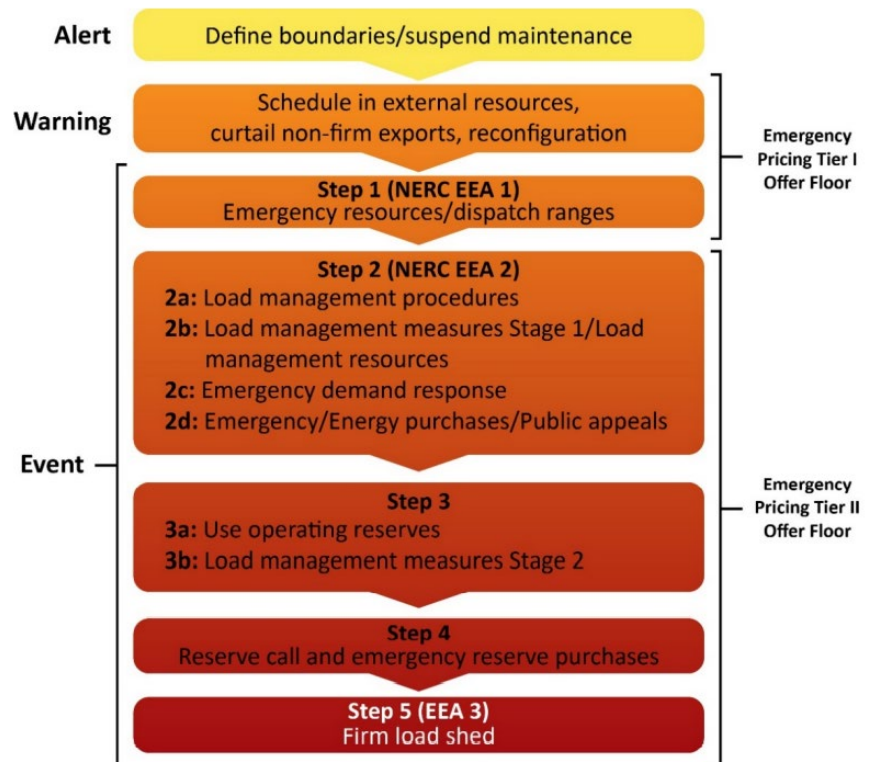
Balancing electricity supply and demand to preserve grid stability is a critical function of balancing authorities. If supply falls below demand, it causes a frequency drop on the electrical grid below the stable system frequency, which can cause vibrations resulting in significant permanent physical damage to electrical equipment. As the frequency drops below safe operating levels, many generators will automatically disconnect from the grid for self-protection. As generators and other electrical equipment shut down, this further reduces electricity supply, causing the system frequency to drop even further.

If no interventions are taken to stabilize the grid, this cascading effect can lead to collapse of the electricity grid and prolonged grid-wide blackout. During the [February 2021 Extreme Cold & Winter Weather Incident](#), significant electricity generation assets went offline in the ERCOT region, causing a frequency drop that triggered additional generation loss. To rebalance supply and demand to stabilize the grid, ERCOT had to quickly shed substantial load, calling on its member utilities to proactively cut off electricity to their customers on a rotating basis over a period of three days. Although grid conditions in neighboring balancing areas were not as severe as in ERCOT, both MISO and SPP implemented brief periods of load shedding during the event.

When a balancing authority predicts there will be a shortage of electricity, there are response measures they can take to rebalance supply and demand. Each balancing authority has its own response protocol with response measures increasing as the anticipated shortage becomes more severe. The first step is typically to issue an alert to market participants describing the situation and suspending non-essential work (such as regular maintenance) to maximize the availability of generation and transmission resources. Balancing authorities may also issue Conservation Alerts, in which they ask consumers to voluntarily reduce their energy usage to reduce demand, especially during peak demand hours. Examples of consumers reducing energy usage include adjusting their thermostats, avoiding using large electric appliances, turning off non-essential lights, etc.

If initial response measures are insufficient to rebalance supply and demand, then a balancing authority will begin declaring energy emergency alerts (EEAs). EEAs have different levels depending on the event.

- At EEA Level 1, a balancing authority will typically call on all available power supplies (regardless of economics), including power from other grids if available, and enable certain demand-side resource deployments.
- At EEA Level 2, a balancing authority will typically initiate demand response programs that shed load from large industrial customers that have contractually agreed. They will also typically make a public appeal for all customers to cut back on electricity consumption.

Exhibit 3. Emergency Alert LevelsSource: [NERC](#)

- At EEA Level 3, balancing authorities will typically order utilities to shed load and inform them how much load they individually need to shed, and each utility then sheds the load by disconnecting circuits around customers with firm contracts. These outages are often “rotated” through the utility’s service territory with customers losing power for several hours at a time, although sometimes customers are without power for the entire event. During load sheds, utilities typically will not disconnect circuits serving critical customers (hospitals, water treatment plants, etc.).

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c))
Emergency Order: Tri-State)
Generation and Transmission)
Association, Platte River Power)
Authority, Salt River Project,)
PacifiCorp, and Xcel Energy)

Order No. 202-25-14

Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
Public Interest Organizations

Filed January 28, 2026

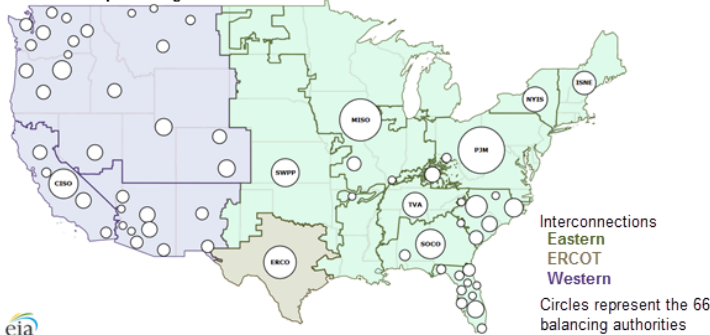
Exhibit 1-116:
EIA Explainer on Balancing Authorities

Today in Energy

July 20, 2016

U.S. electric system is made up of interconnections and balancing authorities

U.S. electric power regions



Source: U.S. Energy Information Administration

Note: The locations of the electric systems are illustrative and are not geographically accurate. The sizes of the circles are roughly indicative of electric system size.

Electricity generated at power plants moves through a complex network of electricity substations, power lines, and distribution transformers before it reaches customers. In the United States, the power system consists of more than 7,300 power plants, nearly 160,000 miles of high-voltage power lines, and millions of low-voltage power lines and distribution transformers, which connect 145 million customers.

Local electricity grids are interconnected to form larger networks for reliability and commercial purposes. At the highest level, the United States power system in the Lower 48 states is made up of three main interconnections, which operate largely independently from each other with limited transfers of power between them.

- The Eastern Interconnection encompasses the area east of the Rocky Mountains and a portion of northern Texas. The Eastern Interconnection consists of 36 balancing authorities: 31 in the United States and 5 in Canada.
- The Western Interconnection encompasses the area from the Rockies west and consists of 37 balancing authorities: 34 in the United States, 2 in Canada, and 1 in Mexico.
- The Electric Reliability Council of Texas (ERCOT) covers most, but not all, of Texas and consists of a single balancing authority.

The network structure of the interconnections helps maintain the reliability of the power system by providing multiple routes for power to flow and by allowing generators to supply electricity to many load centers. This redundancy helps prevent transmission line or power plant failures from causing interruptions in service.

These interconnections describe the physical system of the grid. The actual operation of the electric system is managed by entities called balancing authorities. Most, but not all, balancing authorities are electric utilities that have taken on the balancing responsibilities for a specific portion of the power system. All of the [regional transmission organizations](#) in the United States also function as balancing authorities. ERCOT is unique in that the balancing authority, interconnection, and the regional transmission organization are all the same entity and physical system.

A balancing authority ensures, in real time, that power system demand and supply are finely balanced. This balance is needed to maintain the safe and reliable operation of the power system. If demand and supply fall out of balance, local or even wide-area blackouts can result.

Balancing authorities maintain appropriate operating conditions for the electric system by ensuring that a sufficient supply of electricity is available to serve expected demand, which includes managing transfers of electricity with other balancing authorities. Balancing authorities are responsible for maintaining operating conditions under mandatory reliability standards issued by the [North American Electric Reliability Corporation](#) and approved by the U.S. [Federal Energy Regulatory Commission](#) and, in Canada, by Canadian regulators. These operators monitor the grid to identify potential problems before a situation becomes critical.

Principal contributor: Sara Hoff

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c))
Emergency Order: Tri-State)
Generation and Transmission)
Association, Platte River Power)
Authority, Salt River Project,)
PacifiCorp, and Xcel Energy)

Order No. 202-25-14

Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
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Filed January 28, 2026

Exhibit 1-117:
NERC Emergency Operations

A. Introduction

1. **Title:** **Emergency Operations**
2. **Number:** **EOP-011-4**
3. **Purpose:** To address the effects of operating Emergencies by ensuring each Transmission Operator and Balancing Authority has developed plan(s) to mitigate operating Emergencies and that those plans are implemented and coordinated within the Reliability Coordinator Area as specified within the requirements.
4. **Applicability:**
 - 4.1. **Functional Entities:**
 - 4.1.1 Balancing Authority
 - 4.1.2 Reliability Coordinator
 - 4.1.3 Transmission Operator
 - 4.1.4 Distribution Provider identified in the Transmission Operator's Operating Plan(s) to mitigate operating Emergencies in its Transmission Operator Area
 - 4.1.5 UFLS-Only Distribution Provider identified in the Transmission Operator's Operating Plan(s) to mitigate operating Emergencies in its Transmission Operator Area
 - 4.1.6 Transmission Owner identified in the Transmission Operator's Operating Plan(s) to mitigate operating Emergencies in its Transmission Operator Area
5. **Effective Date:** See Implementation Plan for Project 2021-07. As provided therein, each Distribution Provider, UFLS-Only Distribution Provider, and Transmission Owner that receives notification from the Transmission Operator that it is required to assist in the mitigation of operating Emergencies in the Transmission Operator Area under Requirement R7 shall become compliant with Requirement R8 within 30 calendar months of the notification.

B. Requirements and Measures

- R1.** Each Transmission Operator shall develop, maintain, and implement one or more Reliability Coordinator-reviewed Operating Plan(s) to mitigate operating Emergencies in its Transmission Operator Area. The Operating Plan(s) shall include the following, as applicable: *[Violation Risk Factor: High] [Time Horizon: Real-Time Operations, Operations Planning, Long-term Planning]*
- 1.1.** Roles and responsibilities for activating the Operating Plan(s);
 - 1.2.** Processes to prepare for and mitigate Emergencies including:
 - 1.2.1.** Notification to its Reliability Coordinator, to include current and projected conditions, when experiencing an operating Emergency;
 - 1.2.2.** Cancellation or recall of Transmission and generation outages;
 - 1.2.3.** Transmission system reconfiguration;
 - 1.2.4.** Redispatch of generation request;
 - 1.2.5.** Operator-controlled manual Load shed, undervoltage load shed (UVLS), or underfrequency load shed (UFLS) during an Emergency that accounts for each of the following:
 - 1.2.5.1.** Provisions for manual Load shedding capable of being implemented in a timeframe adequate for mitigating the Emergency;
 - 1.2.5.2.** Provisions to minimize the overlap of circuits that are designated for manual Load shed, UVLS, or UFLS and circuits that serve designated critical loads which are essential to the reliability of the BES;
 - 1.2.5.3.** Provisions to minimize the overlap of circuits that are designated for manual Load shed and circuits that are utilized for UFLS or UVLS;
 - 1.2.5.4.** Provisions for limiting the utilization of UFLS or UVLS circuits for manual Load shed to situations where warranted by system conditions;
 - 1.2.5.5.** Provisions for the identification and prioritization of designated critical natural gas infrastructure loads which are essential to the reliability of the BES as defined by the Applicable Entity; and
 - 1.2.6.** Provisions to determine reliability impacts of:
 - 1.2.6.1.** Cold weather conditions; and
 - 1.2.6.2.** Extreme weather conditions.
- M1.** Each Transmission Operator will have a dated Operating Plan(s) developed in accordance with Requirement R1 and reviewed by its Reliability Coordinator; evidence such as a review or revision history to indicate that the Operating Plan(s) has

been maintained; and will have as evidence, such as operator logs or other operating documentation, voice recordings or other communication documentation to show that its Operating Plan(s) was implemented for times when an Emergency has occurred, in accordance with Requirement R1.

- R2.** Each Balancing Authority shall develop, maintain, and implement one or more Reliability Coordinator-reviewed Operating Plan(s) to mitigate Capacity Emergencies and Energy Emergencies within its Balancing Authority Area. The Operating Plan(s) shall include the following, as applicable: *[Violation Risk Factor: High] [Time Horizon: Real-Time Operations, Operations Planning, Long-term Planning]*

2.1. Roles and responsibilities for activating the Operating Plan(s);

2.2. Processes to prepare for and mitigate Emergencies including:

2.2.1. Notification to its Reliability Coordinator to include current and projected conditions when experiencing a Capacity Emergency or Energy Emergency;

2.2.2. Requesting an Energy Emergency Alert, per Attachment 1;

2.2.3. Managing generating resources in its Balancing Authority Area to address:

2.2.3.1. Capability and availability;

2.2.3.2. Fuel supply and inventory concerns;

2.2.3.3. Fuel switching capabilities; and

2.2.3.4. Environmental constraints.

2.2.4. Public appeals for voluntary Load reductions;

2.2.5. Requests to government agencies to implement their programs to achieve necessary energy reductions;

2.2.6. Reduction of internal utility energy use;

2.2.7. Use of Interruptible Load, curtailable Load, and demand response;

2.2.8. Provisions for excluding critical natural gas infrastructure loads which are essential to the reliability of the BES, as defined by the Applicable Entity, as Interruptible Load, curtailable Load, and demand response during extreme cold weather periods within each Balancing Authority Area;

2.2.9. Provisions for Transmission Operators to implement operator-controlled manual Load shedding, undervoltage Load shedding, or underfrequency Load shedding in accordance with Requirement R1 Part 1.2.5; and

2.2.10. Provisions to determine reliability impacts of:

2.2.10.1. Cold weather conditions; and

2.2.10.2. Extreme weather conditions.

- M2.** Each Balancing Authority will have a dated Operating Plan(s) developed in accordance with Requirement R2 and reviewed by its Reliability Coordinator;

- evidence such as a review or revision history to indicate that the Operating Plan(s) has been maintained; and will have as evidence, such as operator logs or other operating documentation, voice recordings, or other communication documentation to show that its Operating Plan(s) was implemented for times when an Emergency has occurred, in accordance with Requirement R2.
- R3.** The Reliability Coordinator shall review the Operating Plan(s) to mitigate operating Emergencies submitted by a Transmission Operator or a Balancing Authority regarding any reliability risks that are identified between Operating Plans. *[Violation Risk Factor: High] [Time Horizon: Operations Planning]*
- 3.1.** Within 30 calendar days of receipt, the Reliability Coordinator shall:
- 3.1.1.** Review each submitted Operating Plan(s) on the basis of compatibility and inter-dependency with other Balancing Authorities' and Transmission Operators' Operating Plans;
 - 3.1.2.** Review each submitted Operating Plan(s) for coordination to avoid risk to Wide Area reliability; and
 - 3.1.3.** Notify each Balancing Authority and Transmission Operator of the results of its review, specifying any time frame for resubmittal of its Operating Plan(s) if revisions are identified.
- M3.** The Reliability Coordinator will have documentation, such as dated emails or other correspondences that it reviewed, Transmission Operator and Balancing Authority Operating Plans, within 30 calendar days of submittal in accordance with Requirement R3.
- R4.** Each Transmission Operator and Balancing Authority shall address any reliability risks identified by its Reliability Coordinator pursuant to Requirement R3 and resubmit its Operating Plan(s) to its Reliability Coordinator within a time period specified by its Reliability Coordinator. *[Violation Risk Factor: High] [Time Horizon: Operation Planning]*
- M4.** The Transmission Operator and Balancing Authority will have documentation, such as dated emails or other correspondence, with an Operating Plan(s) version history showing that it responded and updated the Operating Plan(s) within the timeframe identified by its Reliability Coordinator in accordance with Requirement R4.
- R5.** Each Reliability Coordinator that receives an Emergency notification from a Transmission Operator or Balancing Authority within its Reliability Coordinator Area shall notify, within 30 minutes from the time of receiving notification, other Balancing Authorities and Transmission Operators in its Reliability Coordinator Area, and neighboring Reliability Coordinators. *[Violation Risk Factor: High] [Time Horizon: Real-Time Operations]*
- M5.** Each Reliability Coordinator that receives an Emergency notification from a Balancing Authority or Transmission Operator within its Reliability Coordinator Area will have, and provide upon request, evidence that could include, but is not limited to, operator logs, voice recordings or transcripts of voice recordings, electronic communications, or equivalent evidence that will be used to determine if the Reliability Coordinator

- communicated, in accordance with Requirement R5, with other Balancing Authorities and Transmission Operators in its Reliability Coordinator Area, and neighboring Reliability Coordinators.
- R6.** Each Reliability Coordinator that has a Balancing Authority experiencing a potential or actual Energy Emergency within its Reliability Coordinator Area shall declare an Energy Emergency Alert, as detailed in Attachment 1. *[Violation Risk Factor: High] [Time Horizon: Real-Time Operations]*
- M6.** Each Reliability Coordinator, with a Balancing Authority experiencing a potential or actual Energy Emergency within its Reliability Coordinator Area, will have, and provide upon request, evidence that could include, but is not limited to, operator logs, voice recordings or transcripts of voice recordings, electronic communications, or equivalent evidence that it declared an Energy Emergency Alert, as detailed in Attachment 1, in accordance with Requirement R6.
- R7.** Each Transmission Operator shall annually identify and notify Distribution Providers, UFLS-Only Distribution Providers and Transmission Owners that are required to assist with the mitigation of operating Emergencies in its Transmission Operator Area through operator-controlled manual Load shedding, undervoltage Load shedding, or underfrequency Load shedding. *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning, Long-term Planning]*
- M7.** Each Transmission Operator will have documentation, such as dated emails or other correspondences that it identified and notified Distribution Providers, UFLS-Only Distribution Providers and Transmission Owners annually in accordance with Requirement R7.
- R8.** Each Distribution Provider, UFLS-Only Distribution Provider, and Transmission Owner notified by a Transmission Operator per R7 to assist with the mitigation of operating Emergencies in its Transmission Operator Area shall develop, maintain, and implement a Load shedding plan. The Load shedding plan shall include the following, as applicable: *[Violation Risk Factor: High] [Time Horizon: Real-Time Operations, Operations Planning, Long-term Planning]*
- 8.1.** Operator-controlled manual Load shedding, undervoltage Load shedding, or underfrequency Load shedding during an Emergency that accounts for each of the following:
- 8.1.1.** Provisions for manual Load shedding capable of being implemented in a timeframe adequate for mitigating the Emergency;
 - 8.1.2.** Provisions to minimize the overlap of circuits that are designated for manual, undervoltage, or underfrequency Load shed and circuits that serve designated critical loads which are essential to the reliability of the BES;
 - 8.1.3.** Provisions to minimize the overlap of circuits that are designated for manual Load shed and circuits that are utilized for UFLS or UVLS;
 - 8.1.4.** Provisions for limiting the utilization of UFLS or UVLS circuits for manual

Load shed to situations where warranted by system conditions; and

8.1.5. Provisions for the identification and prioritization of designated critical natural gas infrastructure loads which are essential to the reliability of the BES as defined by the Applicable Entity.

8.2. Provisions to provide the Load shedding plan to the Transmission Operator for review.

M8. Each Distribution Provider, UFLS-Only Distribution Provider, and Transmission Owner notified by a Transmission Operator per R7 to assist with the mitigation of operating Emergencies in its Transmission Operator Area will have a dated Load shedding plan(s) developed in accordance with Requirement R8 and evidence that the Load shedding plan(s) was provided to its Transmission Operator; evidence such as a review or revision history to indicate that the Load shedding plan(s) has been maintained; and will have as evidence, such as operator logs or other operating documentation, voice recordings or other communication documentation to show that its Load shedding plan(s) was implemented for times when an Emergency has occurred, in accordance with Requirement R8.

C. Compliance

1. Compliance Monitoring Process

- 1.1. Compliance Enforcement Authority:** “Compliance Enforcement Authority” (CEA) means NERC or the Regional Entity, or any entity as otherwise designated by an Applicable Governmental Authority, in their respective roles of monitoring and/or enforcing compliance with the mandatory and enforceable Reliability Standards in their respective jurisdictions.
- 1.2. Evidence Retention:** The following evidence retention period(s) identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the CEA may ask an entity to provide other evidence to show that it was compliant for the full-time period since the last audit.

The applicable entity shall keep data or evidence to show compliance as identified below unless directed by its CEA to retain specific evidence for a longer period of time as part of an investigation.

- The Transmission Operator shall retain the current Operating Plan(s), evidence of review or revision history plus each version issued since the last audit and evidence of compliance since the last audit for Requirements R1 and R4.
 - The Balancing Authority shall retain the current Operating Plan(s), evidence of review or revision history plus each version issued since the last audit and evidence of compliance since the last audit for Requirements R2 and R4.
 - The Reliability Coordinator shall maintain evidence of compliance since the last audit for Requirements R3, R5, and R6.
 - The Transmission Operator shall maintain evidence of compliance since the last audit for Requirement R7.
 - The Distribution Provider, UFLS-Only Distribution Provider, and Transmission Owner shall retain the current Load shedding plan, evidence of review or revision history plus each version issued since the last audit and evidence of compliance since the last audit for Requirements R8.
- 1.3. Compliance Monitoring and Enforcement Program:** As defined in the NERC Rules of Procedure, “Compliance Monitoring and Enforcement Program” refers to the identification of the processes that will be used to evaluate data or information for the purpose of assessing performance or outcomes with the associated Reliability Standard.

Violation Severity Levels

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	N/A	The Transmission Operator developed a Reliability Coordinator- reviewed Operating Plan(s) to mitigate operating Emergencies in its Transmission Operator Area, but failed to maintain it.	The Transmission Operator developed an Operating Plan(s) to mitigate operating Emergencies in its Transmission Operator Area, but failed to have it reviewed by its Reliability Coordinator.	The Transmission Operator failed to develop an Operating Plan(s) to mitigate operating Emergencies in its Transmission Operator Area. OR The Transmission Operator developed a Reliability Coordinator- reviewed Operating Plan(s) to mitigate operating Emergencies in its Transmission Operator Area, but failed to implement it.
R2	N/A	The Balancing Authority developed a Reliability Coordinator-reviewed Operating Plan(s) to mitigate operating Emergencies within its Balancing Authority Area, but failed to maintain it.	The Balancing Authority developed an Operating Plan(s) to mitigate operating Emergencies within its Balancing Authority Area, but failed to have it reviewed by its Reliability Coordinator.	The Balancing Authority failed to develop an Operating Plan(s) to mitigate operating Emergencies within its Balancing Authority Area. OR The Balancing Authority developed a Reliability Coordinator-reviewed Operating Plan(s) to mitigate operating Emergencies within its Balancing Authority Area, but failed to implement it.

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
R3	N/A	N/A	The Reliability Coordinator identified a reliability risk, but failed to notify the Balancing Authority or Transmission Operator within 30 calendar days.	The Reliability Coordinator identified a reliability risk, but failed to notify the Balancing Authority or Transmission Operator.
R4	N/A	N/A	The Transmission Operator or Balancing Authority failed to update and resubmit its Operating Plan(s) to its Reliability Coordinator within the timeframe specified by its Reliability Coordinator.	The Transmission Operator or Balancing Authority failed to update and resubmit its Operating Plan(s) to its Reliability Coordinator.
R5	N/A	N/A	The Reliability Coordinator that received an Emergency notification from a Transmission Operator or Balancing Authority did not notify neighboring Reliability Coordinators, Balancing Authorities and Transmission Operators, but failed to notify within 30 minutes from the time of receiving notification.	The Reliability Coordinator that received an Emergency notification from a Transmission Operator or Balancing Authority failed to notify neighboring Reliability Coordinators, Balancing Authorities and Transmission Operators.
R6	N/A	N/A	N/A	The Reliability Coordinator that had a Balancing Authority experiencing a potential or actual Energy Emergency within its Reliability Coordinator Area failed to declare an Energy Emergency

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
				Alert.
R7	N/A	The Transmission Operator identified on an annual basis the Distribution Providers, UFLS-Only Distribution Providers and Transmission Owners that are required to assist with the mitigation of operating Emergencies in its Transmission Operator Area through Operator-controlled manual Load shedding, undervoltage Load shedding, or underfrequency Load shedding, but notified one or more of those entities more than one, but fewer than 30 days late.	The Transmission Operator identified on an annual basis the Distribution Providers, UFLS-Only Distribution Providers and Transmission Owners, that are required to assist with the mitigation of operating Emergencies in its Transmission Operator Area through Operator-controlled manual Load shedding, undervoltage Load shedding, or underfrequency Load shedding, but notified one or more of those entities 30 days or more, but fewer than 60 days late.	The Transmission Operator did not identify or notify Distribution Providers, UFLS-Only Distribution Providers and Transmission Owners, that are required to assist with the mitigation of operating Emergencies in its Transmission Operator Area through Operator-controlled manual Load shedding, undervoltage Load shedding, or underfrequency Load shedding. OR The Transmission Operator identified on an annual basis the Distribution Providers, UFLS-Only Distribution Providers and Transmission Owners, that are required to assist with the mitigation of operating Emergencies in its Transmission Operator Area through Operator-controlled manual Load shedding, undervoltage Load shedding, or underfrequency Load shedding, but notified one

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
				OR more of those entities 60 days or more late.
R8	N/A	The applicable Distribution Provider, UFLS-Only Distribution Provider, and Transmission Owner developed a Load shedding plan(s), but failed to maintain it in accordance with Requirement R8.	The applicable Distribution Provider, UFLS-Only Distribution Provider, and Transmission Owner developed a Load shedding plan(s), but failed to provide it to its Transmission Operator in accordance with Requirement R8.	The applicable Distribution Provider, UFLS-Only Distribution Provider, and Transmission Owner failed to develop a Load shedding plan(s) in accordance with Requirement R8. OR The Distribution Provider, UFLS-Only Distribution Provider, and Transmission Owner developed a Load shedding plan(s), but failed to implement it in accordance with Requirement R8.

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

None.

Version History

Version	Date	Action	Change Tracking
1	November 13, 2014	Adopted by the NERC Board of Trustees	Merged EOP-001-2.1b, EOP-002-3.1 and EOP-003-2.
1	November 19, 2015	FERC approved EOP-011-1. Docket Nos. RM15-7-000, RM15-12-000, and RM15-13-000. Order No. 818	
2	June 11, 2021	Adopted by the NERC Board of Trustees	Revised under Project 2019-06
2	August 24, 2021	FERC approved EOP-011-2. Docket Number RD21-5-000	
3	October 26, 2022	Adopted by the NERC Board of Trustees	Revised under Project 2021-07
3	February 16, 2023	FERC approved EOP-011-3. <i>N. Am. Elec. Reliability Corp.</i> , 182 FERC 61,094	
4	October 23, 2023	Adopted by the NERC Board of Trustees	Revised under Project 2021-07
4	February 15, 2024	FERC Order issued approving EOP-011-4. Docket No. RD24-1-000	

Attachment 1-EOP-011-4 Energy Emergency Alerts

Introduction

This Attachment provides the process and descriptions of the levels used by the Reliability Coordinator in which it communicates the condition of a Balancing Authority which is experiencing an Energy Emergency.

A. General Responsibilities

- 1. Initiation by Reliability Coordinator.** An Energy Emergency Alert (EEA) may be initiated only by a Reliability Coordinator at 1) the Reliability Coordinator's own request, or 2) upon the request of an energy deficient Balancing Authority.
- 2. Notification.** A Reliability Coordinator who declares an EEA shall notify all Balancing Authorities and Transmission Operators in its Reliability Coordinator Area. The Reliability Coordinator shall also notify all neighboring Reliability Coordinators.

B. EEA Levels

Introduction

To ensure that all Reliability Coordinators clearly understand potential and actual Energy Emergencies in the Interconnection, NERC has established three levels of EEAs. The Reliability Coordinators will use these terms when communicating Energy Emergencies to each other. An EEA is an Emergency procedure, not a daily operating practice, and is not intended as an alternative to compliance with NERC Reliability Standards.

The Reliability Coordinator may declare whatever alert level is necessary, and need not proceed through the alerts sequentially.

- 1. EEA 1 — All available generation resources in use. Circumstances:**
 - The Balancing Authority is experiencing conditions where all available generation resources are committed to meet firm Load, firm transactions, and reserve commitments, and is concerned about sustaining its required Contingency Reserves.
 - Non-firm wholesale energy sales (other than those that are recallable to meet reserve requirements) have been curtailed.
- 2. EEA 2 — Load management procedures in effect. Circumstances:**
 - The Balancing Authority is no longer able to provide its expected energy requirements and is an energy deficient Balancing Authority.
 - An energy deficient Balancing Authority has implemented its Operating Plan(s) to mitigate Emergencies.

- An energy deficient Balancing Authority is still able to maintain minimum Contingency Reserve requirements.

During EEA 2, Reliability Coordinators and energy deficient Balancing Authorities have the following responsibilities:

- 2.1 Notifying other Balancing Authorities and market participants.** The energy deficient Balancing Authority shall communicate its needs to other Balancing Authorities and market participants. Upon request from the energy deficient Balancing Authority, the respective Reliability Coordinator shall post the declaration of the alert level, along with the name of the energy deficient Balancing Authority on the RCIS website.
 - 2.2 Declaration period.** The energy deficient Balancing Authority shall update its Reliability Coordinator of the situation at a minimum of every hour until the EEA 2 is terminated. The Reliability Coordinator shall update the energy deficiency information posted on the RCIS website as changes occur and pass this information on to the neighboring Reliability Coordinators, Balancing Authorities and Transmission Operators.
 - 2.3 Sharing information on resource availability.** Other Reliability Coordinators of Balancing Authorities with available resources shall coordinate, as appropriate, with the Reliability Coordinator that has an energy deficient Balancing Authority.
 - 2.4 Evaluating and mitigating Transmission limitations.** The Reliability Coordinator shall review Transmission outages and work with the Transmission Operator(s) to see if it's possible to return to service any Transmission Elements that may relieve the loading on System Operating Limits (SOLs) or Interconnection Reliability Operating Limits (IROLs).
 - 2.5 Requesting Balancing Authority actions.** Before requesting an EEA 3, the energy deficient Balancing Authority must make use of all available resources; this includes, but is not limited to:
 - 2.5.1 All available generation units are on line.** All generation capable of being on line in the time frame of the Emergency is on line.
 - 2.5.2 Demand-Side Management.** Activate Demand-Side Management within provisions of any applicable agreements.
- 3. EEA 3 — Firm Load interruption is imminent or in progress. Circumstances:**
- The energy deficient Balancing Authority is unable to meet minimum Contingency Reserve requirements.

During EEA 3, Reliability Coordinators and Balancing Authorities have the following responsibilities:

- 3.1 Continue actions from EEA 2.** The Reliability Coordinators and the energy deficient Balancing Authority shall continue to take all actions initiated during EEA 2.

- 3.2 Declaration Period.** The energy deficient Balancing Authority shall update its Reliability Coordinator of the situation at a minimum of every hour until the EEA 3 is terminated. The Reliability Coordinator shall update the energy deficiency information posted on the RCIS website as changes occur and pass this information on to the neighboring Reliability Coordinators, Balancing Authorities, and Transmission Operators.
- 3.3 Reevaluating and revising SOLs and IROLs.** The Reliability Coordinator shall evaluate the risks of revising SOLs and IROLs for the possibility of delivery of energy to the energy deficient Balancing Authority. Reevaluation of SOLs and IROLs shall be coordinated with other Reliability Coordinators and only with the agreement of the Transmission Operator whose Transmission Owner (TO) equipment would be affected. SOLs and IROLs shall only be revised as long as an EEA 3 condition exists, or as allowed by the Transmission Owner whose equipment is at risk. The following are minimum requirements that must be met before SOLs or IROLs are revised:
- 3.3.1 Energy deficient Balancing Authority obligations.** The energy deficient Balancing Authority, upon notification from its Reliability Coordinator of the situation, will immediately take whatever actions are necessary to mitigate any undue risk to the Interconnection. These actions may include Load shedding.
- 3.4 Returning to pre-Emergency conditions.** Whenever energy is made available to an energy deficient Balancing Authority such that the Systems can be returned to its pre- Emergency SOLs or IROLs condition, the energy deficient Balancing Authority shall request the Reliability Coordinator to downgrade the alert level.
- 3.4.1 Notification of other parties.** Upon notification from the energy deficient Balancing Authority that an alert has been downgraded, the Reliability Coordinator shall notify the neighboring Reliability Coordinators (via the RCIS), Balancing Authorities, and Transmission Operators that its Systems can be returned to its normal limits.
- Alert 0 - Termination.** When the energy deficient Balancing Authority is able to meet its Load and Operating Reserve requirements, it shall request its Reliability Coordinator to terminate the EEA.
- 3.4.2 Notification.** The Reliability Coordinator shall notify all other Reliability Coordinators via the RCIS of the termination. The Reliability Coordinator shall also notify the neighboring Balancing Authorities and Transmission Operators.

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c))
Emergency Order: Tri-State)
Generation and Transmission)
Association, Platte River Power)
Authority, Salt River Project,)
PacifiCorp, and Xcel Energy)

Order No. 202-25-14

Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
Public Interest Organizations

Filed January 28, 2026

Exhibit 1-118:
Department Press Release on Centralia Order

[Home](#) [Topics](#) [Strengthen Grid Reliability and Security](#) [Energy Secretary Ensures Washington Coal Plant Remains Open to Ensure Affordable, ...](#)

Energy Secretary Ensures Washington Coal Plant Remains Open to Ensure Affordable, Reliable and Secure Power Heading into Winter

U.S. Secretary of Energy Chris Wright today issued an emergency order to ensure Americans in the Northwestern region of the United States have access to affordable, reliable and secure electricity heading into the cold winter months.

[Energy.gov](#)

December 17, 2025

 2 min

Emergency order addresses critical grid reliability issues, lowering risk of blackouts and ensuring affordable electricity access

WASHINGTON—U.S. Secretary of Energy Chris Wright today issued an emergency order to ensure Americans in the Northwestern region of the United States have access to affordable, reliable and secure electricity heading into the cold winter months. The order directs TransAlta to keep Unit 2 of the Centralia Generating Station in Centralia, Washington available to operate. Unit 2 of the coal plant was scheduled to shut down at the end of 2025. The reliable supply of power from the Centralia coal plant is essential for grid stability in the Northwest. The order prioritizes minimizing the risk and costs of blackouts.

“The last administration’s energy subtraction policies had the United States on track to experience significantly more blackouts in the coming years — thankfully, President Trump won’t let that happen,” said **Energy Secretary Wright**. “The Trump administration will continue taking action to keep America’s coal plants running so we can stop the price spikes and ensure we don’t lose critical generation sources. Americans deserve access to affordable, reliable, and secure energy to heat their homes all the time, regardless of whether the wind is blowing or the sun is shining.”

According to DOE’s [Resource Adequacy Report](#), blackouts were on track to potentially increase 100 times by 2030 if the U.S. continued to take reliable power offline as it did during the Biden administration.

The North American Electric Reliability Corporation (NERC) determined in its 2025-2026 Winter Reliability

Assessment that the WECC Northwest region is at elevated risk during periods of extreme weather, such as prolonged, far-reaching cold snaps.

This order is in effect beginning on December 16, 2025, and continuing until March 16, 2026.

Background:

The [NERC Winter Reliability Assessment](#) warns that “extreme winter conditions extending over a wide area could result in electricity supply shortfalls.” With winter electricity demand continuing to rise, peak demand in the U.S. increased by 2.5% since last winter.

###

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Energy Department Grants Woodside Louisiana
LNG Project Additional Time to Commence
Exports

December 16, 2025

Just Launched: A Critical Materials Career Map

December 17, 2025

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BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c))
Emergency Order: Tri-State)
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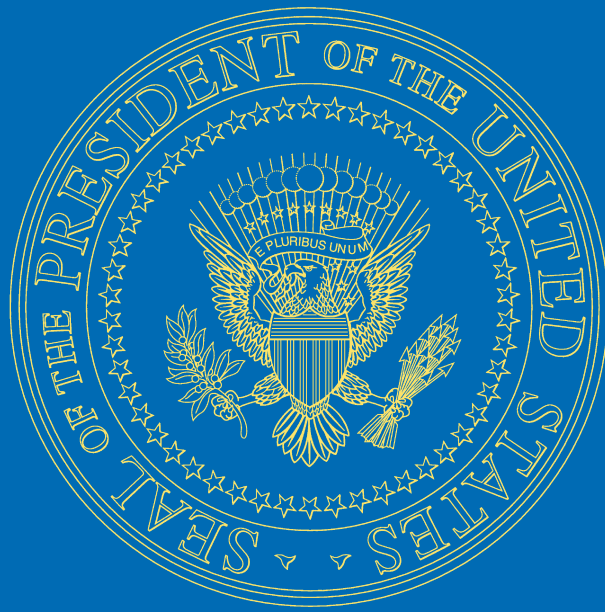
Order No. 202-25-14

Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
Public Interest Organizations

Filed January 28, 2026

Exhibit 1-119:
2001 National Energy Policy

National Energy Policy



Report of the
National Energy Policy Development Group

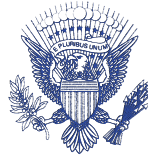
May 2001

Reliable, Affordable, and Environmentally Sound Energy for America's Future

**Report of the
National Energy Policy Development Group**

*“America must have an energy policy that plans
for the future, but meets the needs of today.
I believe we can develop our natural resources
and protect our environment.”*

— President George W. Bush



THE VICE PRESIDENT
WASHINGTON

May 16, 2001

The Honorable George W. Bush
President of the United States
The White House
Washington, D.C. 20500

Dear Mr. President:

On behalf of the National Energy Policy Development Group, I submit for your consideration our National Energy Policy report. As you directed us at the outset of your Administration, we have developed a national energy policy designed to help bring together business, government, local communities and citizens to promote dependable, affordable and environmentally sound energy for the future.

The report reflects the requirements and philosophy you set out for our work. It envisions a comprehensive long-term strategy that uses leading edge technology to produce an integrated energy, environmental and economic policy. To achieve a 21st century quality of life -- enhanced by reliable energy and a clean environment -- we must modernize conservation, modernize our infrastructure, increase our energy supplies, including renewables, accelerate the protection and improvement of our environment, and increase our energy security.

We submit these recommendations with optimism. The tasks ahead are great but achievable. To meet our energy challenge, we must put to good use the resources around us and the talents within us. It summons the best of America and offers a healthier environment, a stronger economy and a brighter future for the American people.

Sincerely,

A handwritten signature in blue ink that reads "Dick Cheney". The signature is fluid and cursive, with the first name "Dick" and last name "Cheney" clearly legible.

Enclosure

Members of the National Energy Policy Development Group

DICK CHENEY

The Vice President

COLIN L. POWELL

The Secretary of State

PAUL O'NEILL

The Secretary of the Treasury

GALE NORTON

The Secretary of the Interior

ANN M. VENEMAN

The Secretary of Agriculture

DONALD L. EVANS

The Secretary of Commerce

NORMAN Y. MINETA

The Secretary of Transportation

SPENCER ABRAHAM

The Secretary of Energy

JOE M. ALLBAUGH

The Director of the Federal Emergency Management Agency

CHRISTINE TODD WHITMAN

The Administrator of the Environmental Protection Agency

JOSHUA B. BOLTEN

The Assistant to the President and Deputy Chief of Staff for Policy

MITCHELL E. DANIELS

The Director of the Office of Management and Budget

LAWRENCE B. LINDSEY

The Assistant to the President for Economic Policy

RUBEN BARRALES

Deputy Assistant to the President and Director of Intergovernmental Affairs

Executive Director: Andrew D. Lundquist

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Overview

Reliable, Affordable, and Environmentally Sound Energy for America's Future

In his second week in office, President George W. Bush established the National Energy Policy Development Group, directing it to “develop a national energy policy designed to help the private sector, and, as necessary and appropriate, State and local governments, promote dependable, affordable, and environmentally sound production and distribution of energy for the future.” This Overview sets forth the National Energy Policy Development (NEPD) Group’s findings and key recommendations for a National Energy Policy.

America in the year 2001 faces the most serious energy shortage since the oil embargoes of the 1970s. The effects are already being felt nationwide. Many families face energy bills two to three times higher than they were a year ago. Millions of Americans find themselves dealing with rolling blackouts or brownouts; some employers must lay off workers or curtail production to absorb the rising cost of energy. Drivers across America are paying higher and higher gasoline prices.

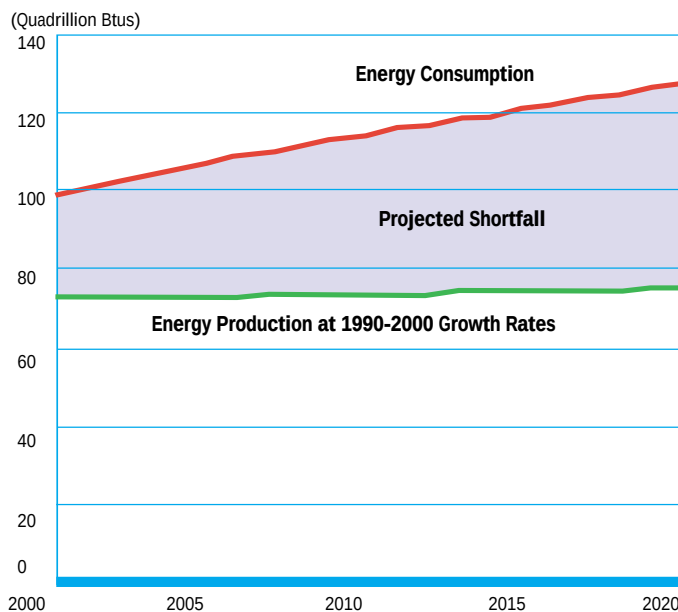
Californians have felt these problems most acutely. California actually began the 1990s with a surplus of electricity generating capacity. Yet despite an economic boom, a rapidly growing population, and a corresponding increase in energy needs, California did not add a single new major electric power plant during the 1990s. The result is a demand for electricity that greatly exceeds the amount available.

A fundamental imbalance between supply and demand defines our nation’s energy crisis. As the chart illustrates, if energy production increases at the same rate as during the last decade our projected energy needs will far outstrip expected levels of production.

This imbalance, if allowed to continue, will inevitably undermine our economy, our standard of living, and our national security. But it is not beyond our power to correct. America leads the world in scientific achievement, technical skill, and entrepreneurial drive. Within our country are abundant natural resources, unrivaled technology, and unlimited human creativity. With forward-looking leadership and sensible policies, we can meet our fu-

Figure 1

Growth in U.S. Energy Consumption Is Outpacing Production



Over the next 20 years, growth in U.S. energy consumption will increasingly outpace U.S. energy production, if production only grows at the rate of the last 10 years.

Sources: Sandia National Laboratories and U.S. Department of Energy, Energy Information Administration.



America's expanding economy, growing population, and rising standard of living will be sustained by our unmatched technological know-how.

ture energy demands and promote energy conservation, and do so in environmentally responsible ways that set a standard for the world.

The Challenge

America's energy challenge begins with our expanding economy, growing population, and rising standard of living. Our prosperity and way of life are sustained by energy use. America has the technological know-how and environmentally sound 21st century technologies needed to meet the principal energy challenges we face: promoting energy conservation, repairing and modernizing our energy infrastructure, and increasing our energy supplies in ways that protect and improve the environment. Meeting each of these challenges is critical to expanding our economy, meeting the needs of a growing population, and raising the American standard of living.

We are already working to meet the first challenge: using energy more wisely. Dramatic technological advances in energy efficiency have enabled us to make great strides in conservation, from the operation of farms and factories to the construction of

buildings and automobiles. New technology allows us to go about our lives and work with less cost, less effort, and less burden on the natural environment. While such advances cannot alone solve America's energy problems, they can and will continue to play an important role in our energy future.

The second challenge is to repair and expand our energy infrastructure. Our current, outdated network of electric generators, transmission lines, pipelines, and refineries that convert raw materials into usable fuel has been allowed to deteriorate. Oil pipelines and refining capacity are in need of repair and expansion. Not a single major oil refinery has been built in the United States in nearly a generation, causing the kind of bottlenecks that lead to sudden spikes in the price of gasoline. Natural gas distribution, likewise, is hindered by an aging and inadequate network of pipelines. To match supply and demand will require some 38,000 miles of new gas pipelines, along with 255,000 miles of distribution lines. Similarly, an antiquated and inadequate transmission grid prevents us from routing electricity over long distances and thereby avoiding regional blackouts, such as California's.

“America must have an energy policy that plans for the future, but meets the needs of today. I believe we can develop our natural resources and protect our environment.”

— President
George W. Bush

Increasing energy supplies while protecting the environment is the third challenge. Even with successful conservation efforts, America will need more energy.

Renewable and alternative fuels offer hope for America's energy future. But they supply only a small fraction of present energy needs. The day they fulfill the bulk of our needs is still years away. Until that day comes, we must continue meeting the nation's energy requirements by the means available to us.

Estimates indicate that over the next 20 years, U.S. oil consumption will increase by 33 percent, natural gas consumption by well over 50 percent, and demand for electricity will rise by 45 percent. If America's energy production grows at the same rate as it did in the 1990s we will face an ever-increasing gap.

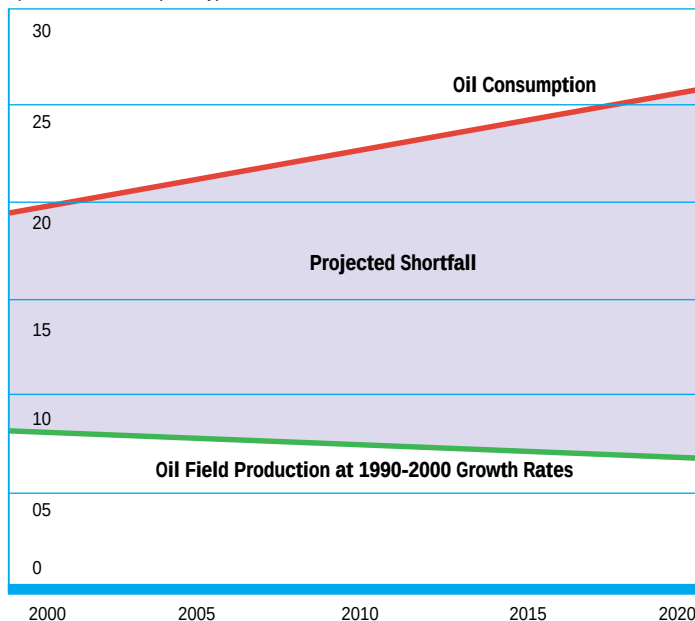
Increases on this scale will require preparation and action today. Yet America has not been bringing on line the necessary supplies and infrastructure.

Extraordinary advances in technology have transformed energy exploration and production. Yet we produce 39 percent less oil today than we did in 1970, leaving us ever more reliant on foreign suppliers. On our present course, America 20 years from now will import nearly two of every three barrels of oil – a condition of increased dependency on foreign powers that do not always have America's interests at heart. Our increasing demand for natural gas – one of the cleanest forms of energy – far exceeds the current rate of production. We should reconsider any regulatory restrictions that do not take technological advances into account.

Figure 2

U.S. Oil Consumption Will Continue to Exceed Production

(Millions of Barrels per Day)



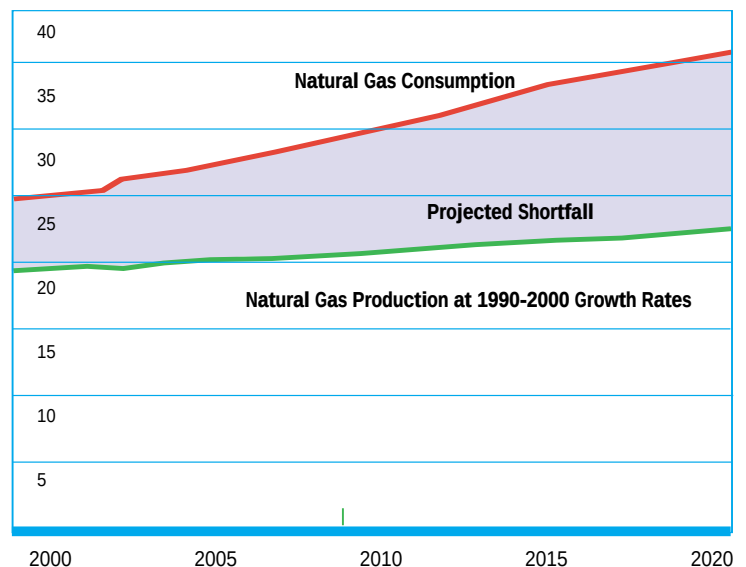
Over the next 20 years, U.S. oil consumption will grow by over 6 million barrels per day. If U.S. oil production follows the same historical pattern of the last 10 years, it will decline by 1.5 million barrels per day. To meet U.S. oil demand, oil and product imports would have to grow by a combined 7.5 million barrels per day. In 2020, U.S. oil production would supply less than 30 percent of U.S. oil needs.

Sources: Sandia National Laboratories and U.S. Department of Energy, Energy Information Administration.

Figure 3

U.S. Natural Gas Consumption Is Outpacing Production

(Trillion Cubic Feet)



Over the next 20 years, U.S. natural gas consumption will grow by over 50 percent. At the same time, U.S. natural gas production will grow by only 14 percent, if it grows at the rate of the last 10 years.

Sources: Sandia National Laboratories and U.S. Department of Energy, Energy Information Administration.

erview chart

We have a similar opportunity to increase our supplies of electricity. To meet projected demand over the next two decades, America must have in place between 1,300 and 1,900 new electric plants. Much of this new generation will be fueled by natural gas. However, existing and new technologies offer us the opportunity to expand nuclear generation as well. Nuclear power today accounts for 20 percent of our country's electricity. This power source, which causes no greenhouse gas emissions, can play an expanding part in our energy future.

The recommendations of this report address the energy challenges facing America. Taken together, they offer the thorough and responsible energy plan our nation has long needed.

Components of the National Energy Policy

The National Energy Policy we propose follows three basic principles:

- The Policy is a long-term, comprehensive strategy. Our energy crisis has been years in the making, and will take years to put fully behind us.
- The Policy will advance new, environmentally friendly technologies to increase energy supplies and encourage cleaner, more efficient energy use.
- The Policy seeks to raise the living standards of the American people, recognizing that to do so our country must fully integrate its energy, environmental, and economic policies.

Applying these principles, we urge action to meet five specific national goals. America must modernize conservation, modernize our energy infrastructure, increase energy supplies, accelerate the protection and improvement of the environment, and increase our nation's energy security.

Modernize Conservation

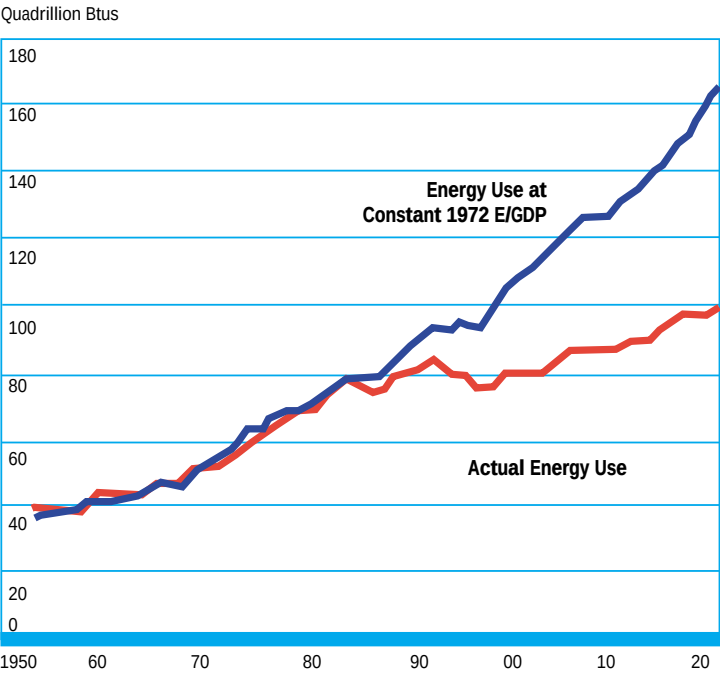
Americans share the goal of energy conservation. The best way of meeting this goal is to increase energy efficiency by applying new technology – raising productivity, reducing waste, and trimming costs. In addition, it holds out great hope for improving the quality of the environment. American families, communities, and businesses all depend upon reliable and affordable energy services for their well being and safety. From transportation to communication, from air conditioning to lighting, energy is critical to nearly everything we do in life and work. Public policy can and should encourage energy conservation.

Over the past three decades, America has made impressive gains in energy efficiency. Today's automobiles, for example, use about 60 percent of the gasoline they

“Here we aim to continue a path of uninterrupted progress in many fields... New technologies are proving that we can save energy without sacrificing our standard of living. And we’re going to encourage it in every way possible.”

— Vice President
Richard B. Cheney

Figure 4
U.S. Economy is More Energy Efficient (Energy Intensity)
Primary Energy Use



Improvements in energy efficiency since the 1970s have had a major impact in meeting national energy needs relative to new supply. If the intensity of U.S. energy use had remained constant since 1972, consumption would have been about 70 quadrillion Btus (74 percent) higher in 1999 than it actually was.

Source: U.S. Department of Energy, Energy Information Administration.

“For the electricity we need, we must be ambitious. Transmission grids stand in need of repair, upgrading, and expansion. . . . If we put these connections in place, we’ll go a long way toward avoiding future blackouts.”

— Vice President
Richard B. Cheney

did in 1972, while new refrigerators require just one-third the electricity they did 30 years ago. As a result, since 1973, the U.S. economy has grown by 126 percent, while energy use has increased by only 30 percent. In the 1990s alone, manufacturing output expanded by 41 percent, while industrial electricity consumption grew by only 11 percent. We must build on this progress and strengthen America’s commitment to energy efficiency and conservation.

The National Energy Policy builds on our nation’s successful track record and will promote further improvements in the productive and efficient use of energy. This report includes recommendations to:

- Direct federal agencies to take appropriate actions to responsibly conserve energy use at their facilities, especially during periods of peak demand in regions where electricity shortages are possible, and to report to the President on actions taken.
- Increase funding for renewable energy and energy efficiency research and development programs that are performance-based and cost-shared.
- Create an income tax credit for the purchase of hybrid and fuel cell vehicles to promote fuel-efficient vehicles.
- Extend the Department of Energy’s “Energy Star” efficiency program to include schools, retail buildings, health care facilities, and homes and extend the “Energy Star” labeling program to additional products and appliances.
- Fund the federal government’s Intelligent Transportation Systems program, the fuel cell powered transit bus program, and the Clean Buses program.
- Provide a tax incentive and streamline permitting to accelerate the development of clean Combined Heat and Power technology.
- Direct the Secretary of Transportation to review and provide recommendations on establishing Corporate Average Fuel Economy (CAFE) standards

with due consideration to the National Academy of Sciences study of CAFE standards to be released in July, 2001.

Modernize Our Energy Infrastructure

The energy we use passes through a vast nationwide network of generating facilities, transmission lines, pipelines, and refineries that converts raw resources into usable fuel and power. That system is deteriorating, and is now strained to capacity.

One reason for this is government regulation, often excessive and redundant. Regulation is needed in such a complex field, but it has become overly burdensome. Regulatory hurdles, delays in issuing permits, and economic uncertainty are limiting investment in new facilities, making our energy markets more vulnerable to transmission bottlenecks, price spikes and supply disruptions. America needs more environmentally-sound energy projects to connect supply sources to growing markets and to deliver energy to homes and business.

To reduce the incidence of electricity blackouts, we must greatly enhance our ability to transmit electric power between geographic regions, that is, sending power to where it is needed from where it is produced. Most of America’s transmission lines, substations, and transformers were built when utilities were tightly regulated and provided service only within their assigned regions. The system is simply unequipped for large-scale swapping of power in the highly competitive market of the 21st century.

The National Energy Policy will modernize and expand our energy infrastructure in order to ensure that energy supplies can be safely, reliably, and affordably transported to homes and businesses. This report includes recommendations to:

- Direct agencies to improve pipeline safety and expedite pipeline permitting.
- Issue an Executive Order directing federal agencies to expedite permits and coordinate federal, state, and local actions necessary for energy-related project approvals on a national basis

in an environmentally sound manner, and establish an interagency task force chaired by the Council on Environmental Quality. The task force will ensure that federal agencies set up appropriate mechanisms to coordinate federal, state and local permitting activity in particular regions where increased activity is expected.

- Grant authority to obtain rights-of-way for electricity transmission lines with the goal of creating a reliable national transmission grid. Similar authority already exists for natural gas pipelines and highways.
- Enact comprehensive electricity legislation that promotes competition, encourages new generation, protects consumers, enhances reliability, and promotes renewable energy.
- Implement administrative and regulatory changes to improve the reliability of the interstate transmission system and enact legislation to provide for enforcement of electricity reliability standards.
- Expand the Energy Department's research and development on transmission reliability and superconductivity.

Increase Energy Supplies

A primary goal of the National Energy Policy is to add supply from diverse sources. This means domestic oil, gas, and coal. It also means hydropower and nuclear power. And it means making greater use of non-hydro renewable sources now available.

One aspect of the present crisis is an increased dependence, not only on foreign oil, but on a narrow range of energy options. For example, about 90 percent of all new electricity plants currently under construction will be fueled by natural gas. While natural gas has many advantages, an over-reliance on any one fuel source leaves consumers vulnerable to price spikes and supply disruptions. There are several other fuel sources available that can help meet our needs.

Currently, the U.S. has enough coal to last for another 250 years. Yet very few

coal-powered electric plants are now under construction. Research into clean coal technologies may increase the attractiveness of coal as a source for new generation plants.

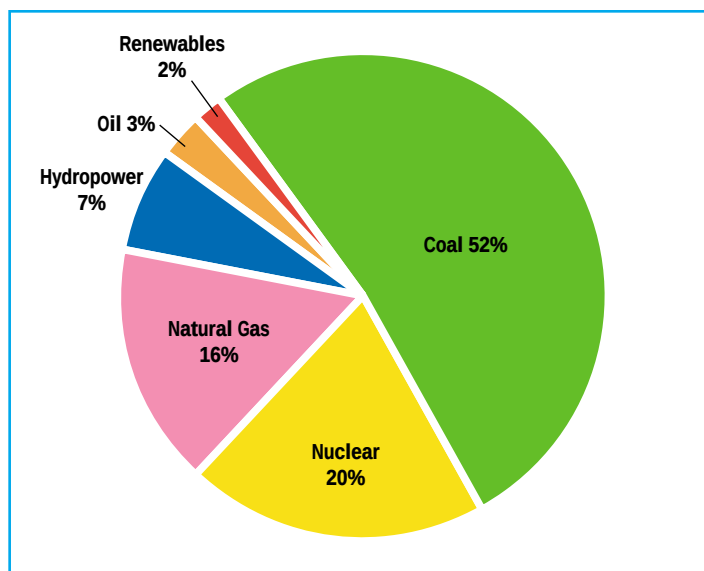
Nuclear power plants serve millions of American homes and businesses, have a dependable record for safety and efficiency, and discharge no greenhouse gases into the atmosphere. As noted earlier, these facilities currently generate 20 percent of all electricity in America, and more than 40 percent of electricity generated in 10 states in the Northeast, South, and Midwest. Other nations, such as Japan and France, generate a much higher percentage of their electricity from nuclear power. Yet the number of nuclear plants in America is actually projected to decline in coming years, as old plants close and none are built to replace them.

Enormous advances in technology have made oil and natural gas exploration and production both more efficient and more environmentally sound. Better technology means fewer rigs, more accurate drilling, greater resource recovery and envi-

“As a country, we have demanded more and more energy. But we have not brought on line the supplies needed to meet that demand.... We can explore for energy, we can produce energy and use it, and we can do so with a decent regard for the natural environment.”

—Vice President
Richard B. Cheney

Figure 5
Fuel Sources for Electricity Generation in 2000



Electricity is a secondary source of energy, generated through the consumption of primary sources. Coal and nuclear energy account for nearly 75 percent of U.S. electricity generation.

Source: U.S. Department of Energy, Energy Information Administration

“We will insist on protecting and enhancing the environment, showing consideration for the air and natural lands and watersheds of our country.”

— Vice President
Richard B. Cheney

ronmentally friendly exploration. Drilling pads are 80 percent smaller than a generation ago. High-tech drilling allows us to access supplies five to six miles away from a single compact drilling site, leaving sensitive wetlands and wildlife habitats undisturbed. Yet the current regulatory structure fails to take sufficient account of these extraordinary advances, excessively restricting the environmentally safe production of energy from many known sources.

Our policy will increase and diversify our nation’s sources of traditional and alternative fuels in order to furnish families and businesses with reliable and affordable energy, to enhance national security, and to improve the environment. This report includes recommendations to:

- Issue an Executive Order directing all federal agencies to include in any regulatory action that could significantly and adversely affect energy supplies a detailed statement on the energy impact of the proposed action.
- Open a small fraction of the Arctic National Wildlife Refuge to environmentally regulated exploration and production using leading-edge technology. Examine the potential for the regulated increase in oil and natural gas development on other federal lands.
- Earmark \$1.2 billion of bid bonuses from the environmentally responsible leasing of ANWR to fund research into alternative and renewable energy resources – including wind, solar, biomass, and geothermal.
- Enact legislation to expand existing alternative fuels tax incentives to include landfills that capture methane gas emissions for electricity generation and to electricity produced from wind and biomass. Extend the number of eligible biomass sources to include forest-related sources, agricultural sources, and certain urban sources.
- Provide \$2 billion over 10 years to fund clean coal technology research and a new credit for electricity produced from biomass co-fired with coal.
- Direct federal agencies to streamline the

hydropower relicensing process with proper regard given to environmental factors.

- Provide for the safe expansion of nuclear energy by establishing a national repository for nuclear waste, and by streamlining the licensing of nuclear power plants.

Accelerate Protection and Improvement of the Environment

America’s commitment to environmental protection runs deep. We are all aware of past excesses in our use of the natural world and its resources. No one wishes to see them repeated. In the 21st century, the ethic of good stewardship is well established in American life and law.

We do not accept the false choice between environmental protection and energy production. An integrated approach to policy can yield a cleaner environment, a stronger economy, and a sufficient supply of energy for our future. The primary reason for that has been steady advances in the technology of locating, producing, and using energy. Since 1970, emissions of key air emissions are down 31 percent. Cars today emit 85 percent less carbon monoxide than 30 years ago. Lead emissions are down 90 percent. Lead levels in ambient air today are 98 percent lower than they were in 1970. America is using more, and polluting less.

One of the factors harming the environment today is the very lack of a comprehensive, long-term national energy policy. States confronting blackouts must take desperate measures, often at the expense of environmental standards, requesting waivers of environmental rules, and delaying the implementation of anti-pollution efforts. Shortfalls in electricity generating capacity and short-sighted policies have blocked construction of new, cleaner plants, leaving no choice but to rely on older, inefficient plants to meet demand. The increased use of emergency power sources, such as diesel generators, results in greater air pollution.

New anti-pollution technologies hold great promise for the environment. The same can be said of 21st century power generators that must soon replace older models; signifi-

cant new resources for land conservation efforts; and continued research into renewable energy sources. All have a place in the National Energy Policy.

The National Energy Policy will build upon our nation's successful track record and will promote further improvements in the productive and efficient use of energy. This report includes recommendations to:

- Enact “multi-pollutant” legislation to establish a flexible, market-based program to significantly reduce and cap emissions of sulfur dioxide, nitrogen oxides, and mercury from electric power generators.
- Increase exports of environmentally friendly, market-ready U.S. technologies that generate a clean environment and increase energy efficiency.
- Establish a new “Royalties Conservation Fund” and earmark royalties from new, clean oil and gas exploration in ANWR to fund land conservation efforts.
- Implement new guidelines to reduce truck idling emissions at truck stops.

Increase Energy Security.

The National Energy Policy seeks to lessen the impact on Americans of energy price volatility and supply uncertainty. Such uncertainty increases as we reduce America's dependence on foreign sources of energy. At the same time, however, we recognize that a significant percentage of our resources will come from overseas. Energy security must be a priority of U.S. trade and foreign policy.

We must look beyond our borders and restore America's credibility with overseas suppliers. In addition, we must build strong relationships with energy-producing nations in our own hemisphere, improving the outlook for trade, investment, and reliable supplies.

Energy security also requires preparing our nation for supply emergencies, and assisting low-income Americans who are most vulnerable in times of supply disruption, price spikes, and extreme weather.

To ensure energy security for our nation and its families, our report includes these recommendations:

- Dedicate new funds to the Low Income Home Energy Assistance Program by funneling a portion of oil and gas royalty payments to LIHEAP when oil and natural gas prices exceed a certain amount.
- Double funding for the Department of Energy's Weatherization Assistance Program, increasing funding by \$1.4 billion over 10 years.
- Direct the Federal Emergency Management Administration to prepare for potential energy-related emergencies.
- Support a North American Energy Framework to expand and accelerate cross-border energy investment, oil and gas pipelines, and electricity grid connections by streamlining and expediting permitting procedures with Mexico and Canada. Direct federal agencies to expedite necessary permits for a gas pipeline route from Alaska to the lower 48 states.

Looking Toward the Future

The President's goal of reliable, affordable, and environmentally sound energy supplies will not be reached overnight. It will call forth innovations in science, research, and engineering. It will require time and the best efforts of leaders in both political parties. It will require also that we deal with the facts as they are, meeting serious problems in a serious way. The complacency of the past decade must now give way to swift but well-considered action.

Present trends are not encouraging, but they are not immutable. They are among today's most urgent challenges, and well within our power to overcome. Our country has met many great tests. Some have imposed extreme hardship and sacrifice. Others have demanded only resolve, ingenuity, and clarity of purpose. Such is the case with energy today.

We submit these recommendations with optimism. We believe that the tasks ahead, while great, are achievable. The energy crisis is a call to put to good use the resources around us, and the talents within us. It summons the best of America, and offers the best of rewards – in new jobs, a healthier environment, a stronger economy, and a brighter future for our people.

“The goals of this strategy are clear: to ensure a steady supply of affordable energy for America's homes and businesses and industries.”

— President
George W. Bush

Taking Stock

Energy Challenges Facing the United States

America's current energy challenges can be met with rapidly improving technology, dedicated leadership, and a comprehensive approach to our energy needs.

Our challenge is clear—we must use technology to reduce demand for energy, repair and maintain our energy infrastructure, and increase energy supply. Today, the United States remains the world's undisputed technological leader; but recent events have demonstrated that we have yet to integrate 21st-century technology into an energy plan that is focused on wise energy use, production, efficiency, and conservation.

Prices today for gasoline, heating oil, and natural gas are dramatically higher than they were only a year ago. In California, homeowners, farmers, and businesses face soaring electricity prices, rolling blackouts, increasing financial turmoil, and an uncertain energy future. Our nation's dependence on foreign sources of oil is at an all-time high and is expected to grow. Current high energy prices and supply shortages are hurting U.S. consumers and businesses, as well as their prospects for continued economic growth.

Our national energy policy must be comprehensive in scope. It must protect our environment. It must also increase our supply of domestic oil, natural gas, coal, nuclear, and renewable energy sources. Our failure over the past several years to modernize our energy infrastructure—the network of transmission lines, gas pipelines, and oil refineries that transports our energy to consumers and converts raw materials into usable fuels—is a result of the

lack of careful planning and lack of a comprehensive national energy plan. The United States faces serious energy challenges: electricity shortages and disruptions in California and elsewhere in the West, dramatic increases in gasoline prices due to record-low inventories, a strained supply system, and continued dependence on foreign suppliers. These challenges have developed from years of neglect and can only be addressed with the implementation of sound policy. There are no easy, short-term solutions.

Our increased dependence on foreign oil profoundly illustrates our nation's failure to establish an effective energy policy. Between 1991 and 2000, Americans used 17 percent more energy than in the previous decade, while during that same period, domestic energy production rose by only 2.3 percent. While U.S. production of coal, natural gas, nuclear energy, and renewable energy has increased somewhat in recent years, these increases have been largely offset by declines in domestic oil production. As a result, America has met almost all of its increased energy demand over the past ten years with increased imports.

U.S. energy consumption is projected to increase by about 32 percent by 2020. Unless a comprehensive national energy policy is adopted, Americans will continue to feel the effects of an inadequate electrical transmission grid, a pipeline system stretched to capacity, insufficient domestic energy supply, and a regional imbalance in supply sources. It is important that we meet these challenges with a comprehensive energy plan that takes a long-term approach to meeting our energy needs.



The U.S. economy depends on reliable and affordable energy. In the coming months, we face several serious long-term energy challenges: electricity shortages and disruptions in California and the West, dramatic increases in gasoline prices due to record-low inventories, a strained supply system, and continued dependence on foreign suppliers.



California's Energy Challenge

Recent and looming electricity blackouts in California demonstrate the problem of neglecting energy supply. They also foretell the consequences of failing to implement a long-term energy plan for our nation as a whole. Though weather conditions and design flaws in California's electricity restructuring plan contributed, the California electricity crisis is at heart a supply crisis.

Since 1995, California's peak summer demand for electricity has risen by at least 5,500 megawatts (MW), while in-state generation has failed to keep pace. California's generation shortfall did not stem from a lack of interest in building capacity. Since 1997, power producers filed applications to build an additional 14,000 MW of new capacity in California.

In addition to a lack of new generation, a crucial transmission bottleneck in the middle of the state—called Path 15—prevents power in the south from being shipped to the north during emergencies.

This year, reduced hydropower availability due to low rainfall, higher than expected unplanned plant outages, and the financial problems of California's utilities exacerbated this growing supply-demand imbalance. As a result, California's supply problem turned into a crisis, resulting in soaring electricity bills for homes and businesses and rolling blackouts.

In part due to the interconnected nature of the western electricity grid, California's critical electricity shortages have helped to drive up electricity costs in the West.

Unfortunately, there are no short-term solutions to long-term neglect. It can take new power plants and transmission facilities years to site, permit, and construct. Despite expedited federal permitting, California's emergency efforts to increase new generation by 5,000 MW by July appear to be falling short. Less than 2,000 MW of new generation is expected to be in place by summer. Even with aggressive conservation measures, peak demand this summer is projected to outstrip supply by several thousand megawatts. The California grid

operator expects more than 30 days of blackouts.

California officials have warned that the crisis may last several years. Though California's efforts to increase generation may not suffice to prevent blackouts this summer, if continued and strengthened, they promise to limit the duration of the crisis.

Recommendations:

★ The National Energy Policy Development (NEPD) Group recommends that the President issue an Executive Order to direct all federal agencies to include in any regulatory action that could significantly and adversely affect energy supplies, distribution, or use, a detailed statement on (1) the energy impact of the proposed action, (2) any adverse energy effects that cannot be avoided should the proposal be implemented, and (3) alternatives to the proposed action. The agencies would be directed to include this statement in all submissions to the Office of Management and Budget of proposed regulations covered by Executive Order 12866, as well as in all notices of proposed regulations published in the Federal Register.

★ The NEPD Group recommends that the President direct the executive agencies to work closely with Congress to implement the legislative components of a national energy policy.

Conservation and Energy Efficiency

Conservation and energy efficiency are crucial components of a national energy plan. Energy efficiency is the ability to use less energy to produce the same amount of useful work or services. Conservation is closely related and is simply using less energy. Improved energy efficiency and conservation reduces energy consumption and energy costs, while maintaining equivalent service in our homes, offices, factories, and automobiles. Greater energy

efficiency helps the United States reduce energy imports, the likelihood of energy shortages, emissions, and the volatility of energy prices.

Over the last three decades, the United States has significantly improved its energy efficiency by developing and expanding the use of energy efficient technologies. Although our economy has grown by 126 percent since 1973, our energy use has increased by only 30 percent. Had energy use kept pace with economic growth, the nation would have consumed 171 quadrillion British thermal units (Btus) last year instead of 99 quadrillion Btus.

About a third to a half of these savings resulted from shifts in the economy, such as the growth of the service sector. The other half to two-thirds resulted from greater energy efficiency. Technological improvements in energy efficiency allow consumers to enjoy more energy services without commensurate increases in energy demand. The rate at which these efficiency improvements are made varies over time, depending on the extent to which factors—such as energy policies, research and development, prices, and market regulations—encourage the development of new, efficient products and consumer investment in these products. An increased rate of improvement in energy efficiency can have a large impact on energy supply and infrastructure needs, reducing the need for new power plants and other energy resources, along with reduced stress on the energy supply infrastructure.

Load management is the ability to adjust energy loads to reflect immediate supply conditions. In the very short term, direct appeals for conservation can ease strained energy supply markets for a time. Over the longer run, the ability to adjust demand on an as-needed basis can be an important source of energy reserves, resulting in lower energy bills for participating customers.

The impact that improvements in energy efficiency can have on energy supply markets grows over time. Electricity demand is projected to rise by 1.8 percent a year over the next 20 years, requiring the addition of some 393,000 MW of generation capacity. At the same time,

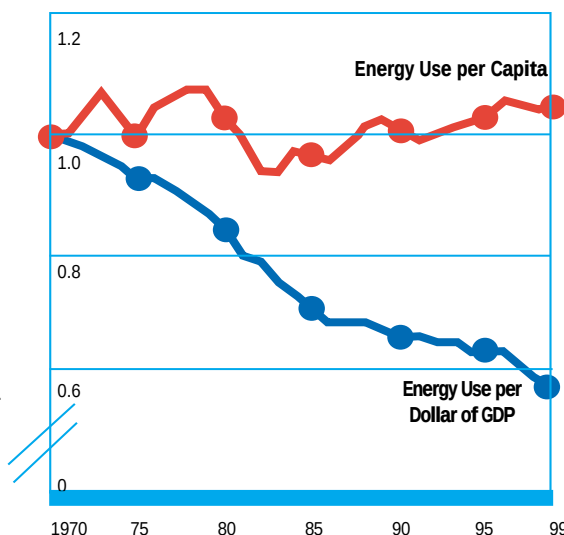
energy efficiency is projected to continue to improve between 2000 and 2020. A decrease in demand from 1.8 percent to 1.5 percent would reduce the need for new generating capacity next year by about 2,000 MW. Extending that reduction over the next 20 years would reduce the need for new generation by 60,000 to 66,000 MW.

While this projection shows that conservation can help ensure the United States has adequate energy supplies for the future, it also shows that conservation alone is not the answer. Even with more conservation, the U.S. will need more energy supplies. Today, new technologies offer new opportunities to enhance our energy efficiency. As these technologies gain market acceptance, they will help ensure a reliable and affordable energy and electric power supply for the nation.

Energy Intensity

The energy intensity of the U.S. economy is measured by the amount of energy used to produce a dollar's worth of gross domestic product (GDP). It now takes only about 56 percent of the energy required in 1970 to produce a

Figure 1-1
U.S. Energy Use per Capita and per Dollar of GDP: 1970–1999
(Index: 1970 = 1)



The energy intensity of the U.S. economy is measured by the amount of energy used to produce a dollar's worth of gross domestic product (GDP). By that yardstick, U.S. energy intensity declined significantly between 1970 and 1985, and has continued to decline, albeit at a slower rate.

Source: U.S. Department of Energy, Energy Information Administration.

Measures of Electrical Power

A watt is a measure of the amount of energy that can be produced during a specific period of time.

- 1 kilowatt (KW)= 1,000 watts
- 1 megawatt (MW)=1million watts
- 1 gigawatt (GW)=1 billion watts
- 1 terawatt (TW)=1 trillion watts

U.S. Energy Efficiency Is Improving

- New home refrigerators now use about one-third less energy than they did in 1972.
- New commercial fluorescent lighting systems use less than half the energy they did during the 1980s.
- Federal buildings now use about 20 percent less energy per square foot since 1985.
- Industrial energy use per unit of output declined by 25 percent from 1980 to 1999.
- The chemical industry's energy use per unit of output has declined by roughly 40 percent in the past 25 years.
- The U.S. government has reduced its energy use in buildings by over 20 percent since 1985.
- The amount of energy required to generate 1 kilowatt-hour of electricity has declined by 10 percent since 1980.

What Causes Transmission Constraints?

When additional electricity flow from one area exceeds a circuit's capacity to carry that flow to another area, the overloaded circuit becomes congested and blocks a steady flow of power. To prevent transmission bottlenecks, system operators curtail transactions between areas or increase generation on the side of the constraint where the electricity is flowing and reduce generation on the opposite side. Transmission constraints result in price differences between regions that exceed differences due to line losses, because electricity can no longer flow freely to the affected area.

A pressing long-term electricity challenge is to build enough new generation and transmission capacity to meet projected growth in demand.

dollar of GDP today (Figure 1-1). This reduction is attributable to improved energy efficiency, as well as to structural changes in the economy, particularly the relative decline of energy-intensive industries.

The decline in the nation's energy intensity accelerated between 1999 and 2000, a period when nonenergy-intensive industries experienced rapid growth. Energy intensity is projected to continue to decline through 2020 at an average rate of 1.6 percent a year. This is a slower rate of decline than experienced in the 1970s and early 1980s, which was characterized by high energy prices and a shift to less energy-intensive industries, but is a more rapid rate of decline than experienced on average during the latter part of the 1980s and the 1990s.

Challenges Confronting Electricity Supply

Our nation's electricity supply has failed to keep pace with growing demand. This imbalance is projected to persist into the future. The adverse consequences have manifested themselves most severely in the West, where supply shortages have led to high prices and even blackouts. In other regions, inadequate supply threatens the reliability and affordability of electric power.

Large amounts of new generating capacity are slated for installation around the country from 2001 to 2004. However, there is a geographic mismatch between where we will generate energy and where it is needed. For example, little capacity is being added where it is most needed, such as in California and eastern New York.



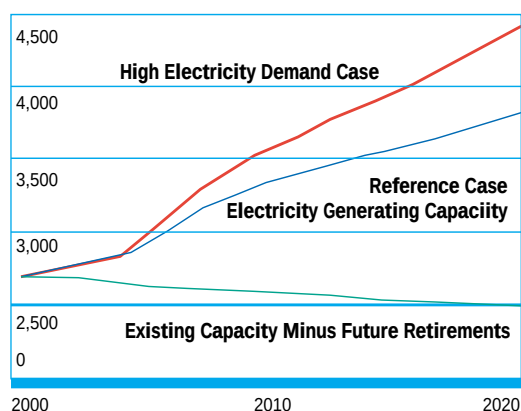
Electricity supply conditions in the Southeast are expected to be tight in the summer of 2001, much as they have been the previous two years. The Northeast may also face supply shortages. If the temperatures of the summer of 2000 had been normal rather than unseasonably cool, New York and New England would most likely have experienced electricity supply shortfalls and price spikes. Critical supply problems could arise if the weather in the summer of 2001 is unusually warm or if plant outages rise above average levels.

Our nation's most pressing long-term electricity challenge is to build enough new generation and transmission capacity to meet projected growth in demand. Across the country, we are seeing the same signs that California faced in the mid-1990s: significant economic regulatory uncertainty, which can result in inadequate supply. This level of uncertainty can vary across the country, depending on state and local regulations. Of the approximately 43,000 MW of new generating capacity that power companies planned in 1994 for construction from 1995 to 1999, only about 18,000 MW were actually built. Although plans have been announced to build more capacity than the country will need over the next five to seven years, this new construction assumes market and regulatory conditions that are not yet assured. Over the next twenty years, the United States will need 1,300 to 1,900 new power plants, which is the equivalent of 60 to 90 new power plants a year (Figure 1-2).

But even with adequate generating capacity, we do not have the infrastructure to ensure reliable supply of electricity. Investment in new transmission capacity has failed to keep pace with growth in demand and with changes in the industry's structure. Since 1989, electricity sales to consumers have increased by 2.1 percent annually, yet transmission capacity has increased by only 0.8 percent annually. As electricity markets become more regional, transmission constraints are impeding the movement of electricity both within and between regions.

The price spikes in the Midwest in the summer of 1998 were in part caused by trans-

Figure 1-2
The U.S. Needs More Power Plants



The nation is going to require significant new generation capacity in the next two decades. Depending on demand, the United States will need to build between 1,300 and 1,900 new power plants—or about one new power plant a week.

Source: U.S. Department of Energy, Energy Information Administration.

mission constraints, which limited the region's ability to import electricity from other regions at a time of high demand. Transmission bottlenecks contributed to the blackouts in California over the past year, and have been a persistent cause of price spikes in New York City during peak demand. Constraints on New England's ability to import low-cost power from Canada could raise electricity prices during periods of high demand.

Electricity is a secondary source of energy, generated through the consumption of primary sources (Figure 1-3). The largest source of U.S. electricity generation is coal, followed by nuclear energy, natural gas, hydropower, oil, and non-hydropower renewable energy.

Coal

Coal is America's most abundant fuel source. The United States has a 250-year supply of coal. Over 1 billion tons of coal were produced in 25 states in 2000. About 99.7 percent of U.S. coal production is consumed domestically, with electricity generation accounting for about 90 percent of coal consumption.

After peaking in 1982, coal prices have generally declined. This trend is projected to continue through 2020, reflecting an expanding shift into lower-cost western coal production and substantial increases in productivity. While coal is expected to

remain the dominant fuel in meeting increasing U.S. electricity demand through 2020, energy policy goals must be carefully integrated with environmental policy goals. The Clean Air Act Amendments of 1990 and related state regulations require electricity generators to reduce emissions of sulfur dioxide and nitrogen oxide.

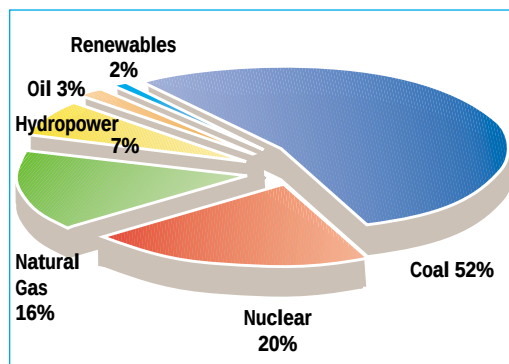
Nuclear Energy

Nuclear energy is the second-largest source (20 percent) of U.S. electricity generation. Nuclear power is used exclusively to generate electricity. Nuclear power has none of the emissions associated with coal and gas power plants, including nitrogen oxides, sulfur dioxide, mercury and carbon dioxide. Costs of electricity generation by nuclear plants compare favorably with the costs of generation by other sources.

While the number of nuclear plants has declined due to retirements, nuclear electricity generation has steadily increased in recent years. Several factors have created a more favorable environment for nuclear energy: safe, standardized plant designs; an improved licensing process; effective safety oversight by the Nuclear Regulatory Commission (NRC); the advent of new technologies; and uncertain, volatile natural gas prices. This more favorable environment has resulted in increased re-licensing of nuclear plants and the consolidation of several plants in the hands of fewer, more experienced operators.

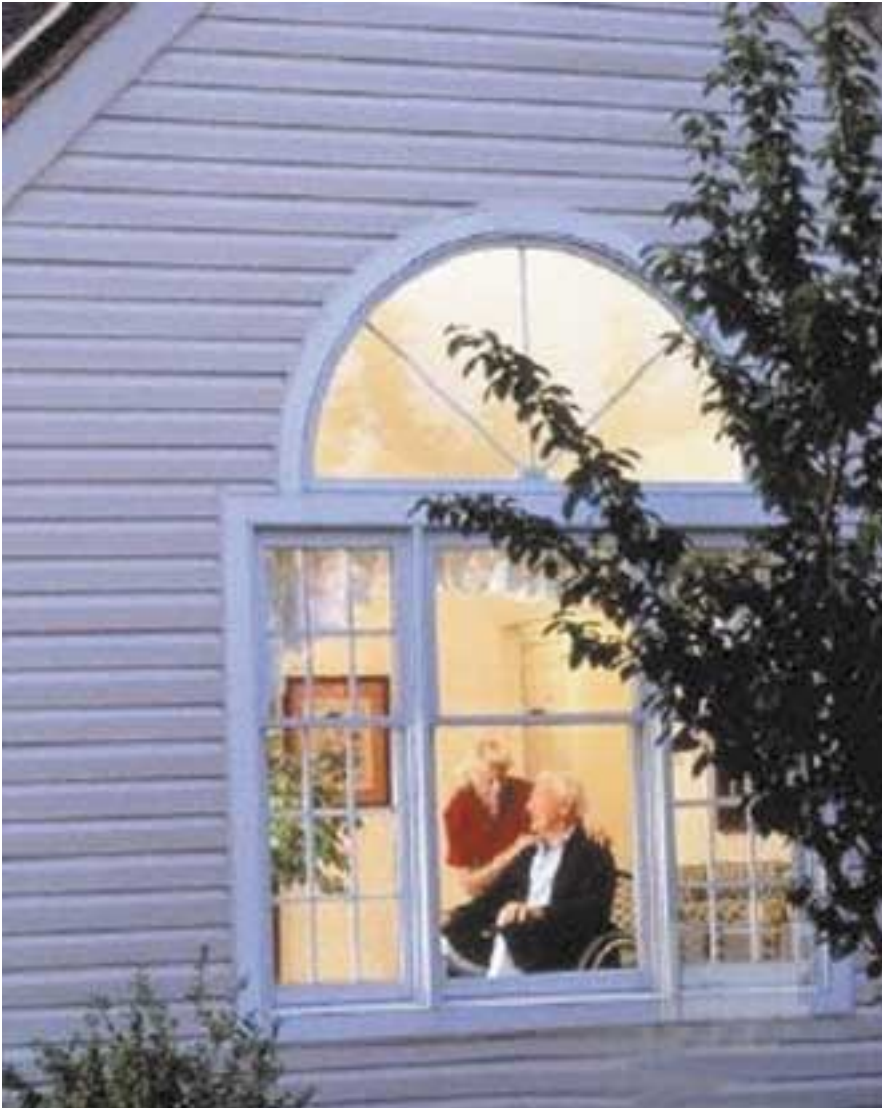
Figure 1-3

Fuel Sources for Electricity Generation in 2000



Electricity is a secondary source of energy, generated through the consumption of primary sources. Coal and nuclear energy account for over 70 percent of U.S. electricity generation.

Source: U.S. Department of Energy, Energy Information Administration.



Many Americans received high heating bills this winter as a result of sharp increases in natural gas prices.

The nuclear industry is closely regulated by the NRC, which provides oversight of the operation and maintenance of these plants. This oversight includes a comprehensive inspection program that focuses on the most significant potential risks of plant operations, and features full-time resident inspectors at each plant, as well as regional inspectors with specialized expertise. In addition to rigorous inspection criteria, the installation of new design features, improvements in operating experience, nuclear safety research, and operator training have all contributed to the nuclear industry's strong safety record.

An important challenge to the use of nuclear energy is the issue of safe and

timely long-term storage of spent nuclear fuel and high- and low-level radioactive waste. Currently, no plans exist to construct any new nuclear plants. However, due to more favorable conditions, the decline in nuclear energy generation has not been as rapid as was predicted only a few years ago, as evidenced by increased re-licensing.

Natural Gas

Natural gas is the third-largest source of U.S. electricity generation, accounting for 16 percent of generation in 2000. Under existing policy, natural gas generating capacity is expected to constitute about 90 percent of the projected increase in electricity generation between 1999 and 2020. Electricity generated by natural gas is expected to grow to 33 percent in 2020—a growth driven by electricity restructuring and the economics of natural gas power plants. Lower capital costs, shorter construction lead times, higher efficiencies, and lower emissions give gas an advantage over coal and other fuels for new generation in most regions of the country.

However, natural gas is not just an electricity source. It is used in many different ways, including as vehicle fuel, as industrial fuel, and in our homes. In addition, natural gas is used as a feedstock during the manufacturing process of such products as chemicals, rubber, apparel, furniture, paper, clay, glass, and other petroleum and coal products. Overall, natural gas accounts for 24 percent of total U.S. energy consumed and for all purposes 27 percent of domestic energy produced.

Eighty-five percent of total U.S. natural gas consumption is produced domestically. The import share of consumption rose from 5 percent in 1987 to 15 percent in 2000, and net imports have comprised more than 50 percent of the growth in gas demand since 1990. Canada, with very large gas supplies and easy pipeline access to the lower 48 states, accounts for nearly all U.S. natural gas imports. Unlike oil, almost all natural gas is produced and sold within the same region. Therefore, prices are determined by regional, rather than global, markets.

In 2000, natural gas prices moved

sharply higher after fifteen years of generally flat prices. Futures prices surged by 320 percent in 2000 to an all-time high of \$9.98 per million Btus in late December 2000—nearly five times higher than the \$2.05 per million Btu average from 1991 to 1999. While prices have declined since the beginning of 2001, they remain much higher than recent levels.

Between 2000 and 2020, U.S. natural gas demand is projected by the Energy Information Administration to increase by more than 50 percent, from 22.8 to 34.7 trillion cubic feet. Others, such as Cambridge Energy Research Associates, expect gas consumption to increase by about 37 percent over that period. Growth is projected in all sectors—industrial, commercial, residential, transportation, and electric generation. More than half of the increase in overall gas consumption will result from rising demand for electricity generation.

Although high natural gas prices have negative effects on consumers, businesses, industries, and the economy as a whole, they also promote more rapid development and adoption of new energy efficient technologies, investment in distribution systems, and greater investment in exploration and development. Although these market responses do not occur rapidly enough to prevent near-term price spikes, over time, they help to hold down prices.

As a result of the sharp increase in natural gas prices, many consumers received historically high utility bills this winter. The price spike has had a particularly severe impact on low-income consumers who use natural gas for heating. In recent months, 5 million consumers have applied for federal and state assistance to pay their heating bills—an increase of 1 million consumers over last year.

The projected rise in domestic natural gas production—from 19.3 trillion cubic feet in 2000 to 29.0 trillion cubic feet in 2020—may not be high enough to meet projected demand. In the near term, incremental production of natural gas is expected to come primarily from unconventional sources in the Rocky Mountain, Gulf Coast, and mid-continent regions; the North Slope of Alaska; and the offshore Gulf of Mexico. Onshore federal lands currently contribute

about 10 percent of U.S. production, and federal offshore production contributes about 26 percent.

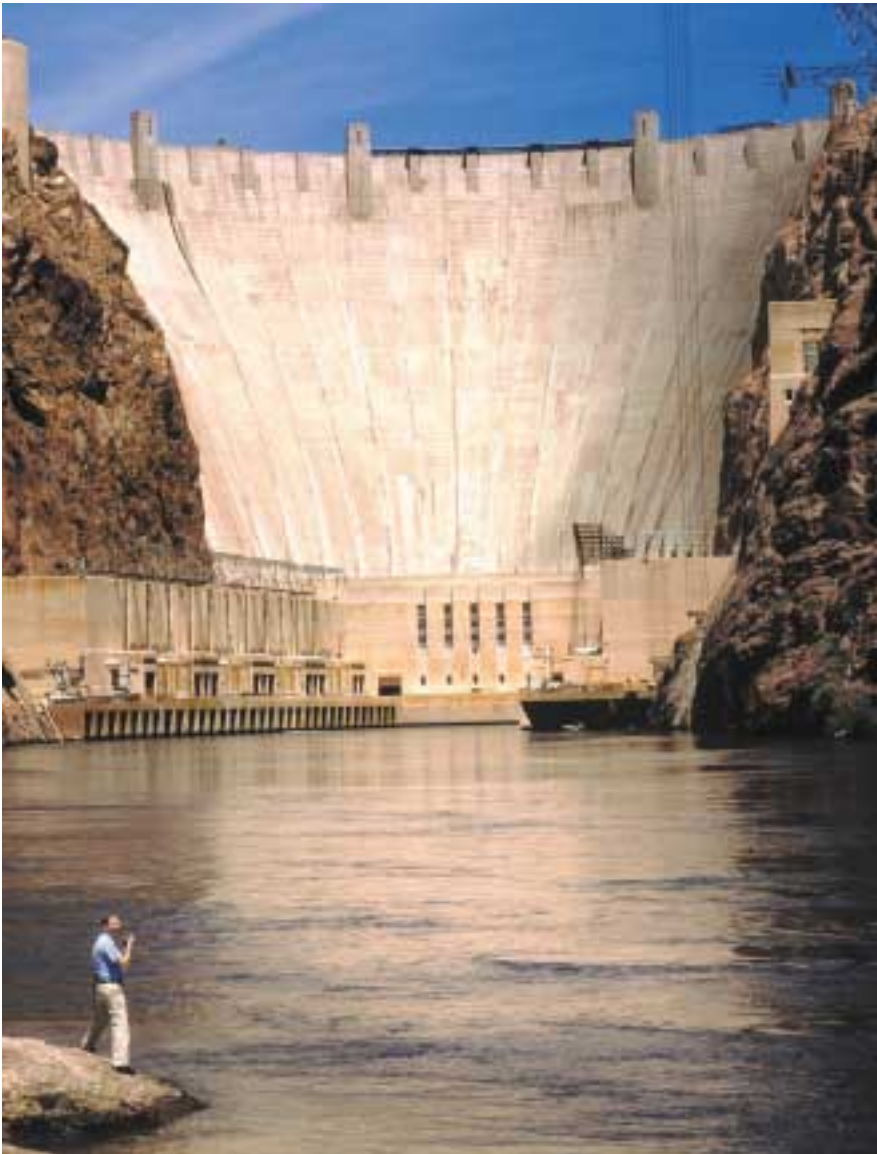
The most significant long-term challenge relating to natural gas is whether adequate supplies can be provided to meet sharply increased projected demand at reasonable prices. If supplies are not adequate, the high natural gas prices experienced over the past year could become a continuing problem, with consequent impacts on electricity prices, home heating bills, and the cost of industrial production. These concerns will redouble if policy decisions sharply reduce electricity generation by any other source, since it is doubtful that natural gas electricity generation could expand to the extent necessary to compensate for that loss of generation.

To meet this long-term challenge, the United States not only needs to boost production, but also must ensure that the natural gas pipeline network is expanded to the extent necessary. For example, although natural gas electricity generation in New England is projected to increase by 16,000 MW through 2000, bottlenecks may block the transmission of necessary supplies. Unless pipeline constraints are eliminated, they will contribute to supply shortages and high prices, and will impede growth in electricity generation.

Hydropower

Hydropower is the fourth-largest source of U.S. electricity generation, accounting for about 7 percent of total generation in 2000. In some regions of the country, such as the Northwest and New York, hydropower makes a much bigger contribution to electricity generation. Although the United States is second only to Canada in hydropower generation, hydropower generation has remained relatively flat in the United States for years.

Hydropower has significant environmental benefits. It is a form of low-cost electricity generation that produces no emissions, and it will continue to be an important source of U.S. energy for the future. Given the potential impacts on fish and wildlife, however, it is important to ef-



Hydropower is the fourth-largest source of U.S. electricity generation. The most significant challenge confronting this source of energy is regulatory uncertainty regarding the federal licensing process.

ficiently and effectively integrate national interests in both natural resource preservation and environmental protection with energy needs.

There are two categories of hydropower projects in the United States: (1) those operated by federal electric utilities, such as the federal power marketing administrations (Bonneville, Western, Southwestern, and Southeastern); and (2) the approximately 2,600 non-federal hydropower dams licensed or exempted by the Federal Energy Regulatory Commission (FERC). The federal utilities have large hydropower systems operated by the Bureau of Reclamation and Army Corps of Engineers, and play an important role meeting electricity

demand, especially in the Northwest and the West. Hydropower projects operate with multiple purposes, such as electricity generation, flood control, navigation, and irrigation.

Although most potential for hydropower has already been developed, there is some undeveloped hydropower capacity in the United States. Much of this capacity could be expanded without constructing a new dam.

The most significant challenge confronting hydropower is regulatory uncertainty regarding the federal licensing process. The process is long and burdensome, and decision-making authority is spread across a range of federal and state agencies charged with promoting different public policy goals. Reforms can improve the hydropower licensing process, ensuring better public participation, ensuring that effective fish and wildlife conditions are adopted, and providing interagency resolution before conflicting mandatory license conditions are presented. The licensing process needs both administrative and legislative reforms. In addition, FERC should be encouraged to adopt appropriate deadlines for its own actions during the process.

Oil

Oil accounts for approximately 3 percent of electricity generation. Oil is used as a primary source to fire electricity generation plants in some regions. Specifically, oil is an important source of electricity in Hawaii, Florida, and some northeastern states. Oil can also be used as an additional source of fuel for electricity generation in plants that can use either natural gas or oil. However, electricity generation from oil is projected to decline to about one-half of one percent of total electricity generation by 2020.

Renewable Energy: A Growing Resource

Renewable energy technologies tap natural flows of energy—such as water, wind, solar, geological, and biomass sources—to produce electricity, fuels, and heat. Non-hydropower renewable electricity generation is projected to grow at a faster rate

than all other generation sources, except natural gas. These sources of energy are continuously renewable, can be very clean, are domestically produced, and can generate income for farmers, landowners, and others. Although its production costs generally remain higher than other sources, renewable energy has not experienced the price volatility of other energy resources.

Non-hydropower renewable energy sources currently account for only about 4 percent of total energy consumption and 2 percent of total electricity generation. The sources of non-hydropower renewable electricity generation are biomass (the direct combustion of plant matter and organic residues, such as municipal solid waste use); geothermal (use of naturally occurring steam and hot water); wind; and solar. Biomass and geothermal account for most renewable electricity generation.

The most important long-term challenge facing renewable energy remains economic. Renewable energy costs are often greater than those of other energy sources. However, these costs have declined sharply in recent years, due to improved technology. If this trend continues, renewable energy growth will accelerate. By 2020, non-hydropower renewable energy is expected to account for 2.8 percent of total electricity generation.

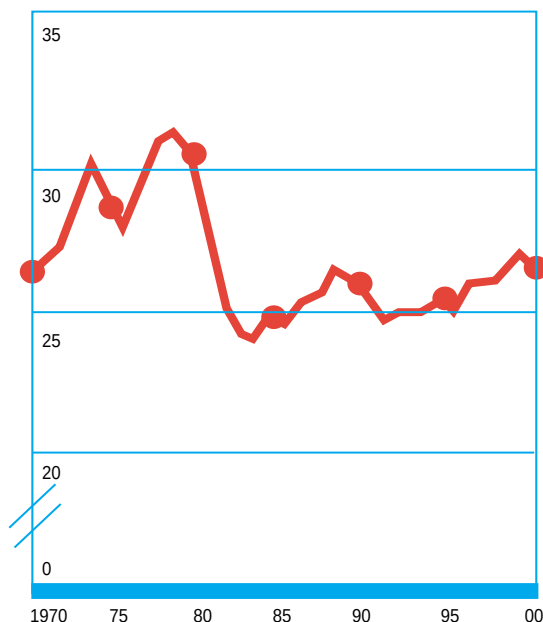
Transportation Energy Needs

Oil is the nation's largest source of primary energy, serving almost 40 percent of U.S. energy needs. In 2000, the United States consumed an average of 19.5 million barrels of oil every day. Transportation fuels account for about two-thirds of our oil consumption, and the industrial sector for 25 percent. Residential and commercial uses, such as heating oil and propane—important fuels in the Northeast and Midwest—account for most of the rest.

The share of oil in U.S. energy supply has declined since the early 1970s, the result of growth in other fuels, particularly coal and nuclear. Per capita oil consumption, which reached a peak in 1978, has fallen by 20 percent from that level (Figure 1-4).

Figure 1-4
U.S. Per Capita Oil Consumption: 1970–2000

(Barrels per Year)



Per capita oil consumption reached a peak in 1978 of 31 barrels. It has fallen by 20 percent since then to 26 barrels per capita.

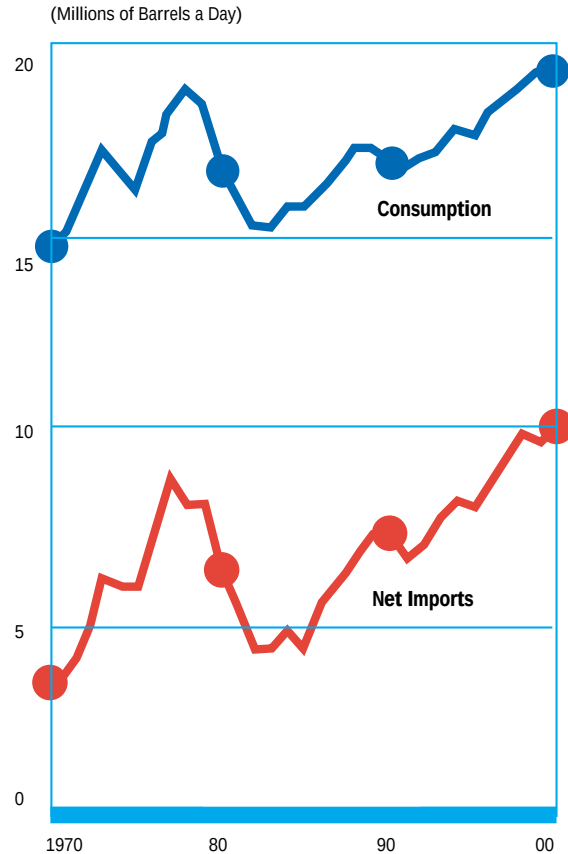
Source: U.S. Department of Energy, Energy Information Administration

Renewable energy technologies tap natural flows of energy to produce electricity, fuels, and heat.

U.S. DEPARTMENT OF ENERGY, NATIONAL
RENEWABLE ENERGY LABORATORY



Figure 1-5
Dependence on Foreign Sources of Oil



U.S. dependence on oil imports is a serious long-term challenge. The economic security of our nation and our trading partners will remain closely tied to global oil market developments.

Source: U.S. Department of Energy, Energy Information Administration.

In 2020, oil is projected to account for roughly the same share of U.S. energy consumption as it does today.

The United States has been a net importer of energy since the 1950s, and U.S. dependence on imports has grown sharply since 1985 (Figure 1-5). Today, oil accounts for 89 percent of net U.S. energy imports. Net oil imports account for most of the rise in energy imports since the mid-1980s, and have grown from about 4.3 million barrels per day (bpd) in 1985 to 10 million bpd in 2000.

World oil prices have been marked by notable price volatility over the past several years. For example, the average initial purchase price of crude oil rose from \$8.03 a barrel in December 1998 to \$30.30 a barrel in November 2000. Spot prices rose even higher. This dramatic price swing was the product of several events. A series of production cuts by the Organization of Petroleum Exporting Countries (OPEC) in 1998 and 1999 sharply curtailed global oil supplies. At the same time, rebounding demand for oil in Asia following roughly two years of economic weakness, and rapid economic growth in the United States boosted oil consumption and squeezed supplies even further. By September 2000, oil prices peaked as markets faced limited supply of crude and petroleum products



Domestic oil supply cannot be increased unless several access and infrastructure challenges are addressed. For example, U.S. refining and pipeline capacity has not kept pace with increasing demand for petroleum products.

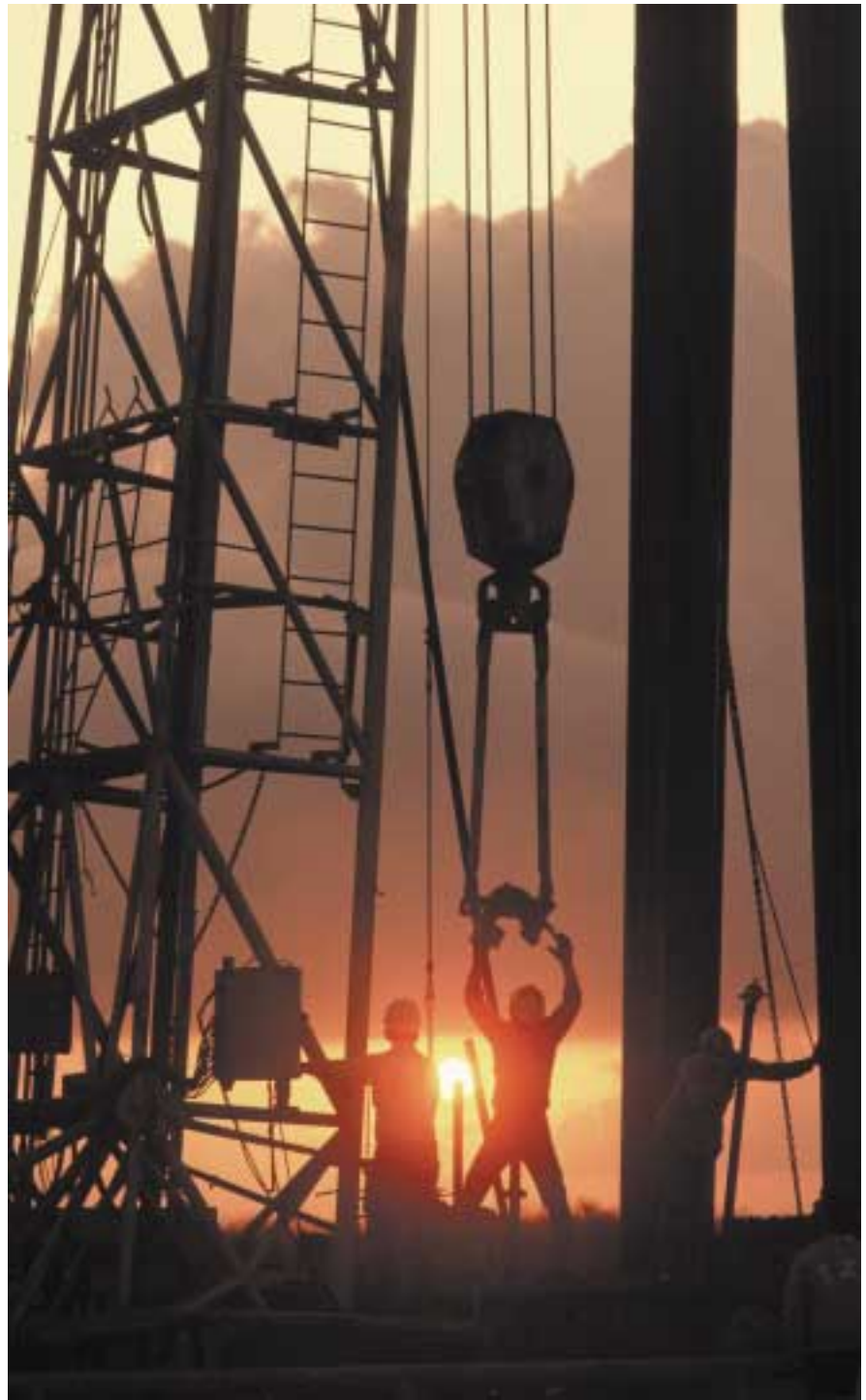
ahead of the winter season, when demand is typically higher. In December 2000, oil prices fell after the market absorbed the impact of a series of OPEC production increases.

This recent price volatility illustrates the effect of intermittent market power exerted by cartel behavior in a global petroleum market. Moreover, prices are set in a market where supply is geographically concentrated. Almost two-thirds of world proven reserves are in the Middle East. Elsewhere, Central and South America account for 9 percent; Africa, 7 percent; North America, 5 percent; Eastern Europe and the former Soviet Union, 5 percent; the rest of Asia, 4 percent; and Western Europe, 2 percent. OPEC's huge oil reserves and production capacity and its periodic efforts to influence prices add to volatility in the market.

Oil prices are expected to remain high through 2002, affecting the cost of transportation, heating, electricity generation, and industrial production. High oil prices mean high prices for petroleum products, such as gasoline, diesel fuel, heating oil, propane, and jet fuel. The summer 2001 base case average gasoline price from the Department of Energy *Short-Term Energy Outlook* is \$1.49 per gallon. However, prices have risen more rapidly than anticipated since the report's release, and a much higher summer average in the range of \$1.50 to \$1.65 per gallon is likely. Some areas have already experienced gasoline prices above \$2.00 per gallon. Gasoline inventories going into the driving season are projected to be lower than last year, which could set the stage for regional supply problems that once again create significant price volatility in gasoline markets.

Price Volatility in Gasoline Markets

During the early summer of 2000, low inventories set the stage for a gasoline price run-up in the Midwest. Several pipeline and refinery problems sent marketers scrambling for limited supplies of both reformulated gasoline (RFG) and conventional gasoline, driving prices up rapidly. In Chicago, the spot price for blend stock for RFG, ex-



cluding ethanol, doubled in about six weeks, from 83 cents per gallon on April 25 to \$1.65 on June 7. Spot prices then fell back over the next five weeks to 84 cents on July 12 as extra supply began arriving. Retail regular-grade RFG prices in the Midwest rose from \$1.47 on April 24 to just over \$2.00 per gallon on June 19, before falling back to \$1.43 by July 24, showing the typical tendency of

Because the United States is a mature oil-producing region, production costs are often higher than in foreign countries.

retail prices to lag spot price changes.

Refiners face additional challenges as a result of various state and local clean fuel requirements for distinct gasoline blends (“boutique fuels”). These different requirements sometimes make it difficult, if not impossible, to draw on gasoline supplies from nearby areas or states to meet local needs when the normal supply is disrupted.

In 2000, very low inventories of gasoline and other refined products on the U.S. East and Gulf coasts increased the market’s susceptibility to external shocks, such as operating problems in refineries or pipelines, or short-term surges in demand. Last winter, heating oil prices were at near-record levels. During 2000, the federal government reduced the vulnerability of the Northeast to heating oil shortages, such as those experienced in January 2000, by creating a 2-million-barrel heating oil reserve in New Jersey and Connecticut.

Because the United States is a mature oil-producing region, production costs are often higher than in foreign countries, particularly OPEC countries. In addition, access to promising domestic oil reserves is limited. U.S. oil production in the lower 48 states reached its peak in 1970 at 9.4 million bpd. A surge in Alaskan North Slope oil production beginning in the late 1970s helped postpone the decline in overall U.S. production, but Alaska’s production peaked in 1988 at 2 million bpd, and fell to 1 million bpd by 2000. By then, U.S. total oil output had fallen to 5.8 million bpd, 39 percent below its peak.

By 2020, U.S. oil production is projected to decline from 5.8 to 5.1 million bpd under current policy. However, oil consumption is expected to rise to 25.8 million bpd by 2020, primarily due to growth in consumption of transportation fuels. Given existing law, production from offshore sources, particularly the Gulf of Mexico, is predicted to play an increasingly important role in the future, accounting for a projected high of 40 percent of domestic oil production by 2010, up from 27 percent today. Technological advances can mitigate the decline in U.S. oil production by enhancing recovery from domestic oil reserves and

lowering production costs.

Our projected growing dependence on oil imports is a serious long-term challenge. U.S. economic security and that of our trading partners will remain closely tied to global oil market developments. Without a change in current policy, the share of U.S. oil demand met by net imports is projected to increase from 52 percent in 2000 to 64 percent in 2020. By 2020, the oil for nearly two of every three gallons of our gasoline and heating oil could come from foreign countries. The sources of this imported oil have changed considerably over the last thirty years, with more of our imports coming from the Western Hemisphere. Despite progress in diversifying our oil suppliers over the past two decades, the U.S. and global economies remain vulnerable to a major disruption of oil supplies.

The Strategic Petroleum Reserve (SPR), the federal government’s major tool for responding to oil supply disruptions, has not kept pace with the growth in imports. The number of days of net oil import protection provided by the Reserve declined from 83 days of imports in 1992 to 54 days of imports today. Net domestic oil imports have increased significantly since 1992, while the SPR’s oil inventory actually decreased.

Domestic oil supply cannot be increased unless several access and infrastructure challenges are addressed. U.S. refining and pipeline capacity has not kept pace with increasing demand for petroleum products. Unless changes take place, the net effect will likely be increased imports, regionally tight markets, and circumstances in which prices for gasoline, heating oil, and other products rise independently of oil prices.

Greater price volatility for gasoline, diesel fuel, heating oil, propane, and jet fuel is likely to become a larger problem over time, unless additional refining capacity and expanded distribution infrastructure can be developed at the same time cleaner products are required. Increasing domestic oil production and reducing demand, particularly for transportation fuels, will re-

quire adoption of a comprehensive national energy policy.

Alternative Transportation Fuels

Development of alternative fuels such as ethanol and other biofuels (liquid fuels derived from organic matter, such as crops), natural gas, and electricity, can help diversify the transportation sector that is so reliant on oil.

Ethanol, a biofuel based on starch crops such as corn, is already making a significant contribution to U.S. energy security, displacing more oil than any other alternative fuel. Other biofuels, such as biodiesel, which can be made from soybean, canola oils, animal fats, and vegetable oils, are making an increasingly important con-

tribution

The success of the federal alternative fuels program has been limited, however. The program focuses on mandating that certain fleet operators purchase alternative fueled vehicles. The hope was that this vehicle purchase mandate would lead to expanded use of alternative fuels. That expectation has not been realized, since most fleet operators purchase dual-fueled vehicles that operate on petroleum motor fuels. Reforms to the federal alternative fuels program could promote alternative fuels use, such as expanding the development of an alternative fuels infrastructure.

Summary of Recommendations

Taking Stock: Energy Challenges Facing the United States

★ The NEPD Group recommends that the President issue an Executive Order to direct all federal agencies to include in any regulatory action that could significantly and adversely affect energy supplies, distribution, or use, a detailed statement on: (1) the energy impact of the proposed action, (2) any adverse energy effects that cannot be avoided should the proposal be implemented, and (3) alternatives to the proposed action. The agencies would be directed to include this statement in all submissions to the Office of Management and Budget of proposed regulations covered by Executive Order 12866, as well as in all notices of proposed regulations published in the Federal Register.

★ The NEPD Group recommends that the President direct the executive agencies to work closely with Congress to implement the legislative components of a national energy policy.

★ The NEPD Group recommends to the President that the NEPD Group continue to work and meet on the implementation of the National Energy Policy, and to explore other ways to advance dependable, affordable, and environmentally responsible production and distribution of energy.

Note: All recommendations in this report are subject to execution in accordance with applicable law. Legislation would be sought where needed. Also, any recommendations that involve foreign countries would be executed in accordance with the customs of international relations, including appropriate diplomatic consultation.

Regional U.S. Energy Challenges

MIDWEST

Energy consumption in the Midwest is dominated by the industrial sector, the sector with the fastest-growing consumption rate through 2020. The transportation sector has the second-fastest consumption growth rate through 2020. States are affected by higher prices for natural gas, propane, and gasoline, and they expect gasoline price spikes this summer. Electricity supplies in some parts of the region may be tight during peak summer demand. High energy prices will drive up farm operating costs, particularly for fertilizer, irrigation, grain drying, and fuel for tractors.

Illinois consumers are reeling from high heating and cooling costs. Landlords are forced to pass on these costs in the form of higher rents. Farmers face low commodity prices, high fuel costs, and dramatically higher fertilizer costs. A key refinery is closing in part because of the cost of meeting cleaner-burning gasoline requirements.

Minnesota's residential electricity use has increased due to population growth and a healthy economy.

Iowa imports over 90 percent of its energy. Farmers are paying twice the 1999 price of fertilizer because of higher prices for natural gas, which is a major component in the fertilizer production.

WEST

Energy consumption in the West is dominated by the transportation sector, which is followed closely by the industrial sector. The region's drought emergency is exacerbating an already challenging energy picture. California is likely to experience more severe electricity blackouts this summer. The Pacific Northwest faces a major shortage of hydropower generation due to low water levels. Electricity prices will remain high in the West until more supply is added. Gasoline could be in short supply this summer in California and other states.

California's energy consumption has grown by about 7 percent a year, while production has remained flat. The point has been reached where demand is occasionally exceeding supply, which has caused rolling blackouts. The situation is likely to worsen this summer when demand will peak.

Oregon's lowest snow pack in history will result in the most severe short-term electricity problem in decades. The state will face high spot market prices and reports the highest gasoline prices in the country.

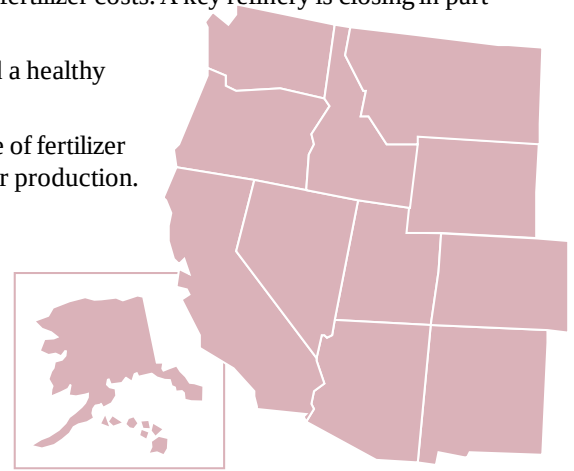
Washington businesses are closing down or cutting back on production. Electricity costs of \$400 per unit compared to \$35 a year ago contributed to the closure of a major paper plant employing 800 employees.

Colorado small business are suffering as well. A 169 percent jump in natural gas prices in one year may force small businesses to close.

Idaho utilities are offering to pay their irrigation customers to not farm portions of their fields to reduce electricity demand and make that saved power available for other local customers. The low snow pack has reduced water in river systems needed for hydropower generation.

Hawaii's geographic isolation contributes to its many energy issues, such as importing 100 percent of its energy, its disproportionately high consumption of jet fuel and heavy reliance on tourism, and its dependence on imported oil for over 90 percent of its primary energy, the majority from sources in the Asia-Pacific region. Electricity is produced mainly from oil, including residuals and distillates from refineries and coal. Because the Islands' electric grids are not interconnected, electric utilities must operate with high reserve margins.

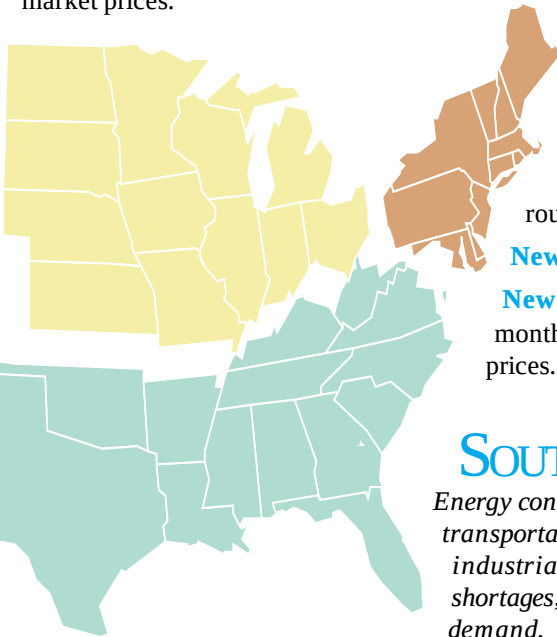
Nevada is covered in large part by federal lands that require federal approval for permitting new transmission and generation facilities. The permitting process can be protracted and cumbersome, despite efforts by federal agencies to streamline and coordinate. The desert climate requires both heating and cooling, the cost of which can be burdensome. While the desert climate is also conducive to geothermal, wind, and solar technologies, additional work is needed to make these technologies economically competitive.



NORTHEAST

Energy consumption in the Northeast is dominated by the transportation sector. Forecasts developed by the Energy Information Administration indicate that the transportation sector will also remain the dominant sector with the fastest-growing consumption rate through 2020. Northeast states' energy challenges include reducing vehicle pollution and interstate transport of power plant emissions. Heavy dependence on heating oil results in disproportionate impacts during cycles of high prices. Energy supplies in the region are limited by electric transmission and gas pipeline bottlenecks.

New York is rushing to complete 11 small natural gas turbines to avoid blackouts in New York City this summer, where customers pay market prices.



Delaware needs upgraded transmission lines to handle increasing loads.

Traditional distributed generation using diesel generators may address these shortfalls, but could raise environmental problems.

Connecticut expects no power shortages this summer, but brownouts are possible if there is a prolonged spike in energy use while power plants are shut down for routine maintenance.

New Hampshire must conserve power on hot days to avoid summer blackouts.

New Jersey regulators have had to allow utilities to raise natural gas rates by 2 percent a month through July 2001 to make up for money lost during the winter due to high fuel prices.

SOUTH

Energy consumption in the South is dominated by the industrial sector, followed by the transportation sector. The transportation sector, however, is expected to grow faster than the industrial sector through 2020. While no state in the region anticipates summer power shortages, electricity supplies in parts of the region may be tight during peak summer demand.

Arkansas' costs of natural gas and propane have doubled and then tripled, contributing to employee layoffs.

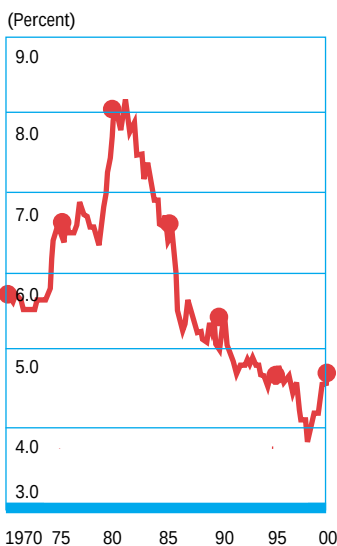
Oklahoma's second-largest industry is the oil and gas industry. The volatility of oil and gas markets can severely affect Oklahomans and the state's economy.

Striking Home

The Impacts of High Energy Prices on Families, Communities, and Businesses

American families, communities, and businesses all depend on reliable and affordable energy for their health, safety, and livelihood. Energy is a critical component of nearly everything that affects our daily lives, from transportation to communication, from food production to medical services, and from air conditioning to heating. Americans expect these services to enhance our lives, and are keenly aware that each additional, unanticipated energy expense is a decrease in funds available for other needs.

Figure 2-1
Income Spent on Energy



Until recently, the share of disposable household income spent on energy steadily declined, falling to a low of 3.8 percent at the end of 1998. Higher prices for oil and other energy products and record cold temperatures in late 2000 bumped this share up to 4.8 percent in the fourth quarter.

Note: Plotted quarterly through the fourth quarter of 2000.

Source: U.S. Department of Commerce, Bureau of Economic Analysis.

Recommendation:

★ The NEPD Group recommends that the President direct the Secretary of Energy to explore potential opportunities to develop educational programs related to energy development and use. This should include possible legislation to create public education awareness programs about energy. Such programs should be long-term in nature, should be funded and managed by the respective energy industries, and should include information on energy's compatibility with a clean environment.

Impacts of High Energy Prices on the Daily Lives of Americans

Many American families and businesses have already felt the strain of rising prices and unreliable energy supplies. Every time energy prices rise, American families have fewer dollars available to meet their needs. Low-income households, energy-intensive industries, and

farmers generally find it difficult to make rapid adjustments to energy price increases.

Rising oil prices act like a tax by foreign oil exporters on Americans. Changing energy prices impose economic costs, such as forcing plants to change schedules, replace machinery, or even shut down. These costs can eventually impact economic growth. So far, increased capital investment by domestic energy producers has offset only a small part of the dampening effects of higher energy costs on consumer spending.

Families

Energy bills for the 74 million middle-class American households consist primarily of home and transportation related expenses. Heating and cooling expenses represent about 40 percent of household energy costs. Other energy expenses include costs for lighting, hot water, appliances, and transportation.

For almost twenty years, the share of household income that Americans spent on their energy needs steadily declined. However, between 1998 and the end of last year, family spending on energy rose by more than 26 percent, from 3.8 to 4.8 percent of after-tax income (Figure 2-1).

Last winter, heating bills for many families tripled. Roughly 50 percent of American families heat their homes with natural gas. Because the last two months of 2000 were particularly cold in some parts of the country, heating bills increased significantly relative to the previous winter. Last winter, average natural gas heating costs in the Midwest increased by 73 percent, from \$540 to \$933. New Englanders' heating bills rose by 27 percent, from \$760 to \$967.





Higher energy prices have forced some energy-intensive manufacturing industries to halt or scale back production and lay off workers.

Many working households can usually accommodate such increases in energy by cutting back on other needs. However, low-income households often have more difficult choices to make. Energy costs for an average low-income household could total 14 percent of family income during the winter of 2000–01, up from about 11 percent for the previous winter. In contrast, energy costs typically represent only about 4 percent of a middle-class family's household budget.

The Low Income Home Energy Assistance Program (LIHEAP) is a federal block grant program that helps low-income consumers pay their energy bills. Last winter, 1.2 million more American families applied for LIHEAP assistance to pay their heating bills, bringing the total close to 5 million American families—up by 26 percent over last year's 3.9 million applicants. As many as 3.6 million families in eighteen states and the District of Columbia risk being unable to pay their bills and having their energy cut off because of the effects of rapidly increasing energy costs.

Recommendations:

★ The NEPD Group recommends that the President take steps to mitigate impacts of high energy costs on low-income consumers. These steps would include:

- Strengthening the Low Income Home Energy Assistance Program by making \$1.7 billion available annually. This is an increase of \$300 million over the regular FY 2001 appropriation.
- Directing the Secretaries of Interior and Health and Human Services to propose legislation to bolster LIHEAP funding by using a portion of oil and gas royalty payments.
- Redirecting royalties above a set trigger price to LIHEAP, whenever crude oil and natural gas prices exceed that trigger price, as determined by the responsible agencies.

★ The NEPD Group recommends that the President increase funding for the Weatherization Assistance Program by \$1.2 billion over ten years. This will roughly double the spending during that period on weatherization. Consistent with that commitment, the FY 2002 Budget includes a \$120 million increase over 2001. The Department of Energy will have the option of using a portion of those funds to test improved implementation approaches for the weatherization program.

★ The NEPD Group recommends that the President support legislation to allow funds dedicated for the Weatherization and State Energy Programs to be transferred to LIHEAP if the Department of Energy deems it appropriate.

The low-income elderly are particularly vulnerable to disruptions in energy supply. If they keep their homes at a reasonable temperature, the high cost of electricity may make it difficult for them to pay their higher electricity bills. This could further result in an elimination of service. Another summer of very hot weather and high energy bills could cause serious health problems for some Americans, particularly those sensitive to high temperatures.

The Department of Energy's Weatherization Assistance Program has reduced the heating and cooling costs of low-income households by weatherizing more than 5 million homes since its inception in 1976. The President has requested \$1.2 billion in additional funding for this program over ten years, roughly double the current level of spending. Consistent with that commitment, the 2002 budget will include a \$120 million increase over 2001.

The Department of Energy's Weatherization Assistance Program

The energy burden on low-income households, as a proportion of income, is four times greater than for other American households. The Weatherization Program provides grant funding for a network of all states and some 970 local weatherization agencies to provide insulation, duct system improvements, furnace upgrades, and other cost-effective, energy-saving improvements based on the energy needs of each home weatherized. Currently, each dollar spent on home weatherization generates \$2.10 worth of energy savings over the life of the home; with additional economic, environmental, health, and safety benefits associated with the installations and resulting home improvements. Typical savings in heating bills, for a natural gas heated home, grew from about 18 percent in 1989 to 33 percent today.

Businesses

For businesses, higher energy prices and disruptions in energy supply may increase inflation and reduce profits, production, investment, and employment. The im-

fact of higher energy prices takes two forms: the higher costs of paying for the energy to run the business, and the higher costs when raw fuel sources are used in manufacturing.

In some energy-intensive industries, rising energy prices have had a significant effect on product prices and operations. For instance, while nonenergy producer prices at the intermediate stage of processing have risen by only 3.6 percent since December 1998, prices of industrial materials and plastic resins, which use petroleum inputs, are up 14 and 23 percent, respectively. DuPont, the leading U.S. producer of plastics, chemicals, and fibers derived from oil and natural gas, faced an increase of \$1.3 billion in raw material costs last year, the largest increase in the industry in a decade. The company expects further disruptions this year due to high energy costs.

The Federal Reserve has reported that businesses have experienced higher energy costs for a number of months, but have been unable to pass these increases on to customers due to intense foreign and domestic competition and slowing demand. On March 7, 2001, the Federal Reserve reported that businesses across the country experienced higher fuel and other energy costs in February 2001, but most businesses were unwilling or unable to pass these costs on to consumers.

This absorption of much of the higher costs of energy has deteriorated the profit

margins of many businesses. About one-quarter of the increase in total unit costs of nonfinancial, nonenergy corporations in the final quarter of last year reflected a rise in energy costs. A more moderate pace of consumer spending, due in part to higher energy prices (natural gas in particular) also contributed to the margin squeeze. The reduction in businesses' purchasing power has also constrained outlays for plants and equipment and most likely intensified the slowdown in business investment that occurred in the last half of 2000.

Energy-intensive manufacturing industries are very sensitive to changes in energy prices, and adjust their production accordingly. Some companies have been forced to halt or scale back production and lay off workers. Others have deemed it more profitable to sell their energy than to produce their products. In the Pacific Northwest, Georgia-Pacific's paper mill closed down and laid off 800 workers until diesel generators could be installed. In recent months, the company's average power costs soared from \$1.2 million to \$10 million.

For other industries, such as computer-driven service industries, energy is not an important component of the total cost. However, many such businesses require a high-quality, reliable source of power. Even a brief loss of power can impose significant costs on high-technology firms.

Energy supply disruptions also impose costs on firms when products or prod-



Disruptions in the supply of energy impose hardships on businesses when products or product inputs are damaged or destroyed, or when production runs are interrupted.



Many companies have been unable to pass higher energy costs on to their customers, which has sharply reduced their profit margins.



Farmers have been hit especially hard by higher fuel and oil prices, which accounted for over a third of the rise in the cost of running their farms.

uct inputs are damaged or destroyed, or when production runs are interrupted. For example, a survey of small businesses conducted by the National Federation of Independent Business in February, 2001, found that more than half of the firms surveyed that had experienced blackouts this year in California were forced to reduce or shut down business operations altogether during the blackouts. About one-third lost sales, almost 21 percent said materials were damaged or destroyed, and nearly 40 percent had to absorb wage costs for work that was not completed.

For businesses that seek to mitigate energy price volatility, an important factor is access to derivatives markets. Both exchange-traded futures and over-the-counter derivative contracts allow firms to substantially reduce their exposure to changes in energy prices. A wide variety of highly liquid futures contracts on energy products such as oil, natural gas, and electricity allow energy users and market participants to reduce or add financial exposure to energy prices. More so-

phisticated and customizable products are available in the over-the-counter derivative markets. As these markets become increasingly liquid and efficient, more firms will take advantage of these products, reducing the economy's sensitivity to shifts in energy prices. However, most small businesses currently lack the resources or sophistication to take advantage of these products, and will therefore remain vulnerable to rising energy costs. The U.S. government should continue to support the development of efficient derivatives markets.

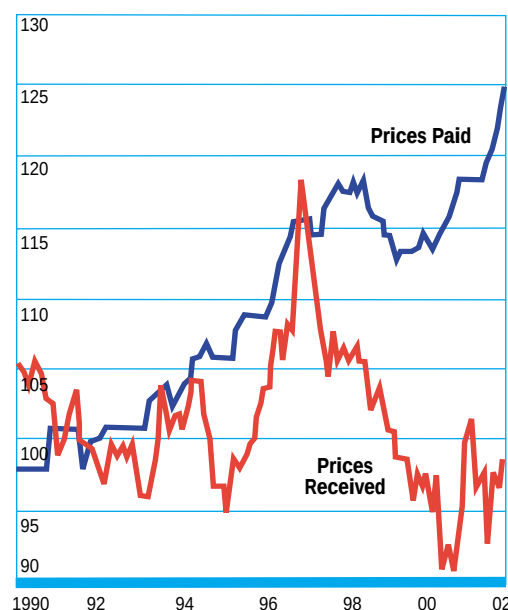
Agriculture

Farmers need ample, affordable energy to run their machinery and equipment. Today, farm production costs are rising sharply, while farm income remains low. Increasing oil prices and interest rates, along with higher prices for other production inputs (including hired labor), boosted farmers' production expenses by 4 percent, or \$7.6 billion, in 2000. The rise in farm production expenses has occurred at a time of continued weakness in the prices farmers receive for their products (Figure 2-2).

Higher fuel and oil prices accounted for over one-third of the increase in farm

Figure 2-2
Farmers Are Being Squeezed by Energy Prices

(Index: 1990–92 = 100)



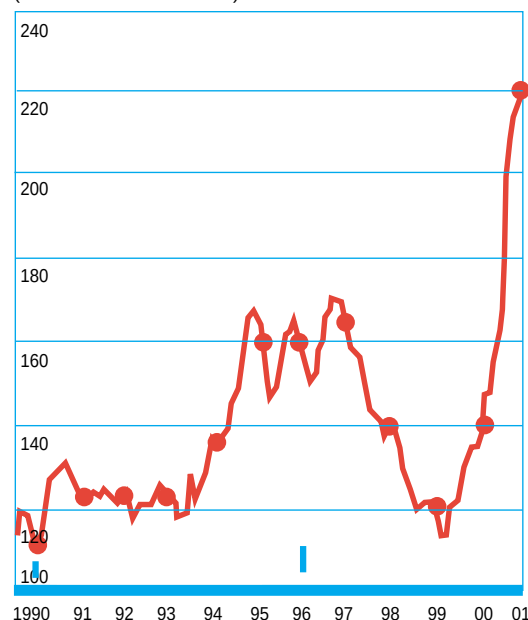
Costs for fuel, fertilizer, and electricity have boosted total prices paid by farmers, while prices farmers receive for their products have remained weak.

Note: Prices paid are for goods, services, interest, taxes, and wages; prices received are for all farm products.

Source: U.S. Department of Agriculture.

Figure 2-3
Farm Costs Are Increasing

(Index: December 1979 = 100)



Rising energy prices had a significant effect on product prices in some industries that are heavily dependent on energy inputs. The most dramatic example is the 90 percent increase in the price of nitrogenous fertilizer since December 1998.

Source: U.S. Department of Labor.

production costs. Retail diesel prices this past winter were \$1.60 a gallon, compared to about \$1.40 a year ago and only \$1.00 two years ago. Propane prices were over \$1.60 a gallon this winter, compared to \$1.10 a year ago. And, natural gas prices hit \$10.00 per million Btus in January, after averaging about \$2.50 for most of 1998–99. Although natural gas prices have declined, they remain much higher than earlier levels.

Natural gas is an important component of farm production costs. For example, it is used to dry grain, heat farm buildings, and run food-processing equipment. Heating costs for poultry producers soared last winter, sharply reducing earnings.

Natural gas also is a major component in the production of fertilizers, pesticides, and other farm chemicals. It accounts for 70 to 90 percent of the cost of producing anhydrous ammonia, a key source of nitrogen fertilizer. Surging natural gas prices have boosted the price of nitrogenous fertilizer by 90 percent since 1998 (Figure 2-3). During last December and January, several nitrogen production plants shut down, and capacity utilization fell to 50 percent. Anhydrous ammonia recently sold for \$330 a ton in the Midwest, compared to \$210 a ton for

all of 2000 and \$160 to \$170 a ton at the start of 2000.

Depending on the region of the country and type of farming enterprises, energy-related expenses range from 10 to 30 percent of operating costs for producing major crops. Farm operating costs are highest where fertilizer use is heaviest and natural gas is used for irrigation pumps, such as wheat, cotton, and corn farms in the West and southwestern plains states. Costs are high for greenhouse and nursery crops that use natural gas for heating. Perishable crops also face problems, as energy costs in processing are markedly higher.

Most of California's 9.5 million irrigated acres use electricity to pump water. In addition to higher bills, California farmers will likely face rolling blackouts this summer, which may disrupt farming and processing operations. Low stream flows in the West this year may lead to more pumping of ground water, which will add to irrigation costs in the West. As a result, the costs of California's agricultural products may rise significantly.

In 2001, farmers' total cash production expenses are forecast to increase by an additional \$1.5 billion to a record \$179.5 billion.

Farm production costs are rising sharply, while farmers' incomes remain low. Depending on the region of the country and type of farming enterprises, energy-related expenses range from 10 to 30 percent of operating costs for producing major crops



Even though total planted acreage is expected to fall this year, higher natural gas prices will raise expenses for nitrogen fertilizer. At the same time, net cash farm income is projected to decline from \$56.4 billion in 2000 to under \$51 billion in 2001, as production expenses continue to rise.

Taken together, fertilizer, fuel, and electricity costs for farmers are forecast to reach \$24 billion for 2001, up by about 28 percent from \$18.7 billion in 1999. This increase is about 9 percent of U.S. net cash farm income, and that share could be much higher for many individual commodities.

Transportation

The transportation sector accounts for nearly 30 percent of total U.S. energy consumption. The major transportation fuel sources are petroleum-based gasoline and diesel, jet, and marine-mode bunker fuels. Natural gas pipelines are used for product distribution, and electricity is the primary source of power for rail transit and liquid pipeline transmission and distribution.

During 2000, oil prices surged to a nine-year high, and gasoline prices skyrocketed. On average, fuel prices rose by 30 to 40 cents a gallon from 1999 prices, resulting in sharp increases for most modes of trans-



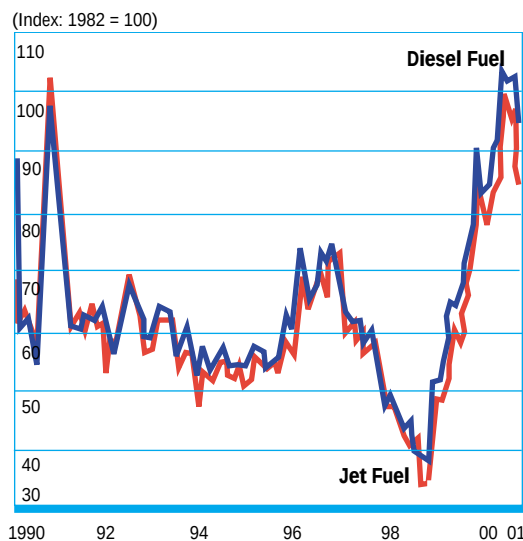
A recent study by a San Francisco Bay business group concluded that blackouts could cost California as much as \$16 billion annually, and \$5 billion in the Bay area alone.

portation, with nearly a 60 percent increase in railroad diesel fuel prices.

Price spikes have hit the travel and trucking industries particularly hard and have led to the closure of some operations. Trucking bankruptcies are currently at an all-time high. Over 3,500 motor carrier operations failed in 2000, a dramatic increase over the previous record high of 2,700 motor carrier failures in 1997. Producer prices for intermediate diesel fuel and aviation fuel each rose by about 140 percent from a low in December 1998, affecting passenger and freight transport in the highway, airline, rail, and other transportation sectors (Figure 2-4).

For most transport operations, energy-related expenses were 7 to 14 percent of total operating costs in 1998–99. This share was expected to jump to 10 to 25 percent in 2000. Excluding private auto travel, U.S. passenger and freight operations in 1999 generated about \$600 billion in annual revenue and paid approximately \$60 billion for fuel and power. If the volume stayed the same in 2000, the various increases in fuel costs for each mode of transportation would yield a fuel bill of

Figure 2-4
Transportation Costs Are on the Rise



The recent 140 percent rise in producer prices for intermediate diesel and airline fuels has affected the price of passenger and freight transport.

Note: Plotted through February 2001.
Source: U.S. Department of Labor.

about \$80 billion—an increase of one-third over the prior year's bill.

Economic Impacts of California's Energy Crunch

In California, 43 percent of small businesses surveyed in February, 2001, said the power problem had dimmed their views about California as an attractive place for doing business. When asked whether they agreed with the statement, "The electricity problem has forced me to take concrete steps exploring the possibility of moving my business out of California," 18.3 percent of small business respondents said they either agreed or strongly agreed with the statement. More than 31 percent said they will probably or definitely cut back on planned business investment, and almost 20 percent are exploring a move to another state. Half of these small businesses concluded that blackouts would reduce their earnings.

The Silicon Valley Manufacturing Group recently estimated that its nearly 200 members lost over \$100 million dollars because of one day of rolling blackouts in June 2000. Countless more millions of dollars have been lost by interruptible commercial power users. Fontana-based California Steel Industries estimates it lost \$2.4 million in a single day after its interruptible power was cut off twice for a total of about 12 hours. A recent study by a San Francisco Bay business group concluded that blackouts could cost California as much as \$16 billion annually, and \$5 billion in the Bay area alone.

The example of California's utilities illustrates the potentially severe negative effects on companies whose business is highly sensitive to energy prices. In this instance, rising energy costs coupled with an inability to pass those costs along to customers has created a sharp increase in short-term liabilities. Pacific Gas & Electric has been forced to file for bankruptcy as a result, and Southern California Edison, while avoiding bankruptcy for the time being, has seen its access to credit markets disappear and the value of its financial assets plummet. Resulting concerns about solvency have led to a withdrawal of bank-

lending facilities and supplier credit.

The situation in California is of particular concern because of the major role the state plays in the regional and national economies. California's economy is equivalent to about 13 percent of U.S. gross domestic product (GDP), and it has accounted for an even larger share of U.S. GDP growth in recent years. Some businesses and consumers have been affected by production losses, lost wages, and higher energy bills resulting from rolling blackouts and higher natural gas prices.

The power supply crunch in California and the West could affect the region's economy, as energy supply uncertainty could reduce investment in the region. California's troubles could also spill over to the national economy:

- California accounted for 11 percent of U.S. manufacturing output in 1998. Sectors in other regions that rely on those products, or that supply inputs to California manufacturers, may share any pain caused by the energy squeeze.

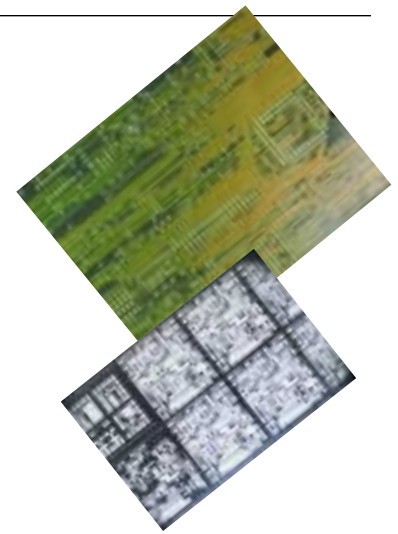
- Disruptions to California's economy could have negative impacts on our international trade. California accounts for over 16 percent of total U.S. commodity exports; nearly 25 percent of industrial equipment and computers, electronics, and instruments exports; and over 15 percent of farm commodity and food product exports.

- The credit problems of the California utilities have boosted commercial paper rates for all lower-rated borrowers, and liquidity in the commercial paper market has fallen. This will push some firms to seek other sources of financing, which can be more costly than commercial paper.

American consumers and businesses are best served when markets function freely. Free markets allow prices to reflect changes in demand and supply, and avoid subsidies, price caps, and other constraints.

Improvements in Energy Efficiency Can Help

Improved energy efficiency strengthens energy security. The 42 percent decline in the intensity of U.S. energy use since the energy crisis in 1973 reflects a combination of technological advances, conservation ef-

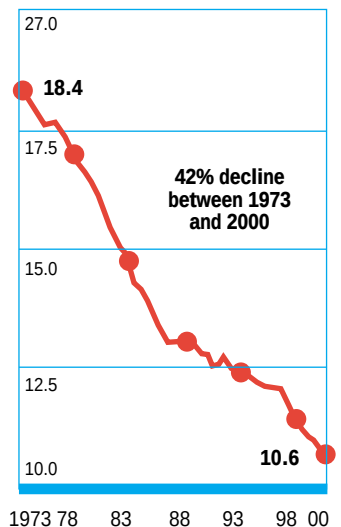


The Silicon Valley Manufacturing Group recently estimated that its nearly 200 members lost over \$100 million dollars because of only one day of rolling blackouts in California.

Figure 2-5

Conservation Through Higher Efficiency Energy Consumption per Dollar of Real GDP

(Thousands of Btus)



1973 78 83 88 93 98 00

Energy intensity is the amount of energy used to produce a dollar's worth of gross domestic product (GDP). As a result of the 42 percent decline in energy intensity since the first energy crisis in 1973, the U.S. economy is far better prepared to day than it was in the 1970s to adjust to energy price or supply shocks.

*Note: Real GDP in 1996 chained dollars.
Source: U.S. Department of Energy,
Energy Information Administration.*

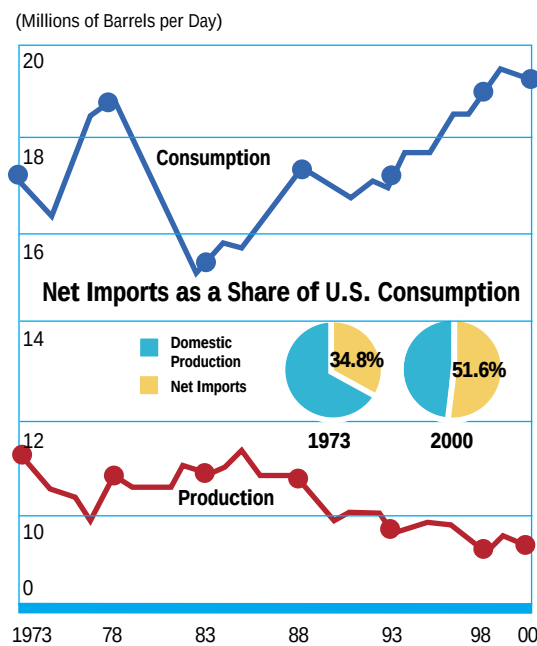
forts, regulatory action, market response, and a shift toward a service economy (Figure 2-5). Our improvements in energy efficiency have prevented our current energy problems from becoming worse.

The macroeconomic effects of a substantial rise in energy prices take two forms. First, to the extent that energy resources are imported, more U.S. dollars must be sent abroad to finance energy consumption, thus reducing funds available for investing in our own country. Second, higher prices cause dislocations among certain sectors of the economy, which could ultimately feed through to lower GDP growth and higher inflation.

Reliance on Foreign Energy

Between 1973 and 2000, U.S. dependence on foreign oil rose from about 35 percent to more than 52 percent of U.S. consumption (Figure 2-6). During the same period, the import share of natural gas consumption climbed from less than 5 percent to more than 15 percent and continues to rise.

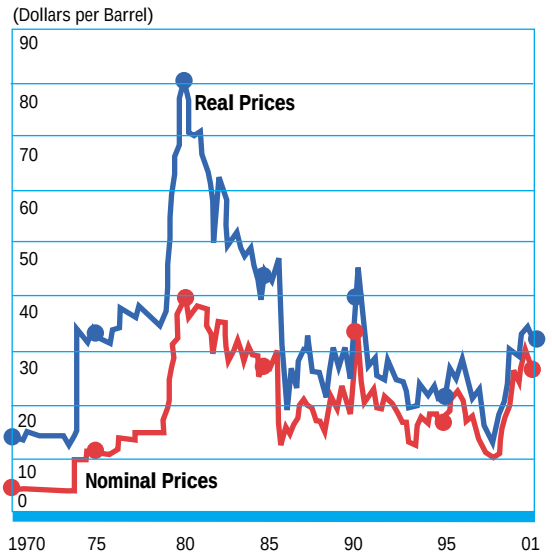
Figure 2-6
Dependence on Oil Imports Is Rising



Over the past few decades, U.S. consumption of oil and petroleum products has increasingly outpaced domestic production. Today the United States imports over half of the oil it consumes—up from about 35 percent in the early 1970s.

*Note: Petroleum includes both crude oil and petroleum products.
Source: U.S. Department of Energy, Energy Information Administration.*

Figure 2-7
Oil Prices Have Risen Sharply
Monthly Spot Price of West Texas Intermediate Crude Oil



Despite the sharp rise in crude oil prices since late 1998, real prices still remain lower than at any time from 1974 to 1985.

Note: Real prices in 2000 dollars. Prices deflated using the Consumer-Price Index—Urban (CPI-U) Research Series for all items linked to CPI-U-X1 prior to December 1977.

Sources: Wall Street Journal; U.S. Department of Labor, Bureau of Labor Statistics.

Imports of energy products make up nearly 11 percent of all U.S. imports. By contrast, U.S. energy exports are relatively small. The energy trade deficit relative to our GDP represents the share of U.S. income that must be exported to purchase foreign fuel to meet domestic energy needs. The U.S. energy trade deficit in 2000 was about \$120 billion, most of which was spent on oil imports.

As a share of GDP, the energy trade deficit had fallen to as low as 0.4 percent at the beginning of 1999, when prices for imported crude oil were less than \$10 a barrel. However, by the end of 2000, these prices had tripled to more than \$30 a barrel (Figure 2-7). As a result of both the oil price spike and growing U.S. demand, the energy deficit deteriorated significantly to 1.3 percent of GDP by the fourth quarter of last year—the largest deficit relative to GDP since the mid-1980s (Figure 2-8). The rise in oil prices alone has added about 0.7 percent of GDP to the U.S. trade deficit, compared to 0.9 percent in the euro currency area, and 0.8 percent in Japan.



Figure 2-8
The U.S. Energy Trade Deficit Has Worsened



The energy trade deficit relative to GDP represents the share of domestic income that must be exported to support domestic energy needs. For the past several years, the United States has been a net importer of energy products. As a consequence, our energy trade balance has been in deficit. By the fourth quarter of 2000, the energy deficit had deteriorated significantly to 1.3 percent of GDP—the largest since the mid-1980s.

Note: Plotted quarterly through the fourth quarter of 2000.
 Source: U.S. Department of Commerce, Bureau of Economic Analysis.

Net U.S. oil imports are 4 billion barrels a year, which means that each \$1 increase in the price of imported crude oil boosts U.S. expenditures by about \$4 billion. Given these guidelines, the \$20 per barrel increase from early 1999 to late 2000 translates into an export of roughly \$80 billion a year (0.9 percent of GDP) when measured from the low price prevailing at the end of 1998.

Impacts of Energy Prices on Financial Markets

An analysis of the financial impacts of higher energy prices can be divided into two parts: the effects on individual firms whose securities comprise the financial markets, and the macroeconomic impact on inflation and interest rates. Rising energy costs and greater volatility in energy prices can have a negative effect on both individual firms and the broader financial environment, generally producing lower asset prices and higher interest rates. The financial market impact to date of rising energy prices has been limited to firms with high sensitivity to energy costs and to those with significant exposure to the California crisis. The second broad effect of rising energy costs is an increase both in measured inflation

Financial markets react to energy costs and the effect those energy costs have on both individual firms and sectors of the market.

and in expectations for future inflation. Both factors have considerable impact on interest rates and, therefore, on the borrowing costs for businesses and consumers throughout the economy.

Inflation Expectations and Interest Rates

Measurable inflation, for both producers and consumers, is a primary concern of the Federal Reserve in conducting monetary policy. Energy costs represent roughly 16 percent of the producer price index for finished goods and 8 percent of the consumer price index. This means that sharply rising energy costs can have a substantial impact on the Federal Reserve's decision-making process. Additional impacts will come from the market's anticipating Federal Reserve actions and pushing short-term interest rates higher than they otherwise would have been. Higher short-term interest rates raise the nominal cost of borrowing for firms and individuals and can slow economic growth.

Rising energy prices can also raise the inflation expectations of lenders, which can result in higher interest rates for borrowing at longer maturities. Rising long-term interest rates can reduce long-term investment, limiting future economic growth and productivity gains. Such an outcome would carry negative consequences for growth-sensitive financial sectors, such as equity and high-yield debt markets.

More broadly, declining credit fundamentals for certain business sectors could raise borrowing costs for firms not directly affected by higher energy prices. For example, commercial paper rates for all lower-rated borrowers have been affected by the credit problems of the California utilities, and liquidity in the market has fallen. As a result, firms may need to seek other sources of financing, such as bank loans (if obtainable) or asset-backed loans, that can be more costly than traditional commercial paper issuance.

Global Financial Markets

The upward pressure on interest rates that may result from higher U.S. energy costs also affects markets beyond our borders. U.S. monetary policy and related movements in short-term interest rates can have a significant impact on other countries. While the effect varies from region to region, many emerging mar-

ket economies, particularly in Latin America, are vulnerable to upward moves in U.S. interest rates.

Higher nominal interest rates in the developed countries tend to reduce the amount of capital flowing to emerging markets. To the extent that this reduces investment, economic activity may be further reduced. In addition, borrowing in dollars is a significant source of funding for sovereign and private-sector entities worldwide, particularly in the emerging markets. Rising U.S. interest rates will increase the interest expenses for these borrowers, diverting funds from more productive uses and reducing overall credit quality.

The global market for energy is highly fragmented and region-specific, with the exception of oil. Nevertheless, certain nations and regions are net importers of energy and are highly sensitive to changing prices. Japan, a major importer of oil and natural gas, is particularly vulnerable. Europe is a net importer of energy, with certain exceptions, while emerging market nations vary widely in their dependence on foreign energy sources.

At the macroeconomic level, rising energy prices will increase the current account deficit of energy-importing nations. Since current account deficits must be financed, these nations will most likely need to pay higher interest rates to attract the necessary capital. As noted, this will tend to reduce domestic investment and lower long-term growth. In some countries, such as the United States or Japan, changes in interest rates and growth expectations can have substantial global impact.

Central banks and monetary authorities vary in the degree to which they focus on inflation in setting monetary policy, making some countries more or less likely than others to raise interest rates in an environment of rising energy prices.

Although Japan maintains a current account surplus due to manufacturing exports, its role as an international creditor could diminish. This may have additional impacts on the global financial markets, since Japanese financial institutions are generally suppliers of global credit.

The impact of rising energy costs on the dollar is likely to be mixed. While slower U.S. growth generally reduces demand for dollars, rising oil prices are likely to increase demand, since oil contracts are usually denominated in dollars.

Summary of Recommendations

★ The NEPD Group recommends that the President direct the Secretary of Energy to explore potential opportunities to develop educational programs related to energy development and use. This should include possible legislation to create public education awareness programs about energy. Such programs should be long-term in nature, should be funded and managed by the respective energy industries, and should include information on energy's compatibility with a clean environment.

★ The NEPD Group recommends that the President take steps to mitigate impacts of high energy costs on low-income consumers. These steps would include:

- Strengthening the Low Income Home Energy Assistance Program by making \$1.7 billion available annually. This is an increase of \$300 million over the regular FY 2001 appropriation.
- Directing the Secretaries of Interior and Health and Human Services to propose legislation to bolster LIHEAP funding by using a portion of oil and gas royalty payments.
- Redirecting royalties above a set trigger price to LIHEAP, whenever crude oil and natural gas prices exceed that trigger price, as determined by the responsible agencies.

★ The NEPD Group recommends that the President increase funding for the Weatherization Assistance Program by \$1.2 billion over ten years. This will roughly double the spending during that period on weatherization. Consistent with that commitment, the FY 2002 Budget includes a \$120 million increase over 2001. The Department of Energy will have the option of using a portion of those funds to test improved implementation approaches for the weatherization program.

★ The NEPD Group recommends that the President support legislation to allow funds dedicated for the Weatherization and State Energy Programs to be transferred to LIHEAP if the Department of Energy deems it appropriate.

★ The NEPD Group recommends the President recognize unique regional energy concerns by working with the National Governors Association and regional governor associations to determine how to better serve the needs of diverse areas of the country.

★ The NEPD Group recommends the President direct FEMA to prepare for potential energy emergencies.

- -FEMA should work with states' Offices of Emergency Management as they expand existing emergency operations plans to identify potential problems and address consequences of the power shortages. FEMA should use its current Regional Incident Reporting System to identify any situations that might demand immediate attention.
- Using the structure of the already existing Federal Response Plan, FEMA should conduct Regional Interagency Steering Committee (RISC) meetings for states affected by the energy shortfalls. The RISC is a FEMA-led interagency committee comprised of agencies and departments that support the Federal Response Plan. Either an upcoming, scheduled RISC meeting or a special-focus RISC meeting can be held to identify the short-term energy outlook, as well as any expected consequences, in each of the states during the peak summer season.

Protecting America's Environment

Sustaining the Nation's Health and Environment

Over the last three decades, American ingenuity has led to a reduction in adverse environmental and public health impacts from energy development and use. Americans demand a reliable energy supply and a clean environment, and we can achieve both. Spurred by strong environmental concerns, competitive forces, and environmental regulations, businesses have developed innovative technologies and pollution-prevention techniques to protect the environment. However, more can be done.

As our energy needs continue to grow and our production and distribution system is strained to capacity, it is clear that the lack of a comprehensive energy policy has environmental costs. For example, to prevent blackouts, California officials must tolerate a large short-term increase in smog-forming nitrogen oxides emissions. In Los Angeles, older, dirtier power plants have had to run longer than expected. California is also rushing to use mid-sized “peaker power plants” and diesel-fired emergency backup generators to keep the lights on.

The short-term cost in increased pollutant emissions of these emergency measures has been stark. Preliminary figures from California's South Coast Air Quality Management District indicate emissions have doubled in the first three months of the year compared with last year. In addition to nitrogen oxides emissions, diesel-fired backup generators also emit toxic soot. But with many days of blackouts predicted in California this summer, these generators will most likely run for much longer than expected, and could greatly increase emissions.

In the longer term, penalties and technological improvements should offset the impact of these increased emissions. However, California's experience demonstrates the environmental costs of not building an adequate supply of clean energy.

Government's Role

The federal government has a unique role in facilitating energy development while simultaneously protecting the environment and conserving our country's natural resource legacy. Energy development initiatives will be successful only if they adequately address their impacts on natural resource values.

Federal, state, tribal, and local governments have the responsibility of protecting unique natural resources and environmental values. In fact, some environmental protections we enjoy today are often taken for granted. For example, lead levels in ambient air today are 98 percent lower than they were in 1970, largely because government regulations required that lead be removed from gasoline. The reduced number of children with IQs below 70 is attributed to reducing lead in our environment.

As U.S. energy needs grow, additional innovations will be necessary to continue improving environmental conditions and to meet new environmental challenges. As we improve the energy production and distribution system, all levels of government must ensure that regulatory systems protecting public health and the environment are rigorous and efficient, and encourage innovation and improvement.



Roughly 30 percent of our nation's electricity supply is now generated by nuclear, hydropower, and renewable sources, all of which have few air emissions.

Air Quality Regulatory Programs

Advances in technology and environmental regulations have decreased aggregate emissions of key air pollutants over the last three decades, despite a marked increase in energy consumption (Figure 3-1). Roughly 30 percent of our nation's electricity supply is now generated by nuclear, hydropower, and renewable sources, all of which have few air emissions.

Nonetheless, fossil fuel-fired power plants, other industrial sources, and vehicles remain significant sources of air pollution (Figure 3-2). These emissions can be associated with significant health problems, including respiratory and cardiopulmonary disease, cancer, and birth defects. In addition, they can be harmful to forests, water bodies, and fish, and can decrease visibility in scenic areas.

Environmental Protection Agency's (EPA) Acid Rain Program, enacted as part of the 1990 Clean Air Act Amendments, is the only program directed primarily at reducing air emissions from electric utilities.

Using flexible market-based incentives instead of technology-forcing standards, the program has reduced sulfur dioxide (SO₂) emissions from utilities faster than required by law for a fraction of the initial cost estimates. By 2010, EPA expects the program will reduce annual SO₂ emissions by 10 million tons from 1980 levels, thus avoiding significant health problems and the costs associated with those levels.

Federal and state regulatory programs also limit air pollution directly by restricting emissions from cars and trucks, and indirectly by setting criteria for the fuel for these vehicles. An individual car meeting 2004 federal requirements will emit 95 percent less carbon monoxide (CO), 94 percent fewer nitrogen oxides (NO_x), and 98 percent fewer hydrocarbons than an average car did before laws limiting such vehicle pollution. Although individual cars and trucks are far cleaner today than they were in 1970, total emissions from the fleet of highway vehicles have remained relatively constant, because Americans drive twice as many miles today (2.5 trillion miles a year) as they did in 1970

(1.1 trillion miles a year).

Despite these and other achievements, further air quality improvements can be sought, as well as ways to address new problems identified by recent scientific findings. EPA has recently adopted new, more stringent standards to further reduce ozone and particulate matter. To meet public health and environmental challenges, power plants, industrial sources, and vehicles will need to produce fewer potentially harmful emissions.

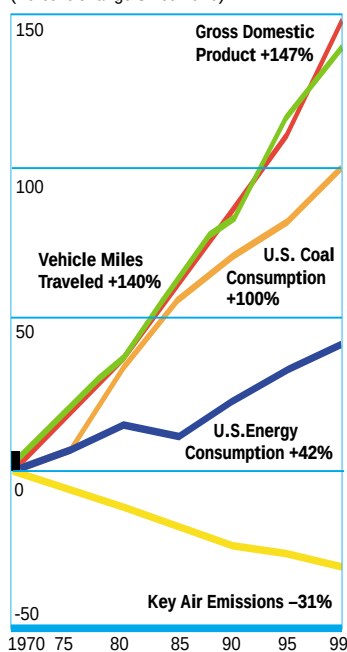
Recommendation:

★ The NEPD Group recommends that the President direct the Administrator of the Environmental Protection Agency (EPA) to propose multi-pollutant legislation. The NEPD Group recommends that the President direct the EPA Administrator to work with Congress to propose legislation that would establish a flexible, market-based program to significantly reduce and cap emissions of sulfur dioxide, nitrogen oxides, and mercury from electric power generators. Such a program (with appropriate measures to address local concerns) would provide significant public health benefits even as we increase electricity supplies.

- Establish mandatory reduction targets for emissions of three main pollutants: sulfur dioxide, nitrogen oxides, and mercury.
- Phase in reductions over a reasonable period of time, similar to the successful acid rain reduction program established by the 1990 amendments to the Clean Air Act.
- Provide regulatory certainty to allow utilities to make modifications to their plants without fear of new litigation.
- Provide market-based incentives, such as emissions-trading credits to help achieve the required reductions.

Figure 3-1
Cleaner Air: Energy Consumption Has Risen While Emissions Have Declined

(Percent Change Since 1970)



Despite a marked increase in U.S. energy consumption, a combination of environmental regulations and technologies has decreased aggregate emissions of key air emissions: SO₂, NO_x, mercury, CO, and volatile organic compounds.

Sources: U.S. Department of Energy, Energy Information Administration, and U.S. Environmental Protection Agency.

Cleaner, More Efficient Technologies

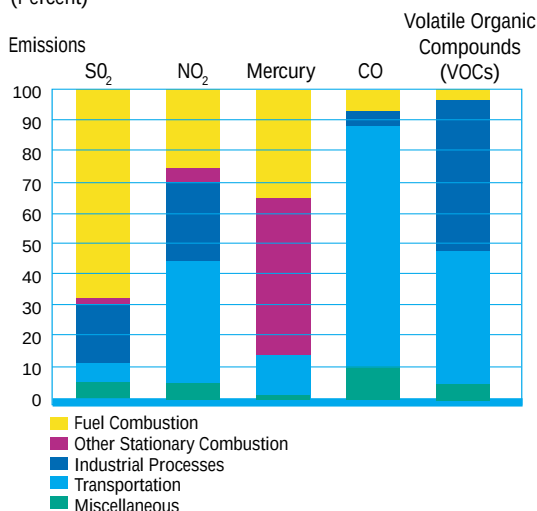
Emission control technologies and emission prevention not only decrease pollution but can also contribute to economic prosperity. Innovative emission control and prevention technology and increasingly efficient energy systems have developed at a brisk pace, increasing our ability to provide cleaner, cheaper energy. Besides reducing pollution, environmental technologies account for about \$21.3 billion in U.S. exports, and support approximately 136,000 U.S. jobs.

The need to reduce emissions from cars and trucks has contributed to technological innovations that have transformed the domestic and global automotive industries. U.S. vehicle emission standards were the primary driving force for the original development of innovative technologies, many of which have become standard design features of today's high-tech vehicles: sophisticated three-way catalysts, on-board computers, oxygen sensors, and fuel-injection systems for cars and advanced fuel systems for trucks. Technologies such as these have allowed today's vehicles to be much cleaner, more efficient, higher performing, more reliable, and more durable than their counterparts of the 1960s and 1970s. Manufacturers are now working on developing state-of-the-art pollution control technology to further reduce emissions from motor vehicles. For optimal performance, this technology requires low-sulfur fuel that, consistent with applicable law, will be required in 2004 for gasoline and 2006 for diesel fuel. Some vehicles use alternative fuels (*e.g.*, natural gas, propane, ethanol, and electricity); others operate with a hybrid gasoline and electrical motor; and others are using fuel cells.

Cleaner Electricity

The source of energy used for power generation significantly affects the amount of air emissions. Clean energy can be generated from nuclear plants, hydropower facilities, wind farms, and solar energy systems with negligible (if any) air emissions. These sources today make up about 30 percent of our electricity supply. Solar and

Figure 3-2
Sources of Pollutants from Energy Generation and Use
(Percent)



wind energy systems will continue to improve with advances in short-term weather and climate forecasting. Improved forecasting can also maximize hydropower efficiency.

Technology significantly reduces pollution from coal-fired power plants, which generate more electricity in the United States than any other source. For example, scrubbers can remove 95 percent of the SO₂ emissions from a coal-fired power plant. With the innovative, market-based SO₂ reduction requirements of the Clean Air Act Amendments of 1990, the estimated cost of using a scrubber on a coal-fired power plant to remove one ton of SO₂ has dropped approximately 40 percent in four years, from \$474/ton in a 1993 estimate to \$282/ton in a 1997 estimate, and continues to decline. Other existing control technologies for coal-fired plants can reduce NO_x emissions by more than 90 percent.

A recently permitted state-of-the-art coal-fired unit, for example, at a Kansas City Power & Light facility, has 88 percent lower NO_x, 99 percent lower particulate matter, and 92 percent lower SO₂ emissions than would an uncontrolled facility.

Recent research by the Department of Energy (DOE), EPA, and private companies suggests that existing technologies can also significantly reduce mercury emissions.

Technologies for Reducing SO₂ Emissions

Many power plants use flue-gas desulfurization, or scrubbers, to reduce SO₂ emissions from burning coal. The most common wet scrubber, the limestone forced-oxidation (LSFO) process, removes SO₂ from the flue gas by sorption and through chemical reactions with the limestone. LSFO technologies can remove up to 98 percent of SO₂ and significant amounts of mercury. The most common dry scrubber, the lime spray-drying process, is used for plants that burn lower-sulfur coals. A lime slurry mixes with the hot flue gas in a spray dryer and reacts with SO₂. By recapturing sorbent at the bottom of the spray dryer removed in a particulate control device, dry scrubbers can remove up to 96 percent of SO₂.

Clean Coal Technologies

New clean coal technologies are showing that air pollution can be reduced, and energy efficiency increased, by using America's abundant supply of coal.

Most conventional air emission control technologies installed on coal-fired electric-generating boilers have been designed to remove a specific pollutant from the stack flue gas. Because these technologies may not be the most cost effective means of reducing multiple pollutants, several companies are developing a single-control technology to reduce multiple air pollutants to levels equivalent to those achieved by conventional controls.

For example, a First Energy plant in New Hampshire recently pilot-tested state-of-the-art technology that has cut NO_x emissions by 76 percent, SO₂ by 44 percent, total particulate matter by 99.94 percent, and mercury by 81 percent. The process uses electrically charged particles instead of catalysts to oxidize the air pollutants into products that are easily removed and can be converted to gypsum, fertilizer, and concentrated acids. American Electric Power is installing a wet scrubber system that it expects will remove up to 75 percent NO_x and

90 percent mercury. It injects a phosphorus mixture into the hot flue gas, causing the release of ozone. The ozone then oxidizes the mercury into ionic mercury and the NO_x into N₂, both of which are water-soluble and easily removed.

Technologies for Improved Efficiencies

Two-thirds of the energy used in a conventional coal-fired power plant is wasted in the production of electricity. These losses can be minimized through a number of innovations, including installing high efficiency steam turbines, reducing steam leaks, and using software to optimize combustion efficiency. New coal-burning power plants can achieve efficiencies of over 40 percent using existing technology, and companies are developing even more efficient technologies. Wasted energy can also be recycled for use in industrial processes or for heating buildings.

A family of technologies known as combined heat and power (CHP) can achieve efficiencies of 80 percent or more. In addition to environmental benefits, CHP projects offer efficiency and cost savings in a variety of settings, including industrial boilers, energy systems, and small, building-scale applications. At industrial facilities alone, there is potential for an additional 124,000 megawatts (MW) of efficient power from gas-fired CHP, which could result in annual emission reductions of 614,000 tons of NO_x emissions and 44 million metric tons of carbon equivalent. CHP is also one of a group of clean, highly reliable distributed energy technologies that reduce the amount of electricity lost in transmission while eliminating the need to construct expensive power lines to transmit power from large central power plants.

The U.S. Department of Energy, through its Clean Coal Technology Program, is working with utilities and scientists to develop even cleaner, more efficient electricity-generating systems using coal. One of the most promising new approaches to using coal for clean production of electricity is integrated gasification combined-cycle (IGCC) technology. IGCC power plants convert coal to a gaseous fuel, from which most

Using flexible market-based incentives, EPA's Acid Rain Program has reduced sulfur dioxide (SO₂) emissions from utilities faster than required by law for a fraction of the initial cost estimates.



Clean Coal Technologies Up Close

The Wabash River Coal Gasification Project in Terre Haute, Indiana, is one of the cleanest, most efficient coal-burning facilities in the country. Partly funded by the Department of Energy (DOE) as part of its Clean Coal Technology Program, the 262-MW coal gasification facility is owned and operated by PSI Energy and Global Energy, Inc. Instead of being directly burned, the coal is gasified and then combusted in a combined-cycle gas turbine. This allows the coal to burn more efficiently—which means it gets more energy than a traditional plant out of the same amount of coal. The Wabash River Facility is over 20 percent more efficient than a typical coal-fired power plant.

The gasification process also allows many of the impurities in the coal to be removed before it is combusted to generate electricity. At the Wabash River project, over 99 percent of the sulfur is removed from the coal and marketed to industrial users of sulfur. Slag is also removed and is marketed to the construction industry. The plant's design allows it to burn other fuels, such as petroleum coke.

DOE is currently working with Global Energy and other industry partners to see if the plant could also be used to co-produce chemical feedstocks and transportation fuels. Additionally, DOE and its partners are studying lessons learned from the project to design a less expensive, more efficient coal gasification facility that would be ready for commercial deployment by 2005.

of the impurities are removed prior to combustion, and then use the gaseous fuel in a combustion turbine to produce electricity. Waste heat from the turbine is used to generate steam and drive a steam turbine, to produce more electricity.

Coal gasification plants offer the flexibility to burn other fuels, such as petroleum coke, and to make other products in addition to electricity, such as chemical feedstocks and transportation fuels. Hydrogen, which is produced directly in the coal gasifier, can be used in fuel cell-equipped vehicles. Methane, hydrogen, and other gasified coal products can be recombined into more traditional fuels, such as methanol, gasoline, or diesel fuel. Because these fuels would contain essentially no sulfur, they would easily meet EPA's sulfur standards for transportation fuels, and they would be usable in fuel cell-equipped vehicles designed for these fuels.

Two plants demonstrating coal gasification technology have already been built in the United States and have achieved over 98 percent SO₂ reduction, 90 percent NO_x reduction, particulate emissions below detectable levels, and approximately 38 percent efficiency. EPA believes that lessons

learned will enable the next plant of this design to achieve 42 percent efficiency, and the research goal is to achieve 60 percent efficiency for plants introduced after 2015.

A modern gas-fired power plant has virtually no SO₂ or mercury emissions and emits 97 percent less NO_x and 50 percent less carbon dioxide (CO₂) than a traditional coal-fired plant. Natural gas as a source of electricity generation is on the rise, in part because it can help generators meet increasingly stringent clean air requirements.

Conservation and Environmental Protection

Conserving energy minimizes adverse environmental effects. Government partnerships with businesses and consumers are improving the energy efficiency of homes, office buildings, transportation sources, and industrial sites throughout the country. EPA's voluntary conservation and energy efficiency programs include Energy Star products labeling; Energy Star Residential programs for both new homes and home improvement; Energy Star Buildings, principally for commercial buildings; and new Energy Star for Industry, which focuses on manufacturers. In 2000, business participation in EPA's voluntary energy efficiency

programs reduced NOx emissions by more than 160,000 tons.

Through EPA's and the Department of Transportation's Commuter Choice Leadership Initiative, private-public employers are offering employees a variety of commuting options, which encourage commuting patterns that save fuel and energy while reducing emissions. For example, a 10 percent reduction in the rate of growth in vehicle miles traveled can result in annual savings of 38 million barrels of gasoline (82 million barrels of oil) by 2005, and can remove 45,000 metric tons of NOx, 37,000 metric tons of hydrocarbons, and 4.8 million metric tons of carbon-equivalent emissions.

Energy efficiency and conservation in the home are also important factors. Examples include EPA's home improvement program, which involves efficient appliances, duct work to prevent air conditioners from leaking, efficient windows, programmable thermostats, and efficient residential lighting.

Federal and state regulators are working with businesses and communities to mitigate adverse environmental impacts by requiring developers and operators to choose more environmentally friendly sites, infrastructure routes, and operational criteria; fostering the use of technologies that both protect the environment and still meet energy production goals; and requiring reclamation and mitigation of any environmental damage.

Water Quality

Oil, gas, and coal extraction processes can degrade water quality through their discharges. Energy generation and use can also degrade water quality by directly discharging pollutants into water bodies; changing the temperature, timing, and flow characteristics of water bodies; and emitting pollutants into the air that are ultimately deposited in water. Leaking storage tanks and pipelines release petroleum and fuel additives that can contaminate surface water and ground water, including drinking-water supplies.

Federal and state regulators are working with businesses and communities to mitigate these adverse impacts by requiring developers and operators to choose more environmentally friendly sites, infrastructure routes, and operational criteria; fostering the use of technologies that both protect the environment and meet energy production goals; and requiring reclamation and mitigation of any environmental damage. For example, as a result of an analysis under the National Environmental Policy Act of the impacts of a new power plant in California, the company building the plant agreed to change the design to use a dry cooling method. This change reduced ground-water consumption by 95 percent and eliminated both cooling tower "blowdown" water and particulate emissions, while still achieving the desired energy production. Adverse impacts to aquatic life from cooling-water intakes, thermal discharges, and hydropower intakes can be minimized with proper design and environmental controls. A cooperative government, industry, and community-based approach during project siting and design will help ensure full consideration of the effects upon fish and aquatic resources.

Programs to reduce air pollution also help clean up water bodies. For example, reducing electric utilities' air emissions of NOx and SO₂ and vehicles' NOx emissions reduces eutrophication and acid deposition in estuaries, both of which can harm fish populations and threaten commercial and recreational yields. For example, roughly 25 percent of nitrogen (which contributes to



eutrophication) entering Chesapeake Bay is from air emissions. And by significantly reducing SO₂ air emissions, the Acid Rain Program has helped reduce the acidification of water bodies.

Airborne mercury emitted by coal-fired power plants has been deposited into thousands of water bodies, and humans can be exposed to toxic methyl mercury when they eat fish from these waters. The Bush Administration will propose legislation adding mercury to the list of pollutant emissions from power plants that will be subject to mandatory limits.

Fish, Wildlife, and Their Habitat

Ecosystems provide food, shelter, and critical breeding and spawning grounds for fish and wildlife, and support commercial and recreational fishing, tourism, and other activities that contribute billions of dollars to the U.S. economy every year. Oil and gas exploration and production, hydropower dams, power plants, pipelines, and other energy-related projects can potentially affect fish, wildlife, and habitat. However, technological advances, a strong commitment to environmental protection, and the use of appropriate regulatory tools can enable proper energy development to go forward in an environmentally sensitive manner. It is important to recognize and to continue the progress in this area.

When energy development is proposed, the federal government has the dual

Recommendation: A

★ The NEPD Group recommends that the President direct the Secretary of the Interior to work with Congress to create the “Royalties Conservation Fund.”

- This fund will earmark potentially billions of dollars in royalties from new oil and gas production in ANWR to fund land conservation efforts.
- This fund will also be used to eliminate the maintenance and improvements backlog on federal lands.



responsibilities of facilitating such energy development *and* conserving our natural resource legacy.

Special efforts are often necessary to ensure that proposed energy projects do not diminish the vitality of these unique resources. Working together, the public, businesses, and federal, state, tribal, and local governments can ensure that environmental impacts are carefully evaluated when considering energy exploration and production activities. For example, such precautions have been important for the exploration and production that is already allowed today in 42 National Wildlife Refuges.

Hydropower Generation

Hydropower, although a clean energy source, does present environmental challenges. Unless properly designed and operated, hydropower dams can injure or kill fish, such as salmon, by blocking their passage to upstream spawning pools. Innovations in fish ladders, screens, and hatcheries are helping to mitigate these adverse impacts. Ongoing dam relicensing efforts are resulting in community involvement and the industry's application of the latest technologies to ensure the maintenance of downstream flows and the upstream passage of fish. These efforts also have been successful in identifying and removing older, nonfunctioning dams and other impediments to fish movements.

Technological advances and a strong commitment to environmental protection are enabling the healthy coexistence of our nation's diverse ecosystems with the development of energy resources.



Ecosystems provide food, shelter, and critical breeding and spawning grounds for fish and wildlife, and support commercial and recreational fishing, tourism, enhance our quality of life, and other activities that contribute billions of dollars to the U.S. economy every year.



Some natural resource areas are to be protected from any exploration. In other areas, energy development can proceed using the most advanced designs and technologies to ensure that proposed energy projects do not diminish the vitality and diversity of these unique resources.

An example of such successful collaboration involves the Wanapum Dam on the Columbia River. In coordination with the National Marine Fisheries Service, the Grant County Public Utility District No. 2 installed spillway deflectors that effectively reduced concentrations of total dissolved gas that can harm fish and other aquatic life. Furthermore, through the unique collaboration on this project, the cost for the spillway deflectors was a fraction of that for deflectors installed at other hydropower projects.

Coal, Oil, and Gas Exploration and Production

Certain exploration and production activities can pose environmental impacts to wildlife habitat, unless conducted in a way that protects the environment. In sensitive areas, these effects can often be avoided or minimized by timing exploration and operation activities in light of migration, nesting, and other critical time periods for wildlife. In addition, new technologies designed to lessen these and other impacts can be used, such as double-walled pipes to reduce the risk of oil spills.

Surface impacts from coal mining and oil exploration can temporarily damage habitats during the operation phases until reclamation is complete. To mitigate impacts during mining, for example, storm-water runoff and discharge into undisturbed environments are controlled. After mining is complete, reclamation efforts required by the Surface Mining Control and Reclamation Act restore viable habitats through careful reconstruction of physical and botanical resources. For instance, in the Powder River Basin, as part of reclamation, coal companies strategically place large boulders and other rock material to create wildlife cover and denning habitat. Restoration of wildlife habitat on these reclaimed areas has been quite successful.

In Alaska's Arctic—home to such animals as polar bears, musk oxen, caribou, wolves, and arctic fox—the bitterly cold winters have proven to be beneficial for environmentally responsible energy development. For example, when the North Slope is

frozen and snow-covered, seismic trains can travel across it to gather geophysical information. Furthermore, companies have adopted innovative techniques to reduce the possible impacts of exploration and development. In Alaska's National Petroleum Reserve, the "footprint" from most exploratory wells on federal lands is short-lived and has minimal impact due to the use of ice roads and ice pads that melt with the spring thaw. Advances in extended-reach drilling technologies have also served to minimize environmental effects during energy production activities.

A lengthy 1999 Department of Energy study examined the environmental benefits of new exploration and production technologies and concluded that "improvements over the past 40 years have dramatically reduced industry's footprint on the fragile tundra, have minimized waste produced, and have protected the land for resident and migrating wildlife." The same study concluded that "it is important to tell this remarkable story of environmental progress in E&P [exploration and production] technology. Greater awareness of the industry's achievements in environmental protection will provide the context for effective policy, and for informed decision-making by both the private and public sectors."

Waste Management

Vigilant management and careful disposal of waste from energy extraction and production can prevent the contamination of our air, land, and water. Federal and state authorities are working to ensure that energy projects maintain sound programs to safely handle wastes from mining, drilling, generation and transmission.

Nuclear power plants present waste management challenges unique among energy-generating technologies. They generate spent fuel, as well as other radioactive waste, which must be isolated from ecosystems and human contact for long periods of time. Currently, spent fuel is stored at reactor sites in a number of states, although capacity is limited. Newer technologies have been developed to reduce the volume and

increase the manageability of spent fuel, but such spent fuel will still require safe handling and long-term isolation.

While the federal government has the responsibility to address such high-level wastes, states have the responsibility to address low-level wastes from nuclear plants, such as clothing and equipment. Disposal options for this type of radioactive waste are limited, because siting these facilities has been controversial. In fact, there are only three disposal facilities active in the United States.

Accidental Releases

Since the passage of the Oil Pollution Act in 1990, which, among other things, required double-hulled vessels and improved industry readiness, oil spilled in coastal zone waters has decreased from almost 8 million gallons in 1990 to just over 1 million gallons in 1999. Most energy production facilities implement comprehensive risk-management plans, which reduce the potential for accidents and help local officials prepare for accidents that may arise.

In contrast, inland oil spills do not appear to be decreasing at the same rate as coastal spills. The federal government receives many more inland oil spill notifications (9,000 notifications a year in the early 1990s versus 10,000 to 12,000 a year in the late 1990s), and many very large inland oil spills occur each year (over 100,000 gallons). The continued problem with inland oil spills may be due to aging pipelines, storage tanks, and other infrastructure components.

Since the advent of commercial nuclear power generation, there have been no radiation-related injuries or deaths associated with the operation of a commercial nuclear power plant in the United States. The most significant incident from a nuclear plant in the United States, at Three Mile Island in 1979, prompted improved safety regulation of nuclear plants. New nuclear reactor designs promise even higher safety levels than the reactors currently operating in this country.

Radiation exposure from nuclear facilities is extremely rare. In fact, roughly 82 percent of human exposure to radiation comes from natural sources: radon gas; the human body, which contains radioactive elements; outer space; and rocks and soil. Radon accounts for about 55 percent of our exposure to natural sources of radiation; radioactive elements in our own bodies account for 11 percent; rocks and soil account for 11 percent; and outer space, including the sun, accounts for 8 percent. The remaining 18 percent of average human radiation exposure comes from man-made sources, primarily medical and dental X-rays and consumer products.

The safety of U.S. nuclear energy plants has improved sharply in recent years. A safe nuclear energy plant is one that runs well, experiences few unplanned outages, and has a well-disciplined work force that follows procedures and avoids accidents. The safety of a U.S. nuclear energy plant is typically gauged by monitoring indicators of its performance in these areas: unplanned automatic reactor shutdowns, the annual percentage of possible power generated, and the industrial safety accident rate for plant workers.

In 2000, for the fourth year in a row, the number of unscheduled reactor shutdowns was zero. The industry generated 91.1 percent of its potential maximum output, breaking its 1999 record of 88.7 percent, far better than the typical 80 percent number of ten years ago.

Today, U.S. nuclear plants are more efficient and safer than ever. In the increasingly deregulated marketplace, competition has forced improvements in plant operations that have benefited safety performance as much as economic performance.

Climate Change

Energy-related activities are the primary sources of U.S. man-made greenhouse gas emissions, representing about 85 percent of the U.S. man-made total carbon-equivalent emissions in 1998.

Forests can absorb carbon dioxide, which accounts for the largest share of greenhouse gas emissions. Working with the U.S. Fish and Wildlife Service Research, Illinova Generating Company has voluntarily committed to reforesting 100,000 acres of bottomland hardwood forests on National Wildlife Refuges in the Lower Mississippi River Valley.

Scientists continue to learn more about global climate change, its causes, potential impacts, and possible solutions.

The United States recognizes the seriousness of this global issue as scientists attempt to learn more about climate change. The United States is making progress in reducing emissions of greenhouse gases. Recent data show that the rate of growth in U.S. greenhouse gas emissions has begun to decline, even as the U.S. economy has been growing at an unprecedented rate. For example, historically U.S. CO₂ emissions have grown at roughly half the rate of GDP. In recent years, however, very robust growth in the nation's GDP has been accompanied by a slowdown in the growth of greenhouse gas emissions. In both 1998 and 1999, U.S.

GDP grew by more than 4 percent a year, while CO₂ emissions grew by less than 1.5 percent a year. In addition, the carbon intensity of the U.S. economy—the amount of CO₂ emitted per unit of GDP—declined by 15 percent during the 1990s.

The United States has reduced greenhouse gas emissions by promoting energy efficiency and the broader use of renewable energy through a wide range of public-private partnership programs. These programs save energy, cut energy bills, enhance economic growth, and reduce emissions of conventional air pollutants as well as greenhouse gases.

The U.S. government, businesses, and nongovernmental organizations are sequestering carbon, at home and abroad. For example, working with the U.S. Fish and Wildlife Service Research, Illinova Generating Company has voluntarily committed to reforesting 100,000 acres of bottomland hardwood forests on National Wildlife Refuges in the Lower Mississippi River Valley. It is projected that this project will sequester approximately 13.5 million tons of carbon, improve fish and wildlife populations by restoring the natural forest wetland habitats, and enhance the Gulf of Mexico's near-shore aquatic environment by restoring natural forested wetland filters to the Mississippi River floodplain.

Industry and the federal government are researching various new technologies that will reduce greenhouse gas emissions or sequester those emissions, in geologic formations, oceans, and elsewhere.



Regulatory Structure

The United States has adopted many regulatory protections to limit the environmental damage and public health consequences of the exploration, extraction, production, and use of energy. Most environmental controls are implemented through state or federal permitting or review systems, which often require time for agency review and public participation. Facilities may need several different permits or reviews from different agencies, and they may also need to meet local licensing or zoning laws. Businesses have an interest in moving expeditiously to respond to consumers' needs. The public also has an interest in participating in the system to ensure that appropriate health and environmental precautions will be taken.

Regulatory requirements are not static. New scientific information and new control technologies result in new regulations and modifications to existing regulations over time. However, some level of certainty in the regulatory environment is important for all parties. Businesses can plan more effectively in such an environment, and regulators can focus on ensuring that the desired outcomes are in fact achieved consistently. For example, studies have shown that if electricity generators knew today what their emission requirements for several emissions would be for a defined time period, they would most likely control emissions more cost effectively and sooner than if their emission requirements were decided upon one gas at a time.

Traditional permit and regulatory programs may not always be the most effective and efficient way to protect the environment. Increasingly, regulatory programs are considering approaches that include market-based incentives. These types of incentives offer advantages over traditional forms of regulation because they set high performance standards and then allow market forces to determine the most effective way to meet them. While not appropriate for every situation, market-based incentives can control pollution at a lower cost to society than traditional regulation, stimulate

technological improvements, and be structured to achieve larger reductions in pollution than would result from traditional regulations.

A good example of a U.S. market-based program is the Acid Rain Program, which has reduced SO₂ air emissions from utilities at a fraction of the initial cost estimates. Other emerging market-based environmental protection mechanisms include effluent trading, wetland mitigation banks, tradable development rights, easement purchases, off-site mitigation, and leasing or purchasing of water rights. These programs can reduce mitigation or pollution control costs, increase business flexibility, and provide transparency and environmental protection for the public.



The environmental review process can also be made more open, understandable, predictable, and coordinated among federal agencies and with state and local agencies. It can be improved by providing greater information to clarify expectations for energy developers, facilitating concurrent reviews by federal agencies by standardizing certain information needs, sharing information received by project applicants, and seeking opportunities to integrate required environmental processes and reviews.

Recommendation:

★ The NEPD Group recommends that the President issue an Executive Order to rationalize permitting for energy production in an environmentally sound manner by directing federal agencies to expedite permits and other federal actions necessary for energy-related project approvals on a national basis. This order would establish an interagency task force chaired by the Council on Environmental Quality to ensure that federal agencies responsible for permitting energy-related facilities are coordinating their efforts. The task force will ensure that federal agencies set up appropriate mechanisms to coordinate federal, state, tribal, and local permitting activity in particular regions where increased activity is expected.

Summary of Recommendations

Protecting America's Environment: Sustaining the Nation's Health and Environment

★ The NEPD Group recommends that the President direct the Administrator of the Environmental Protection Agency (EPA) to propose multi-pollutant legislation. The NEPD Group recommends that the President direct the EPA Administrator to work with Congress to propose legislation that would establish a flexible, market-based program to significantly reduce and cap emissions of sulfur dioxide, nitrogen oxides, and mercury from electric power generators. Such a program (with appropriate measures to address local concerns) would provide significant public health benefits even as we increase electricity supplies.

- Establish mandatory reduction targets for emissions of three main pollutants: sulfur dioxide, nitrogen oxides, and mercury.
- Phase in reductions over a reasonable period of time, similar to the successful acid rain reduction program established by the 1990 amendments to the Clean Air Act.
- Provide regulatory certainty to allow utilities to make modifications to their plants without fear of new litigation.
- Provide market-based incentives, such as emissions trading credits to help achieve the required reductions.

★ The NEPD Group recommends the President direct the Secretary of the Interior to work with Congress to create the “Royalties Conservation Fund.”

- This fund will earmark potentially billions of dollars in royalties from new oil and gas production in ANWR to fund land conservation efforts.
- This fund will also be used to eliminate the maintenance and improvements backlog on federal lands.

★ The NEPD Group recommends the President issue an Executive Order to rationalize permitting for energy production in an environmentally sound manner by directing federal agencies to expedite permits and other federal actions necessary for energy-related project approvals on a national basis. This order would establish an interagency task force chaired by the Council on Environmental Quality to ensure that federal agencies responsible for permitting energy-related facilities are coordinating their efforts. The task force will ensure that federal agencies set up appropriate mechanisms to coordinate federal, state, tribal, and local permitting activity in particular regions where increased activity is expected.

Using Energy Wisely

Increasing Energy Conservation and Efficiency

The Department of Energy has installed two low-sulfur light bulbs as a test at its Forrestal Building headquarters in Washington, D.C. The two golf ball-sized bulbs, like those on the opposite page, are at each end of a 240-foot, 10-inch-wide reflective plastic “light pipe.”

U.S. DEPARTMENT OF ENERGY

Energy efficiency is the ability to use less energy to produce the same amount of lighting, heating, transportation, and other energy services. For a family or business, conserving energy means lower energy bills. For the country as a whole, greater energy efficiency helps us make the most of U.S. energy resources, reduces energy shortages, lowers our reliance on energy imports, mitigates the impact of high energy prices, and reduces pollution. Improvements in efficiency can be particularly effective in reducing energy demand when energy is most expensive.

Conservation and energy efficiency are important elements of a sound energy

policy. Improved energy efficiency is the result of many decisions, including those of individual consumers; manufacturers of cars and appliances; home builders; and state, federal, and local government officials. The federal government can promote energy efficiency and conservation by including the dissemination of timely and accurate information regarding the energy use of consumers' purchases, setting standards for more energy efficient products, and encouraging industry to develop more efficient products. The federal government can also promote energy efficiency and conservation through programs like the Energy Star program, and search for more innovative technologies that improve efficiency and conservation through research and development.

Since 1973, the U.S. economy has grown nearly five times faster than energy use (126 percent versus 26 percent). Had Americans continued to use energy as intensively as in 1970, the U.S. would have consumed about 177 quadrillion Btus of energy last year, compared to about 99 quadrillion Btus actually consumed.

British Thermal Unit (Btu)

A British thermal unit is the amount of heat required to raise the temperature of one pound of water one degree Fahrenheit at sea level. Put another way, it is approximately the same amount of energy contained in a wooden match head.

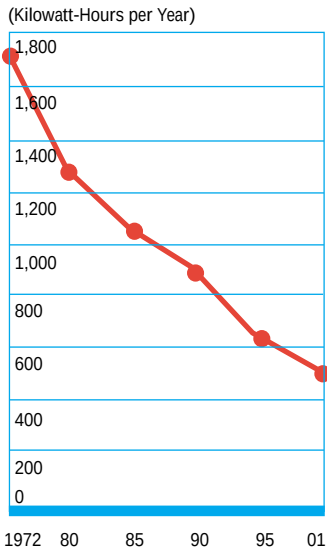


U.S. DEPARTMENT OF ENERGY



Figure 4-1

New Refrigerator-Freezers are Using Less Energy Consumption per Unit for New Shipments



Over the last thirty years, the energy efficiency of refrigerator-freezer appliances has increased by approximately 70 percent.

Sources: AHAM 2000 Major Home Industry Fact Book and BTS appliance standard.

Improving Efficiency through Innovative Technologies

One measure of energy efficiency is energy intensity—the amount of energy it takes to produce a dollar of gross domestic product (GDP). While about half of the long-term decline in energy intensity can be attributed to changes in the economy, especially the shift from manufacturing to services, the other half reflects improved energy efficiency. Gains in energy efficiency over the last three decades were built on a combination of technological improvements, better management practices, and learning to put these technologies and practices to their best use in automobiles, homes, offices, factories, and farms. In many areas the results have been quite impressive. New home refrigerators use about one-third of the electricity they used in 1972 (Figure 4-1). Compact fluorescent lights use about 25 percent of the electricity of the incandescent bulbs they replace. Automobiles use roughly 60 percent of the gasoline they did in 1972 per mile driven. These individual technological improvements have resulted in significant reductions in energy use (Figure 4-2).

Several new and innovative technolo-

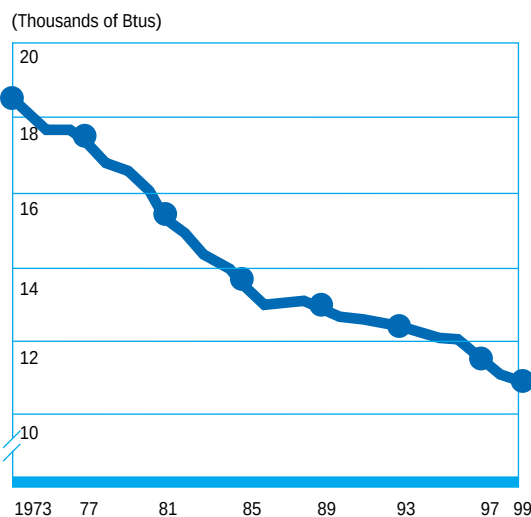
gies offer expanded opportunities to improve our energy efficiency. For example, advanced sensors and controls enable more efficient operation of buildings and factories, and allow equipment and lights to be turned off or dimmed when not in use. Hybrid vehicles use power electronics and battery storage to get more out of every gallon of gasoline consumed, and provide the ability to double vehicle mileage. Cogeneration of electricity and heat and combined heat and power allow for the productive use of much of the waste heat from electricity production, which accounts for about two-thirds of the energy used to produce electricity.

District Energy St. Paul— A Combined Heat and Power Plant

District Energy St. Paul, Inc., is a combined heat and power plant that can operate on natural gas, oil, or clean-burning coal that is mixed with wood chips. These wood wastes come from downed trees, trimmings, and branches. District Energy has been able to keep its rates stable because it is able to rely on a diverse fuel supply. District Energy serves about 75 percent of all building space in the city. Nearly 150 large buildings and 3,200 residential units use the system. It is the largest system of its kind in the nation.

Figure 4-2

The U.S. Economy Has Become More Energy Efficient



The amount of energy used by the United States in relation to its economic output has steadily declined since the early 1970s.

Source: U.S. Department of Energy, Energy Information Administration.

Recommendation:

★ The NEPD Group recommends that the President direct the Secretary of Energy to conduct a review of current funding and historic performance of energy efficiency research and development programs in light of the recommendations of this report. Based on this review, the Secretary of Energy is then directed to propose appropriate funding of those research and development programs that are performance-based and are modeled as public-private partnerships.

Consumer Choices

The two most important factors in consumers' decisions about purchasing an energy efficient product are price and the life of the product. When energy prices are high, consumers tend to weigh energy efficiency more heavily. Unless consumers are informed about the price of energy, they may not have the incentive to select the most energy efficient product.

Consumers do not receive timely signals about rising electricity costs in order to make adjustments to their energy use and efficiency. When consumers' peak costs are averaged with off-peak costs, the higher cost of peak electricity supplies is masked. As a result, consumers may not recognize the benefits of investing in technologies that best target peak consumption.

Some energy efficiency improvements are easiest and most cost effective to undertake when first building new factories, cars, equipment, appliances, and buildings. Some energy-using equipment, like computers, are used for only a few years before being replaced. Other equipment is used from five to twenty years, such as home appliances, home electronics, and lighting systems. Some capital stock, such as buildings and boilers, can last a half a century or more.

The average car now lasts fourteen years, and newer cars have even more longevity. Vehicle efficiency improvements require significant technological changes. Development of new-car production models requires at least three to four years, which limits the rate at which new technologies can enter the market. Making fundamental changes, such as switching to the use of a fuel cell, would take even longer. Once those new vehicles are in the showroom, it then takes several more years before they constitute any sizable percentage of total vehicles.

In a typical U.S. home, appliances are responsible for about 20 percent of the energy bills. Refrigerators, freezers, clothes washers, dryers, dishwashers, and ranges and ovens are the primary energy-using appliances in most households. Taking steps to save energy while using these appliances, and replacing old inefficient appli-



ances with modern ones can save money.

The federal government established a mandatory program in the 1970s requiring that certain types of new appliances bear a label to help consumers compare the energy efficiency of various products. Under this program, all refrigerators, freezers, clothes washers, and dishwashers are sold with yellow Energy Guide labels to indicate their energy efficiency. These labels provide an estimated annual operating cost of the appliance, and also indicate the cost of operating the models with the highest annual operating cost and the lowest annual operating cost. By comparing a model's annual operating cost with the operating cost of the most efficient model, you can compare their efficiencies. This labeling program ensures that consumers have the information they need to make the right decisions when they purchase major home appliances. However, Energy Guide labels are not currently required for some products, such as kitchen ranges, microwave ovens, clothes dryers, on-demand water heaters, portable space heaters, and lights.

The federal government not only ensures consumers have information on the energy efficiency of major home appliances. It also promotes the most energy efficient products through the Energy Star program, a joint program run by the Department of Energy and the Environmental Protection

Some efficiency improvements are easiest and most cost-effective to undertake when first building new factories, cars, equipment, appliances and buildings.



In April 2001, the Sustainable Buildings Industry Council showcased a net-zero-energy home featuring passive solar design strategies, an integrated photovoltaic system, domestic solar hot water, high-efficiency lights and appliances, and a host of sustainable, market-ready components and systems.

SUSTAINABLE BUILDINGS INDUSTRY COUNCIL



A 48-story skyscraper at the corner of Broadway and 42nd Street in New York City has a photovoltaic skin that uses thin-film PV panels to replace traditional glass cladding material. The PV curtain wall extends from the 35th to the 48th floors on the south and east walls of the tower, making it a highly visible part of the New York City skyline.

U.S. DEPARTMENT OF ENERGY, NATIONAL RENEWABLE ENERGY LABORATORY

Agency. Energy Star is only awarded to appliances that significantly exceed minimum energy efficiency standards. The Energy Star program does not extend to all products. Energy efficiency would be further promoted if the Energy Star program were expanded to a broader range of products.

Recommendation:

★ The NEPD Group recommends that the President direct the Secretary of Energy to promote greater energy efficiency.

- Expand the Energy Star program beyond office buildings to include schools, retail buildings, health care facilities, and homes.
- Extend the Energy Star labeling program to additional products, ap-

pliances, and services.

- Strengthen Department of Energy public education programs relating to energy efficiency.

Energy efficiency can also be improved by the establishment of minimum energy efficiency standards. Congress enacted legislation in 1987 and 1988 to establish minimum energy efficiency standards for many major appliances. These standards apply to manufacturers, not consumers. Appliance manufacturers must produce products that meet the minimum level of energy efficiency. These rules do not affect the marketing of products manufactured before the standards went into effect, and any products made beforehand can be sold. The new standards will stimulate energy savings that benefit the consumer, and reduce fossil fuel consumption, thus reducing air emissions.

These laws established minimum energy efficiency standards for many appliances, including refrigerators, refrigerator-freezers, freezers, room air conditioners, fluorescent lamp ballasts, and incandescent reflector lamps, clothes dryers, clothes washers, dishwashers, kitchen ranges, and ovens, pool heaters, and water heaters. The Energy Policy Act of 1992 added standards for fluorescent and incandescent reflector lamps, plumbing products, electric motors, and commercial water heaters, and heating, ventilation, and air conditioning systems. Under current law, the Department of Energy can raise the minimum energy efficiency standards for these appliances if certain criteria are met, such as cost, technological feasibility, and the impact on competition among appliance manufacturers. In addition, the Department can set energy efficiency standards for appliances not covered by these laws.

Recommendation:

★ The NEPD Group recommends that the President direct the Secretary of Energy to take steps to improve the energy efficiency of appliances.

- Support appliance standards program for covered products, setting higher standards where technologically feasible and economically justified.
- Expand the scope of the appliance standard program, setting standards for additional appliances where technologically feasible and economically justified.

Energy Efficiency

Government Agencies

As the largest energy consumer in the nation, the U.S. government's cost- and energy-saving opportunity is enormous. In 1999, the government consumed nearly 1.1 percent of all U.S. energy and spent nearly \$8 billion for its vehicles, operations, and its nearly 500,000 buildings.

The federal government has reduced its energy use in buildings by about 30 percent from 1990 levels, largely by installing energy efficient technologies (Figure 4-3). It has reduced its energy use for vehicles and equipment by 35 percent. Some of these improvements are attributable to the Department of Energy, whose Federal Energy Management Program helps government agencies reduce their energy and water use, manage their utility costs, and promote renewable energy.

Recommendations:

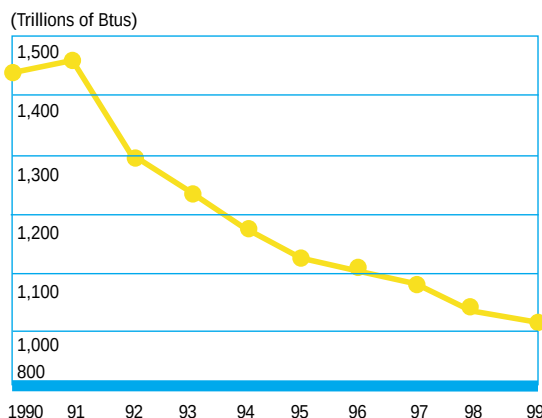
- ★ The NEPD Group recommends that the President direct heads of executive departments and agencies to take appropriate actions to conserve energy use at their facilities to the maximum extent consistent with the effective discharge of public responsibilities. Agencies located in regions where electricity shortages are possible should conserve especially during periods of peak demand.
- Agencies should report to the President, through the Secretary of Energy, within 30 days of the conservation actions taken.

State and local governments have unique opportunities for energy savings in schools, transportation, state buildings, and building codes. For example, the Texas School Energy Management Program could save school districts as much as \$100 million in energy costs every year by helping school districts evaluate their energy needs and resources. Similarly, Wisconsin's Energy Initiative is working with utilities to make basic changes to public buildings. By installing new lighting fixtures and taking other steps, Wisconsin estimates that it will save \$60 million in state spending on energy over ten years.

Residential and Commercial Buildings

There are significant opportunities to improve the energy efficiency of buildings and homes through technologies and better practices. For existing homes, immediate options for improving efficiency include reducing air infiltration with caulking and weather stripping, installing modern thermostats, sealing ductwork, and adding insulation. These steps can reduce the 40 percent share of residential energy bills that

Figure 4-3
The U.S. Government is Reducing Its Energy Consumption



During the 1990s, energy use in federal buildings decreased by about 30 percent.

Source: U.S. Department of Energy, Energy Information Administration.



PULTE HOMES

Building America—Pulte Homes

Pulte Homes Southwest Division has used technical assistance from the Department of Energy's Building America program to create what one residential expert calls "the best production house in the world," which won the 2001 National Association of Home Builders' Energy Value Award. In Tucson, Phoenix, and Las Vegas, Pulte Homes has worked with the Department of Energy to redesign the energy features of its basic models.

Using advanced insulation techniques, highly efficient equipment and windows, and right-sized heating and cooling systems, the homes look the same, but perform so well they use half the energy for heating and cooling at virtually no increase in construction costs.

The whole building/systems engineering approach used in the Building America program allows builders to add more insulation and more efficient windows while reducing the size of the heating and cooling equipment. The trade-off means no added cost to the builder, better value for the buyer, reduced electric load for the utility, and improved affordability.

go toward heating and cooling. Additional savings are possible when efficient appliances are purchased or major home renovations are undertaken. Installing a new, more efficient gas furnace can save up to 20 percent annually on natural gas. New buildings offer the greatest energy efficiency opportunities and can be designed to be both more comfortable and more efficient, cutting heating and cooling costs by close to 50 percent.

In commercial buildings, typically the quickest, most cost effective way to increase energy efficiency is to replace the lighting systems. Sensors help to avoid 24-hour operation of lights and equipment that are only used for a portion of the day. As with homes, advances in windows, heating and air conditioning systems, overall building designs, and equipment and appliances present significant energy saving opportunities.

Many families and businesses can face obstacles to realizing energy cost reductions.

Insufficient Information

Monthly energy bills generally report only total electricity or natural gas used, leaving families and businesses unsure about which energy services are most responsible for their energy use, and which investments could best help them reduce their costs. In addition, consumers may be unsure about the credibility of the energy-saving claims of individual manufacturers, salesmen, and designers. This incomplete information causes imperfections in the marketplace that hinder purchases of efficient technologies that would actually save families and businesses money.

Lack of Availability

Frequently, the most energy efficient products cost more and are not widely available, especially in smaller communities. Builders who would like to construct more efficient homes and businesses face the same problem at the wholesale level. For example, to keep costs down, builders are less likely to install top-of-the-line,

highly efficient products. The less expensive and generally less efficient products are heavily stocked and deeply discounted due to volume ordering. The decisions made about the energy efficiency of buildings and homes are not usually made by the consumer who will ultimately pay the energy bills. The incentive is for the builders to choose the material that poses the least cost to the builder, which is not necessarily the most energy efficient choice.

Lack of Automation

People often walk out of their offices and homes with the lights on and the air conditioner running. Turning off unused appliances, electronics, and lights is not always easy. Lack of automation (e.g., daylight sensors) means that conservation mostly depends on people turning off switches. Some appliances and electronics, such as stereos, video tape players, and televisions, continue to use electricity even after they are turned off.

Higher Initial Costs

Efficient products often cost more than less efficient versions, especially when they are first introduced to the market. Unless consumers can verify the resulting savings, they may be reluctant to pay the additional costs. Businesses that adopt labeling programs that spell out energy savings may be more successful in selling a more efficient, yet initially more expensive product. Higher initial costs can be particularly difficult for the purchaser or builder of a new home or office building.

Industry and Agriculture

Six industries consume three-quarters of all industrial energy: lumber and paper; chemicals; petroleum refining; primary metals; food processing; and stone, clay, and glass. Improved energy efficiency in these energy-intensive industries yields even larger improvements in overall productivity, product quality, safety, and pollution prevention. Manufacturing companies generally obtain their largest savings from



improved efficiency of motors (motors account for 54 percent of electricity use in manufacturing) and from improved steam and hot-water systems. Many companies can reduce energy needs further by cogenerating their electricity and heat for steam.

Energy use for U.S. agriculture grew during the 1960s and 1970s, peaking in 1978. High energy prices during the 1970s and early 1980s caused many farmers to find ways to reduce their energy costs, such as by switching from gasoline-powered to more fuel-efficient diesel-powered engines, adopting conservation tillage practices, shifting to larger multiprocessor machines, and using energy saving methods for drying and irrigating crops. These measures helped farmers reduce their energy use by 41 percent from 1978 to 1998, while agricultural output grew by about 40 percent over the same period.

Farmers can reap additional energy savings as they replace old machinery with more energy efficient equipment. Furthermore, farmers can adopt more advanced practices, such as precision farming, that optimize the use of machines, chemicals, and fertilizers to achieve energy savings. New seed varieties can also reduce energy-intensive chemical requirements.

Despite the opportunity for increased energy efficiency, the industrial and agricultural sectors face several obstacles. Because many manufacturing and farming operations are highly specialized, they need specific information on energy-saving opportunities to effectively respond to energy price signals and supply problems.

High energy prices during the 1970s and early 1980s caused many farmers to find ways to reduce their energy costs, such as by switching from gasoline-powered to more fuel efficient diesel-powered engines and by adopting conservation tillage practices.

Cogeneration

In 1998, Malden Mills Industries, a textile manufacturer employing 2,300 workers in Lawrence, Massachusetts, installed a state-of-the-art combined heat and power (CHP) facility. The system uses two 4.3 MW industrial gas turbines, retrofitted with ceramic combustion liners, that were developed as part of the Department of Energy's Advanced Turbine Systems program, and that enable higher operating temperatures and lower emissions. The CHP system saves Malden Mills more than \$1 million annually. The liners have accumulated more than 9,500 hours of successful operation and have cut emissions of nitrogen oxides and carbon monoxide to less than 15 parts per million.



In order for manufacturing or agriculture to switch to more efficient energy products and practices, significant costs are incurred due to production delays, waste and spoilage, and labor costs. As a result, manufacturers and farmers tend to use readily available and reliable equipment when upgrading, instead of untested, newer products and approaches.

Because of their large needs for both heat and electricity, businesses find combined heat and power (CHP) systems particularly attractive. However, replacing old, inefficient boilers with highly efficient CHP systems may add a number of new regulatory requirements (such as air permits), but does not offer the same tax depreciation incentives the tax code grants to power plants.

Recommendations:

★ The NEPD Group recommends that the President direct the Secretary of the Treasury to work with the Congress on legislation to encourage increased energy efficiency through combined heat and power (CHP) projects by shortening the depreciation life for CHP projects or providing an investment tax credit.

★ The NEPD Group recommends that the President direct the Administrator of the Environmental Protection Agency (EPA) to work with local and state governments to promote the use of well-designed CHP and other clean power generation at brownfield sites, consistent with the local communities' interests. EPA will also work to clarify liability issues if they are raised at a particular site.

★ The NEPD Group recommends that the President direct the EPA Administrator to promote CHP through flexibility in environmental permitting.

Conservation can be improved by car pooling, telecommuting, increasing public transit choices, and pricing highway use during periods of peak demand.

Transportation

Transportation plays a key role in a growing U.S. economy, comprising 16 percent of GDP in 1998, 10.5 percent of total employment, and 27 percent of total U.S. energy consumption. Trucks and automobiles account for over three-fourths of the sector's petroleum use, with the remainder attributable to rail, ship, air, and pipeline systems. Mass transit ridership has increased by 21 percent since 1996. Automobiles today use roughly 60 percent of the gasoline they did in 1972 per mile driven, due in part to new technology, such as better engine and design controls, improved transmission, weight reduction, and improved aerodynamics. Despite the adoption of more efficient transportation technologies, average fuel economy for passenger vehicles has remained relatively flat for ten years and is, in fact, at a twenty-year low, in large part due to the growth and popularity of low-fuel-economy pickup trucks, vans, and sport utility vehicles (Figure 4-4).

Recommendation:

★ The NEPD Group recommends that the President direct the Secretary of Transportation to:

- Review and provide recommendations on establishing Corporate Average Fuel Economy (CAFE) standards with due consideration of the National Academy of Sciences study to be released in July 2001. Responsibly crafted CAFE standards should increase efficiency without negatively impacting the U.S. automotive industry. The determination of future fuel economy standards must therefore be addressed analytically and based on sound science.
- Consider passenger safety, economic concerns, and disparate impact on the U.S. versus foreign fleet of automobiles.
- Look at other market-based approaches to increasing the national average fuel economy of new motor vehicles.

Opportunities for reducing oil demand in the transportation sector include increasing conservation, vehicle efficiency, and alternative fuels. Conservation can be improved by car pooling, telecommuting, and increasing transit choices. For example, an increase in the average fuel economy of the on-road vehicle fleet by three miles per gallon would save one million barrels of oil a day, or about half of the global shortfall between supply and demand that triggered the oil price increases since 1998. In addition, fuel conservation can be further improved by technologies to reduce congestion.

A recent analysis indicates that the fuel economy of a typical automobile could be enhanced by 60 percent by increasing engine and transmission efficiency and reducing vehicle mass by about 15 percent. Several promising efficiency technologies are being presented to the U.S. market. For example, some automobile manufacturers have already introduced hybrid vehicles, and others have announced that they will introduce hybrid vehicles within the next several years. Advanced lightweight materials offer up to 6 percent improvement in mileage for each 10 percent reduction in body weight. Although promising, it may be many years before hybrids become a substantial part of the automotive fleet.

Recommendations:

★ The NEPD Group recommends that the President direct the Secretary of Transportation to review and promote congestion mitigation technologies and strategies and to work with the Congress on legislation to implement these strategies.

★ The NEPD Group recommends that the President direct the Secretary of the Treasury to work with Congress on legislation to increase energy efficiency with a tax credit for fuel-efficient vehicles. The NEPD Group recommends that a temporary, efficiency-based income tax credit be available for purchase of new hybrid or fuel cell vehicles between 2002 and 2007.

Higher Initial Production Costs

Because of the large economies of scale in automobile manufacturing, new technologies with limited early production runs often enter the market at higher initial costs. In this highly competitive international market, higher initial production costs can be a significant impediment to the introduction of new technologies. Unless U.S. automakers can remain competitive with their overseas counterparts, it is unlikely they will invest in new, more efficient technologies. Vehicle efficiency technologies, such as advanced engines, fuel cells, and cutting-edge electronic drive-train technologies, will become widely available only when component costs are reduced or demand is increased.

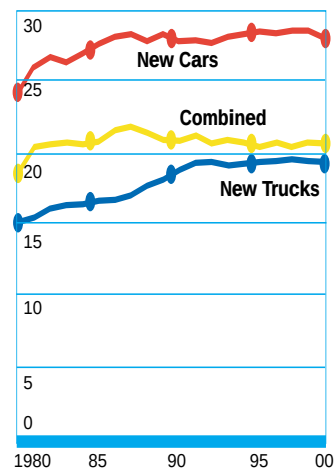
Hybrid Vehicles

The engine of a conventional gasoline vehicle is typically sized for the small amount of time the driver spends accelerating to enter the freeway, to pass another car, or to climb a hill. Most of the time it operates at less than 20 percent efficiency. An attractive alternative is to use a hybrid system that allows the engine to operate at peak efficiency, and get a boost from a battery when entering the freeway or climbing a hill. Not only does this system allow improved performance from a smaller engine, but the energy usually lost in stopping the car can be recovered and stored in the battery.

What does this mean to the average American? Significantly improved fuel economy and reduced emissions.

Figure 4-4
Fuel Efficiency of Light Vehicles Has Remained Flat

(Miles per Gallon)



Despite the adoption of more efficient transportation technologies, U.S. average fuel economy has been flat for 10 years. In large part, this is due to the growth of low-fuel-economy pickup trucks, vans, and sport utility vehicles.

Source: U.S. Department of Energy, Energy Information Administration.

Summary of Recommendations

Using Energy Wisely: Increasing Energy Conservation and Efficiency

- ★ The NEPD Group recommends that the President direct the Office of Science and Technology Policy and the President's Council of Advisors on Science and Technology to review and make recommendations on using the nation's energy resources more efficiently.
- ★ The NEPD Group recommends that the President direct the Secretary of Energy to conduct a review of current funding and historic performance of energy efficiency research and development programs in light of the recommendations of this report. Based on this review, the Secretary of Energy is then directed to propose appropriate funding of those research and development programs that are performance-based and are modeled as public-private partnerships.
- ★ The NEPD Group recommends that the President direct the Secretary of Energy to promote greater energy efficiency.
 - Expand the Energy Star program beyond office buildings to include schools, retail buildings, health care facilities, and homes.
 - Extend the Energy Star labeling program to additional products, appliances, and services.
 - Strengthen Department of Energy public education programs relating to energy efficiency.
- ★ The NEPD Group recommends that the President direct the Secretary of Energy to improve the energy efficiency of appliances.
 - Support the appliance standards program for covered products, setting higher standards where technologically feasible and economically justified.
 - Expand the scope of the appliance standards program, setting standards for additional appliances where technologically feasible and economically justified.
- ★ The NEPD Group recommends that the President direct heads of executive departments and agencies to take appropriate actions to conserve energy use at their facilities to the maximum extent consistent with the effective discharge of public responsibilities. Agencies located in regions where electricity shortages are possible should conserve especially during periods of peak demand. Agencies should report to the President, through the Secretary of Energy, within 30 days on the conservation actions taken.
- ★ The NEPD Group recommends that the President direct the Secretary of the Treasury to work with Congress to encourage increased energy efficiency through combined heat and power (CHP) projects by shortening the depreciation life for CHP projects or providing an investment tax credit.
- ★ The NEPD Group recommends that the President direct the Administrator of the Environmental Protection Agency (EPA) to work with local and state governments to promote the use of well-designed CHP and other clean power generation at brownfields sites, consistent with the local communities' interests. EPA will also work to clarify liability issues if they are raised at a particular site.
- ★ The NEPD Group recommends that the President direct the EPA Administrator to promote CHP through flexibility in environmental permitting.
- ★ The NEPD Group recommends that the President direct the Secretary of Transportation to:
 - Review and provide recommendations on establishing Corporate Average Fuel Economy (CAFE) standards with due consideration of the National Academy of Sciences study to be released in July 2001. Responsibly

crafted CAFE standards should increase efficiency without negatively impacting the U.S. automotive industry. The determination of future fuel economy standards must therefore be addressed analytically and based on sound science.

- Consider passenger safety, economic concerns, and disparate impact on the U.S. versus foreign fleet of automobiles.
- Look at other market-based approaches to increasing the national average fuel economy of new motor vehicles.

★ The new NEPD Group recommends that the President direct the Secretary of Transportation to review and promote congestion mitigation technologies and strategies and work with Congress on legislation to implement these strategies.

★ The NEPD Group recommends that the President direct the Secretary of the Treasury to work with Congress on legislation to increase energy efficiency with a tax credit for fuel-efficient vehicles. The NEPD Group recommends that a temporary, efficiency-based income tax credit be available for purchase of new hybrid fuel cell vehicles between 2002 and 2007.

★ The NEPD Group recommends that the President direct all agencies to use technological advances to better protect our environment.

- The Administration remains committed to investing in Intelligent Transportation Systems (ITS) and encourages the private sector to invest in ITS applications. This Department of Transportation (DOT) program funds the development of improved transportation infrastructure that will reduce congestion, such as traveler information/navigation systems, freeway management, and electronic toll collection. ITS applications reduce fuel associated with travel.
- The Administration remains committed to the DOT's fuel-cell-powered transit bus program, authored by the Transportation Equity Act for the 21st Century (TEA-21). This program demonstrates the viability of fuel-cell power plants for transit bus applications.
- The Administration remains committed to the Clean Buses program. TEA-21 establishes a new clean fuel formula grant program, which provides an opportunity to accelerate the introduction of advanced bus propulsion technologies into the mainstream of the nation's transit fleet.

★ The NEPD Group recommends that the President direct the EPA and DOT to develop ways to reduce demand for petroleum transportation fuels by working with the trucking industry to establish a program to reduce emissions and fuel consumption from long-haul trucks at truck stops by implementing alternatives to idling, such as electrification and auxiliary power units at truck stops along interstate highways. EPA and DOT will develop partnership agreements with trucking fleets, truck stops, and manufacturers of idle-reducing technologies (*e.g.*, portable auxiliary packs, electrification) to install and use low-emission-idling technologies.

★ The NEPD Group recommends that the President direct the Secretary of Energy to establish a national priority for improving energy efficiency. The priority would be to improve the energy intensity of the U.S. economy as measured by the amount of energy required for each dollar of economic productivity. This increased efficiency should be pursued through the combined efforts of industry, consumers, and federal, state, and local governments.

★ The NEPD Group recommends that the President direct the EPA Administrator to develop and implement a strategy to increase public awareness of the sizable savings that energy efficiency offers to homeowners across the country. Typical homeowners can save about 30 percent (about \$400) a year on their home energy bill by using Energy Star-labeled products.

Energy for a New Century

Increasing Domestic Energy Supplies

America's energy strength lies in the abundance and diversity of its energy resources, and in its technological leadership in developing and efficiently using these resources. Our nation has rich deposits of coal, oil, and natural gas. The United

States is the third-largest oil-producing nation in the world, despite a thirty-year decline in domestic production. While our economy runs primarily on fossil fuels, we also have long experience with hydropower and nuclear energy. We are pursuing the ability to further capture the energy of sunlight, the heat of the earth, and the power of wind.

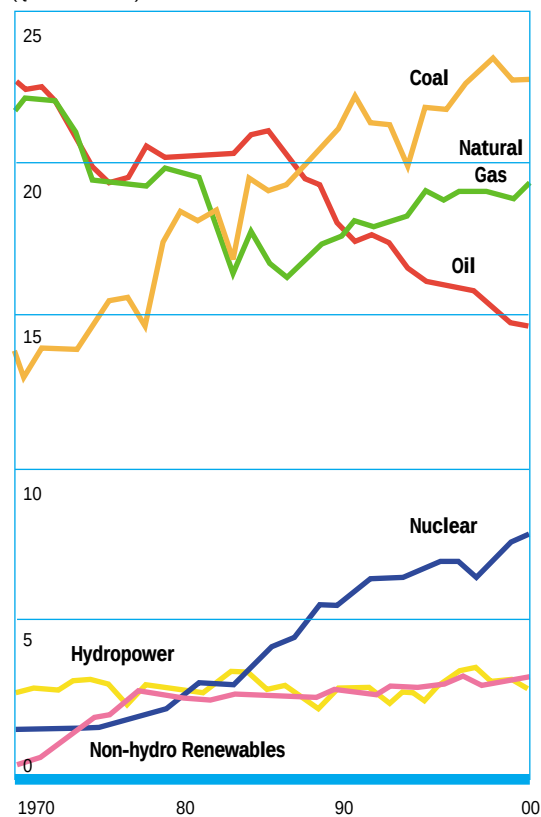
Economic factors will help determine the future development of our nation's energy sources. These factors will be shaped not only by conservation, energy demand, and the cost of energy development, but also by the regulations that federal, state, and local governments put in place to balance energy needs with legitimate competing aims, including the protection of the environment. A number of factors will make it difficult to increase domestic energy production in response to the growing demand for energy: economic and technological factors associated with depletion of the fossil fuel resource base in the U.S.; regulatory uncertainty; limitations on access to federal lands with high potential for new discoveries; infrastructure constraints, such as electricity transmission and gas pipeline bottlenecks; and conflicts with legitimate land use, environmental, and other public policy goals.

The United States has significant domestic energy resources, and remains a major energy producer. Between 1986 and 2000, production of coal, natural gas, nuclear energy, and renewable energy increased. However, these increases have been largely offset by declines in oil production (Figure 5-1).

Figure 5-1

U.S. Energy Production: 1970–2000

(Quadrillion Btus)



Production of coal, the nation's most abundant fuel source, exceeded 1 billion tons in 2000. Electricity generation accounted for about 90 percent of U.S. coal consumption last year.

Source: U.S. Department of Energy, Energy Information Administration.



Even with improved energy efficiency, the United States will need more energy supply. U.S. energy demand is projected to rise to 127 quadrillion Btus by 2020, even with significantly improved energy efficiency. However, domestic production is expected to rise to only 86 quadrillion Btus by 2020. The shortfall between projected energy supply and demand in 2020 is nearly 50 percent. That shortfall can be made up in only three ways: import more energy; improve energy efficiency even more than expected; and increase domestic energy supply.

The challenge for our nation is to use technology to maintain and enhance the diversity of our supplies, thus providing a reliable and affordable source of energy for Americans. These goals can and must be accomplished while maintaining our commitment to environmental protection.

Oil and Natural Gas

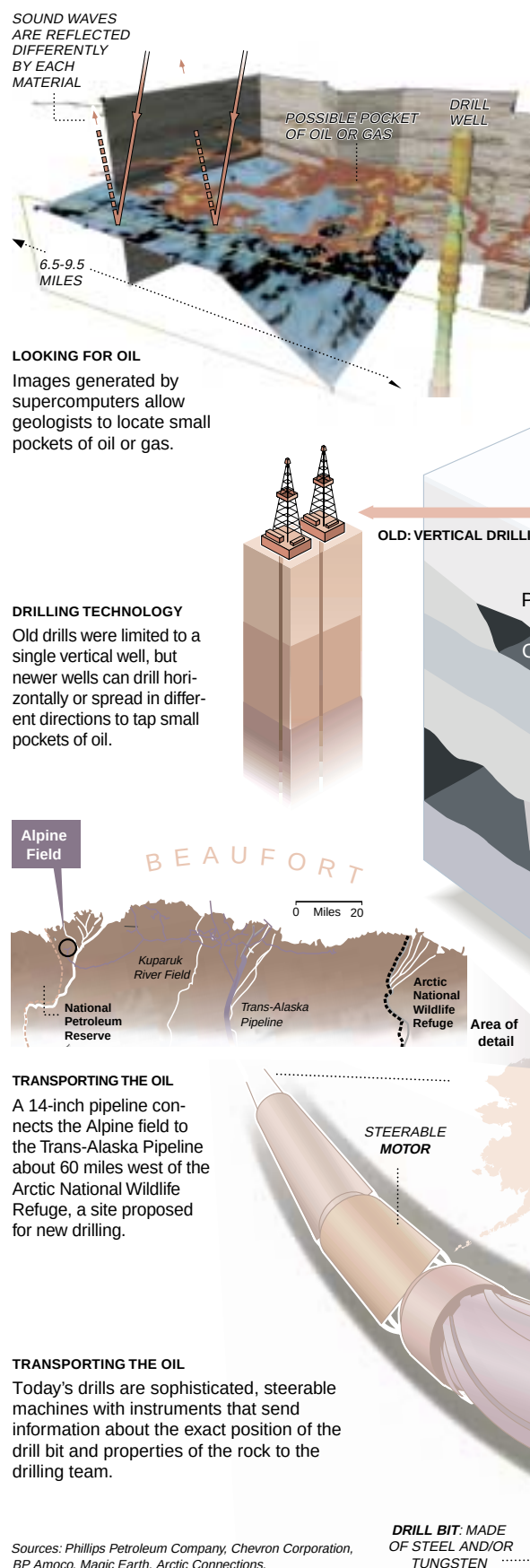
Oil and natural gas are the dominant fuels in the U.S. economy, providing 62 percent of the nation's energy and almost 100 percent of its transportation fuels. By 2020, the Energy Information Administration expects the United States will need about 50 percent more natural gas and one-third more oil to meet demand.

U.S. oil production is expected to decline over the next two decades. Over the same period, demand for natural gas will most likely continue to outpace domestic production. As a result, the United States will rely increasingly on imports of both natural gas and oil from Canada, and imports of oil and liquefied natural gas from producers across the globe.

21st Century Technology

Remaining U.S. oil reserves are becoming increasingly costly to produce because much of the lower-cost oil has already been largely recovered. The remaining resources have higher exploration and production costs and greater technical challenges, because they are located in geologically complex reservoirs, (e.g., deep water

Figure 5-2



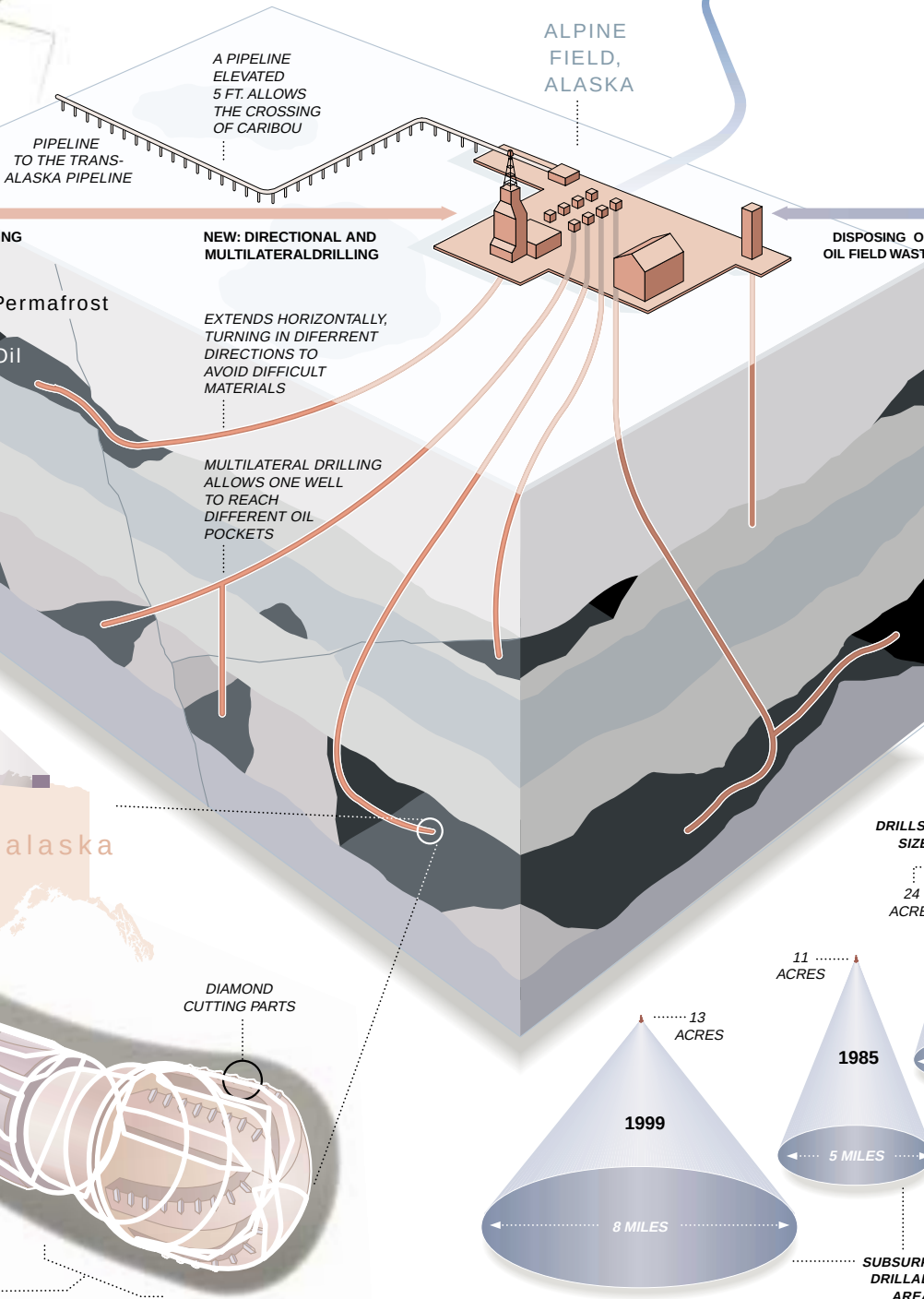
Using the Latest Drilling Technology to Reduce Environmental Damage

Oil drilling sites like those in the Alpine field on Alaska's North Slope are using cutting-edge technology in hopes of reducing environmental damage.

Recent advances are lessening the industry's impact on the fragile Arctic ecosystem.



BP Amoco



GETTING THERE

To minimize the project's impact on the environment, temporary ice roads are used in the winter, leaving few traces after they thaw.

DISPOSING OF WASTES

Mud and debris from drilling used to be placed in big reserve pits. Today, rock cuttings are crushed, mixed with the mud, and sent deep into the earth where they originated. This minimizes the size of well pads.

CROSSING A RIVER

Although traditional pipelines are built above ground, the pipeline to the Trans-Alaska Pipeline plunges beneath the Colville River, preserving the surface and the river bed environment.

OCCUPYING LESS OF THE TUNDRA

The new drilling technology allows for smaller surface production pads and larger areas explored in the earth.

Source: New York Times News Service

21st Century Technology: The Key to Environmental Protection and New Energy Production

Producing oil and gas from geologically challenging areas while protecting the environment is important to Americans and to the future of our nation's energy security. New technology and management techniques allow for sophisticated energy production as well as enhanced environmental protection. A technology evolution has occurred in the way oil and natural gas are found. The computer, three dimensional seismic technology, and other technologies have transformed the process from one based on "feel," to one highly dependent on the most advanced and sophisticated technology available. These technologies reduce cost and protect the environment.

Today's oil and gas exploration technology, for example, is boosting the success rate of pinpointing new resources. The results: fewer dry holes, reduced waste volumes, and a cleaner environment. Smaller, lighter drilling rigs coupled with advances in directional and extended-reach drilling significantly increase protection of the environment.

- Advanced, more energy efficient drilling and production methods:
 - reduce emissions;
 - practically eliminate spills from offshore platforms; and
 - enhance worker safety, lower risk of blowouts, and provide better protection of groundwater resources.
- With each improvement in operational performance and efficiency, more oil and gas resources can be recovered with fewer wells drilled, resulting in smaller volumes of:
 - cuttings;
 - drilling muds and fluids; and
 - produced waters.
- Modular drilling rigs, "slimhole" drilling, directional drilling, and other advances enable:
 - production of oil and gas with increased protection to wetlands and other sensitive environments;
 - reduced greenhouse gas emissions;
 - and worker safety through the use of innovative best management practices.

Other examples of advanced technology include:

- 3-D seismic technology that enables geologists to use computers to determine the location of oil and gas before drilling begins, dramatically improving the exploration success rate;
- deep-water drilling technology that enables exploration and production of oil and gas at depths over two miles beneath the ocean's surface;
- high-powered lasers that may one day be used for drilling for oil and gas; and
- highly sophisticated directional drilling that enables wells to be drilled long horizontal distances from the drilling site.

:

and harsh environments).

While the resource base that supplies today's natural gas is vast, U.S. conventional production is projected to peak as early as 2015. Increasingly, the nation will have to rely on natural gas from unconventional resources, such as tight sands, deep formations, deep water, and gas hydrates. Also, many resources are in environmentally sensitive areas that require use of less intrusive technologies.

New technologies are being developed to reduce both the environmental effects and the economic costs of exploration for oil and gas. These exciting new technologies, like horizontal drilling and three-dimensional seismic technology allow for much greater precision and significantly less impact on the environment (Figure 5-2).

Small independent businesses account for 50 and 65 percent, respectively, of domestic petroleum and natural gas production in the lower 48 states. However, even when new technology is available, independent producers can lack the investment capital needed to apply the technology and be unable to cope with the increased economic and technical risks associated with harder-to-recover resources.

For example, most new gas wells drilled in the United States will require hydraulic fracturing. This is a common procedure used by producers to complete gas wells by stimulating the well's ability to flow increased volumes of gas from the reservoir rock into the wellbore. During a fracture procedure, fluid and a propping agent (usually sand) are pumped into the reservoir rock, widening natural fractures to provide paths for the gas to migrate to the wellbore. In certain formations, it has been demonstrated that the gas flow rate may be increased as much as twenty-fold by hydraulic fracturing. Each year nearly 25,000 oil and gas wells are hydraulically fractured.

The use of hydraulic fracturing in natural gas production from coal seams is one of the fastest-growing sources of gas production. This source will most likely face added controls, and costs to ensure that disposal (by re-injection or discharge) of production waters is done in an environmentally sensitive manner.

For each of these issues, opportunities exist to better coordinate, improve performance, and meet America's energy, public health, safety and environmental goals.

Recommendation:

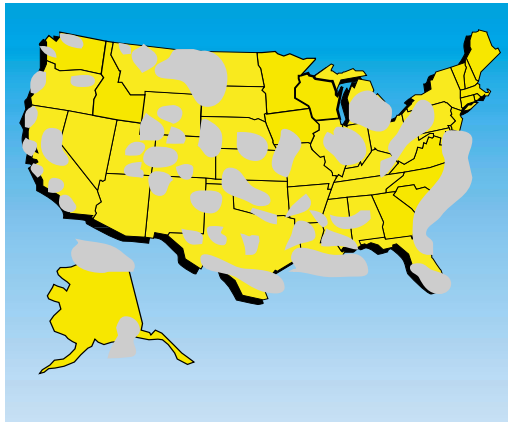
★ The NEPD Group recommends that the President direct the Secretaries of Energy and the Interior to promote enhanced oil and gas recovery from existing wells through new technology.

Small independent businesses account for 50 and 65 percent, respectively, of domestic petroleum and natural gas production in the lower 48 states.

Anywhere from 30 to 70 percent of oil, and 10 to 20 percent of natural gas, is not recovered in field development. It is estimated that enhanced oil recovery projects, including development of new recovery techniques, could add about 60 billion barrels of oil nationwide through increased use of existing fields (Figure 5-3).

Figure 5-3

Major U.S. Oil and Gas Fields



The United States is the most mature oil-producing region in the world, and much of our easy-to-find resource base has been depleted. Advanced exploration and production technologies of the past two decades have played a key role in recovering additional oil and natural gas from existing fields.

Source: U.S. Department of Energy, Energy Information Administration.

Public Lands Leasing

The federal government owns about 31 percent of the nation's land, so it can have a major role in increasing energy production in appropriate places. A large portion of U.S. energy resources are contained in these federal lands and offshore areas. Public lands provide nearly 30 percent of

annual national energy production, and are estimated to contain a substantial majority of the nation's undiscovered domestic energy resources.

Portions of federal onshore and offshore lands are off-limits to oil and gas exploration and development. Access is restricted for a variety of reasons, including administrative land withdrawals for competing land uses, such as national defense or water projects; and stipulations affecting surface occupancy, use, and timing for environmental compatibility.

Recommendations:

★ The NEPD Group recommends that the President direct the Secretary of the Interior to examine land status and lease stipulation impediments to federal oil and gas leasing, and review and modify those where opportunities exist (consistent with the law, good environmental practice, and balanced use of other resources).

- Expedite the ongoing Energy Policy and Conservation Act study of impediments to federal oil and gas exploration and development.
- Review public lands withdrawals and lease stipulations, with full public consultation, especially with the people in the region, to consider modifications where appropriate.

★ The NEPD Group recommends that the President direct the Secretary of the Interior to consider economic incentives for environmentally sound offshore oil and gas development where warranted by specific circumstances: explore opportunities for royalty reductions, consistent with ensuring a fair return to the public where warranted for enhanced oil and gas recovery; for reduction of risk associated with production in frontier areas or deep gas formations; and for development of small fields that would otherwise be uneconomic.

Offshore

Congress has designated about 610 million acres off limits to leasing on the Outer Continental Shelf (OCS), which contains large amounts of recoverable oil and gas resources. These Congressional moratoria have been expanded by Presidential action through 2012, effectively confining the federal OCS leasing program to the central and western Gulf of Mexico, a small portion of the eastern Gulf, existing leases off California's shore, and areas off of Alaska.

Concerns over the potential impacts of oil spills have been a major factor behind imposition of the OCS moratoria. For areas that are available for possible development, it is projected that with advanced technology, we could recover 59 billion barrels of oil and 300 trillion cubic feet of natural gas. This type of exploration and production from the OCS has an impressive environmental record. For example, since 1985, OCS operators have produced over 6.3 billion barrels of oil, and have spilled only 0.001 percent of production. Naturally occurring oil seeps add about 150 times as much oil to the oceans. Additionally, about 62 percent of OCS energy production is natural gas, which poses little risk of pollution.

For those areas that are available for potential coastal zone and OCS exploration and production activity, businesses must comply with a variety of federal and state statutes, regulations, and executive orders. Aspects of these, under the Coastal Zone Management Act and the Outer Continental Shelf Lands Act and their regulations, attempt to provide for responsible development while considering important environmental resources. However, effectiveness is sometimes lost through a lack of clearly defined requirements and information needs from federal and state entities, as well as uncertain deadlines during the process. These delays and uncertainties can hinder proper energy exploration and production projects.

The Deep Water Royalty Relief Act of 1995, granting variable royalty reductions for new leases in deep water, contributed to a significant increase in deep-water leasing in the central and western Gulf over the last five years. The opportunities created in deep water help spur the development of new

technologies and infrastructure for this frontier area. However, substantial economic risks remain to investment in deep water and continued incentives could help draw investment in other countries. Similar incentives could spur development in other technological frontiers, such as deep gas, or make possible continued production from both offshore and onshore fields near the end of their economic life.

Recommendation:

★ The NEPD Group recommends that the President direct the Secretaries of Commerce and Interior to re-examine the current federal legal and policy regime (statutes, regulations, and Executive Orders) to determine if changes are needed regarding energy-related activities and the siting of energy facilities in the coastal zone and on the Outer Continental Shelf (OCS).

Arctic Outer Continental Shelf

It is estimated there are significant undiscovered resources in the two planning areas of the Arctic OCS. Geologists estimate that there are approximately 22.5 billion barrels of oil and 92 trillion cubic feet of natural gas in the Arctic OCS. The Beaufort Sea Planning Area encompasses approximately 65 million acres. Active leases within the Beaufort Sea Planning Area represent only 0.4 percent of the total acreage, and only 5 percent of the leased acreage is being actively pursued for development and production. The Chukchi Sea Planning Area encompasses approximately 63.7 million acres, none of which is currently leased.

Lease offerings totaling 58 million acres over the past twenty years have resulted in 34 exploratory wells. Two oil discoveries are now moving toward production, but economic factors have delayed several others. These discoveries have estimated recoverable reserves of more than 260 million barrels of oil. This is another area where periodic, well-scheduled lease sales can help contribute to national energy production.



The high-technology oil industry requires an educated, technologically sophisticated work force. Many workers left the industry in the mid-1980s because of job insecurity caused by price volatility. The lack of an experienced work force today may limit the amount and increase the cost of future exploration and production activity.

U.S. DEPARTMENT OF ENERGY

Recommendation:

★ The NEPD Group recommends that the President direct the Secretary of the Interior continue OCS oil and gas leasing and approval of exploration and development plans on predictable schedules.

Onshore

North Slope Oil and Gas

The Alaska North Slope is a promising area for discovery of additional reserves to increase our domestic production of oil and natural gas. Currently, state lands on Alaska's North Slope provide about 17 percent of U.S. oil production. Oil and gas development in the Arctic, however, needs to be done in an environmentally responsible manner, using new technology and relying upon the best available scientific information. Such technology is making it possible to explore and develop oil and gas with significantly less impact on the environment. Areas with potential for oil and gas development are the National Petroleum Reserve-Alaska (NPR-A), the Arctic Outer Continental Shelf, and the Arctic National Wildlife Refuge (ANWR).

National Petroleum Reserve–Alaska

The National Petroleum Reserve–Alaska lies between the Brooks Range and the Arctic Ocean. The U.S. Geological Survey (USGS) estimates a high potential for oil and gas resources in the NPR–A, with a mean estimate of 2.1 billion barrels of oil and 8.5 trillion cubic feet of gas. A leasing program was designed and initiated in 1999 for the northeast sector of NPR–A, resulting in the award of 133 leases covering 900,000 acres. Eight exploratory wells have been completed in the past two years, and additional exploratory wells are expected this coming winter.

Recommendation:

★ The NEPD Group recommends that the President direct the Secretary of the Interior to consider additional environmentally responsible oil and gas development, based on sound science and the best available technology, through further lease sales in the National Petroleum Reserve–Alaska. Such consideration should include areas not currently leased within the Northeast corner of the Reserve.

Arctic National Wildlife Refuge

The Alaska National Interest Lands Conservation Act expanded ANWR from 9 million acres to 19 million acres, and designated 8 million acres as wilderness. Congress specifically left open the question of management of a 1.5-million-acre Arctic Coastal Plain area of ANWR because of the likelihood that it contains significant oil and gas resources. Section 1002 of the Act directed the Department of the Interior to conduct geological and biological studies of the Arctic Coastal Plain, “the 1002 Area,” and to provide to Congress the results of those studies with recommendations on future management of the area. Section 1003 of the Act prohibits leasing of the 1002 Area until authorized by an act of Congress.

In 1987, after more than five years of biological baseline studies, surface geological studies, and two seasons of seismic ex-

ploration surveys, the Department of the Interior recommended to Congress that the 1002 Area be leased for oil and gas exploration and production in an environmentally sensitive manner. In 1995, both the Senate and the House passed legislation containing a provision to authorize leasing in the 1002 Area, but the legislation was vetoed.

In May 1998, the USGS issued revised estimates of oil and gas resources in the 1002 Area. The 1998 USGS assessment shows an overall increase in estimated oil resources when compared to all previous government estimates. The estimate reaffirms the 1002 Area’s potential as the single most promising prospect in the United States. The total quantity of recoverable oil within the entire assessment area is estimated to be between 5.7 and 16 billion barrels (95 percent and 5 percent probability range) with a mean value of 10.4 billion barrels. The mean estimate of 10.4 billion barrels is just below the amount produced to date from North America’s largest field, Prudhoe Bay, since production began 23 years ago. Peak production from ANWR could to be between 1 and 1.3 million barrels a day and account for more than 20 percent of all U.S. oil production. ANWR production could equal 46 years of current oil imports from Iraq.

Technological improvements over the past 40 years have dramatically reduced industry’s footprint on the tundra, minimized waste produced, and protected the land for resident and migratory wildlife. These advances include the use of ice roads and drilling pads, low-impact exploration approaches such as winter-only exploration activities, and extended reach and through-tubing rotary drilling. These technologies have significantly reduced the size of production-related facilities on the North Slope. Estimates indicate that no more than 2,000 acres will be disturbed if the 1002 Area of ANWR is developed. For purposes of comparison, ANWR is about the size of the state of South Carolina, whereas the developed area is estimated to be less than one-fifth the size of Washington D.C.’s Dulles International Airport.

Recommendation:

★ The NEPD Group recommends that the President direct the Secretary of the Interior to work with Congress to authorize exploration and, if resources are discovered, development of the 1002 Area of ANWR. Congress should require the use of the best available technology and should require that activities will result in no significant adverse impact to the surrounding environment.

Other Onshore Restrictions

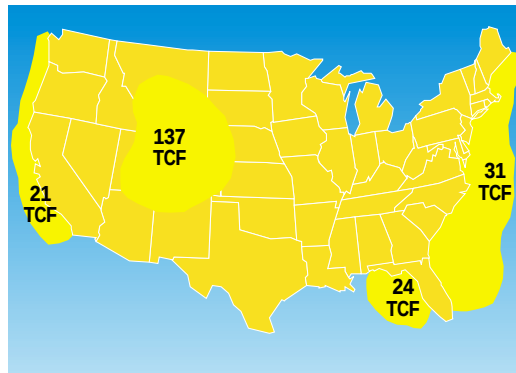
There is a significant potential for oil and gas resources on federal land in the lower 48 states as well. According to the most recent estimates from the USGS and the Minerals Management Service, oil resources underlying federal lands in the lower 48 states are estimated to be 4.1 billion barrels, and natural gas reserves are estimated to be 167 trillion cubic feet (Figure 5-4). Much of these potential resources have been placed off-limits or are subject to significant restrictions. For example, about 40 percent of the natural gas resources on federal land in the Rocky Mountain region have been placed off-limits.

The Department of the Interior initiated a study to examine the energy potential and restrictions on development on federal lands in the lower 48 states. In many cases, limits on oil and gas development are appropriate. However, improved technology has helped to reduce the impact of oil and gas development on the environment.

Exploration and Production

To meet increased natural gas demand in the coming decades, total wells drilled annually will need to double the 1999 level by 2020. Very few new onshore rigs have been built since the mid-1980s, because the oil field supply and service sectors have been hit especially hard by price volatility. Major additions to the offshore rig fleet will also be needed just to develop existing leases. The lack of an experienced work force may limit the speed and increase the cost of exploration and production activity.

Figure 5-4
**Restricted Natural Gas Resource Areas
in the U.S. Lower 48**



Much of the nation's oil and gas resource base resides on federal lands or in federal waters. A large portion of this is not open to exploration and development. For example, an estimated 40 percent or 137 trillion cubic feet of potential natural gas resource in the Rockies is either closed to exploration (29 tcf) or is open to development under restrictive provisions (108 tcf).

Source: U.S. Department of Energy, Energy Information Administration.

Electricity

Electricity is an essential part of modern life. When supply fails to keep pace with demand, costs to consumers and businesses rise and reliability falls. The California experience demonstrates the crippling effect that electricity shortages and blackouts can have on a state or region. This summer, the possibility exists for more intense electricity shortfalls in the West, with additional problems possible in New York City and on Long Island.

Electricity demand is projected to grow sharply over the next twenty years. Based on current estimates, the United States will need about 393,000 MW of new generating capacity by 2020 to meet the growing demand. If the U.S. electricity demand continues to grow at the high rate it has recently, we will need even more generating capacity. To meet that future demand, the United States will have to build between 1,300 to 1,900 new power plants; that averages out to be more than 60 to 90 plants a year, or more than one a week.

Over the next few years, if the demand for electricity continues to grow as predicted, and if we fail to implement a

comprehensive energy plan that recognizes the need to increase capacity, we can expect our electricity shortage problems to grow. The result will be higher costs and lower reliability.

Electricity Restructuring

One of the most important energy issues facing the Administration and Congress is electricity restructuring. The electricity industry is going through a period of dramatic change. To provide ample electricity supplies at reasonable prices, states are opening their retail markets to competition. This is the most recent step in a long transition from reliance on regulation to reliance on competitive forces.

Changes in Wholesale Electricity Market

This transition from regulation to competition began in 1978 with enactment of the Public Utility Regulatory Policies Act, which promoted independent electricity generation. Open-access transmission policies adopted by the Federal Energy Regulatory Commission (FERC) in the late 1980s further promoted competition in wholesale power markets. Congress largely ratified these policies with enactment of

the Energy Policy Act of 1992, which further promoted non-utility generation. FERC took another large step to promote competition with its open-access rule in 1996, which provided greater access to the transmission grid, the highway for interstate commerce in electricity.

Changes in the Retail Electricity Market

Increased competition in wholesale power markets encourages states to open retail electricity markets. Under current law, FERC has jurisdiction over the wholesale power market, while states have jurisdiction over retail markets. Beginning in 1996, states began opening their retail markets to competition in order to lower electricity prices. Twenty-five states have opted to open their retail electricity markets to competition.

Most new electricity generation is being built not by regulated utilities, but by independent power producers. These companies assume the financial risk of investment in new generation, and their success rides on their ability to generate electricity at a low cost.

These dramatic changes affecting the industry led to important structural changes. Independent power producers, which were once infant industries, now dwarf many utilities. Utility mergers, which were once rare, are now commonplace. U.S. utilities have been purchased by foreign companies, and U.S. utilities have in turn purchased utilities abroad. While utilities had service areas that were limited to a single state or region, independent power producers are international companies that can build power plants across the globe. Many utilities that were once vertically integrated divested themselves of generation, either voluntarily or because of state law.

Pending Congressional Action

Since 1995, Congress has been grappling with electricity competition legislation. Initial efforts sought to require states to open their retail markets by a date certain. Subsequent efforts focused on promoting competition in electricity markets and complementing state retail competition plans. Under this

Electricity demand is projected to rise sharply over the next twenty years. If we fail to build the 1,300–1,900 new power plants needed to increase generation and transmission capacity, current electricity shortages will become more frequent and more widespread.

U.S. DEPARTMENT OF ENERGY



approach, federal legislation focused on core federal issues, including:

- regulation of interstate commerce;
- assuring open access to the interstate and international transmission system;
- enhancing reliability of the grid;
- lowering barriers to entry;
- reforming outdated federal electricity laws, such as the Public Utility Holding Company Act and Public Utility Regulatory Policies Act of 1978;
- reforming the role of federal electric utilities in competitive markets;
- protecting consumers; and
- clarifying federal and state regulatory jurisdictions.

Recommendations:

★ The NEPD Group recommends that the President direct the Secretary of Energy to propose comprehensive electricity legislation that promotes competition, protects consumers, enhances reliability, improves efficiency, promotes renewable energy, repeals the Public Utility Holding Company Act, and reforms the Public Utility Regulatory Policies Act.

★ The NEPD Group recommends the President encourage FERC to use its existing statutory authority to promote competition and encourage investment in transmission facilities.

California Electricity Crisis

The California electricity crisis is not a test of the merits of competition in electricity markets. Instead, it demonstrates that a poorly designed state retail competition plan can have disastrous results if electricity supply does not keep pace with increased demand. At heart, the California electricity crisis is a supply crisis. California allowed demand to outstrip supply, and did little to lower barriers to entry through reform of an inflexible siting process. The risk that the California experience will repeat itself is low, since other states have not modeled their retail competition plans on California's plan.

The California crisis also shows that state electricity markets do not stay neatly confined within legal and jurisdictional bounds. Due to regional interconnection, disastrous mistakes made by the State of California have dire effects on the entire West. California's failure to reform flawed regulatory rules affecting the market drove up wholesale prices. Actions such as forcing utilities to purchase all their power through volatile spot markets, imposing a single-price auction system, and barring bilateral contracts all contributed to the problems that California now faces.

Lessons Learned from Successful Deregulation

As stated previously, 25 states have decided to open their retail electricity markets. A comparison of the different approaches taken by California and other states demonstrates that competition will benefit consumers if implemented effectively. A better gauge of the potential for retail competition to lower prices can be found in Pennsylvania, where electricity prices have fallen significantly as a result of competition. There is also reason to believe that the plan in Texas will have similar success.

A major difference between the California experience and the approaches taken by Pennsylvania and Texas is that the latter states ensured they had adequate electricity supplies. Pennsylvania and Texas took steps to ensure that procedures for adding new power plants were efficient. Unlike California, which imports 25 percent of its electricity, Pennsylvania is a net exporter of power, and Texas imports almost no power from other states. For these reasons, Pennsylvania and Texas have ample electricity supply to meet demand, while California is confronting a serious supply shortage.

In addition, California required its utilities to divest themselves of much of their generation, unlike Pennsylvania and Texas. This action forced California utilities to rely much more heavily on buying power, at ever-increasing prices, instead of generating power themselves.

Another major difference is that Pennsylvania and Texas did not require their utilities to purchase electricity through volatile spot markets. This requirement, combined with frozen retail rates imposed by the State, forced California utilities to purchase power at much higher costs than could be passed along to the consumer. As a result, the California regulatory plan resulted in unreliable service, destroyed the financial health of the State's utilities, and drove one utility into bankruptcy.

The federal government does not site power plants; that is a responsibility of the states. For that reason, delays relating to the construction of new power plants are usually the result of state action. A number of federal agencies, such as the Environmental Protection Agency, the Department of Commerce, and the Department of the Interior, do issue air and other permits for generation facilities. Some of the concerns about permitting or review delays in other states can be similarly addressed by expediting processes. These agencies, pursuant to President Bush's Executive Order, have expedited permit-processing applications for energy production in California.

Some of the concerns about permitting or review delays in other states can be similarly addressed by expediting processes. For example, in 1999–2000, the time for issuing air permits (including the time for public participation) for turbines was reduced to three to four months (compared to the twelve months allowed by the regulations) for the majority of permit applications.

Fuels for Electricity Generation

Electricity is not a primary source of energy. It is generated by the use of primary energy sources (Figure 5-5). Coal, nuclear energy, natural gas and hydropower account for about 95 percent of total electricity generation, with oil and renewable energy contributing the remainder. Despite this healthy diversity of energy sources, each type of electricity resource is faced with constraints to maintaining or expanding its contribution to electricity production.

Coal

Coal is used almost exclusively to generate electricity. Coal power plants account for over 50 percent of all U.S. electricity generation, and over 80 percent of generation in twelve states in the Midwest, Southeast, and West. Coal electricity generation costs are low, and coal prices have proved remarkably stable. In 1999, the United States produced 1.1 billion tons of coal. Production of coal from federal and tribal lands, which has increased substantially in the past decade, accounted for 38 percent of this total.

Although coal is the nation's most abundant fossil energy source, production and market issues can affect the adequacy of supply. Production issues include the protection of public health, safety, property, and the environment, and the effectiveness of federal and state agencies implementing various laws governing coal mining. These issues have resulted in some coal resources becoming uneconomical to produce. Statutory, regulatory, and administrative difficulties also may limit or prevent the production of some coal resources. However, technological advances in cleaner coal technology have allowed for significant progress toward reducing these barriers. There are also opportunities to protect the environment while lowering costs through further improvements in technology.

Over the past decade, greater efficiencies, lower capital costs, fewer emissions and quicker start-up times have made power plants fueled by natural gas a more attractive choice for new coal generation. Recently, however, rising natural gas prices have renewed interest in building coal power plants.

Uncertainty about future environmental controls is of particular concern for companies that operate existing coal power plants. Regulations under development include a variety of measures requiring reductions in emissions of nitrogen oxide, sulfur dioxide, and mercury. In addition, rules related to discharges to streams and cooling-water intake structures, possible regulation of large-volume wastes as hazardous wastes,

uncertainty over rules requiring air permits for certain modifications to power plants, and uncertainty over global and domestic efforts to reduce carbon dioxide emissions also play a role. This regulatory uncertainty discourages power producers from building coal power plants and is one reason the United States is relying so heavily on natural gas power generation to meet growing electricity demand.

Much of the current uncertainty has resulted because regulators do not weigh the cumulative impacts of their proposals. Compliance decisions by businesses concerning each new regulation must often be made without the benefit of clear information regarding additional requirements that may be imposed. More effective and economical compliance strategies are possible if companies know the full range of requirements with which they must comply.

If rising U.S. electricity demand is to be met, then coal must play a significant role. Under current policies, in the next two decades, nuclear electricity generation and hydropower are projected to decline. Natural gas electricity generation is projected to increase from about 16 to 36 percent of total generation, which would require the tripling of natural gas used for electricity generation. Significantly, this projected increase in natural gas genera-

tion assumes that coal electricity generation will continue to account for about 50 percent of U.S. electricity generation. If policies are adopted that sharply lower coal electricity generation, then the likely result is an even greater dependence on natural gas generation. This creates concern about the adequacy of natural gas supplies and policies.

Clean Coal Technology

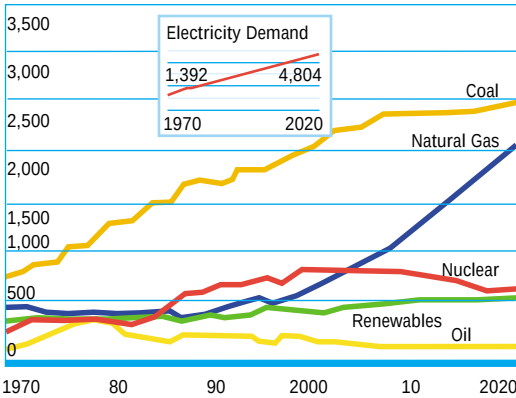
Technology has been and will continue to be a key to achieving our energy, economic, and environmental goals. In recent years, technological advancements through efforts of both the public and private sectors have led to substantial reductions in the cost of controlling sulfur dioxide and nitrogen oxide emissions, while the effectiveness of control systems increased significantly. The Department of Energy, through its Clean Coal Technology Program, has worked to provide effective control technologies. These nitrogen oxide and sulfur dioxide control technologies have moved into the utility marketplace and now provide a means to achieve cost effective regulatory compliance.

For example, most power plants that can use low nitrogen oxide burners have now installed them, and about 25 percent of all coal power plants have either ordered or installed selective catalytic reduction technology, which reduces nitrogen oxide emissions.

Technologies like fluidized-bed combustion and integrated gasification combined cycle have been developed that further reduce emissions. Fluidized-bed combustion is a low-emitting nitrogen oxide combustion technology that allows the use of fuels, such as coal pile washer waste, that were not formerly usable. Integrated gasification combined cycle is a relatively new technology that uses refinery waste as fuel.

Future coal electricity generation will need to meet new challenges to reduce emissions even further, especially mercury emissions. The Department of Energy is supporting efforts to develop more cost effective control technology. Indeed, the goal

Figure 5-5
Electricity Generation by Fuel: Current Trends
(Billions of Kilowatt-Hours)



Source: U.S. Department of Energy, Energy Information Administration

Clean Coal Technology

Clean Coal Technology describes a category of technologies that allow for the use of coal to generate electricity while meeting environmental regulations at low cost.

- In the short term, the goal of the program is to meet existing and emerging environmental regulations, which will dramatically reduce compliance costs for controlled mercury, NO_x, SO₂, and fine particulate at new and existing coal power plants.

- In the mid-term, the goal of the program is to develop low-cost, super-clean coal power plants, with efficiencies 50 percent higher than today's average. The higher efficiencies will reduce emissions at minimal costs.

- In the long term, the goal of the program is to develop low-cost, zero-emission power plants with efficiencies close to double that of today's fleet.

of these research, development, and demonstration programs is to develop and demonstrate coal power systems with near zero environmental emissions, while maintaining low production costs.

Recommendations:

- ★ The NEPD Group recognizes the importance of looking to technology to help us meet the goals of increasing electricity generation while protecting our environment. To that end, the NEPD Group recommends that the President direct the Department of Energy to continue to develop advanced clean coal technology by:

- Investing \$2 billion over 10 years to fund research in clean coal technologies.
- Supporting a permanent extension of the existing R&D tax credit.
- Directing agencies to explore regulatory approaches that will encourage advancements in environmental technology.

- ★ The NEPD Group recommends that the President direct federal agencies to provide greater regulatory certainty relating to coal electricity generation through clear policies that are easily applied to business decisions.

Nuclear Energy

Nuclear energy accounts for 20 percent of all U.S. electricity generation, and more than 40 percent of the electricity generation in ten states in the Northeast, the South, and the Midwest. Despite the closure of several less efficient plants during the 1990s, the 103 U.S. nuclear energy plants currently operating produce more electricity today than at any time in history.

There are a number of reasons why nuclear energy expansion halted in the 1980s. Regulatory changes implemented after the Three Mile Island incident in 1979 lengthened the licensing period to an average of fourteen years, resulting in large cost overruns. Increased public concern

about the safety of nuclear energy after the accident often resulted in active opposition to proposed plants. As a result, the last completed nuclear energy plant in the United States was ordered in 1973.

Since the 1980s, the performance of nuclear energy plant operations has substantially improved. While U.S. nuclear energy plants once generated electricity only around 70 percent of the time, the average plant today is generating electricity close to 90 percent. This improved performance has lowered the cost of nuclear generation, which is now competitive with other sources of electricity (Figure 5-6).

There is potential for even greater generation from existing nuclear energy plants. Experts estimate that 2,000 MW could be added from existing nuclear power plants by increasing operating performance to 92 percent. In addition, about 12,000 MW of additional nuclear electricity generation could be derived from uprating U.S. nuclear power plants, a process that uses new technologies and methods to increase rated power levels without decreasing safety. However, modifications to uprate plants can be expensive and require extensive licensing review and approval by the Nuclear Regulatory Commission (NRC). Another way to increase nuclear generation from existing plants is through license renewal. Many nuclear utilities are planning to extend the operating license of existing nuclear plants by twenty years, and the licenses of as many as 90 percent of the currently operating nuclear plants may be renewed.

The nuclear energy industry is closely regulated by the NRC, which provides rigorous oversight of the operation and maintenance of these plants. This oversight includes a comprehensive inspection program that focuses on the most significant potential risks of plant operations and features full-time resident inspectors at each plant, as well as regional inspectors with specialized expertise. The NRC has made great strides to provide greater regulatory certainty while maintaining high safety standards.

The installation of new design features, improvements in operating experience, nuclear safety research, and operator training have all contributed to the strong safety record of the nuclear energy industry. Since the Three Mile Island incident in 1979, the nuclear industry's safety record has significantly improved. This safety record has been achieved through a defense-in-depth philosophy accomplished by way of engineering design, quality construction, safe operation, and emergency planning. This philosophy provides for diverse and redundant systems to prevent accidents from occurring, as well as multiple safety barriers to mitigate the effects of accidents in the highly unlikely event they do occur.

Over the last several years, utilities have begun purchasing nuclear plants from other operators as the industry undergoes consolidation. Several nuclear utilities have merged, creating management teams with extensive expertise in running and maintaining nuclear plants. These mergers are impeded by tax rules relating to the transfer of decommissioning funds.

Utilities are also considering nuclear energy as an option for new generation. The NRC

has certified three standardized nuclear power plant designs, and Congress enacted legislation in 1992 to reform the nuclear licensing process. Under this process, a utility can apply for a combined construction and operating license for one of these standardized designs in a streamlined process. This reformed licensing process provides for site permits—a way to resolve siting issues early in the process. Building new generators on existing sites avoids many complex issues associated with building plants on new sites. Many U.S. nuclear plant sites were designed to host four to six reactors, and most operate only two or three; many sites across the country could host additional plants.

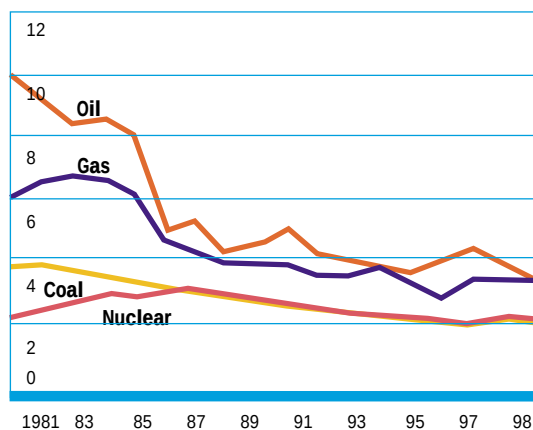
Advanced reactor technology promises to improve nuclear safety. One example of an advanced reactor design is the gas-cooled, pebble-bed reactor, which has inherent safety features. The industry has an interest in this and other advanced reactor designs.

The federal government must also provide for the safe disposal of nuclear waste. At present, nuclear waste continues to be stored at local plant sites. The Department of Energy is over a decade behind schedule for accepting nuclear waste from utilities, but has made progress toward characterization of the Yucca Mountain, Nevada site. Construction of an exploratory studies facility has been completed, a viability assessment was published, and recently scientists placed their extensive research about Yucca Mountain on the record for public scrutiny. However, key regulatory standards to protect public health and the environment at the repository have not been issued.

The Administration will continue to study the science to determine whether to proceed with the consideration of this site as the location for the repository. If the Administration decides to proceed, the Department of Energy must file a license application with the NRC. No waste will be sent to any location until the NRC determines it to be safe.

Other countries have developed different approaches for nuclear waste disposal. For example, the French, British and Japanese rely on reprocessing, an in-

Figure 5-6
Nuclear Generation is Competitively Priced
(1998 Cents per Kilowatt-Hour)



Note: Fuel costs are included.⁶

Source: Utility Data Institute via the Nuclear Energy Institute.⁶



Calvert Cliffs is the first U.S. nuclear plant to receive a renewed license from the Nuclear Regulatory Commission. The renewal will allow the plant to continue producing environmentally sound electricity for an additional twenty years.

CONSTELLATION ENERGY GROUP

dustrial approach that separates nuclear waste into usable fuel and highly concentrated waste. While this approach does not obviate the need for geologic disposal of nuclear waste, it could significantly optimize the use of a geologic repository. There is growing interest in new technology known as accelerator transmutation, which could be used in combination with reprocessing to reduce the quantity and toxicity of nuclear waste.

Recommendations:

★ The NEPD Group recommends that the President support the expansion of nuclear energy in the United States as a major component of our national energy policy. Following are specific components of the recommendation:

- Encourage the Nuclear Regulatory Commission (NRC) to ensure that safety and environmental protection are high priorities as they prepare to evaluate and expedite applications for licensing new advanced-technology nuclear reactors.
- Encourage the NRC to facilitate efforts by utilities to expand nuclear energy generation in the United States by uprating existing nuclear plants safely.

- Encourage the NRC to relicense existing nuclear plants that meet or exceed safety standards.
- Direct the Secretary of Energy and the Administrator of the Environmental Protection Agency to assess the potential of nuclear energy to improve air quality.
- Increase resources as necessary for nuclear safety enforcement in light of the potential increase in generation.
- Use the best science to provide a deep geologic repository for nuclear waste.
- Support legislation clarifying that qualified funds set aside by plant owners for eventual decommissioning will not be taxed as part of the transaction.
- Support legislation to extend the Price–Anderson Act.

★ The NEPD Group recommends that, in the context of developing advanced nuclear fuel cycles and next generation technologies for nuclear energy, the United States should reexamine its policies to allow for research, development and deployment of fuel conditioning methods (such as pyroprocessing) that reduce waste streams and enhance proliferation resistance. In doing so, the United States will continue to discourage the accumulation of separated plutonium, worldwide.

★ The United States should also consider technologies, in collaboration with international partners with highly developed fuel cycles and a record of close cooperation, to develop reprocessing and fuel treatment technologies that are cleaner, more efficient, less waste-intensive, and more proliferation-resistant.

Hydropower

Although hydropower generation accounts for only about 7 percent of overall U.S. electricity generation, the following states depend heavily on this source of energy: Idaho, Washington, Oregon, Maine, South Dakota, California, Montana, and New York.

Hydropower generation has remained relatively flat for years. The most significant constraint on expansion of U.S. hydropower generation is physical; most of the best locations for hydropower generation have already been developed. Potential does remain for some increases in hydropower generation, and capacity can be optimized by adding additional turbines and increasing efficiency at existing facilities.

Also, the amount of hydropower generation depends upon the quantity of available water. A drought can have a devastating effect on a region that depends on hydropower. In fact, this year's water availability has been a contributing factor in California's electricity supply shortages. The amount of hydropower generation depends upon the quantity of available water. A drought can have a devastating effect on a region that depends on hydropower. In fact, this year's water availability has been a contributing factor in California's electricity supply shortages.

The Federal Energy Regulatory Commission is required to incorporate mandatory conditions proposed by different state and federal resource agencies into hydropower licenses. Decision-making authority in the licensing process is diffused among a host of federal and state agencies, all of which are pursuing different statutory missions. The hydropower licensing process is prolonged, costly, and poses regulatory uncertainty. The challenge is to efficiently and effectively balance national interests in natural resource and environmental preservation with energy needs.

Recommendation:

★ The NEPD Group recognizes there is a need to reduce the time and cost of the hydropower licensing process. The NEPD Group recommends that the President encourage the Federal Energy Regulatory Commission (FERC) and direct federal resource agencies to make the licensing process more clear and efficient, while preserving environmental goals. In addition, the NEPD Group recognizes the importance of optimizing the efficiency and reliability of existing hydropower facilities, and will encourage the Administration to adopt efforts toward that end.

- Support administrative and legislative reform of the hydropower licensing process.
- Direct federal resource agencies to reach interagency agreement on conflicting mandatory license conditions before they submit their conditions to FERC for inclusion in a license.
- Encourage FERC to adopt appropriate deadlines for its own actions during the licensing process.

Natural Gas

Currently, natural gas provides about 16 percent of U.S. electricity generation. Seven states obtain over one-third of their generation from natural gas (Rhode Island, New York, Delaware, Louisiana, Texas, California, and Alaska). Perhaps more importantly, natural gas-fired electricity is projected to constitute about 90 percent of capacity additions between 1999 and 2020. The amount of natural gas used in electricity generation is projected to triple by 2020.

Ensuring the long-term availability of adequate, reasonably priced natural gas supplies is a challenge. Low gas prices in 1998 and 1999 caused the industry to scale back gas exploration and production activity. Since 2000, the North American natural gas market has remained tight due to strong demand and diminished supplies. Last year, natural gas prices quadrupled, which resulted in substantially higher prices for electricity generated with natural gas.

While the largest barriers to expanded natural gas electricity generation relate to production and pipeline constraints, there are several other barriers. Environmental regulations affect the use of gas for electricity generation. Although natural gas electric plants produce fewer emissions than coal-fired power plants, they still emit nitrogen oxides, carbon dioxide and small amounts of toxic air emissions.'

Oil

While oil fuels only about 3 percent of total U.S. electricity generation, it is the dominant source of electricity generation in Hawaii, and provides over 20 percent of the generation in Massachusetts, Connecticut, Delaware, Maine, and Florida. Over the next twenty years, market conditions are expected to reduce today's level of oil electricity generation by about 80 percent.

Renewable Energy

Hydropower is, to date, the most successful form of renewable energy. However, some forms of renewable energy generation—wind, geothermal, and biomass—have the potential to make more significant contributions in coming years, and the cost of most forms of renewable energy has declined sharply in recent years. The most important barrier to increased renewable energy production remains economic; nonhydropower renewable energy generation costs are greater than other traditional energy sources. The following chapter discusses renewable and alternative energy in greater detail.

High-tech power plants, like this combined cycle plant, are signaling a new age in electric power generation. The capability to co-produce electricity and a slate of fuels and chemicals makes the technology economically attractive to a broad range of industrial applications.

TAMPA ELECTRIC COMPANY



Summary of Recommendations

Energy for a New Century: Increasing Domestic Energy Supplies

★ The NEPD Group recommends that the President direct the Secretaries of Energy and the Interior to promote enhanced oil and gas recovery from existing wells through new technology.

★ The NEPD Group recommends that the President direct the Secretary of Energy to improve oil and gas exploration technology through continued partnership with public and private entities.

★ The NEPD Group recommends that the President direct the Secretary of the Interior to examine land status and lease stipulation impediments to federal oil and gas leasing, and review and modify those where opportunities exist (consistent with the law, good environmental practice, and balanced use of other resources).

- Expedite the ongoing Energy Policy and Conservation Act study of impediments to federal oil and gas exploration and development.
- Review public lands withdrawals and lease stipulations, with full public consultation, especially with the people in the region, to consider modifications where appropriate.

★ The NEPD Group recommends that the President direct the Secretary of the Interior to consider economic incentives for environmentally sound offshore oil and gas development where warranted by specific circumstances: explore opportunities for royalty reductions, consistent with ensuring a fair return to the public where warranted for enhanced oil and gas recovery; for reduction of risk associated with production in frontier areas or deep gas formations; and for development of small fields that would otherwise be uneconomic.

★ The NEPD Group recommends that the President direct the Secretaries of Commerce and Interior to re-examine the current federal legal and policy regime (statutes, regulations, and Executive Orders) to determine if changes are needed regarding energy-related activities and the siting of energy facilities in the coastal zone and on the Outer Continental Shelf (OCS).

★ The NEPD Group recommends that the President direct the Secretary of the Interior continue OCS oil and gas leasing and approval of exploration and development plans on predictable schedules.

★ The NEPD Group recommends that the President direct the Secretary of the Interior to consider additional environmentally responsible oil and gas development, based on sound science and the best available technology, through further lease sales in the National Petroleum Reserve-Alaska. Such consideration should include areas not currently leased within the Northeast corner of the Reserve.

★ The NEPD Group recommends that the President direct the Secretary of the Interior work with Congress to authorize exploration and, if resources are discovered, development of the 1002 Area of ANWR. Congress should require the use of the best available technology and should require that activities will result in no significant adverse impact to the surrounding environment.

★ The NEPD Group recommends that the President direct the Secretary of the Interior to work with Congress and the State of Alaska to put in place the most expeditious process for renewal of the Trans-Alaska Pipeline System rights-of-way to ensure that Alaskan oil continues to flow uninterrupted to the West Coast of the United States.

★ The NEPD Group recommends that the President direct the Secretary of Energy to propose comprehensive electricity legislation that promotes competition, protects consumers, enhances reliability, promotes renewable energy, improves efficiency repeals the Public Utility Holding Company Act, and reforms the Public Utility Regulatory Policies Act.

★ The NEPD Group recommends that the President encourage FERC to use its existing statutory authority to promote competition and encourage investment in transmission facilities.

★ The NEPD Group recognizes the importance of looking to technology to help us meet the goals of increasing electricity generation while protecting our environment. To that end, the NEPD Group recommends that the President direct the Department of Energy to continue to develop advanced clean coal technology by:

- Investing \$2 billion over 10 years to fund research in clean coal technologies.
- Supporting a permanent extension of the existing research and development tax credit.
- Directing federal agencies to explore regulatory approaches that will encourage advancements in environmental technology.

★ The NEPD Group recommends that the President direct federal agencies to provide greater regulatory certainty relating to coal electricity generation through clear policies that are easily applied to business decisions.

★ The NEPD Group recommends that the President support the expansion of nuclear energy in the United States as a major component of our national energy policy. Following are specific components of the recommendation:

- Encourage the Nuclear Regulatory Commission (NRC) to ensure that safety and environmental protection are high priorities as they prepare to evaluate and expedite applications for licensing new advanced-technology nuclear reactors.
- Encourage the NRC to facilitate efforts by utilities to expand nuclear energy generation in the United States by uprating existing nuclear plants safely.
- Encourage the NRC to relicense existing nuclear plants that meet or exceed safety standards.
- Direct the Secretary of Energy and the Administrator of the Environmental Protection Agency to assess the potential of nuclear energy to improve air quality.
- Increase resources as necessary for nuclear safety enforcement in light of the potential increase in generation.
- Use the best science to provide a deep geologic repository for nuclear waste.
- Support legislation clarifying that qualified funds set aside by plant owners for eventual decommissioning will not be taxed as part of the transaction.
- Support legislation to extend the Price–Anderson Act.

★ The NEPD Group recommends that, in the context of developing advanced nuclear fuel cycles and next generation technologies for nuclear energy, the United States should reexamine its policies to allow for research, development and deployment of fuel conditioning methods (such as pyroprocessing) that reduce waste streams and enhance proliferation resistance. In doing so, the United States will continue to discourage the accumulation of separated plutonium, worldwide.

★ The United States should also consider technologies (in collaboration with international partners with highly developed fuel cycles and a record of close cooperation) to develop reprocessing and fuel treatment technologies that are cleaner, more efficient, less waste-intensive, and more proliferation-resistant.

★ The NEPD Group recognizes there is a need to reduce the time and cost of the hydropower licensing process. The NEPD Group recommends that the President encourage the Federal Energy Regulatory Commission (FERC) and direct federal resource agencies to make the licensing process more clear and efficient, while preserving environmental goals. In addition, the NEPD Group recognizes the importance of optimizing the efficiency and reliability of existing hydropower facilities and will encourage the Administration to adopt efforts toward that end.

- Support administrative and legislative reform of the hydropower licensing process.
- Direct federal resource agencies to reach interagency agreement on conflicting mandatory license conditions before they submit their conditions to FERC for inclusion in a license.
- Encourage FERC to adopt appropriate deadlines for its own actions during the licensing process.

Nature's Power

Increasing America's Use of Renewable and Alternative Energy

A sound national energy policy should encourage a clean and diverse portfolio of domestic energy supplies. Such diversity helps to ensure that future generations of Americans will have access to the energy they need.

Renewable energy can help provide for our future needs by harnessing abundant, naturally occurring sources of energy, such as the sun, the wind, geothermal heat, and biomass. Effectively harnessing these renewable resources requires careful planning and advanced technology. Through improved technology, we can ensure that America will lead the world in the development of clean, natural, renewable and alternative energy supplies.

Renewable and alternative energy supplies not only help diversify our energy portfolio; they do so with few adverse envi-

ronmental impacts. While the current contribution of renewable and alternative energy resources to America's total electricity supply is relatively small—only 9 percent—the renewable and alternative energy sectors are among the fastest growing in the United States. Non-hydropower only account for 2 percent of our electricity needs. However, electricity generation from non-hydropower renewable energy grew by nearly 30 percent in the 1990s. Continued growth of renewable energy will continue to be important in delivering larger supplies of clean, domestic power for America's growing economy.

Renewable energy resources tap naturally occurring flows of energy to produce electricity, fuel, heat, or a combination of these energy types. One type of renewable energy, hydropower, has long provided a significant contribution to the U.S. energy supply and today is competitive with other forms of conventional electricity. However, there is limited growth potential for hydropower. Non-hydropower renewable energy is generated from four sources: biomass, geothermal, wind, and solar (Figure 6-1). The United States has significant potential for renewable resource development. These nondepletable sources of energy are domestically abundant and often have less impact on the environment than conventional sources. They can provide a reliable source of energy at a stable price, and they can also generate income for farmers, landowners, and others who harness them.

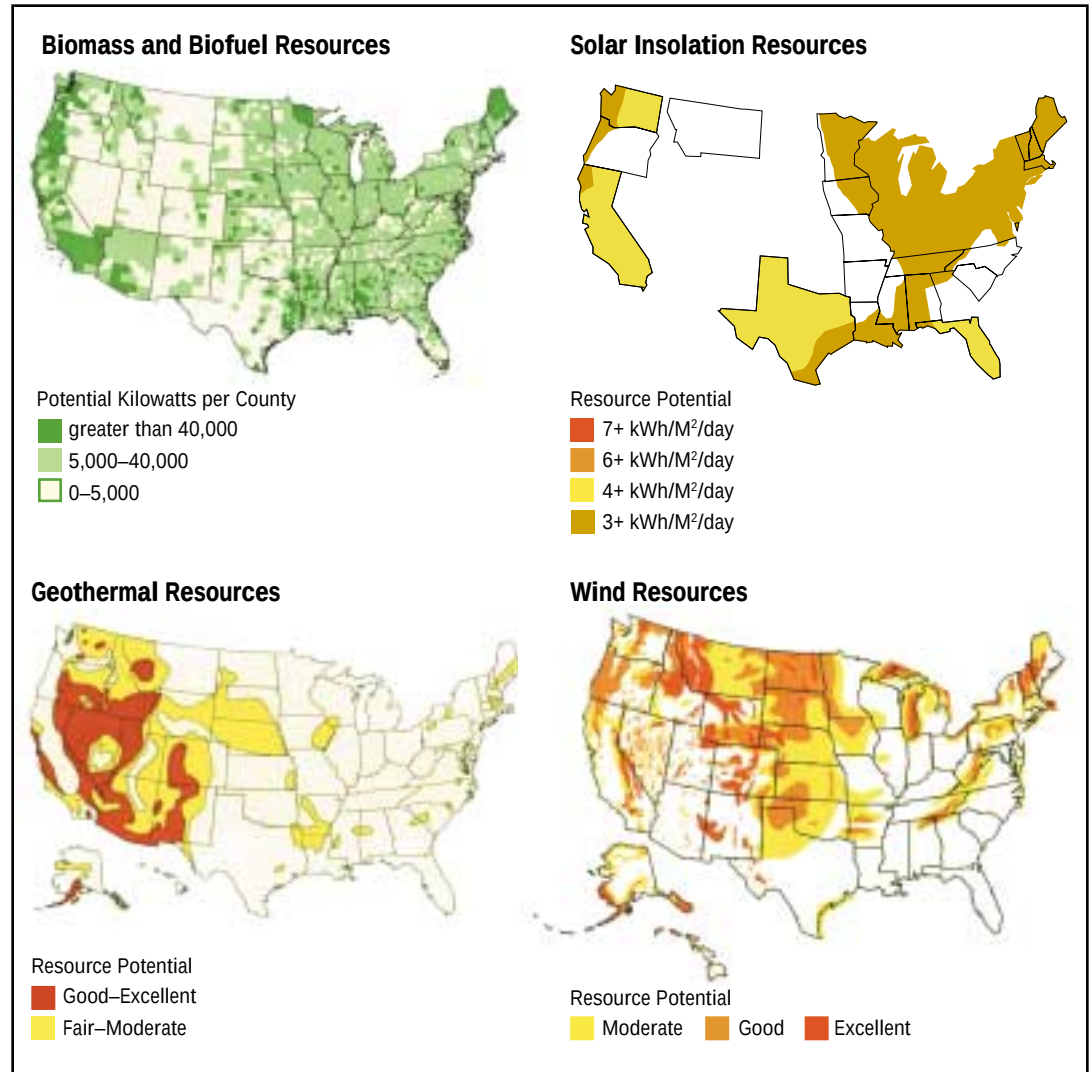
Renewable hydropower has long provided a significant contribution to the U.S. energy supply. Today, hydropower is competitive with other forms of conventionally generated electricity.





Figure 6-1

U.S. Resource Potential for Renewable Energy



Almost every state has the potential for wind energy and for biomass and biofuel production. The Southwest has the greatest potential for solar energy, and geothermal energy resources are most abundant in the West.

Source: U.S. Department of Energy, National Renewable Energy Laboratory.

Recommendation:

★ The NEPD Group recommends that the President direct the Secretaries of the Interior and Energy to re-evaluate access limitations to federal lands in order to increase renewable-energy production, such as biomass, wind, geothermal, and solar.

Alternative energy includes: alternative fuels that are transportation fuels other than gasoline and diesel, even when the

type of energy, such as natural gas, is traditional; the use of traditional energy sources, such as natural gas, in untraditional ways, such as for distributed energy at the point of use through microturbines or fuel cells; and future energy sources, such as hydrogen and fusion.

Both renewable and alternative energy resources can be produced centrally or on a distributed basis near their point of use. Providing electricity, light, heat, or mechanical energy at the point of use diminishes the

need for some transmission lines and pipe lines, reducing associated energy delivery losses and increasing energy efficiency. Distributed energy resources may be renewable resources, such as biomass cogeneration in the lumber and paper industry or rooftop solar photovoltaic systems on homes, or they may be alternative uses of traditional energy, such as natural gas microturbines.

Recommendations:

★ The NEPD Group supports the increase of \$39.2 million in the FY 2002 budget amendment for the Department of Energy's Energy Supply account that would provide increased support for research and development of renewable energy resources.

★ The NEPD Group recommends that the President direct the Secretary of Energy to conduct a review of current funding and historic performance of renewable energy and alternative energy research and development programs in light of the recommendations of this report. Based on this review, the Secretary of Energy is then directed to propose appropriate funding of those research and development programs that are performance-based and are modeled as public-private partnerships.

Renewable Energy Technologies

Biomass

Biomass is organic matter that can be used to provide heat, make fuel, and generate electricity. Wood, the largest source of biomass, has been used to provide heat for thousands of years. Many other types of biomass are also used as an energy source, such as plants, residue from agriculture or forestry, and the organic component of municipal and industrial wastes. Landfill gas is also considered a biomass source. Biomass resources can be replenished through culti-

Microturbines

Microturbines are small combustion turbines approximately the size of a refrigerator with outputs of 25 to 500 kilowatts. Microturbines can be used to power a home or small business. This technology has evolved largely from automotive and truck turbochargers, auxiliary power units for airplanes, and small jet engines.

Compared to other technologies for small-scale power generation, microturbines offer a number of significant advantages, including a small number of moving parts; compact size; lightweight, optimal efficiency; lower emissions and electricity costs; and opportunities to use waste fuels. For these reasons, microturbines could easily capture a significant share of the distributed generation market.

vation of what are known as energy crops, such as fast-growing trees and grasses.

Unlike other renewable energy sources, biomass can be converted directly into liquid fuels, called biofuels, to meet our transportation needs. The two most common biofuels are ethanol and biodiesel.

Ethanol is made by fermenting any biomass that is rich in carbohydrates, such as corn. It is mostly used as a fuel additive to reduce a vehicle's emissions. Biodiesel is made using vegetable oils, animal fats, algae, or even recycled cooking greases. It can be used as a diesel additive to reduce emissions or in its pure form to fuel a vehicle. Beyond energy benefits, development of biomass benefits rural economies that produce crops used for biomass, particularly ethanol and biomass electricity generation.

Biomass, like corn, that is rich in carbohydrates can be converted directly into biofuels to meet our transportation needs. The biofuel ethanol is mostly used as a fuel additive to reduce vehicles' smog-causing emissions. In June 1992, the Greater Peoria Mass Transit District began operating fourteen ethanol-powered buses along regular city routes.

U.S. DEPARTMENT OF ENERGY



Biomass is also used to generate electricity. This is accomplished through the direct combustion of wood, municipal solid waste, and other organic materials; co-firing with coal in high efficiency boilers; or combustion of biomass that has been chemically converted into fuel oil. In the lumber and paper industries, wood scraps are sometimes directly fed into boilers to produce steam for their manufacturing processes or to heat their buildings. For that reason, renewable energy offers a particular advantage to the lumber and paper industry, and many analysts project the industry may soon become a net seller of electricity. Co-firing coal power plants with biomass has environmental benefits, since co-firing can significantly reduce emissions. Biomass accounts for 76 percent of renewable electricity generation and 1.6 percent of total U.S. electricity supply.

Even gas for generating electricity can be produced from biomass. Gasification systems use high temperatures to convert biomass into a gas that is used to fuel a turbine. The decay of biomass in landfills also produces methane, a gas that can be captured and burned in a boiler to produce steam for electricity generation or for industrial processes. Using methane emissions increases electricity supplies, reduces pollution from landfills and reduces greenhouse gas emissions. The technologies to collect and use landfill methane to generate electricity are already in the market. How-

ever, they have not been successfully integrated at present due to the perceived higher risk of new technologies.

Recommendation:

★ The NEPD Group recommends that the President direct the Secretary of the Treasury, to work with Congress on legislation to expand the section 29 tax credit to make it available for new landfill methane projects. The credit could be tiered, depending on whether a landfill is already required by federal law to collect and flare its methane emissions due to local air pollution concerns.

Geothermal

Geothermal energy is the use of steam and hot water generated by heat from the Earth to perform work. Some geothermal power plants use steam or hot water from a natural underground reservoir to power a generator. Others use hot water to provide direct heat for residential and other buildings, and for other applications.

The most readily accessible resources for geothermal power generation in the United States are located in the West, Alaska, and Hawaii. A wide array of high technology geological, geochemical, and geophysical techniques are used to locate geothermal resources. In large measure, the technology for developing these resources has been adapted from the oil industry. Improvements in drill bits, drilling techniques, advanced instruments, and other technological advances have made energy production from geothermal resources increasingly efficient.

Geothermal accounts for 17 percent of renewable electricity generation and 0.3 percent of total U.S. electricity supply. However, the net installed capacity of U.S. geothermal power plants has increased significantly, from 500 MW in 1973 to 2,800 MW today.

Hot water near the surface of the Earth can also be used directly for heat. These direct-use applications include heat

The Geysers in northern California is the world's largest producer of renewable geothermal power. The dry-steam field has successfully produced power since the early 1960s, when Pacific Gas & Electric installed the first 11-megawatt plant. Today, nearly 2,000 megawatts are on line – enough energy to supply the electricity needs of San Francisco and Oakland.

PACIFIC GAS & ELECTRIC



ing buildings, growing plants in green houses, drying crops, heating water at fish farms, and several industrial processes, such as pasteurizing milk.

In addition, individual homeowners, farmers, and businesses can tap into geothermal energy through geothermal heat pumps to heat and cool buildings. A geothermal heat pump system consists of a heat pump, an air delivery system, a heat exchanger, and a system of pipes buried in the shallow ground near the building. In the winter, a heat pump removes heat from the heat exchanger and pumps that heat into the indoor air delivery system. In the summer, the process is reversed, and the heat pump moves heat from the indoor air into the heat exchanger. The heat removed from the indoor air during the summer can also be used to provide a free source of hot water. Geothermal heat pumps can be used almost anywhere in the United States, and can significantly increase system efficiencies.

Recommendation:

★ The NEPD Group recommends that the President direct the Secretary of the Interior to determine ways to reduce the delays in geothermal lease processing as part of the permitting review process.

Wind Energy

Wind energy has been used since at least 200 B.C. for grinding grain and pumping water. By 1900, windmills were used on farms and ranches in the United States to pump water and, eventually, to produce electricity. Windmills developed into modern-day wind turbines.

Wind turbines are used for several applications. Wind power uses the naturally occurring energy of the wind for practical purposes like generating electricity, charging batteries, or pumping water. Large, modern wind turbines operate together in wind farms to produce electricity for utilities. Small turbines are used by homeowners, farmers, and remote villages to help meet localized energy needs.

Wind turbines capture energy by using propeller-like blades that are mounted on a



rotor. These blades are placed on top of high towers, in order to take advantage of the stronger winds at 100 feet or more above the ground. The wind causes the propellers to turn, which then turn the attached shaft to generate electricity. Wind can be used as a stand-alone source of energy or in conjunction with other renewable energy systems. Wind and natural gas hybrid systems are a promising approach that offers clean power to consumers.

Wind energy accounts for 6 percent of renewable electricity generation and 0.1 percent of total electricity supply. However, advances by research labs, universities, utilities, and wind energy developers have helped cut wind energy's costs by more than 80 percent during the last twenty years. The industry is poised for growth. In some parts of the country, electricity from wind power can be produced at prices that are comparable to other conventional energy technologies. The United States has many areas with abundant wind energy potential, namely in the West, the Great Plains and New England.

Solar

Sunlight, or solar energy, can be used to generate electricity; heat water; and heat, cool, and light buildings. Photovoltaic (solar cell) systems use semiconductor materials similar to those used in computer chips to capture the energy in sunlight and to convert it directly into electricity. Photovoltaic cells have been used in everything from

In 1996, the National Association of Home Builders constructed advanced townhouses featuring standing-seam roofs and other energy efficient materials and systems. The townhouse on the right differs from the others in that it has an integrated photovoltaic standing-seam roof that also produces electricity.

TIM ELLISON, ENERGY CONVERSION DEVICES

the solar cells in calculators to the space station Freedom.

Another technology for harnessing the sun's energy is a concentrating solar power system, which uses the sun's heat to generate electricity. The sunlight is collected and focused with mirrors to create a high intensity heat source that in turn can be used to generate electricity through a steam turbine or a heat engine.

Solar hot water systems use the sun to heat water for domestic or industrial use. Many large commercial buildings also use solar collectors for heat. A solar ventilation system can be used in cold climates to pre heat air as it enters a building. The heat from a solar collector can even be used to provide energy for cooling a building.

Some architects are using careful design and new optical materials to use sunlight to reduce the need for traditional lighting and to cut down on heating and cooling costs. For example, materials that absorb and store the sun's heat can be built into the sunlit floors and walls. The floors and walls

will store heat during the day and slowly release heat at night.

While solar energy technologies have undergone technological and cost improvements and are well established in high value markets like remote power, satellites, communications, and navigational aids, continued research is needed to reduce costs and improve performance. Solar energy accounts for 1 percent of renewable electricity generation and 0.02 percent of total U.S. electricity supply.

Alternative Energy

Alternative Transportation Fuels

Alternative fuels are any transportation fuels made from a nontraditional source, including ethanol, biodiesel, and other biofuels. These can be made from biomass resources, including liquid fuels (e.g., ethanol, methanol, biodiesel) and gaseous fuels (e.g., hydrogen and methane). Biofuels are primarily used to fuel vehicles, but can also fuel engines or fuel cells for electricity generation. Alternative fuels also

Recommendations:

- ★ The NEPD Group recommends that the President direct the Administrator of the Environmental Protection Agency to develop a new renewable energy partnership program to help companies more easily buy renewable energy, as well as receive recognition for the environmental benefits of their purchase, and help consumers by promoting consumer choice programs that increase their knowledge about the environmental benefits of purchasing renewable energy.
- ★ The NEPD Group recommends that the President direct the Secretary of the Treasury to work with Congress on legislation to extend and expand tax credits for electricity produced using renewable technology, such as wind and biomass. The President's budget request extends the present 1.7 cents per kilowatt hour tax credit for electricity produced from wind and biomass; expands eligible biomass sources to include forest-related sources, agricultural sources, and certain urban sources; and allows a credit for electricity produced from biomass co-fired with coal.
- ★ The NEPD Group recommends that the President direct the Secretary of the Treasury to work with Congress on legislation to provide a new 15 percent tax credit for residential solar energy property, up to a maximum credit of \$2,000.
- ★ The NEPD Group recommends that the President direct the Secretaries of the Interior and Energy to work with Congress on legislation to use an estimated \$1.2 billion of bid bonuses from the environmentally responsible leasing of ANWR for funding research into alternative and renewable energy resources, including wind, solar, geothermal, and biomass.

Alternative Fuel Vehicles

Alternative fuel vehicles (AFVs) can run on methanol, ethanol, compressed natural gas, liquefied natural gas, propane, hydrogen, electricity, biodiesel, and natural gas. Today, more than 450,000 alternative vehicles are operating in the United States. Some of the barriers to using AFVs include:

Cost—For example, a Ford Crown Victoria that runs on compressed natural gas costs about \$4,000 more than its gasoline counterpart.

Refueling Infrastructure—Refueling infrastructure is limited, which can make refueling inconvenient and travel options difficult.

Travel Distance—Ability to travel a long distance on a single volume of fuel. Alternative fuels have an energy content lower than that of gasoline, which means that AFVs cannot travel as far as traditional vehicles on a single tank of fuel.

In the short term, natural gas and propane offer the greatest potential for market growth, especially in niche markets where lower fuel costs make them attractive, such as transit buses, school buses, shuttles, and other heavy-duty vehicles. Ethanol vehicles offer tremendous potential if ethanol production can be expanded. Electric vehicles could reach large numbers in the future if technology breakthroughs help bring costs down and increase driving distance. Fuel cell vehicles operating on compressed hydrogen offer long-term potential. Compressed natural gas offers a distribution stepping-stone to a hydrogen-refueling infrastructure.

include traditional energy sources, such as natural gas and liquid propane that are traditionally not used as a transportation fuel.

Currently, there are approximately 450,000 alternative fuel vehicles in the United States, and more than 1.5 million flexible-fuel vehicles that can use gasoline or a mixture of ethanol and gasoline. Ethanol is made by converting the carbohydrate portion of biomass into sugar, which is then converted into ethanol through a fermentation process. Ethanol is the most widely used biofuel, and its production has increased sharply since 1980, rising from 200 million gallons a year to 1.9 billion gallons. Today, many states are considering phasing out the use of MTBE (methyl tertiary butyl ether), an oxygenate additive for gasoline. If they do so, that will likely spur greater reliance on ethanol.

Each year, approximately 65 percent of the oil consumed in the United States is used for transportation. As a result, vehicle emissions have become the leading source of U.S. air pollution. However, recent advances in fuels and vehicle design are helping increase fuel efficiency and reduce toxic substances discharged into the air.

Changes in the composition of trans

portation fuels, such as gasoline and diesel fuels, are one way to improve vehicle performance while reducing emissions and lowering oil consumption. Reformulated gasoline contains fuel additives such as ethanol to increase oxygen content, which reduces harmful emissions such as carbon monoxide. Low-sulfur gasoline reduces sulfur oxide emissions. New diesel fuels, some of which have lower sulfur contents or are produced from clean-burning natural gas, can help vehicles with diesel engines achieve lower emissions.

In addition to advanced transportation fuels, alternative fuels are being developed, such as biodiesel, electricity, ethanol, hydrogen, methanol, natural gas, and propane. These alternative fuels not only reduce dependence on petroleum transportation fuels. They reduce or entirely eliminate harmful emissions as well. With the exception of natural gas and propane, these fuels also have the potential of being generated from renewable resources, such as ethanol from corn. The federal government has promoted development of alternative fuels for many years and this program has helped to reduce U.S. reliance on oil-based fuels.

The evolution toward more efficient,

environmentally friendly transportation fuels has been mirrored by improvements in vehicle design, components, and materials. Alternative fuel vehicles, which can either switch between two fuels or run on a mixture of two fuels such as gasoline and ethanol, are now available. Recent developments in both alternative fuel vehicles and petroleum-based vehicles, such as advances in engines, drive trains, and emission-control technologies, may double or triple the efficiency of current vehicles. Some of these new technologies include hybrid electric vehicles, which combine an engine with an electric motor, and fuel cells, which produce electricity by converting a fuel, generally hydrogen and oxygen, into water.

A number of issues drive the research and marketability of advanced alternative fuel vehicles and petroleum-based vehicles in the United States. The goal of reducing U.S. dependence on imported oil, combined with the link between vehicle emissions and air pollution, have prompted the development of emissions and fuel economy standards for car manufacturers. In addition, federal, state, and local governments have enacted regulations, laws, and incentives designed to reduce the number of vehicle miles traveled and to encourage businesses and individuals to purchase alternative fuel vehicles.

The success of the federal alternative fuels program has been limited, however. The current program focuses on mandating certain fleet operators to purchase alternative fueled vehicles. The hope was that this vehicle purchase mandate would lead to expanded use of alternative fuels. That expectation has not been realized, since most fleet operators purchase dual-fueled vehicles that operate on petroleum motor fuels. The Clean Air Act required the use of oxygenates, such as MTBE (methyl tertiary butyl ether) and ethanol in fuel. These oxygenates account for 92 percent of alternative fuel use. Reforms to the federal alternative fuels program could promote alternative fuels use instead of mandating purchase of vehicles that ultimately run on petroleum fuels.

Recommendation:

★ The NEPD Group recommends that the President direct the Secretary of Treasury to work with Congress to continue the ethanol excise tax-exemption.-

Distributed Energy

Untapped opportunities for reducing energy demand loads could be realized by better integrating electricity supply systems and customers. Improved integration can produce a variety of benefits for tight energy markets, including reducing peak demand loads, bypassing congested areas of transmission by placing new generating capacity closer to the consumer, and thus achieving greater overall system efficiencies.

Current electricity load management efforts are typically limited to cutting off interruptible or nonfirm customers, appeals to the public to conserve, and brownouts. Some utilities are incorporating current generation metering, sensor, and control technologies to take the next step: selective reduction of individual energy-using appliances. In some areas, residents can reduce their monthly bills by allowing the utility to electronically turn off selected appliances, such as water heaters, on a rotating basis. If this option is well managed, consumers are unaware of the temporary loss service, and critical systems continue to run unimpeded. Advanced integrated supply-and-demand load management controls also allow for widespread “demand auctions,” in which consumers can decide which energy services to forego on which days.

Distributed energy resources describe a variety of smaller electricity-generating options well suited for placement in homes, offices, and factories, or near these facilities. Distributed energy systems have the distinct advantage of being brought on line faster than new central power plants. While natural gas microturbines and solar roof panels are the most familiar types of distributed energy, other distributed energy resources include: combined heat and power, stationary fuel cells, generation of

bioenergy from landfill methane recovery, and small wind systems. Photovoltaic solar distributed energy is a particularly valuable energy generation source during times of peak use of power.

Efficiency gains from distributed energy come from three sources. First, transmission and distribution line losses (about 5 percent) are reduced because the energy is generally used near the source. Second, the co-location with consumption makes it more feasible to use waste heat, displacing otherwise needed natural gas or electricity for heating purposes. And, third, the co-location with consumption allows for the integration of on-site energy efficiency and generating capabilities. For example, in the residential market, distributed energy applications can make possible the concept of the “net zero energy home,” in which the overall level of energy produced at the home equals or exceeds the amount of energy used in the home.

Despite these advantages, a number of impediments and competing policy objectives discourage the wider application of integrated electricity supply and demand solutions, many of which reflect the relative newness and lack of familiarity with these technologies.

For example, the lack of standards governing interconnection of distributed energy to the grid impedes development. The lack of standards prevents a uniformly effective means of getting excess distributed energy to the grid.

In addition, current air quality regulations do not take into account the additional energy savings from many distributed energy technologies. Likewise, distributed energy systems purchased by consumers may receive different tax rates than those purchased by traditional electricity producers.

Although distributed energy can alleviate distribution constraints, these systems often cannot be sited and permitted in a timely manner. For instance, land-use zoning codes may not allow generating equipment in association with residential or commercial land uses, and building code officials may not know enough about solar roof systems to provide timely building permits.

As with energy efficiency equipment, load management integrating systems, both controls and distributed energy, have higher first costs associated with lower future energy bills.

Another barrier to development of distributed energy is the need for net metering, which enables consumers to install a small electricity project at their homes and sell the excess to the local utility, offsetting their purchases from the utility at other times. Net metering can lower the cost to consumers of distributed energy projects. Some consumers are reluctant to install distributed renewable energy resources because many regions do not have the regulatory framework under which consumers can sell energy back to the grid under a net metering system.

Future Energy Sources

As we look to the long-term future of alternative energy technologies, there is significant promise in these technologies to meet an ever-growing portion of our nation’s energy needs.

Hydrogen

In the long run, alternative energy technologies such as hydrogen show great promise. Hydrogen is the most common element in the universe and can be made from water. Converting hydrogen into energy is compatible with existing energy technologies, such as fuel cells, engines, and combustion turbines. The energy for extracting hydrogen could come from existing, traditional fuels, or it could be derived from renewable energy sources, such as solar, nuclear, and fossil, to achieve the cleanest possible energy cycle. Hydrogen can be converted into useful energy forms efficiently and without detrimental environmental effects. Unlike other energy sources, its production by-product is water.

In the future, hydrogen may be able to be used in furnaces and as a transportation fuel for automobiles, buses, trains, ships and airplanes. Hydrogen could also be converted directly into electricity by fuel cells. Combustion of hydrogen with oxygen results in pure steam, which has many appli-



There is a significant promise in renewable technologies to meet an ever-growing portion of our nation's energy needs. Wind power has significant growth potential. The principal challenges to achieving this level of renewable energy generation are cost and market acceptance of renewable power technologies.

U.S. DEPARTMENT OF ENERGY, NATIONAL
RENEWABLE ENERGY LABORATORY

cations in industrial processes and space heating. Moreover, hydrogen is an important industrial gas and raw material in numerous industries, such as computer, metallurgical, chemical, pharmaceutical, fertilizer and food industries.

An energy infrastructure that relies on hydrogen could enable much greater use of distributed energy systems. These systems are small, modular electricity generators that can be placed right where they are needed for heating, cooling, and powering offices, factories, and residences. Hydrogen fuel cells are a promising type of distributed energy system that can provide the exacting reliability needed for the high-tech industry.

Fuel cells can produce electricity and heat from hydrogen, natural gas, and petroleum fuels, and fuel gases derived from coal and biomass. What makes fuel cells unique is that they can use fuels without combustion, simply by chemical reactions, making them extremely clean and efficient.

Fuel cells were developed by the National Aeronautics and Space Administration to generate electricity, heat, and water in space vehicles. The first-generation fuel cells for stationary power applications entered the commercial market in 1995. This type of fuel cell is used to generate very high-quality electricity and heat with negligible emissions in commercial and industrial settings. It is most likely to be used in cases where users are willing to pay a premium for cleaner, more reliable power than is available from the commercial grid.

The second generation of stationary fuel cells is currently in the demonstration phase, including a combined fuel cell–turbine hybrid. These fuel cells are expected to be more efficient and cost less when used in similar distributed energy systems. Smaller fuel cells for residential units are also being developed, and some are in the demonstration phase.

Despite technical progress, high costs remain the main deterrent to widespread fuel cell use. Significant cost reductions must be achieved before fuel cells will be competitive with internal combustion engines, and the size and weight of fuel cell systems must be reduced even more to ac-

commodate vehicle packaging requirements.

The primary challenge to using more hydrogen in our energy systems is the cost of producing, storing, and transporting it. A serious challenge confronting a move toward distributed energy is the transition away from centralized energy systems of supply and production. These challenges are not expected to be resolved overnight, but progress made in the last few years has already far surpassed the expectations of just a decade ago.

A significant amount of promising research and development has already been completed. The automobile industry is aggressively exploring the fuel cell as the future of the industry. Moreover, a new first generation class of distributed energy technologies are already hitting the market.

Fusion

Fusion—the energy source of the sun—has the long-range potential to serve as an abundant and clean source of energy. The basic fuels, deuterium (a heavy form of hydrogen) and lithium, are abundantly available to all nations for thousands of years. There are no emissions from fusion, and the radioactive wastes from fusion are short lived, only requiring burial and oversight for about 100 years. In addition, there is no risk of a melt-down accident because only a small amount of fuel is present in the system at any time. Finally, there is little risk of nuclear proliferation because special nuclear materials, such as uranium and plutonium, are not required for fusion energy. Fusion systems could power an energy supply chain based on hydrogen and fuel cells, as well as provide electricity directly.

Although still in its early stages of development, fusion research has made some advances. In the early 1970s, fusion research achieved the milestone of producing 1/10 of one watt of fusion power, for 1/100 of a second. Today the energy produced from fusion is 10 billion times greater, and has been demonstrated in the laboratory at powers over 10 million watts in the range of a second.

Internationally, an effort is underway in Europe, Japan, and Russia to develop plans for constructing a large-scale fusion science and engineering test facility. This test facility may someday be capable of steady operation with fusion power in the range of hundreds of megawatts.

Both hydrogen and fusion must make significant progress before they can be come viable sources of energy. However, the technological advances experienced over the last decade and the advances yet to come will hopefully transform the energy sources of the distant future.

Recommendation:

- ★ The NEPD Group recommends that the President direct the Secretary of Energy to develop next-generation-technology—including hydrogen and fusion.-
- Develop an education campaign that communicates the benefits of alternative forms of energy, including hydrogen and fusion.
- Focus research and development efforts on integrating current programs regarding hydrogen, fuel cells, and distributed energy.

Current Markets for Renewable and Alternative Energy Advances in Technology

Non-hydropower renewable energy accounts for about 4 percent of current U.S. energy production, divided evenly between electricity generation and transportation fuels such as ethanol. Between 1990 and 1999, renewable energy generation grew by 29 percent, and renewable energy is projected to continue to grow (Figure 6-1). Renewable fuel consumption, including ethanol for gasoline blending, is projected to grow at an average rate of 1.1 percent a year through 2020. In 2020, 55 percent of renewables are projected to be used for electricity generation and the rest for dispersed heating, industrial uses, and fuel blending.

The success of renewables is, in part,

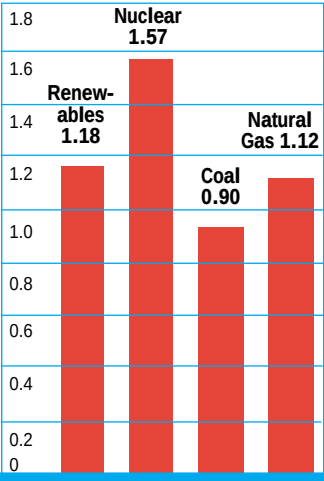
the result of over twenty years of research, development, and demonstration conducted by the public and private sectors. This work has dramatically improved these technologies and has reduced their costs by as much as 90 percent. For example:

- The Department of Energy (DOE), the National Renewable Energy Laboratory (NREL), and Alstom Energy Systems jointly created Advanced Direct-Contact Condensers, which improve the efficiency and generating capacity of electric power plants by providing the best surface area for condensing spent steam. This technological advance, tested in geothermal applications in California, can improve the efficiency of electricity production by 5 percent and capacity by 17 percent.
- United Solar Systems in Michigan pioneered the first commercial use of solar photovoltaics as a building material. The triple-junction, thin-film technology is now sold as flexible solar panels, solar shingles for building roofs, and a peel-and-stick-on variety for standing seam metal roofs. United Solar is now building a larger manufacturing plant in Michigan that is five times the size of its existing manufacturing facility. DOE collaborates with United Solar on research and development helping overcome hurdles in manufacturing. As a result, United Solar is able to provide unique solar electric products using a unique roll-to-roll manufacturing process.

• In partnership with DOE, NREL, Battelle Lab, Burlington Electric and others, Future Energy Resources Corporation of Norcross, Georgia, was able to build, test, and operate the world's first biomass gasification system. The McNeil Plant, located in Burlington, Vermont, gasifies rather than combusts wood chips to power a gas boiler. The technology has shown itself to be commercially viable, and is being considered worldwide by industries as a way of upgrading existing inefficient and aging boilers.

Improved renewable and alternative energy technologies are becoming increasingly attractive to a number of energy companies seeking to build new business opportunities for the future (Figure 6-3). Following are a few examples:

Figure 6-1
Increases in U.S. Energy Production: 1990–1999
(Quadrillion Btus)



During the last decade, renewable energy sources contributed substantially to the growth in U.S. energy production, outpacing all fuel sources except for nuclear energy.

Source: U.S. Department of Energy, Energy Information Administration.

Table 6-2

Electricity Generated by Renewable Energy Sources: 1999

	Solar	Wind	Geothermal	Biomass	Hydropower
Current net summer capacity (MW)	350	2,600	2,870	6,170	79,130
Annual generation (millions of kWh)	940	4,460	13,070	36,570	312,000
Expected growth in generation (%)	PV: 19.3 Thermal: 21	5.3	3.3	3.0	-0.1
Cost (cents/kWh)	20	4–6	5–8	6–20	2–6

Renewable energy has become a significant source of electric power in the United States.

Note: Capacity, generation, and growth data do not include off-grid electricity, thermal, or other nonelectricity energy production, municipal solid waste, or methane from landfills.

Sources: U.S. Department of Energy, Energy Information Administration and Office of Power Technologies.

- FPL Group announced in January 2001 the construction of two major wind farms: a 300 MW facility on the Washington–Oregon border, and a 25.5 MW facility in Wisconsin. The company now has more than 1,000 MW of wind generating capacity in operation or under construction in seven states.

- CalEnergy Company has made renewable and alternative energy generation a central focus of its power portfolio. The company operates 1,300 MW of geothermal, natural gas, hydropower, and other power facilities in the U.S. and abroad, with an other 750 MW currently under construction.

- General Motors, Ford, DaimlerChrysler, Texaco, BP/Amoco, and Shell are collectively spending between \$500 million and \$1 billion dollars a year on fuel cells, hydrogen storage, and infrastructure development for passenger vehicles. Ongoing bus demonstrations in the United States and Europe are expected to commercialize fuel cell power hydrogen buses in the next five years.

Because alternative and renewable energy resources can be used in so many different ways throughout the economy to produce so many combinations of energy types, their total use is often difficult to measure precisely. As of 1996, California alone had over 10 MW of installed distributed energy, a large increase in generating

capacity during a period of otherwise limited growth in generation (Figure 6-3). In 1999, several types of renewable energy were used to produce electricity (Table 6-2).

On the transportation side, there are approximately 450,000 alternative fuel vehicles in the United States. Additionally, there are more than 1.5 million flexible-fuel vehicles that can use gasoline or a high mixture of ethanol and gasoline. These include the Ford Taurus, the DaimlerChrysler Caravan, and the General Motors S10 pickup. Ethanol is the most widely used biofuel, and its production is currently 1.9 billion gallons a year, representing a nearly ten-fold growth from about 200 million gallons a year in 1980.

Recommendation:

★ The NEPD Group recommends that the President direct the Secretary of the Treasury to work with Congress to develop legislation to provide for a temporary income tax credit available for the purchase of new hybrid or fuel-cell vehicles.-

Hybrid Electric Vehicles

Hybrid electric vehicles (HEVs) combine the internal combustion engine of a conventional engine with the battery and electric motor of an electric vehicle, resulting in twice the fuel economy of conventional vehicles. This combination offers the extended range and rapid refueling that consumers expect from a conventional vehicle, with a significant portion of the energy and environmental benefits of an electric vehicle. The practical benefits of HEVs include improved fuel economy and lower emissions compared to conventional vehicles. The car's flexibility will mean convenient use for individuals as well as businesses.

Removing Barriers to Renewable and Alternative Energy Growth

Perhaps the greatest barrier to growth of renewable energy is cost. Currently, the cost of renewable energy generation fre

quently exceeds the costs of conventional electricity generation. In recent years, though, the costs of renewable energy have declined substantially. For example, the cost of wind energy has declined by more than 80 percent over the past twenty years and is increasingly competitive with conventional electricity generation sources. Wind, biomass, and geothermal are all in creasingly competitive with conventional electricity generation.

The ability of these technologies to meet specific market needs is another factor in how quickly their market share will grow. These technologies and energy sources provide multiple benefits to the energy producer and the consumer. For example, many of these technologies are modular and can be constructed rapidly, adding an immediate source of new power in areas that otherwise might face a short fall. Distributed renewable energy resources can enhance the reliability and quality of power.

Cogeneration uses of waste products and heat can increase profits by reducing purchased electricity costs, as well as costs for process steam and heating or cooling. Several sectors, including lumber and paper, steel, and chemical manufacturing, are exploring the increased use of cogeneration. With the technological development of biomass gasification, the lumber and paper industry could become a seller of electricity.

Recommendation:

★ The NEPD Group recommends that the President direct the Administrator of the Environmental Protection Agency to issue guidance to encourage the development of well designed combined heat and power (CHP) units that are both highly efficient and have low emissions. The goal of this guidance would be to shorten the time needed to obtain each permit, provide certainty to industry by ensuring consistent implementation across the country, and encourage the use of these cleaner, more efficient technologies.

Renewable technologies can help provide insurance against price volatility. In addition, many renewable technologies can help industry achieve compliance with the Clean Air Act and other environmental regulations. In some cases, renewables can be more readily located in urban areas whose air quality does not meet regulatory requirements.

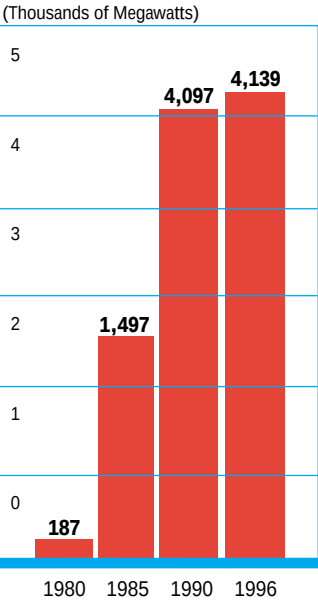
With the growth rate for non-hydro power renewable electricity generation more than doubling the expected growth in overall electricity capacity, these energy sources will play a more significant role in electricity markets in the next two decades. However, the extent to which these domestic resources are successfully tapped will depend in large part on continued technological development.

For renewable and alternative energy to play a greater role in meeting our energy demands, these sources of generation must be able to integrate into our existing distribution system. The tools that form the necessary interface between distributed energy systems and the grid need to be less expensive, faster, more reliable, and more compact.

Promising technologies exist that will improve the transmission, storage, and reliability of renewable energy. An example of recent technological success that will allow for increased access to all forms of energy, including renewable energy, is the high-temperature superconducting underground power transmission cables that the Department of Energy is developing in partnership with industry. These cables will allow a 300 percent increase in capacity without excavation to lay new transmission lines. This summer, Detroit Edison is demonstrating this commercially viable high-temperature superconducting cable system in an application that serves 14,000 customers.

Renewable and alternative energy technologies, such as wind energy and combined heat and power could be significantly expanded, given today's technologies. They could be further expanded with added investment in technology. For example, wind energy could be developed that could be adapted to sites with lower wind speeds than is feasible today. Combined heat and

Figure 6-3
Growth in California's Renewable Energy Capacity



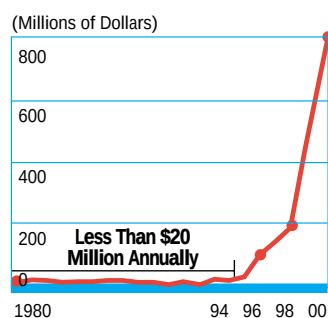
Source: U.S. Department of Energy, Energy Information Administration.



While solar energy technologies have undergone technological and cost improvements, and are well established in high value markets like remote power, satellites, communications, and navigational aids continued research is needed to reduce costs and improve performance.

U.S. DEPARTMENT OF ENERGY

Figure 6-4
Investors Are Betting on Distributed Energy



In the last few years, surging venture capital investments showed strong support for distributed energy technologies.

*Note: Data for 2000 are projected investments.
Source: Nth Power via the Economist, August 5, 2000.*

power in buildings offers great potential for increased system efficiencies and lower costs. New developments in microturbine and fuel cell technologies are also highly promising. Performance improvements of other technologies, such as photovoltaic systems, would facilitate much wider use. In addition to technological performance, attention to several key market and regulatory constraints would accelerate the development and use of renewable and alternative energy in the marketplace.

Because many renewable and alternative energy technologies do not fit into traditional regulatory categories, they are often subjected to competing regulatory requirements or to requirements that were never designed to address them. For example, much of the current Clean Air Act does not specifically address the use of new, more efficient renewable energy technologies. Consequently, the Act does not provide significant incentives for the development of such technologies.

The lack of interconnection standards or guidelines for electricity supply and loads impedes the use of distributed energy technologies. As a result, developers of small renewable energy projects must negotiate interconnection agreements on a site-by-site basis with local distribution companies that are often opposed to distributed energy projects because of the increased competition. Although a few states have established interconnection standards, there is no national standard to facilitate development of distributed energy (Figure 6-4).

New combined heat and power facilities may face air permitting hurdles when they replace marginally dirty boilers. The Clean Air Act does not recognize the pollution prevention benefits of the increased efficiency of combined heat and power units. At the same time, these combined heat and power investments are taxed at the industry's tax rate, not at the rate they would receive if they were considered part of the utility sector for tax purposes.

In addition, modifications to permitting and siting requirements may be necessary to facilitate the incorporation of these technologies into buildings.

The infrastructure needed for increasing the use of renewable and alternative energy varies considerably. In particular, the alternative fuels infrastructure lags far behind the existing infrastructure for conventional fuels. The lack of infrastructure for alternative fuels is a major obstacle to consumer acceptance of alternative fuels and the purchase of alternative fuel vehicles. It is also one of the main reasons why most alternative fuel vehicles actually operate on petroleum fuels, such as gasoline and diesel. In addition, a considerable enlargement of ethanol production and distribution capacity would be required to expand beyond their current base in the Midwest in order to increase use of ethanol-blended fuels.

The use of natural gas or electricity for vehicles requires enhancements to these distribution systems, such as compression stations for natural gas. While many alternative fuels can be shipped by pipeline, they may require separation within the pipeline to avoid mixing different energy products. Geographically dispersed renewable energy plants often face significant transmission barriers, including unfavorable grid schedule policies and increased embedded costs.

Uncertainty regarding the tax treatment of these technologies and energy sources can discourage long-term investment. Though existing tax credits provide an incentive for investing in some types of renewable energy, the limited scope of the credit and its frequent expiration discourages investment.

Summary of Recommendations

Nature's Power: Increasing America's Use of Renewable and Alternative Energy

- ★ The NEPD Group recommends that the President direct the Secretaries of the Interior and Energy to re-evaluate access limitations to federal lands in order to increase renewable energy production, such as biomass, wind, geothermal, and solar.
- ★ The NEPD Group supports the increase of \$39.2 million in the FY 2002 budget amendment for the Department of Energy's Energy Supply account that would provide increased support for research and development of renewable energy resources.
- ★ The NEPD Group recommends that the President direct the Secretary of Energy to conduct a review of current funding and historic performance of renewable energy and alternative energy research and development programs in light of the recommendations of this report. Based on this review, the Secretary of Energy is then directed to propose appropriate funding of those research and development programs that are performance-based and are modeled as public-private partnerships.
- ★ The NEPD Group recommends that the President direct the Secretary of the Treasury to work with Congress on legislation to expand the section 29 tax credit to make it available for new landfill methane projects. The credit could be tiered, depending on whether a landfill is already required by federal law to collect and flare its methane emissions due to local air pollution concerns.
- ★ The NEPD Group recommends that the President direct the Secretary of the Interior to determine ways to reduce the delays in geothermal lease processing as part of the permitting review process.
- ★ The NEPD Group recommends that the President direct the Administrator of the Environmental Protection Agency to develop a new renewable energy partnership program to help companies more easily buy renewable energy, as well as receive recognition for the environmental benefits of their purchase, and help consumers by promoting consumer choice programs that increase their knowledge about the environmental benefits of purchasing renewable energy.
- ★ The NEPD Group recommends that the President direct the Secretary of the Treasury to work with Congress on legislation to extend and expand tax credits for electricity produced using wind and biomass. The President's budget request extends the present 1.7 cents per kilowatt hour tax credit for electricity produced from wind and biomass; expands eligible biomass sources to include forest-related sources, agricultural sources, and certain urban sources; and allows a credit for electricity produced from biomass co-fired with coal.
- ★ The NEPD Group recommends that the President direct the Secretary of the Treasury to work with Congress on legislation to provide a new 15 percent tax credit for residential solar energy property, up to a maximum credit of \$2,000.
- ★ The NEPD Group recommends that the President direct the Secretaries of the Interior and Energy to work with Congress on legislation to use an estimated \$1.2 billion of bid bonuses from the environmentally responsible leasing of ANWR for funding research into alternative and renewable energy resources, including wind, solar, geothermal, and biomass.

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- ★ The NEPD Group recommends that the President direct the Secretary of the Treasury to work with Congress to continue the ethanol excise tax exemption.
 - ★ The NEPD Group recommends that the President direct the Secretary of Energy to develop next-generation technology—including hydrogen and fusion.
 - Develop an education campaign that communicates the benefits of alternative forms of energy, including hydrogen and fusion.
 - Focus research and development efforts on integrating current programs regarding hydrogen, fuel cells, and distributed energy.
 - Support legislation reauthorizing the Hydrogen Energy Act.
 - ★ The NEPD Group recommends that the President direct the Secretary of the Treasury to work with Congress to develop legislation to provide for a temporary income tax credit available for the purchase of new hybrid or fuel-cell vehicles between 2002 and 2007.
 - ★ The NEPD Group recommends that the President direct the Administrator of the Environmental Protection Agency to issue guidance to encourage the development of well-designed combined heat and power (CHP) units that are both highly efficient and have low emissions. The goal of this guidance would be to shorten the time needed to obtain each permit, provide certainty to industry by ensuring consistent implementation across the country, and encourage the use of these cleaner, more efficient technologies.

America's Energy Infrastructure

A Comprehensive Delivery System

One of the greatest energy challenges facing America is the need to use 21st-century technology to improve America's aging energy infrastructure. Americans need a comprehensive, long-term solution to deliver energy to industry and consumers in a reliable and safe manner.

Our energy infrastructure is comprised of many components, such as the physical network of pipes for oil and natural gas, electricity transmission lines and other means for transporting energy to consumers. This infrastructure also includes facilities that turn raw natural resources into useful energy products. The rail network, truck lines, and marine transportation are also key components of America's energy infrastructure.

The energy industry has undergone major changes in the last two decades, and more are expected. These changes affect how our energy infrastructure operates. For example, while the electricity industry was once vertically integrated, it is increasingly separated into three isolated segments: generation, transmission, and distribution.

Our energy infrastructure has failed to keep pace with the changing requirements of our energy system. Domestic refining capacity has not matched increases in demand, requiring the United States to import refined products. Natural gas pipelines have not expanded sufficiently to meet demand. The electricity transmission system is constrained by insufficient capacity. Rail capacity was significantly increased during the 1970s when rail facilities were improved to move more coal. Since then, however, few additions to the coal transportation rail network have been built.

The United States needs to modernize its energy infrastructure. One sign of a lack of an energy policy in recent years has been the failure to maintain the infrastructure needed to move energy where it is needed most.

Electricity

The electricity infrastructure includes a nationwide power grid of long-distance transmission lines that move electricity from region to region, as well as the local distribution lines that carry electricity to homes and businesses. Electricity originates at power plants, which are primarily fueled by coal, nuclear, natural gas, water and, to a lesser extent, oil. Coal, natural gas and oil powered plants require a dependable transportation infrastructure to deliver the fuels necessary for the production of electricity. A transportation network for waste disposal is also necessary for power plants that create by products.

Restructuring

The electricity industry has undergone considerable changes in the last two decades. These changes affect how our electricity infrastructure operates. Major industry restructuring has separated once vertically integrated electric utilities that supplied generation, transmission, and distribution services into distinct entities. To facilitate competition at the wholesale level, in 1996, the Federal Energy Regulatory Commission (FERC) required transmission-owning utilities to "unbundle" their transmission and power marketing functions, and provide nondiscriminatory, open access to their transmission systems by other utilities

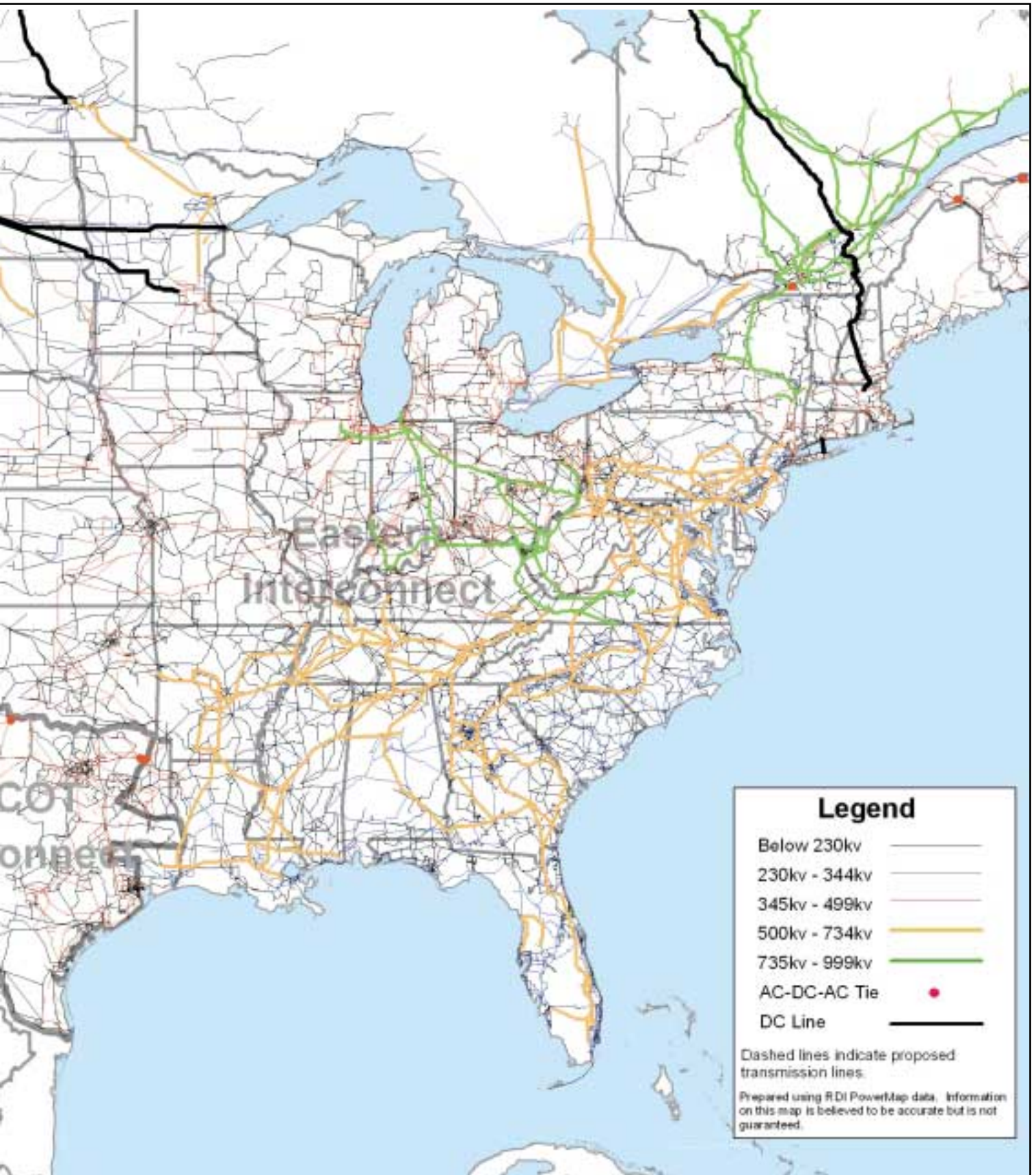


FIGURE 7-1
**North American
Transmission Lines**

About 204,000 miles of long-distance transmission lines move power from region to region. The four integrated transmission grids serving North America are the Western Interconnection, Eastern Interconnection, Electric Reliability Council of Texas, and Province of Quebec.

Source: PA Consulting Group





and independent power producers. At the retail level, some states have required utilities to divest their generation assets as part of restructuring. These utilities currently supply only transmission and distribution services for customers who purchase electricity (i.e., generation services) from other firms. In addition, power marketers—who often do not own generation, transmission, or distribution facilities—buy and sell power on wholesale markets and market electricity directly to customers.

Electricity competition has led to significant changes in the operation of the bulk power grid, which are the power plants and high-voltage transmission facilities that make up the wholesale power market. More electricity is being shipped longer distances over a transmission system that was initially designed only to provide limited power and reserve sharing among neighboring utilities. Electric utilities that were once solely responsible for ensuring that adequate generation was available to meet demand now purchase a substantial amount of the power they need from the wholesale market, relying on independent power producers to build and operate plants.

Electricity Generation

There are roughly 5,000 power plants in the United States, and they have a total generating capacity of nearly 800,000 megawatts. Over the past few years, there has been an explosion of “merchant” power plants proposed by independent power producers seeking to sell into wholesale markets. In spite of this interest, a number of regions of the country are experiencing capacity shortages as a result of wholesale market design problems and barriers to siting and building new power plants.

Over the next ten years, demand for electric power is expected to increase by about 25 percent, and more than 200,000 megawatts of new capacity will be required. However, under current plans electric transmission capacity will increase by only 4 percent. This shortage could lead to serious transmission congestion and reliability problems.

Transmission Grid

The United States does not have a national transmission grid. Instead, there are four integrated transmission grids serving North America: the Western Interconnection, Eastern Interconnection, Electric Reliability of Council of Texas, and the Province of Quebec (Figure 7-1). These regional grids themselves are international, encompassing the United States, Canada, and part of Mexico.

Transactions between the four integrated transmission grids are very limited because they are interconnected at only a few locations through interties, so for all practical purposes they can be viewed as separate transmission grids. The four integrated transmission grids break down into a series of smaller regions, largely defined by transmission constraints. Altogether, 204,000 miles of transmission lines in North America move power from the point of generation to where electricity is needed. There are 157,810 miles of transmission lines in the United States. Transmission grid expansions are expected to be slow over the next ten years, with additions totaling only 7,000 miles.

The transmission system is the highway system for interstate commerce in electricity. Transmission allows the sale of electricity between regions. In a particular region, transmission can be a substitute for generation, allowing that region to import power that otherwise would have to be generated within that region. In some cases, transmission expansion may be more cost effective than generation additions, allowing a region better access to lower-cost generation.

Transmission constraints limit these power flows, and result in consumers paying higher prices for electricity. The electricity price spikes in the Midwest in the summer of 1998 were caused in part by transmission constraints limiting the ability of the region to import electricity from other regions of the country that had available electricity. During the summer of 2000, transmission constraints limited the ability to sell low-cost power from the Midwest to the South during a period of peak demand,

resulting in higher prices for consumers. Transmission capacity limits could result in price pressures and reliability problems this summer in California, Long Island, the Great Lakes, the Southeast, and New England (Figure 7-2).

Regional shortages of generating capacity and transmission constraints combine to reduce the overall reliability of electric supply in the country and are reducing the quality of power delivered to end users. Power quality is becoming an increasingly important issue as our digital economy continues to grow.

One factor limiting reliability is the lack of enforceable reliability standards. Since 1968, the reliability of the U.S. transmission grid has depended entirely on voluntary compliance with reliability standards. There is a broad recognition that voluntary adherence with reliability standards is no longer a viable approach in an increasingly competitive electricity market. There is a need to provide for enforcement of mandatory reliability standards. Broad support has emerged for development of these standards by a self-regulating organization overseen by FERC.

Recommendations:

★ The NEPD Group recommends that the President direct the Secretary of Energy to work with FERC to improve the reliability of the interstate transmission system and to develop legislation providing for enforcement by a self-regulatory organization subject to FERC oversight.

★ The NEPD Group recommends that the President direct the Secretary of Energy to expand the Department's research and development on transmission reliability and superconductivity.

Transmission constraints were also a primary factor in blackouts in northern California, which imports power from both the Northwest and southern California. When resources are not available in the Northwest, electricity supply must come

Figure 7-2

Current Electric Power Bottlenecks



Transmission capacity limits could result in price pressures and reliability problems this summer in California, Long Island, the Great Lakes, the Southeast, and New England. The arrows in this figure depict the locations and directions of current transmission congestion.

Source: North American Electric Reliability Council.

from southern California's Path 15 transmission route. Path 15 does not have sufficient capacity to provide all of the power needed in northern California.

Recommendation:

★ The NEPD Group recommends that the President direct the Secretary of Energy to authorize the Western Area Power Administration to explore relieving the "Path 15" bottleneck through transmission expansion financed by nonfederal contributions.

Transmission constraints have been a persistent cause of price spikes in New York City in recent years. The New York Independent System Operator (the grid operator in that state) estimates that the city will be short about 400 MW below their desired reserve margin of power during the summer peak. To fill this gap, the New York Power Authority is trying to install additional generation capacity in the city. Market-oriented approaches could also be used to create additional capacity and alleviate some of the potential problems.

If transmission constraints are not removed, the result can be higher prices and

lower reliability. There are various reasons why transmission constraints exist. One is the lack of sufficient investment in transmission. Transmission investment has lagged dramatically over the past decade (Figure 7-3). There is a need to ensure that transmission rates create incentives for adequate investment in the transmission system, especially as restructuring leads to the creation of transmission companies whose only business is operation of transmission facilities. FERC recognizes this need and has expressed a willingness to consider innovative transmission pricing proposals.

Another cause of transmission constraints is the siting process. Under current law, siting of transmission facilities is a responsibility of state governments, not the federal government, even though the transmission system is not only interstate but also international, extending into both Canada and Mexico. This stands in stark contrast to siting of other interstate facilities, such as natural gas pipelines, oil pipelines, railroads, and interstate highways.

Federal law governing the responsibility for siting transmission facilities was written in 1935, nearly 80 years ago. At the time, transmission facilities were not inter-

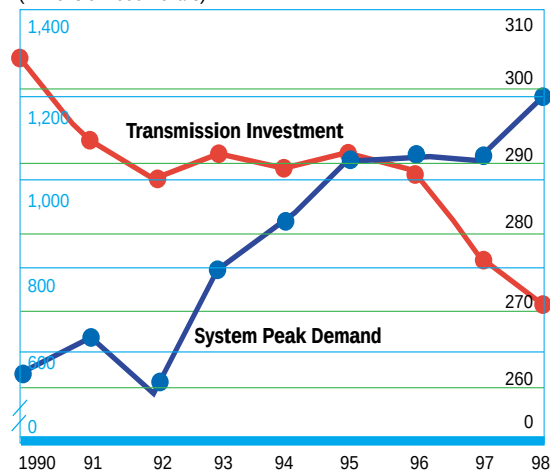
state, and there was virtually no interstate commerce in electricity. Congress did not anticipate the development of an interstate and international transmission system.

State decisions on where to locate transmission lines often do not recognize the importance of proposed transmission facilities to the interstate grid. For example, a recent decision by regulators in Connecticut to block a proposed transmission line to Long Island did not recognize the need for electricity on Long Island. Some state siting laws require that the benefits of a proposed transmission facility accrue to the individual state, resulting in the rejection of transmission proposals that benefit an entire region, rather than a single state.

Much has changed since 1935. The transmission system is the highway for interstate commerce in electricity. Transmission constraints are resulting in higher prices for consumers and lower reliability. The siting process must be changed to reflect the interstate nature of the transmission system.

Figure 7-3

U.S. Investment in New Electric Power Transmission (Millions of 1990 Dollars)



Growth in peak demand for electricity has far outstripped investment in transmission capacity. As a result, transmission constraints could aggravate already limited supplies of power and could result in high prices in some areas of the country.

Source: PA Consulting Group, based on data from the UDI data base.

Recommendations:

★ The NEPD Group recommends that the President direct the appropriate federal agencies to take actions to remove constraints on the interstate-transmission grid and allow our nation's electricity supply to meet the growing needs of our economy.-

- Direct the Secretary of Energy, by December 31, 2001, to examine the benefits of establishing a national grid, identify transmission bottlenecks, and identify measures to remove transmission bottlenecks.
- Direct the Secretary of Energy to work with FERC to relieve transmission constraints by encouraging the use of incentive rate-making proposals.
- Direct the federal utilities to determine whether transmission expansions are necessary to remove constraints. The Administration should review the Bonneville Power Administration's (BPA's) capital and



financing requirements in the context of its membership in a regional RTO, and if additional Treasury financing appears warranted or necessary in the future, the Administration should seek an increase in BPA's borrowing authority at that time.

- Direct the Secretary of Energy, in consultation with appropriate federal agencies and state and local government officials, to develop legislation to grant authority to obtain rights-of-way for electricity transmission lines, with the goal of creating a reliable national transmission grid. Similar authority already exists for natural gas pipelines in recognition of their role in interstate commerce.

Another cause of transmission constraints is limited access to federal lands. The federal government is the largest land owner in the United States and owns most of the land in some western states. Limited access to federal lands can block needed transmission expansion. A case in point is a transmission line being built from West Vir-

ginia to Virginia. Five years ago, the Department of Energy identified that line as critical to the reliability of the transmission system on the East Coast. Five years later, the line is still not complete. Improved access to federal land can help remove transmission constraints.

Rights-of-Way on Federal Lands

The Bureau of Land Management (BLM) estimates that 90 percent of the oil and natural gas pipeline and electric transmission rights-of-way in the western United States cross federal lands. These lands are principally lands managed by either the BLM or the U.S. Forest Service. Rights-of-way are authorized through an approval process that allows the public to comment on proposals to locate infrastructure items, like utility poles, on these rights-of-way. As part of this process, proposals are examined for resource and other use conflicts, and a national interest test is applied prior to approval.

The BLM administers 85,000 rights-of-way, including 23,000 for oil and gas pipelines and 12,000 for electric transmission lines. It processes over 1,200 pipeline and electric system right-of-way applications a year, with an increase in applications of

The electric power infrastructure includes a nationwide "power grid" of long-distance transmission lines that move electricity from the point of generation to where the electricity is needed. Over the next ten years, U.S. demand for electric power is expected to increase by 25 percent, while transmission capacity is expected to increase by only 4 percent.



Virtually all natural gas in the United States is moved via pipeline. The current domestic natural gas transmission capacity of approximately 23 trillion cubic feet (tcf) will be insufficient to meet the projected 50 percent increase in U.S. consumption projected for 2020.

over 10 percent a year in recent years. The demand for additional energy and electricity is expected to increase the need for rights-of-way across federal lands.

Other federal entities also deal with rights-of-way, each approaching the issue from a unique perspective. The National Park Service is authorized to grant leases and permits, but discourages rights-of-way corridors unless there are no practical alternatives. The U.S. Fish and Wildlife Service manages National Wildlife Refuge lands for wildlife and habitat values, and allows corridors where they were pre-existing or are determined to be compatible with the purposes for which a refuge was established. The Bureau of Reclamation is authorized to grant rights-of-way over lands acquired or withdrawn for reclamation purposes, if compatible with authorized project purposes. The Bureau of Indian Affairs and tribal governments are authorized to grant rights-of-way across both tribal and individually owned Indian lands.

Pipelines

After being pumped from the ground in domestic oil fields, oil travels through gathering lines to pipelines, which bring it to refineries, where it is transformed into petroleum products like gasoline, diesel fuel, or heating oil. These products then travel through pipelines and tanker trucks to distribution outlets for purchase by consumers. Natural gas must similarly travel from gas fields through gathering lines to processing facilities, and then into pipelines

and local distribution lines to its final destination. These pipeline systems involve a complex infrastructure of their own, including pump stations or compressor stations, and control systems that open and close valves and switch product flow through pipes, often with the use of computer technology.

Oil Pipelines

The two million miles of oil pipelines in the United States are the principal mode for transporting oil and petroleum products such as gasoline. They account for about 66 percent of domestic product movements (Figure 7-4). Increases in the demand for oil and changes in where it is supplied will lead to the need for more pipeline capacity.

Pipelines are less flexible than other forms of oil transport, because they are fixed assets that cannot be easily adjusted to changes in supply and demand. Once built, they are an efficient way to move petroleum and petroleum products. A modest sized pipeline carries the equivalent of 750 tanker truckloads a day—the equivalent of a truckload leaving every two minutes, 24 hours a day, 7 days a week. Replacing the same pipeline with a railroad train of tank cars, carrying 2,000 barrels each, would require a 75-car train to arrive and be unloaded every day. Pipelines are relatively inexpensive to operate and are generally quiet and safe. Ensuring pipeline safety requires careful management, as multiple products move through a single pipeline system at the same time.

Insufficient domestic pipeline capacity has caused peak-load problems in moving oil and petroleum products such as gasoline from one region of the country to another. For example, many energy analysts forecasted the possibility of a shortage last winter in the upper Midwest of liquefied petroleum gas used for heating and for drying crops. Others were concerned about possible shortages of heating oil in New England.

Energy supply shortages can create operational difficulties for the pipelines themselves. The complex interrelationship

of our energy infrastructure is evident, since pipelines have been shut down for varying time periods due to regional electricity shortages.

For example, fuel supplies to Las Vegas and Phoenix became dangerously low when blackouts in California shut down the main pipeline serving those areas. The California Public Utilities Commission (CPUC) has granted a waiver of penalties to oil pipelines that have interruptible contracts for electricity to help ensure the uninterrupted flow of motor fuel supplies to California. The California Energy Commission asked the CPUC to grant the waiver in order to minimize the threat to public health due to disruptions of fossil fuel supplies. While the waiver of penalties does not guarantee that disruptions of power to petroleum product pipelines will not occur, it diminishes the threat by allowing disruptions to occur only when they are coordinated with the entire petroleum product delivery system, from refinery to pipeline to terminals. Both Phoenix and Las Vegas would benefit from this decision because refineries and pipelines from California supply the two cities.

Much of the existing oil pipeline infrastructure is old, requiring regular safety and environmental reviews to ensure its reliability. The potential risk of pipeline accidents to human health and safety is of grave concern. In June 1999, a petroleum product pipeline ruptured and caught fire in Bellingham, Washington. In addition to tragic loss of life, the pipeline's 18-month shutdown caused an economic hardship to the Seattle-Tacoma Airport and other local businesses that relied on the pipeline for aviation and diesel fuels. To avoid similar crises, the Department of Transportation, which has responsibility for pipeline safety, has adopted regulations and other risk management approaches to ensure safety in pipeline design, construction, testing, operation, maintenance, and emergency response.

Recommendation:

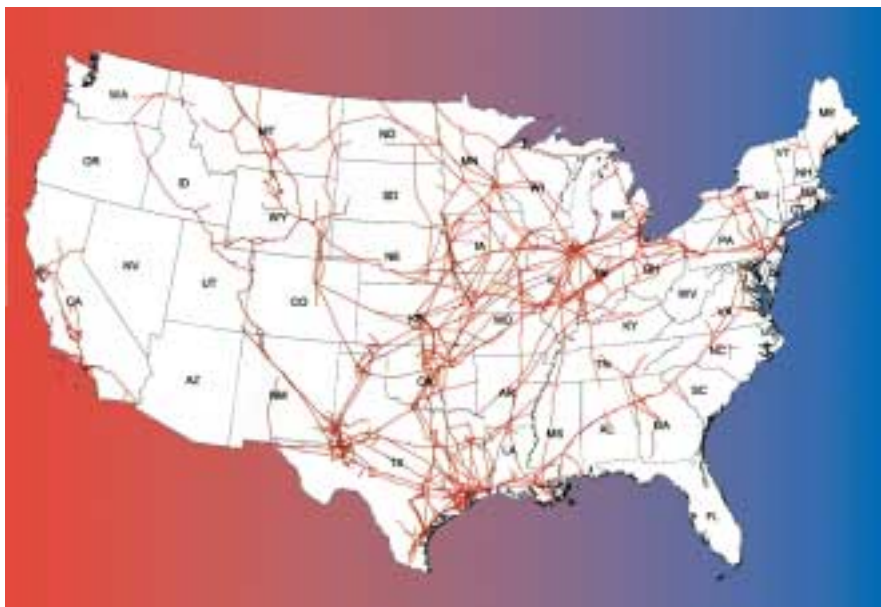
★ The NEPD Group recommends that the President direct the Secretary of the Interior to work with Congress and the State of Alaska to put in place the most expeditious process for renewal of the Trans-Alaskan Pipeline System rights-of-way to ensure that Alaskan oil continues to flow uninterrupted to the West Coast of the United States.-

The Trans-Alaska Pipeline System is the single most important crude oil pipeline in the United States, and is perhaps the most regulated oil pipeline in the world. The pipeline system has carried nearly one-fifth of all domestically produced oil for the last two decades. Since beginning operations in 1977, it has transported more than 13 billion barrels of oil from Alaska's North Slope across 800 miles to the Port of Valdez. Since the pipeline began operation, only 0.00014 percent of the total amount of oil transported through it has been spilled.

The pipeline's federal grant and state lease for right-of-way expires in 2004 and will require renewal. That process will in-

Figure 7-4

U.S. Oil Pipelines



The two million miles of oil pipelines in the United States are the principal mode for transporting crude oil and refined products. They account for about 66 percent of domestic product movements.

Source: U.S. Department of Transportation, Office of Pipeline Safety.



Several federal agencies are authorized to grant rights-of-way for oil and gas pipeline and electric transmission systems on federal lands, and each approaches the issue from a unique perspective. Authorizing agencies include the Bureau of Land Management, the U.S. Forest Service, the National Park Service, the U.S. Fish and Wildlife Service, the Bureau of Reclamation, and the Bureau of Indian Affairs.

volve a thorough review of compliance with federal laws and regulations, including those related to safety and environmental impacts. Because nearly 50 percent of the right-of-way is owned by the State of Alaska, they must also renew the applicable state permits. To commence the formal portion of the federal renewal process, regulations require a renewal application to be filed with the Alaska Office of the BLM of the Department of the Interior. To the extent possible, a single, joint federal/state approach should be considered.

Natural Gas Pipelines

Virtually all natural gas in the United States is moved via pipeline (Figure 7-5). The current domestic natural gas transmission capacity of approximately 23 trillion cubic feet (tcf) will be insufficient to meet the projected 50 percent increase in U.S. consumption projected for 2020.

Some parts of the country, such as California and New England, already face capacity shortages. Several pipeline opera-

tors have applied for permits to increase their delivery of natural gas to California, but right-of-way issues and local permitting delays have constrained the ability to transport natural gas to California, contributing to high prices. In addition, the natural gas pipeline connections from Canada are near capacity, so any greater U.S. reliance on Canadian natural gas will require increased pipeline capacity.

One of the largest known reserves of natural gas in the United States has been found in the Arctic, associated with the development of oil at Alaska's Prudhoe Bay. These known gas reserves, over 35 tcf, would make a significant long-term contribution to the nation's energy supplies if delivered to the lower 48 states. It is estimated there may be an additional 100 tcf on the North Slope of Alaska. Recently, as the energy supply situation has changed, interest has renewed in tapping into Alaska's natural gas supplies. Over the past year, the Alaska North Slope gas producers have been reviewing whether projected market conditions will make transportation of this natural gas economically feasible. The North Slope gas producers are scheduled to complete that review by the end of 2001.

Recommendation:

★ The NEPD Group recommends that the President direct the Secretaries of Energy and State, coordinating with the Secretary of the Interior and the Federal Energy Regulatory Commission, to work closely with Canada, the State of Alaska, and all other interested parties to expedite the construction of a pipeline to deliver natural gas to the lower 48 states. This should include proposing to Congress any changes or waivers of law pursuant to the Alaska Natural Gas Transportation Act of 1976 that may be required.

America needs the energy that Alaska's North Slope natural gas can provide. The Administration seeks to expedite the construction of a pipeline to deliver this natural gas to the lower 48 states.

In addition to shortfalls in capacity, sources of natural gas have shifted from the Southwest to the deep water of the Gulf of Mexico, the Rocky Mountains, western Canada, and the Canadian Atlantic. At the same time, demand has shifted from the industrial Midwest to the growing population centers in the South and the West. An additional 263,000 miles of distribution pipelines and 38,000 miles of new transmission pipelines will be necessary to meet increased consumption and the new geographic realities of supply and demand.

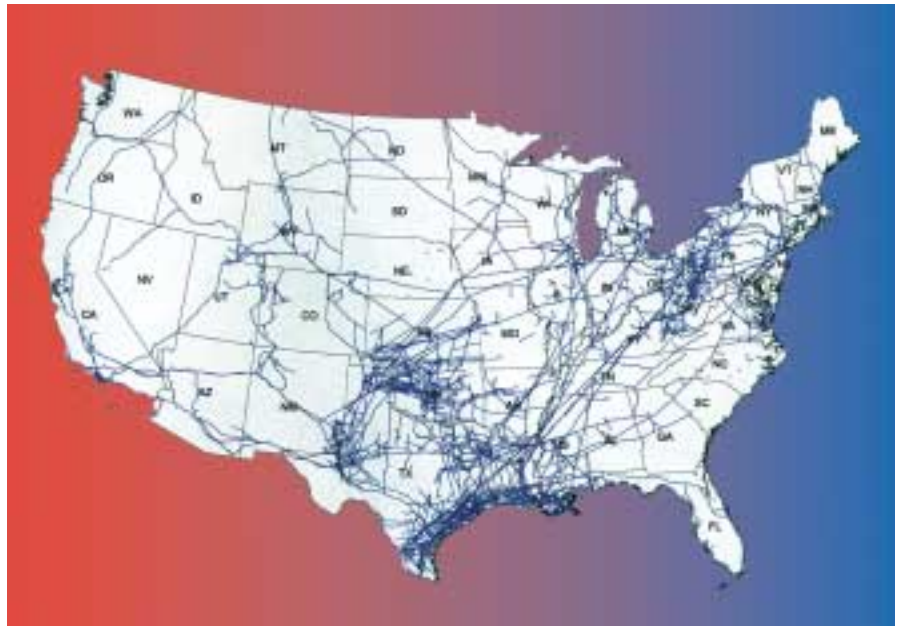
Several factors complicate efforts to meet the need for increased pipeline capacity, including encroachment on existing rights-of-way and heightened community resistance to pipeline construction. Currently it takes an average of four years to obtain approvals to construct a new natural gas pipeline. In some cases it can take much longer.

The projected growth in energy demand has called into question whether regulatory actions and permitting processes can keep pace with the necessary construction of new facilities for storage and delivery. Consistent federal, state, and local government policies, and faster, more predictable regulatory decisions on permitting for oil and natural gas pipelines are needed to enable timely and cost-effective infrastructure development. The permitting process has a positive role in protecting the environment, public health, and safety by allowing all interested parties an opportunity to participate effectively and fully in the deliberations prior to the permit issuance.

Recent pipeline ruptures involving a natural gas pipeline near Carlsbad, New Mexico, and an underground natural gas storage facility near Hutchinson, Kansas, highlight the need to develop technologies and policies that protect people, environment, and the safety of the nation's energy infrastructure. The federal government has an important role in ensuring and improving the safety of these gas pipelines. New technologies need to be developed to improve monitoring and assessment of system integrity, improve data quality for system

Figure 7-5

U.S. Natural Gas Transmission Pipelines



Virtually all natural gas in the United States is moved via pipeline. The forecast of a doubling in the number of new natural gas wells drilled annually and an 80 percent increase in the number of active drilling rigs will require new pipelines.

Source: U.S. Department of Transportation, Office of Pipeline Safety.

planning, extend the serviceability and life of the national natural gas transmission and distribution network, provide safer transport of energy products, and lessen the impacts of the energy infrastructure on the environment.

Recommendations:

- ★ The NEPD Group recommends that the President support legislation to improve the safety of natural gas pipelines, protect the environment, strengthen emergency preparedness and inspections and bolster enforcement.
- ★ The NEPD Group recommends that the President direct agencies to continue their interagency efforts to improve pipeline safety and expedite pipeline permitting in an environmentally-sound manner and encourage the Federal Energy Regulatory Commission to consider improvements in the regulatory process governing approval of interstate-natural gas pipeline projects.



U.S. demand for refined petroleum products currently exceeds its domestic capacity to produce them. The refinery industry is now running at nearly 100 percent of capacity during the peak gasoline consumption season.

Oil Refineries

U.S. demand for refined petroleum products, such as gasoline and heating oil, currently exceeds our domestic capacity to produce them. The refinery industry is now running at nearly 100 percent of capacity during the peak gasoline consumption season and is producing record levels of needed products at other times. The excess demand has recently been met by increased imports.

The U.S. refining industry has experienced a decade of low profitability and rates of return on investment. This has discouraged investment in new refineries. In fact, almost 50 U.S. refineries closed over the last ten years, and no major refineries have been built in the last twenty-five years.

During the last ten years, overall refining capacity grew by about 1 to 2 percent a year as a result of expansion in the capacity of existing, larger refineries. Although there was a significant, sustained improvement in margins during 2000, those gains arose out of a very tight supply situation and high, volatile prices. Industry consolidation has been a key response to this poor profitability.

The U.S. refining industry is also facing major infrastructure problems. While the industry expanded steadily through the 1970s, it went through a period of consolidation after the oil shocks of 1973 and 1978.

Ongoing industry consolidation, in an effort to improve profitability, inevitably leads to the sale or closure of redundant facilities by the new combined ownership. This has been particularly true of terminal facilities, which can lead to reductions in inventory and system flexibility. While excess capacity may have deterred some new capacity investments in the past, more recently, other factors, such as regulations, have deterred investments.

Refiners are subject to significant environmental regulation and face several new clean air requirements over the next decade. Refiners will face many clean fuel production standards, which require the production of many different kinds of gasoline and diesel fuel for different parts of the country. New Environmental Protection Agency rules will require refiners to produce gasoline and diesel fuel with significantly lower sulfur content. New clean air requirements will benefit the environment, but will also require substantial capital investments and additional government permits. The proliferation of distinct regional and state gasoline and diesel product standards, the significant permitting needed, and the downtime to make the needed physical and operational changes will challenge refiners and governments to effectively coordinate in order to reduce the likelihood of supply shortfalls and price spikes.

Recommendation:

★ The NEPD Group recommends that the President direct the Administrator of the EPA to study opportunities to maintain or improve the environmental benefits of state and local “boutique” clean fuel programs while exploring ways to increase the flexibility of the fuels distribution infrastructure, improve fungibility, and provide added gasoline market liquidity. In concluding this study, the Administrator shall consult with the Departments of Energy and Agriculture, and other agencies as needed.

Since 1990, refiners have met growing demand by increasing the use of existing equipment and increasing the efficiency and capacity of existing plants. Even with these efforts, however, refining capacity has begun to lag behind peak summer demand. Price volatility and the cyclical nature of oil markets inhibit investment in supply infrastructure. While investors can withstand market fluctuations for some commodities, large investments in oil exploration and development—such as for drilling required to maintain a steady supply and the pipelines needed to bring supply to market—are often curtailed during times of low oil prices. The outcome of this lack of steady investment is less supply, higher prices, and the abandonment of marginal oil resources that may never be recovered.

Recommendations:-

★ The NEPD Group recommends that the President direct the Administrator of the Environmental Protection Agency and the Secretary of Energy to take steps to ensure America has adequate refining capacity to meet the needs of consumers.-

- Provide more regulatory certainty to refinery owners and streamline the permitting process where possible to ensure that regulatory overlap is limited.
- Adopt comprehensive regulations

(covering more than one pollutant and requirement) and consider the rules’ cumulative impacts and benefits.

★ The NEPD Group recommends that the President direct the Administrator of the Environmental Protection Agency, in consultation with the Secretary of Energy and other relevant agencies, to review New Source Review regulations, including administrative interpretation and implementation, and report to the President within 90 days on the impact of the regulations on investment in new utility and refinery generation capacity, energy efficiency, and environmental protection.

- The NEPD Group recommends that the President direct the Attorney General to review existing enforcement actions regarding New Source Review to ensure that the enforcement actions are consistent with the Clean Air Act and its regulations.

Energy Transportation Infrastructure

The infrastructure used to transport energy products includes ocean tankers; in land barges; specialized trucks for oil and refined products, such as gasoline and heating oil; railroad tank cars and coal cars; and the waterways, highways, and railroads upon which they travel. There is also a substantial inventory of river and oceanside port facilities that are used for moving energy materials.

Marine Transportation

Marine transportation of oil and refined products accounts for nearly one-third of domestic shipments. Approximately 3.3 billion barrels of oil and petroleum products and 229 million short tons of coal move through the nation’s ports and waterways every year.

There are three kinds of ship transport of domestic energy products. Tankers



Double-hulled tank barges provide distribution of petroleum products.

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primarily carry Alaskan oil to the West Coast. Product tankers transport refined products from the Gulf of Mexico to the Atlantic Coast, from the Gulf to the West Coast, and between ports within the West Coast. Tank barges provide coastwise distribution of refined product imports, distribution from pipeline terminals, and inland distribution. In addition, 477 foreign tankers and 64 U.S. flag tankers deliver oil and petroleum products to the United States. They deliver approximately 2.1 million barrels a day, for a total of 770 million barrels a year.

Ships are also used to import liquefied natural gas (LNG). With increasing demand for natural gas for electricity generation, there is a potential for substantial growth in the demand for LNG imports. From 1998 to 1999, the number of LNG carrier arrivals in Boston increased by 350 percent. In addition, mothballed terminals at Elba Island, Georgia, and Cove Point, Maryland, may reinstate LNG imports by 2002.-

Winter storms, extended darkness, and ice formation disrupt barge and tanker movements. The U.S. Coast Guard's fleet of ice breakers has become an important component of the energy infrastructure for the New England, Mid-Atlantic, and Great Lakes regions.

U.S. COAST GUARD



Unlike pipelines, water transportation requires the positioning of vessels to where cargoes are located. For example, it can take three weeks to move a tanker from the Gulf of Mexico to the West Coast. Consequently, tanker markets do not respond quickly to temporary surges in demand, which typically result in price spikes.

Safety

In accordance with the Oil Pollution Act of 1990, a timeline has been established to replace all single-hulled vessels with double-hulled vessels. Many have already been replaced. Modern navigation and port services also help to prevent maritime oil spills. Spill-response technologies and coordinated response plans are key to minimizing damage to property and the environment. Oil spill technology has improved during the last decade and will continue to do so. Risk assessments, preparedness drills, and cleanup strategies are all necessary safeguards for transporting energy goods. As maritime transportation grows, port and waterway infrastructure, as well as the availability of accurate and timely navigation information, will continue to be important for the safe, efficient delivery of energy.

New England's Dependence on Marine Transportation

New England has no refineries, and its small oil pipeline system is not connected to the interstate pipeline system. As a result, New England must rely on tanker and barge shipments of petroleum products from the south as well as direct imports from overseas. There is some question as to whether this distribution system is sufficient to meet the future needs of the region and, if not, what steps need to be taken to ensure future economical, reliable energy supplies.

In recent years, lower national inventories, market forces, and other factors have combined to create much lower inventories for petroleum products such as heating oil in the Northeast. A supply system with less capacity in reserve is more vulnerable to variations in product delivery, and is less capable of absorbing the disruptions in barge and tanker movements that inevitably come

with winter storms, extended darkness, and ice formation. A rapid change to colder weather affects both supply and demand: households need more fuel at the same time that harbors and rivers experience severe ice conditions.

For the New England and Mid-Atlantic seaboards, U.S. Coast Guard icebreakers have become an important component of the infrastructure necessary to provide energy to the region.

The Department of Energy established the Northeast Heating Oil Reserve to ensure heating oil supplies in the region. This emergency buffer can support a shortage for approximately ten days, which is the time required for ships to carry heating oil from the Gulf of Mexico to New York Harbor.

Even with the Reserve in place, marine transportation remains the only source of heating oil for the New England's winter months.

Recommendation:

★ The NEPD Group supports the President's budget proposal to provide \$8 million to maintain the two-million-barrel Northeast Heating Oil Reserve. Operated by the private sector, the Reserve helps ensure adequate supplies of heating oil in the event that colder than normal winters occur in the Northeast United States.

Rail Transportation

Coal, which provides about 52 percent of America's electricity, is the most important single commodity carried by rail. Over the past ten years, the rail share of coal transportation has increased, primarily as a result of increases in low-sulfur western coal, which moves long distances over rail. In 1999, domestic railroads carried 68 percent of the nation's coal, and in 2000, they transported an average of 14.4 million tons of coal a week.

Transportation costs account for 30 to 50 percent of the final delivered price of coal to utilities. About 74 percent of U.S.

low-sulfur coal reserves are located in Montana and Wyoming. Demand for clean coal from Wyoming's Powder River Basin is expected to increase because of its environmental benefits. However, rail capacity problems in the Powder River Basin have created a bottleneck in the coal transportation system.

With little excess capacity in the rail lines supporting the Powder River Basin, expected increases in demand could result in capacity shortfalls and delays in providing coal to power plants that are relying increasingly on "just-in-time" shipments to reduce inventory costs. Additionally, delays in other parts of the rail network, such as at key rail facilities, can undermine the efficiency and reliability of the system. There is a need to eliminate bottlenecks in the coal transportation system.

Infrastructure Security

The energy infrastructure is vulnerable to physical and cyber disruption that could threaten its integrity and safety. Disruptions could come from natural events, like geomagnetic storms and earthquakes, or could come from accidents, equipment failures, or deliberate sabotage. In addition, the nation's transportation and power infrastructures have grown increasingly complex and interdependent. Consequently, any disruption can have extensive consequences.

Transportation facilities have weathered relatively short interruptions in power as a result of natural disasters and accidents, with varying degrees of impact. In a few instances, they have experienced intermittent, lengthy outages that have affected not only primary systems, but integrated services as well, such as voice, data, Internet, and wireless networks that may be used to transmit control information. The growing reliance on computer technologies, automated monitoring and control systems, and electronic commerce makes the system more efficient and vibrant, but also requires a greater level of diligence and use of safeguards.

Accurate weather and climate forecasting can prevent millions of dollars in

damage to U.S. energy infrastructure. For example, the interaction of geomagnetic storms with the Earth's magnetic field can cause additional current to enter transmission lines, which at times has caused regional grid collapse and has destroyed power plant electrical transformers. Given sufficient warning, the industry can initiate protective countermeasures, such as when several northeastern power plants shed 20 percent of their load during a July 2000 geomagnetic storm.

Improvements in forecasting can further assist in the management of energy resources and materials, can prevent power outages in many cases, and can accelerate restoration of power after outages that do occur. Also, data from extreme weather events can be used to design and build infrastructure, such as transmission lines, pipelines, and hydropower dams.

Summary of Recommendations

America's Energy Infrastructure: A Comprehensive Delivery System

- ★ The NEPD Group recommends that the President direct the Secretary of Energy to work with the Federal Energy Regulatory Commission (FERC) to improve the reliability of the interstate transmission system and to develop legislation providing for enforcement by a self-regulatory organization subject to FERC oversight.
- ★ The NEPD Group recommends that the President direct the Secretary of Energy to expand the Department's research and development on transmission reliability and superconductivity.
- ★ The NEPD Group recommends that the President direct the Secretary of Energy to authorize the Western Area Power Administration to explore relieving the "Path 15" bottleneck through transmission expansion financed by nonfederal contributions.
- ★ The NEPD Group recommends that the President direct the appropriate federal agencies to take actions to remove constraints on the interstate transmission grid and allow our nation's electricity supply to meet the growing needs of our economy.
 - Direct the Secretary of Energy, by December 31, 2001, to examine the benefits of establishing a national grid, identify transmission bottlenecks, and identify measures to remove transmission bottlenecks.
 - Direct the Secretary of Energy to work with FERC to relieve transmission constraints by encouraging the use of incentive rate-making proposals.
 - Direct the federal utilities to determine whether transmission expansions are necessary to remove constraints. The Administration should review the Bonneville Power Administration's (BPA's) capital and financing requirements in the context of its membership in a regional RTO, and if additional Treasury financing appears warranted or necessary in the future, the Administration should seek an increase in BPA's borrowing authority at that time.
 - Direct the Secretary of Energy, in consultation with appropriate federal agencies and state and local government officials, to develop legislation to grant authority to obtain rights-of-way for electricity transmission lines, with the goal of creating a reliable national transmission grid. Similar authority already exists for natural gas pipelines in recognition of their role in interstate commerce.

★ The NEPD Group recommends that the President direct the Secretary of the Interior to work with Congress and the State of Alaska to put in place the most expeditious process for renewal of the Trans-Alaskan Pipeline System rights-of-way to ensure that Alaskan oil continues to flow uninterrupted to the West Coast of the United States.

★ The NEPD Group recommends that the President direct the Secretaries of Energy and State, coordinating with the Secretary of the Interior and the Federal Energy Regulatory Commission, to work closely with Canada, the State of Alaska, and all other interested parties to expedite the construction of a pipeline to deliver natural gas to the lower 48 states. This should include proposing to Congress any changes or waivers of law pursuant to the Alaska Natural Gas Transportation Act of 1976 that may be required.

★ The NEPD Group recommends that the President support legislation to improve the safety of natural gas pipelines, protect the environment, strengthen emergency preparedness and inspections and bolster enforcement.

★ The NEPD Group recommends that the President direct agencies to continue their interagency efforts to improve pipeline safety and expedite pipeline permitting in an environmentally sound manner and encourage FERC to consider improvements in the regulatory process governing approval of interstate natural gas pipeline projects.

★ The NEPD Group recommends that the President direct the Administrator of the EPA to study opportunities to maintain or improve the environmental benefits of state and local “boutique” clean fuel programs while exploring ways to increase the flexibility of the fuels distribution infrastructure, improve fungibility, and provide added gasoline market liquidity. In concluding this study, the Administrator shall consult with the Departments of Energy and Agriculture, and other agencies as needed.

★ The NEPD Group recommends that the President direct the Administrator of the Environmental Protection Agency and the Secretary of Energy to take steps to ensure America has adequate refining capacity to meet the needs of consumers.

- Provide more regulatory certainty to refinery owners and streamline the permitting process where possible to ensure that regulatory overlap is limited.
- Adopt comprehensive regulations (covering more than one pollutant and requirement) and consider the rules’ cumulative impacts and benefits.

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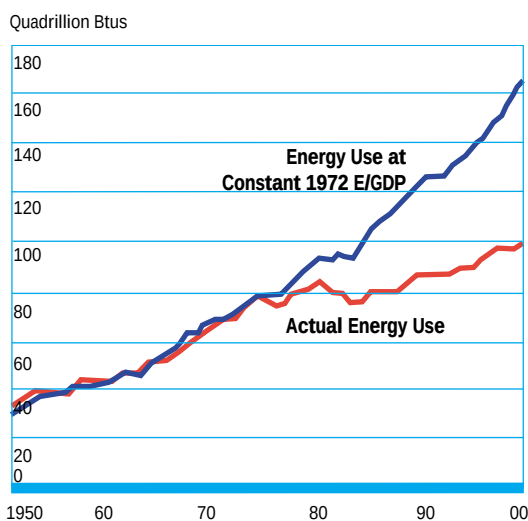
Strengthening Global Alliances

Enhancing National Energy Security and International Relationships

U.S. national energy security depends on sufficient energy supplies to support U.S. and global economic growth. Energy policies that have emphasized reliance on market forces have led to major energy security gains over the past two decades. Major improvements in exploration and production technology, as well as the trend toward opening new areas around the globe for exploration and development, have yielded significant dividends:

- The U.S. and world economies have diversified their sources of oil supplies, largely through increased production in the Western Hemisphere, the North Sea, and Africa.
- The world's fuel mix is also more diverse, primarily because of greater reliance on natural gas and nuclear power.
- The rate of growth in U.S. oil demand has slowed significantly since the first oil shocks of the 1970s because of more energy-efficient industries, structural changes in the economy, and greater efficiencies in vehicles, appliances, and buildings.

Figure 8-1
The U.S. Economy is More Energy Efficient (Energy Intensity)
Primary Energy Use



Improvements in energy efficiency since the 1970s have had a major impact in meeting national energy needs relative to new supply. If the intensity of U.S. energy use had remained constant since 1972, consumption would have been about 70 quadrillion Btus (74 percent) higher in 1999 than it actually was.

Source: U.S. Department of Energy, Energy Information Administration.

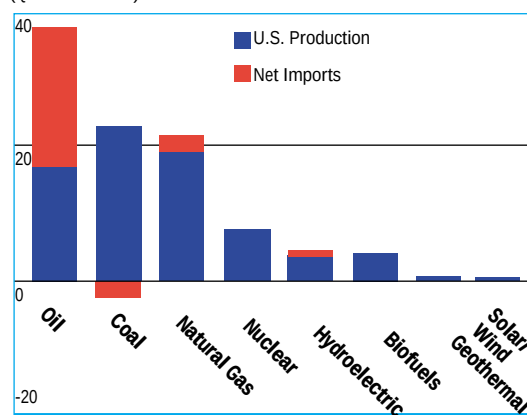
Since 1970, as the economy has shifted toward greater use of more efficient technologies, U.S. energy intensity (the amount of energy it takes to produce a dollar of GDP) has declined by 30 percent (Figure 8-1). However, energy use per person in the United States is expected to rise as is overall demand for energy.

Measures to enhance U.S. energy security by meeting this increased demand must begin at home. The first step toward a sound international energy policy is to use our own capability to produce, process, and transport the energy resources we need in an efficient and environmentally sustainable manner. Market solutions to limit the growth in our oil imports would reduce oil consumption for our economy and increase our economic flexibility in responding to any domestic or international disruption of oil or other energy supplies. The United States produces 72 of the 99 quadrillion British thermal units (Btus) of



Figure 8-2
Sources of U.S. Fuel Consumption in 1999

(Quadrillion Btus)



The United States produced 72 of the 98 quadrillion Btus of energy that it consumed in 1999. We are self-sufficient in virtually all our energy resources, except oil, of which we import 52 percent of our net requirements, and natural gas, of which we import 15–16 percent net, primarily from Canada.

Source: U.S. Department of Energy, Energy Information Administration.

energy that it consumes (Figure 8-2). We are self-sufficient in virtually all our energy resources except oil, of which we import 52 percent of our net requirements, and natural gas, of which we import 15 to 16 percent of our net requirements, primarily from Canada.

We should not, however, look at energy security in isolation from the rest of the world. In a global energy marketplace, U.S. energy and economic security are directly linked not only to our domestic and international energy supplies, but to those of our trading partners as well. A significant disruption in world oil supplies could adversely affect our economy and our ability to promote key foreign and economic policy objectives, regardless of the level of U.S. dependence on oil imports.

Our energy security also depends on an efficient domestic and international infrastructure to support all segments of the energy supply chain. We can strengthen our own energy security and the shared prosperity of the global economy by working cooperatively with key countries and institutions to expand the sources and types of global energy supplies. We can also advance these goals by increasing the effi

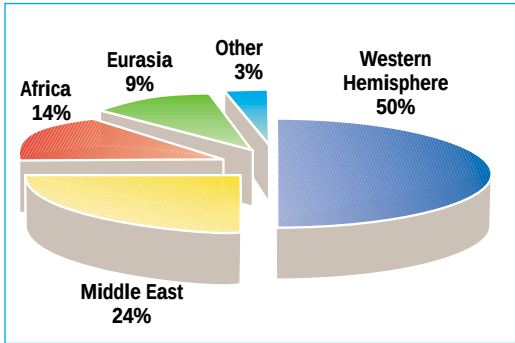
ciency of energy consumption, enhancing the transparency and efficient operation of energy markets, and strengthening our capacity to respond to disruptions of oil supplies. Energy is fundamental to economic growth, and we believe that economic growth and environmental protection can be mutually achieved.

We need to strengthen our trade alliances, to deepen our dialogue with major oil producers, and to work for greater oil production in the Western Hemisphere, Africa, the Caspian, and other regions with abundant oil resources. Greater cooperation with our allies in addressing the growth in oil demand in the transportation sector is particularly important, given the growing demand for oil and other energy resources. Significant economic and environmental benefits can be realized from increased energy efficiency and from the use of clean energy technologies. We need to ensure that our partners in the International Energy Agency (IEA) continue to meet their obligations for emergency supply reserves. Finally, we must continue to work with the IEA, the Asia-Pacific Economic Cooperation (APEC) forum, and others to encourage other large importers to consider measures to augment their oil reserves

Oil Imports and Global Reserves

The U.S. influence on overall world markets is substantial in terms of production and consumption. The United States is the world's second largest natural gas producer and its third largest oil producer. The United States consumes over 25 percent of the oil produced worldwide, slightly more than half of which it imports. Nevertheless, because the price of our domestic and imported oil is determined by a world market, our energy security interests transcend the source of our physical energy supplies (Figure 8-3). Given the large and projected growing volume of U.S. oil imports, our energy and economic security will increase if we take the steps necessary to realize America's potential as a major world oil and natural gas producer.

Figure 8-3
Regional Sources of U.S. Oil Imports in 2000



Slightly over half of the oil the United States imports every day comes from the Western Hemisphere. Canada, Venezuela, and Mexico account for the bulk (41%) of these imports.

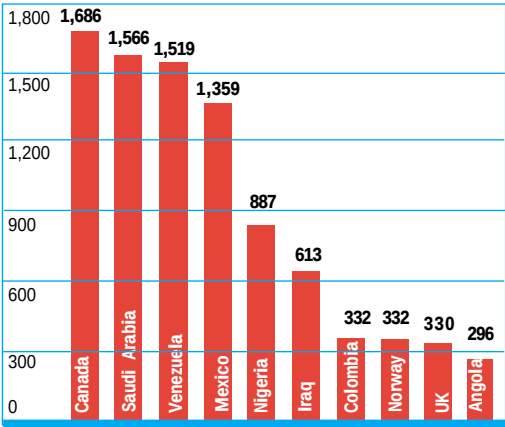
Source: U.S. Department of Energy, Energy Information Administration.

Recommendation:

★ The NEPD Group recommends that the President make energy security a priority of our trade and foreign-policy.-

In 2000, nearly 55 percent of U.S. gross oil imports came from four countries: 15 percent from Canada, 14 percent each from Saudi Arabia and Venezuela, and 12 percent from Mexico (Figure 8-4). The security of U.S. energy supply is enhanced by

Figure 8-4
Top 10 Suppliers of U.S. Oil Imports in 2000



In 2000, nearly 55 percent of gross U.S. oil imports came from four leading suppliers: Canada (15%), Saudi Arabia (14%), Venezuela (14%), and Mexico (12%).

Source: U.S. Department of Energy, Energy Information Administration.-

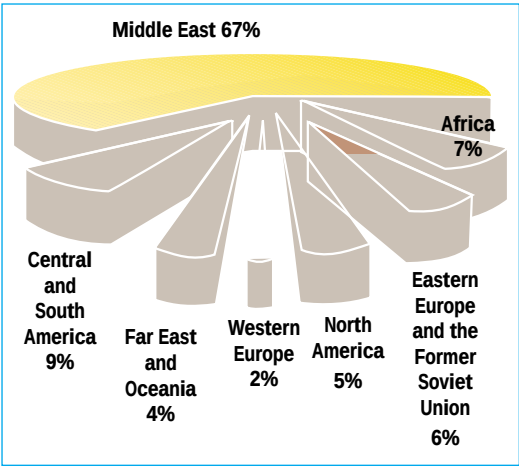
several factors characterizing our diplomatic and economic relationships with our four top suppliers. These factors range from geographic proximity and free trade agreements to integrated pipeline networks, reciprocal energy-sector investments, shared security commitments, and, in all cases, long-term reliable supply relationships (Figure 8-5).

Saudi Arabia and the Middle East Oil Supplies

By 2020, Gulf oil producers are projected to supply between 54 and 67 percent of the world's oil. Thus, the global economy will almost certainly continue to depend on the supply of oil from Organization of Petroleum Exporting Countries (OPEC) members, particularly in the Gulf. This region will remain vital to U.S. interests. Saudi Arabia, the world's largest oil exporter, has been a linchpin of supply reliability to world oil markets.

Saudi Arabia has pursued a policy of investing in spare oil production capacity, diversifying export routes to both of its coasts, and providing effective assurances that it will use its capacity to mitigate the

Figure 8-5
Proven World Oil Reserves in January 2000



The world's proven crude oil reserves remain relatively concentrated. The Middle East holds 664 billion barrels, or roughly two-thirds of the world's conventional oil reserves, followed by the Western Hemisphere (14%) and Africa (7%).

Source: U.S. Department of Energy, Energy Information Administration.

Saudi Arabia has pursued a policy of investing in spare oil production capacity, diversifying export routes to both of its coasts, and providing effective assurances that it will use its capacity to mitigate the impact of oil supply disruptions in any region.

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impact of oil supply disruptions in any region (Figure 8-6). Algeria, Kuwait, Oman, Qatar, Saudi Arabia, the United Arab Emirates (UAE), Yemen, and other states in the region with which we maintain diplomatic relations have all, to some extent, opened their energy sectors to international investment. This development provides an important opportunity to further encourage foreign investment in these important energy-producing countries, thereby broadening our shared commercial and strategic interests. By any estimation, Middle East oil producers will remain central to world oil security. The Gulf will be a primary focus of U.S.

international energy policy, but our engagement will be global, spotlighting existing and emerging regions that will have a major impact on the global energy balance.

Recommendation:

★ The NEPD Group recommends that the President support initiatives by Saudi Arabia, Kuwait, Algeria, Qatar, the UAE, and other suppliers to open up areas of their energy sectors to foreign investment.

Improving Market Transparency

The United States must work with oil producers to improve the transparency, timeliness, and accuracy of the data that guide global oil markets. A lack of timely and accurate data relating to both oil production and inventory levels has contributed to the price volatility witnessed in 2000. Discussions among the major oil producers and consumer countries should be designed to improve the transparency, accuracy, and timeliness of data that guide the market. In turn, enhanced data quality and increased data transparency will improve market efficiency. Refocusing that dialogue beyond short-term market developments to long-term issues of world economic growth, improving data quality, and addressing energy infrastructure is needed to maintain a smooth flow of energy from the wellhead to the consumer.

Recommendation:

★ The NEPD Group recommends that the President direct the Secretaries of State, Energy and Commerce work to improve dialogue among energy producing and consuming nations.

Promoting International Trade and Investment

Longstanding U.S. policy supports a liberalized global energy sector that is open to international trade and investment. The United States benefits from international investments at home that have increased our



Figure 8-6
Saudi Arabia Export Pipelines



Saudi Arabia, the world's largest oil supplier, maintains major oil export ports and storage capacity on both the Gulf and the Red Sea.

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energy sector's capacity and its infrastructure. Both producers and consumers will benefit from ensuring that the global energy infrastructure is sufficient and flexible to meet growing global demand.

American energy firms remain world leaders, and their investments in energy producing countries enhance efficiencies and market linkages while increasing environmental protections. Expanded trade and investment between oil importing and exporting nations can increase shared interests while enhancing global energy and economic security. Promoting such investment will be a core element of our engagement with major foreign oil producers.

Recommendations:

★ The NEPD Group recommends that the President direct the Secretaries of State, Commerce and Energy to continue supporting American energy firms competing in markets abroad and use our membership in multilateral organizations, such as the Asia-Pacific Economic Cooperation (APEC) forum, the Organization for Economic Cooperation and Development (OECD), the World Trade Organization (WTO) Energy Services Negotiations, the Free Trade Area of the Americas (FTAA), and our bilateral relationships to implement a system of clear, open, and transparent rules and procedures governing foreign investment; to level the playing field for U.S. companies overseas; and to reduce barriers to trade and investment.

★ The NEPD Group recommends that the President direct the Secretaries of Commerce and Energy, and the U.S. Trade Representative, to support a sectoral trade initiative to expand investment and trade in energy-related goods and services that will enhance exploration, production, and refining, as well as the development of new technologies.

Reviewing and Reforming Sanctions

Economic sanctions include U.S. unilateral sanctions as well as multilateral sanctions, such as United Nations (UN) Security Council Resolutions. Sanctions can advance important national and global security objectives and can be an important foreign policy tool, especially against nations that support terrorism or seek to acquire weapons of mass destruction. Nevertheless, sanctions should be periodically reviewed to ensure their continued effectiveness and to minimize their costs on U.S. citizens and interests.

Recommendation:

★ The NEPD Group recommends that the President direct the Secretaries of State, Treasury, and Commerce to initiate a comprehensive review of sanctions. Energy security should be one of the factors considered in such a review.-

Diversity of Supply

Concentration of world oil production in any one region of the world is a potential contributor to market instability, benefiting neither oil producers nor consumers. Periodic efforts by OPEC to maintain oil prices above levels dictated by market forces have increased price volatility and prices paid by consumers, and have worked against the shared interests of both producers and consumers in greater oil market stability. This remains a policy challenge, which we will meet over the longer term through a comprehensive energy policy that addresses both supply and demand, as well as through increased engagement with all our major suppliers. Greater diversity of world oil production remains important.

Encouraging greater diversity of oil production and, as appropriate, transportation, within and among geographic regions has obvious benefits to all market participants. Technological advances will enable the United States to accelerate the diversification of oil supplies, notably through deep-



The United States is helping developing countries use energy efficient technologies. Photovoltaic-powered pumps are being used in many wells throughout rural India for collecting potable water.

U.S. DEPARTMENT OF ENERGY, NATIONAL RENEWABLE ENERGY LABORATORY

water offshore exploration and production in the Atlantic Basin, stretching from off shore Canada to the Caribbean, Brazil, and West Africa. The Caspian Sea can also be a rapidly growing new area of supply.

The ongoing development of so-called “heavy oil” reserves in the Western Hemisphere is an important factor that promises to significantly enhance global oil reserves and production diversity. Recent Canadian and Venezuelan success in making heavy oil deposits commercially viable suggests that they will contribute substantially to the diversity of global energy supply, and to our own energy supply mix over the medium to long term. Leading non-OPEC oil exporters, such as Mexico and Norway, remain critical to the diversity of global energy supply.

Growing levels of conventional and heavy oil production and exports from the Western Hemisphere, the Caspian, and Africa are important factors that can lessen the impact of a supply disruption on the U.S. and world economies. Overall U.S. policies in each of these high-priority regions will focus on improving the investment climate and facilitating the flow of needed investment and technology.

Bilateral energy working groups, such as the U.S.-Kazakhstan Oil, Gas and Commercial Energy Working Group and the U.S.-Russian Oil and Gas Working Group, can improve the trade climate in high-priority countries. In addition to seeking new sources of oil, the United States is helping developing countries use energy efficient technologies to mitigate the environmental impacts of energy use, and to improve access to energy resources.

WTO members are beginning to examine global trade in energy services. The United States has called on WTO members to open markets eligible for private participation in the entire range of energy services, from exploration to the final customer. The energy service proposal would attempt to ensure nondiscriminatory access to foreign providers of energy services. Equally important, the U.S. proposal suggests that WTO members consider how to best create a pro-competitive regulatory en-

Figure 8-7

Canada-U.S. Natural Gas Pipelines: 2001



Canada-U.S. Oil Pipelines: 2001

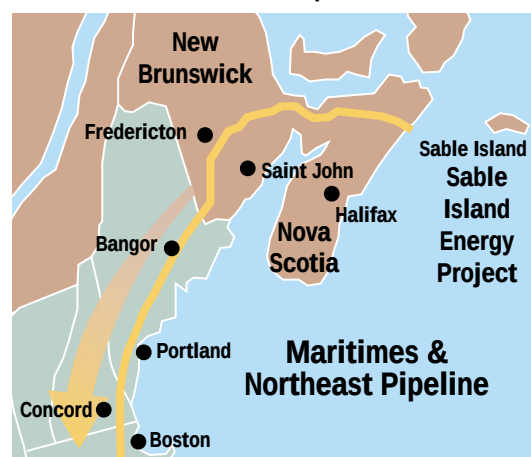


An integrated network of oil and gas pipelines demonstrates the seamless nature of North American energy trade.

Sources: Lakehead Pipe Line Company, Inc., and Canadian Association of Petroleum Producers.

Figure 8-8

Maritimes and Northeast Pipeline: 2000



New England's geography made it the “last stop” for natural gas pipelines stretching thousands of miles across the continent from the South and the West. Consequently, the region became the most oil-dependent area in the country, particularly for home heating and electricity. With the January 1, 2000, inauguration of Atlantic Canada's Maritimes and Northeast Pipeline, New England is now at the beginning of the line for natural gas flowing across the border from Canada at Calais, Maine. Overall, the region's fuel mix is becoming increasingly diversified, with natural gas demand slated to increase by 2.4 percent a year through 2020.

Source: Maritimes and NorthEast Pipeline.

environment for energy services, so that opaque or discriminatory regulatory practices do not undermine commitments to open their domestic markets to foreign service providers. Such objectives can also be pursued in the FTAA and APEC.

Toward a North American Energy Framework

Increased U.S., Canadian, and Mexican energy production and cooperation would enhance energy security and, through our economic links in the North America Free Trade Agreement (NAFTA) economy, fundamentally advance each country's economic security. As state and federal governments consider energy reforms, there will be a need to ensure compatible regulatory frameworks with our neighbors while recognizing differences in jurisdictions.

Canada

Canada's deregulated energy sector has become America's largest overall energy trading partner, and our leading foreign supplier of natural gas, oil, and electricity. Canada's sustainable development based energy strategies contribute to the health of the NAFTA economy and of our shared environment.

Canada provided 14 percent of U.S. natural gas supply last year. An integrated network of pipelines demonstrates the seamless nature of North American energy trade (Figure 8-7). Estimated natural gas deposits in Alaska and Northwest Canada exceed 70 trillion cubic feet, representing over three years of total U.S. consumption at present levels.

To advance shared economic and environmental objectives, the private sector is poised to develop the continent's northern gas reserves, with pipeline linkages between both countries. To the east, recent development of Canada's Atlantic offshore energy reserves has made significant strides, with major offshore natural gas and oil production now available. Canada's Atlantic energy development is now providing previously untapped sources of clean-burning natural gas not only to Nova Scotia and New Brunswick but also to heating oil-de-



pendent New England (Figure 8-8).

Our large cross-border electricity trade flows in each direction. Our electricity imports from Canada are derived largely from hydropower produced in eastern Canada, Canadian and American hydropower projects in the Pacific Northwest operating pursuant to the Columbia River Treaty, and a nuclear power plant in New Brunswick. All of these sources provide important trade and clean air benefits, while allowing both countries to benefit from load sharing and integration. The reliability of the North American electricity grid can be enhanced yet further through closer coordination and compatible regulatory and jurisdictional approaches.

Canada's oil trade, responding to market signals, increased 4 percent worldwide and 10 percent with the United States last year. Estimates of Canada's recoverable heavy oil sands reserves are substantial, and new technologies are being deployed to develop their potential. Production from these promising areas now approaches 600,000 barrels a day. Their continued development can be a pillar of sustained North American energy and economic security.

Mexico

Our energy relationship with Mexico reflects the increasingly interrelated character of NAFTA economies and our contiguous border. U.S. natural gas reserves, pipe-

Offshore oil platform near Campeche, Mexico. Mexico's large crude oil reserves—approximately 25 percent larger than our own proven reserves—makes it a likely source of increased oil production over the next decade.

U.S. EMBASSY, MEXICO CITY

Figure 8-9

Mexican Oil and Gas Resources: 2001



Mexico's large oil reserves—approximately 25 percent larger than U.S. proven reserves—make it a likely source of increased oil production over the next decade.

Source: U.S. Central Intelligence Agency.

A carrier transports liquefied natural gas (LNG) from Trinidad and Tobago—our largest LNG supplier—to Boston harbor. LNG currently represents 16 percent of New England's natural gas supply.

CABOT LNG

lines, and industries are closer to the growing border area than some of Mexico's reserves. The United States is a net exporter of refined petroleum products and natural gas to Mexico, primarily through pipeline connections to northern Mexico. Mexico is a leading and reliable source of imported oil, and its large reserve base, approximately 25 percent larger than our own proven reserves, makes Mexico a likely source of increased oil production over the

next decade (Figure 8-9).

Mexico began exporting 50 megawatts of electricity from Baja to California in January 2001. However, the transmission infrastructure on both sides of the border is insufficient for greater flows of energy in either direction without expansion. In the United States, our process for "Presidential Permitting" of cross-border infrastructure linkages needs to be updated and streamlined.

Mexico will make its own sovereign decisions on the breadth, pace, and extent to which it will expand and reform its electricity and oil and gas capacities. Where the country has opened its energy sector to private investment, such as in natural gas transmission, distribution, and storage, investments have been made to our mutual benefit. To the extent Mexico seeks to attract additional foreign investment consistent with its Constitution, which reserves exploration and production rights to the Mexican government, the United States should actively encourage the U.S. private sector to consider market-based investments.

Recommendations:

★ The NEPD Group recommends that the President direct the Secretaries of State, Commerce, and Energy to engage in a dialogue through the North American Energy Working Group to develop closer energy integration among Canada, Mexico, and the United States and identify areas of cooperation, fully consistent with the countries' respective sovereignties.

★ The NEPD Group recommends that the President direct the Secretaries of Energy and State, in consultation with the Federal Energy Regulatory Commission, to review their respective oil, natural gas, and electricity cross boundary "Presidential Permitting" authorities, and to propose reforms as necessary in order to make their own regulatory regimes more compatible for cross-border trade.



★ The NEPD Group recommends that the President direct the Secretaries of Energy and State, coordinating with the Secretary of the Interior and the Federal Energy Regulatory Commission, to work closely with Canada, the State of Alaska, and all other interested parties to expedite the construction of a pipeline to deliver natural gas to the lower 48 states. This should include proposing to Congress any changes or waivers of law pursuant to the Alaska Natural Gas Transportation Act of 1976 that may be required.

South America: Latin America and the Caribbean

Latin America and the Caribbean are growing not only as major producing regions, but also as major consumers of oil and natural gas. Trinidad and Tobago's progressive investment code has made it the hemisphere's largest exporter of LNG and the largest supplier of LNG to the United States in 2000. Unprecedented development of Central and South America's vast natural gas reserves—222.7 trillion cubic feet as of January 2000, illustrated by transcontinental pipelines linking Bolivia, Brazil, Argentina, Chile, Paraguay, and Uruguay—increase regional self-reliance, affirm economic integration, aid the environment, and stem the growth in oil demand. Colombia has also become an important supplier of oil to the United States.

The United States, with Venezuela, is a co-coordinator of the Hemispheric Energy Initiative process. In March 2001, a Summit of the Americas Hemispheric Energy Ministerial meeting was hosted by the Government of Mexico. At the meeting, the region's energy ministers pledged to support integration and sustainable development in the hemisphere, recognizing the need to foster stable and transparent regulatory frameworks. In April 2001, the thirty-four democratically elected leaders of the Western Hemisphere met in Quebec City for the Third Summit of the Americas. They called for a renewed effort to strengthen the hemisphere's energy cooperation and integration.



Venezuela is the world's fifth largest oil exporter, and the third largest oil supplier to the United States. Its energy industry is increasingly integrated into the U.S. marketplace. Venezuela's downstream investments in the United States make it a leading refiner and gasoline marketer here. Growing U.S. and international investments in Venezuela's energy sector, particularly in its resource-rich heavy oil sector, are enhancing the country's ability to meet its development goals and to keep pace with a growing world energy marketplace. Venezuela is also moving to liberalize its natural gas sector, which will increase opportunities for foreign investment to expand Venezuelan natural gas production. These positive steps along with conclusion of a Bilateral Investment Treaty, which is now being negotiated, would provide investors from both the United States and Venezuela incentives for increased investment.

Brazil has long been a pioneer in the development of deep-water offshore oil and gas resources. Its world-class oil industry is now moving to become a partner with U.S. and international investors to more fully develop its prolific offshore oil reserves. This welcome development will enhance hemispheric energy production from well-established sedimentary basins.

U.S. Secretary of Energy Spencer Abraham listens to his colleagues at the Summit of the Americas Hemispheric Energy Ministerial meeting in Mexico City on March 9, 2001.

U.S. EMBASSY, MEXICO CITY

Recommendations:

- ★ The NEPD Group recommends that the President direct the Secretaries of State and Commerce to conclude negotiations with Venezuela on a Bilateral Investment Treaty, and propose formal energy consultations with Brazil, to improve the energy investment climate for the growing level of energy investment flows between the United States and each of these countries.
- ★ The NEPD Group recommends that the President direct the Secretaries of Energy, Commerce, and State to work through the Summit of the Americas Hemispheric Energy Initiative to develop effective and stable regulatory frameworks and foster reliable supply sources of all fuels within the region.

Africa

Sub-Saharan Africa holds 7 percent of world oil reserves and comprises 11 percent of world oil production. Along with Latin America, West Africa is expected to be one of fastest-growing sources of oil and gas for the American market. African oil tends to be of high quality and low in sulfur, making it suitable for stringent refined product requirements, and giving it a growing market share for refining centers on the East Coast of the United States.

In 2000, OPEC member Nigeria exported an average of 900,000 barrels of oil per day to the United States, out of its total production of 2.1 million barrels of oil per day. Nigeria, in partnership with the private sector, has set ambitious production goals as high as 5 million barrels of oil per day over the coming decade.

Angola's growing offshore oil industry, with participation by U.S. and international oil firms, is also a major source of growth. In 2000, Angola exported 300,000 barrels of oil per day out of its 750,000 barrels of oil per day of total production to the United States, and is thought to have the potential to double its exports over the next ten years. Other significant exporters to the United States included Gabon and the Congo-Brazzaville.

The World Bank has supported Chad's efforts to begin ambitious oil development. This year an international consortium that includes U.S. firms began investing \$3.5 billion in this pipeline from Chad to Cameroon, the largest infrastructure project in Africa to date. When complete, the pipeline will allow Chad to export up to 250,000 barrels of oil per day.

The U.S. Agency for International Development (USAID) has provided technical assistance in support of a West Africa Power Pool and associated pipeline project involving a number of U.S. oil companies, and is providing assistance for the creation of a regional regulatory framework that will enable Ghana and Nigeria to become major exporters of natural gas and electricity.

The West Africa Gas Pipeline is a 161 mile (1,000-kilometer), \$400 million on shore/offshore natural gas pipeline connecting Nigeria with Benin, Togo, and Ghana. The pipeline is being built by a consortium of companies, and includes financing by the U.S. Export-Import Bank.

Recommendations:

- ★ The NEPD Group recommends that the President direct the Secretaries of State, Energy, and Commerce to rein-vigorate the U.S.-Africa Trade and Economic Cooperation Forum and the U.S.-African Energy Ministerial process; deepen bilateral and multilateral engagement to promote a more receptive environment for U.S. oil and gas trade, investment, and operations; and promote geographic diversification of energy supplies, addressing such issues as transparency, sanctity of contracts, and security.
- ★ The NEPD Group recommends that the President direct the Secretaries of State, Energy, and Commerce to recast the Joint Economic Partnership Committee with Nigeria to improve the climate for U.S. oil and gas trade, investment, and operations and to advance our shared energy interests.
- ★ The NEPD Group recommends that the President direct the Secretaries of

State, Energy, and Commerce to support more transparent, accountable, and responsible use of oil resources in African producer countries to enhance the stability and security of trade and investment environments.

The Caspian

Proven oil reserves in Azerbaijan and Kazakhstan are about 20 billion barrels, a little more than the North Sea and slightly less than the United States. Exploration, however, is continuing, and proven reserves are expected to increase significantly.

For example, initial results of the exploration well at Kazakhstan's Kashagan field indicate the find is one of the most important in thirty years, and is comparable to Prudhoe Bay in size. Current exports from the region are only about 800,000 barrels of oil per day, in part due to limited export route options. However, potential exports could increase by 1.8 million barrels of oil per day by 2005, as the United States works closely with private companies and countries in the region to develop commercially viable export routes, such as the Baku-Tbilisi-Ceyhan (BTC) and Caspian Pipeline Consortium oil pipelines (Figure 8 10). Moreover, there is considerable optimism that exports could grow even more substantially in subsequent years because of positive prospects for new oil and gas finds as additional geologic structures undergo exploration, and the development of new export routes.

Foreign investors and technology are critical to rapid development of new commercially viable export routes. Such development will ensure that rising Caspian oil production is effectively integrated into world oil trade. U.S.-supported East-West pipeline routes will add substantial new oil transportation capacity to allow continued expansion of production and exports. Over land routes via pipeline, such as the planned BTC oil pipeline, will also help mitigate maritime risks in the crowded Bosphorus Straits. To help countries prepare for increased oil production within the re-

Figure 8-10

Caspian Energy Export Pipelines: 2001



Several oil and natural gas pipeline projects are proposed for the Caspian area.

Source: U.S. Central Intelligence Agency.

gion, the United States is working with Black Sea and Caspian Sea border states to ensure that they develop adequate oil spill response capabilities.

Recommendations:

- ★ The NEPD Group recommends that the President direct the Secretaries of State, Commerce, and Energy to support the BTC oil pipeline as it demonstrates its commercial viability.-
- ★ The NEPD Group recommends that the President direct the Secretaries of Commerce, State, and Energy to continue working with relevant companies and countries to establish the commercial conditions that will allow oil companies operating in Kazakhstan the option of exporting their oil via the BTC pipeline.-
- ★ The NEPD Group recommends that the President direct the Secretaries of State, Commerce, and Energy to support the efforts of private investors and regional governments to develop the Shah Deniz gas pipeline as a way to help Turkey and Georgia diversify their natural gas supplies and help Azerbaijan export its gas via a pipeline that will continue diversification of secure energy supply routes.-
- ★ The NEPD Group recommends that the President direct appropriate federal agencies to complete the current cycle of oil spill response readiness workshops and to consider further appropriate steps to ensure the implementation of the workshops' recommendations.-
- ★ The NEPD Group recommends that the President direct the Secretary of State to encourage Greece and Turkey to link their gas pipeline systems to allow European consumers to diversify their gas supplies by purchasing Caspian gas.-
- ★ The NEPD Group recommends that the President direct the Secretaries of Commerce, Energy, and State to deepen their commercial dialogue with Kazakhstan, Azerbaijan, and other Caspian states to provide a strong, transparent, and stable business climate for energy and related infrastructure projects.-

Russia

Russia has about 5 percent of the world's proven oil reserves. In 2000, Russia produced an average of 6.7 million barrels of oil and natural gas liquids per day, making it both the world's third largest producer and second largest exporter at 4.2 million barrels of oil per day. Russia's oil production in 2000 represented an increase of 7 percent over 1999, the first increase since the dissolution of the Soviet Union. A similar rate of increase is projected for 2001. New fields are being developed, including those with U.S. and other foreign investors.

Nevertheless, substantial infrastructure investment is still needed, as well as legislation and a stable and reliable regime of contracting to finalize the Production Sharing Agreement (PSA) mechanism for private-sector participation and actions to improve the general investment climate. Russian oil firms are increasingly active on a global scale, with upstream and downstream investments in the Caspian, the United States, Africa, South Asia, and Europe, enhancing Russia's ability to develop its own and international oil reserves.

Russia holds 33 percent of the world's natural gas reserves, exporting a full 35 percent of its production to Europe and Central Asia in 1999. Russian natural gas exports can increase regional fuel diversification and advance environmental goals. With production declines now evident in existing fields, development of new reserves that require substantial new investments will be necessary.

Recommendations:

- ★ The NEPD Group recommends that the President direct the Secretaries of State, Commerce, and Energy to deepen the focus of the discussions with Russia on energy and the investment climate.-
- ★ The NEPD Group recommends that the President direct the Secretaries of Commerce, State, and Energy to assist U.S. companies in their dialogue on the investment and trade climate with-

Russian officials, to encourage reform of the PSA law and other regulations and related tax provisions, as well as general improvements in the overall investment climate. This will help expand private investment opportunities in Russia and will increase the international role of Russian firms.

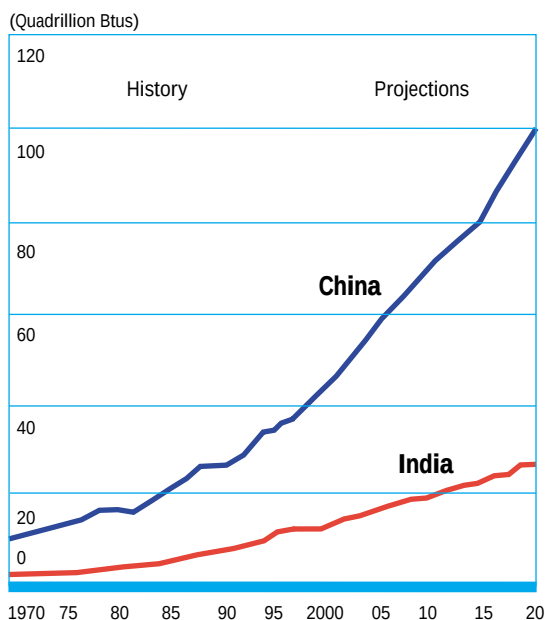
Asia

Asia holds less than 5 percent of world proven oil reserves, but accounts for more than 10 percent of oil production and about 30 percent of world oil consumption. The developing countries of the Pacific Rim are expected to increase their total petroleum imports by almost 43 percent between 1997 and 2020. The developing countries of Asia are expected to remain heavily dependent on Middle East imports.

China is a critical player in global energy security issues, since its net oil imports are expected to rise from approximately 1 million barrels of oil per day at present to possibly 5 to 8 million barrels of oil per day by 2020, with a predominant (over 70 percent) dependence on Middle East imports. China moved in the mid-1990s from being a net oil exporter to a net oil importer.

About 7 percent of the world's proven natural gas reserves are located in Asia. Asian gas production represents about 11 percent of the world total, and consumption is less than 3 percent of world natural gas demand. Other natural gas producers, such as Malaysia, Myanmar, and Australia, are net gas exporters. Currently Japan, South Korea, and Taiwan are the major gas importers in Asia. China, in addition to accelerating domestic exploration and development of natural gas resources, is planning to import gas via pipeline from Central Asia. India, likewise, is considering several potential LNG import projects (Figure 8-11).

Figure 8-11
Energy Consumption in China and India: 1970–2020



China and India account for the bulk of projected growth in oil demand in non-OECD countries.

Source: U.S. Department of Energy, Energy Information Administration.

Recommendations:

- ★ The NEPD Group recommends that the President direct the Secretaries of State, Commerce, and Energy to continue to work in the APEC Energy-Working Group to examine oil market-data transparency issues and the variety of ways petroleum stocks can be used as an option to address oil market disruptions.-
- ★ The NEPD Group recommends that the President direct the Secretaries of State and Energy to work with India's Ministry of Petroleum and Natural Gas to help India maximize its domestic oil and gas production.-

Diversification of Fuel Mix

The growing demand for more fuel efficient technologies offers U.S. businesses significant trade and investment opportunities overseas, while addressing rising world oil demand. The United States supports a practical, market-based approach that en

courages the adoption of efficient technologies, including those relating to natural gas, nuclear energy, and renewable energy. This approach takes into account existing national and international programs and has the potential to energize both public action and private involvement. Introduction of these technologies abroad also supports U.S. national interests by reducing competition for the oil resources on which the global economy continues to rely. Overall, the U.S. government's goal is to adopt policies that support innovative finance and market mechanisms that will provide U.S. businesses and consumers greater incentives to make more cost effective, energy efficient investment and consumption decisions.

Increased use of renewable energy technologies would improve U.S. energy security, yield global environmental benefits, improve social and economic stability in the developing world, and provide significant trade and investment opportunities to U.S. businesses. Promotion of clean energy technology exports can mitigate international dependence on oil supplies from volatile regions, help lower energy costs for U.S. consumers, bring U.S. firms greater access to large foreign markets, and enhance U.S. integration with global sources of innovation. In consultation with U.S. industry, the U.S. government is participating in efforts of the IEA, the G-8, the OECD, the United Nations, and multilateral development banks to formulate effective strategies for accelerated market penetration of renewable energy technologies. Significant market penetration will depend on further reducing the costs of deploying these technologies.

The Clean Energy Technology Exports Working Group, a Federal interagency task force comprised of USAID and the Departments of Commerce and Energy, is creating a strategic plan that will provide a roadmap for future exports of U.S. clean energy technologies. Through its international trade programs, the Department of Commerce will showcase market-ready U.S. technologies that generate a cleaner environment and increase energy efficiency.

Recommendation:

★ The NEPD Group recommends that the President direct the Secretaries of Commerce, State, and Energy to promote market-based solutions to environmental concerns; support exports of U.S. clean energy technologies and encourage their overseas development; engage bilaterally and multilaterally to promote best practices; explore collaborative international basic research and development in energy alternatives and energy efficient technologies; and explore innovative programs to support the global adoption of these technologies.

Climate Change

The President is committed to addressing the issue of global climate change in a manner that protects our environment and economy. Toward this end, the Administration is undertaking a Cabinet-level review of domestic and international policies for addressing this issue.

The United States invited other nations to re-examine global climate change issues, including technologies and market-based systems. Increasing our understanding of the most recent science and further research into the science of climate change will be essential to developing the optimal strategy.

There is increasing awareness of global competition for fossil fuels and their potential threats to the global environment. The United States can diminish both risks by becoming more energy efficient at home, by working with other nations, and by encouraging developing countries to use the cleanest and most energy-efficient technologies. Through educational programs, the United States can encourage developing countries to use advanced U.S. energy technologies, energy management practices, and market-based policies. The United States is uniquely positioned to help emerging nations build energy and institutional capacity and to finance energy-related activities and services. Doing so could prove to be a cost effective investment, for both the United States and emerging economies.

Recommendation:

★ The NEPD Group recommends that the President direct federal agencies to support continued research into global climate change; continue efforts to identify environmentally and cost-effective ways to use market mechanisms and incentives; continue development of new technologies; and cooperate with allies, including through international processes, to develop technologies, market-based incentives, and other innovative approaches to address the issue of global climate change.

Oil Consumption

Although U.S. energy security can be reinforced by domestic efforts to enhance supply and use energy more efficiently, growth in international oil demand will exert increasing pressure on global oil availability. Worldwide oil consumption is projected to grow by 2.1 percent a year over the next two decades. However, oil demand is projected to grow three times as fast in non-OECD countries as in OECD countries, which will increase worldwide competition for global oil supplies and put increased pressure on our shared environment. Accordingly, non-OECD countries' share of oil demand is expected to rise from 41 percent to 52 percent (Figure 8-12). China and India will be major contributors to this growth in demand and will rely heavily on imports to meet their needs. This growth will increase the stake that many developing countries have in ensuring access to significant energy resources, as well as their incentive to pursue energy efficiency.

Transportation has been responsible for nearly all the growth in OECD oil consumption over the last twenty years, and is projected to be the leading source of future growth in oil consumption through 2020. Transportation-related fuel consumption in the developing world is expected to more than double by 2020, growing at an annual average rate of 4 percent. Therefore, both OECD and developing countries will need

to increase their focus on efficiencies in the transportation sector. The momentum to create market mechanisms supporting alternative-fuel vehicles will increase. Best practices that seek to reduce the cost of these technologies and to promote market penetration should be pursued. Without additional efforts to reduce this growth in consumption, the transportation sector's fuel needs will force an increasing dependence on oil in the developed and developing worlds.

Recommendations:

★ The NEPD Group recommends that the President seek to increase international cooperation on finding alternatives to oil, especially for the transportation sector.-

★ The NEPD Group recommends that the President direct the Secretary of State to reinvigorate its dialogue with the European Union on energy issues, and resume the consultative process this year in Washington.-

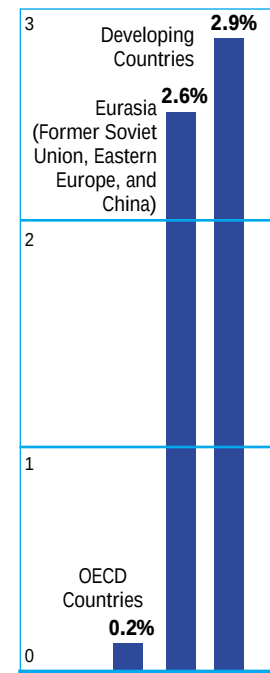
★ The NEPD Group recommends that the President promote a coordinated approach to energy security by calling for an annual meeting of G-8 Energy Ministers or their equivalents.-

Emergency Preparedness for Oil Supply Disruption

U.S. and world exposure to oil supply disruptions increases as the size of strategic and commercial stocks relative to demand declines. This vulnerability is a result of rising global demand, tight supplies, and inadequate efforts to establish or expand oil stockpiles. Such a situation magnifies the importance of U.S. coordination with other members of the IEA, comprised of most OECD member governments. Each IEA member that is a net oil importer is required to hold stocks equal to 90 days or more of its net imports. The IEA maintains agreed mechanisms for coordinating the use of these stocks in responding to a physical supply disruption. Collectively, the net oil-importing members of the IEA currently hold

Figure 8-12
Projected Oil Consumption Rates in Three Economic Regions: 1999–2020

(Percent)



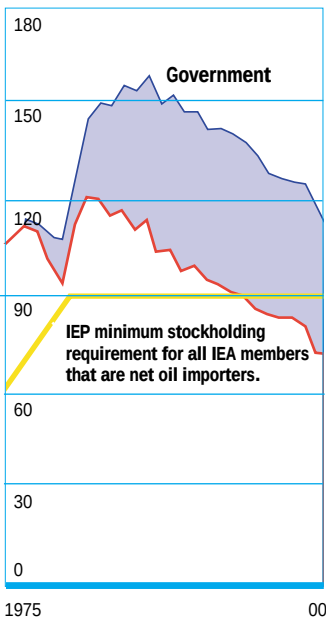
Over the next two decades, oil consumption in developing countries and Eurasia will grow three times faster than in the rest of the world.

Source: U.S. Department of Energy, Energy Information Administration.

Figure 8-13

Stocks of IEA Net Importers: 1975–2000

(Days Of Net Imports)



The International Energy Agency, of which the United States is a member, closely tracks the amount of strategic and commercial petroleum stocks maintained by its member states. The International Energy Program (IEP) Agreement “binds Participating Countries to make specific measures to meet any oil supply emergency and, over the long term, to reduce dependence on oil.”

Source: International Energy Agency.

approximately 113 days worth of strategic and commercial stocks. U.S. stocks, which include both government and commercial stocks, are slightly above the IEA average. While this is more than required, it is far below the peak coverage of 157 days reached in 1986. Moreover, several member states have fallen below the 90-day threshold (Figure 8-13).

The United States meets part of its IEA obligation through government-owned stocks held in the U.S. Strategic Petroleum Reserve (SPR). The SPR currently holds 541 million barrels of oil, which is enough to cover the loss of all U.S. imports for 54 days or a partial disruption for much longer. Close to 33 million barrels of oil will be deposited in the SPR by the fourth quarter of 2002, returning oil that had been “exchanged” out of the reserve last year. SPR oil can be withdrawn at a maximum rate of over 4 million barrels of oil per day initially and could reach the market within fifteen days of a Presidential directive. Because of increased net oil imports, the days of oil import coverage provided by the SPR have declined considerably over the past decade. In 1990, the SPR contained enough oil to compensate for the loss of 82 days worth of U.S. imports—substantially more than today’s 54-day supply. As domestic production and import patterns evolve, the Administration will work to inform Congress about changing coverage levels provided by the SPR. It should be noted that the United States also counts on the SPR as a national defense fuel reserve.

The oil market’s day-to-day operation and its ability to respond to supply problems depend heavily on the availability of information on supply, demand, and price. The oil market volatility of the past two years has emphasized the need for more comprehensive and timely oil market information.

Recommendations:

- ★ The NEPD Group recommends that the President reaffirm that the SPR is designed for addressing an imminent or actual disruption in oil supplies, and not for managing prices.
- ★ The NEPD Group recommend that the President direct the Secretary of Energy to work within the International Energy Agency (IEA) to ensure that member states fulfill their stock holding.
- ★ The NEPD Group recommends that the President direct the Secretary of Energy to encourage major oil-consuming countries that are not IEA members to consider strategic stocks as an option for addressing potential supply disruptions. In this regard, we should work closely with Asian economies, especially through APEC.
- ★ The NEPD Group recommends that the President direct the Secretary of Energy offer to lease excess SPR storage facilities to countries (both IEA and non-IEA members) that might not otherwise build storage facilities or hold sufficient strategic stocks, consistent with statutory authorities.
- ★ The NEPD Group recommends that the President, at such time that exchanged SPR barrels are returned to the SPR, should determine whether offshore Gulf of Mexico royalty oil deposits to the SPR should be resumed, thereby increasing the size of our reserve.
- ★ The NEPD Group recommends that the President direct the Secretary of Energy to work closely with Congress to ensure that our SPR protection is maintained.
- ★ The NEPD Group recommends that the President direct the Secretary of Energy to work with producer and consumer country allies and the IEA to craft a more comprehensive and timely world oil data reporting system.

Summary of Recommendations

Strengthening Global Alliances: Enhancing National Energy Security and International Relationships

- ★ The NEPD Group recommends that the President make energy security a priority of our trade and foreign policy.
- ★ The NEPD Group recommends the President support initiatives by Saudi Arabia, Kuwait, Algeria, Qatar, the UAE, and other suppliers to open up areas of their energy sectors to foreign investment.
- ★ The NEPD Group recommends that the President direct the Secretaries of State, Energy and Commerce work to improve dialogue among energy producing and consuming nations.
- ★ The NEPD Group recommends that the President direct the Secretaries of State, Commerce, and Energy to continue supporting American energy firms competing in markets abroad and use our membership in multilateral organizations, such as the Asia-Pacific Economic Cooperation (APEC) forum, the Organization for Economic Cooperation and Development (OECD), the World Trade Organization (WTO) Energy Services Negotiations, the Free Trade Area of the Americas (FTAA), and our bilateral relationships to implement a system of clear, open, and transparent rules and procedures governing foreign investment; to level the playing field for U.S. companies overseas; and to reduce barriers to trade and investment.
- ★ The NEPD Group recommends that the President direct the Secretaries of Commerce and Energy, and the U.S. Trade Representative, to support a sectoral trade initiative to expand investment and trade in energy-related goods and services that will enhance exploration, production, and refining, as well as the development of new technologies.
- ★ The NEPD Group recommends that the President direct the Secretaries of State, Treasury, and Commerce to initiate a comprehensive review of sanctions. Energy security should be one of the factors considered in such a review.
- ★ The NEPD Group recommends that the President direct the Secretaries of State, Commerce, and Energy to engage in a dialogue through the North American Energy Working Group to develop closer energy integration among Canada, Mexico, and the United States and identify areas of cooperation, fully consistent with the countries' respective sovereignties.
- ★ The NEPD Group recommends that the President direct the Secretaries of Energy and State, in consultation with the Federal Energy Regulatory Commission, to review their respective oil, natural gas, and electricity cross-boundary "Presidential Permitting" authorities, and to propose reforms as necessary in order to make their own regulatory regimes more compatible for cross-border trade.
- ★ The NEPD Group recommends that the President direct the Secretaries of Energy and State, coordinating with the Secretary of the Interior and the Federal Energy Regulatory Commission, to work closely with Canada, the State of Alaska, and all other interested parties to expedite the construction of a pipeline to deliver natural gas to the lower 48 states. This should include proposing to Congress any changes or waivers of law pursuant to the Alaska Natural Gas Transportation Act of 1976 that may be required.

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- ★ The NEPD Group recommends that the President direct the Secretaries of State and Commerce to conclude negotiations with Venezuela on a Bilateral Investment Treaty, and propose formal energy consultations with Brazil, to improve the energy investment climate for the growing level of energy investment flows between the United States and each of these countries.
 - ★ The NEPD Group recommends that the President direct the Secretaries of Energy, Commerce, and State to work through the Summit of the Americas Hemispheric Energy Initiative to develop effective and stable regulatory frameworks and foster reliable supply sources of all fuels within the region.
 - ★ The NEPD Group recommends that the President direct the Secretaries of State, Energy, and Commerce to reinvigorate the U.S.-Africa Trade and Economic Cooperation Forum and the U.S.-African Energy Ministerial process; deepen bilateral and multilateral engagement to promote a more receptive environment for U.S. oil and gas trade, investment, and operations; and promote geographic diversification of energy supplies, addressing such issues as transparency, sanctity of contracts, and security.
 - ★ The NEPD Group recommends that the President direct the Secretaries of State, Commerce, and Energy to support more transparent, accountable, and responsible use of oil resources in African producer countries to enhance the stability and security of trade and investment environments.
 - ★ The NEPD Group recommends that the President direct the Secretaries of State, Commerce, and Energy to support the BTC oil pipeline as it demonstrates its commercial viability.
 - ★ The NEPD Group recommends that the President direct the Secretaries of Commerce, State, and Energy to continue working with relevant companies and countries to establish the commercial conditions that will allow oil companies operating in Kazakhstan the option of exporting their oil via the BTC pipeline.
 - ★ The NEPD Group recommends that the President direct the Secretaries of State, Commerce, and Energy to support the efforts of private investors and regional governments to develop the Shah Deniz gas pipeline as a way to help Turkey and Georgia diversify their natural gas supplies and help Azerbaijan export its gas via a pipeline that will continue diversification of secure energy supply routes.
 - ★ The NEPD Group recommends that the President direct appropriate federal agencies to complete the current cycle of oil spill response readiness workshops and to consider further appropriate steps to ensure the implementation of the workshops' recommendations.
 - ★ The NEPD Group recommends that the President direct the Secretary of State to encourage Greece and Turkey to link their gas pipeline systems to allow European consumers to diversify their gas supplies by purchasing Caspian gas.

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- ★ The NEPD Group recommends that the President direct the Secretaries of Commerce, Energy, and State to deepen their commercial dialogue with Kazakhstan, Azerbaijan, and other Caspian states to provide a strong, transparent, and stable business climate for energy and related infrastructure projects.
 - ★ The NEPD Group recommends that the President direct the Secretaries of State, Commerce, and Energy to deepen the focus of the discussions with Russia on energy and the investment climate.
 - ★ The NEPD Group recommends that the President direct the Secretaries of Commerce, State, and Energy to assist U.S. companies in their dialogue on the investment and trade climate with Russian officials, to encourage reform of the PSA law and other regulations and related tax provisions, as well as general improvements in the overall investment climate. This will help expand private investment opportunities in Russia and will increase the international role of Russian firms.
 - ★ The NEPD Group recommends that the President direct the Secretaries of State, Commerce, and Energy to continue to work in the APEC Energy Working Group to examine oil market data transparency issues and the variety of ways petroleum stocks can be used as an option to address oil market disruptions.
 - ★ The NEPD Group recommends that the President direct the Secretaries of State and Energy to work with India's Ministry of Petroleum and Natural Gas to help India maximize its domestic oil and gas production.
 - ★ The NEPD Group recommends that the President direct the Secretaries of Commerce, State, and Energy to promote market-based solutions to environmental concerns; support exports of U.S. clean energy technologies and encourage their overseas development; engage bilaterally and multilaterally to promote best practices; explore collaborative international basic research and development in energy alternatives and energy-efficient technologies; and explore innovative programs to support the global adoption of these technologies.
 - ★ The NEPD Group recommends that the President direct federal agencies to support continued research into global climate change; continue efforts to identify environmentally and cost-effective ways to use market mechanisms and incentives; continue development of new technologies; and cooperate with allies, including through international processes, to develop technologies, market-based incentives, and other innovative approaches to address the issue of global climate change.
 - ★ The NEPD Group recommends that the President seek to increase international cooperation on finding alternatives to oil, especially for the transportation sector.
 - ★ The NEPD Group recommends that the President direct the Secretary of State to reinvigorate its dialogue with the European Union on energy issues, and resume the consultative process this year in Washington.

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- ★ The NEPD Group recommends that the President promote a coordinated approach to energy security by calling for an annual meeting of G-8 Energy Ministers or their equivalents.
 - ★ The NEPD Group recommends that the President reaffirm that the SPR is designed for addressing an imminent or actual disruption in oil supplies, and not for managing prices.
 - ★ The NEPD Group recommend that the President direct the Secretary of Energy to work within the International Energy Agency (IEA) to ensure that member states fulfill their stockholding.
 - ★ The NEPD Group recommends that the President direct the Secretary of Energy to encourage major oil-consuming countries that are not IEA members to consider strategic stocks as an option for addressing potential supply disruptions. In this regard, we should work closely with Asian economies, especially through APEC.
 - ★ The NEPD Group recommends that the President direct the Secretary of Energy to offer to lease excess SPR storage facilities to countries (both IEA and non-IEA members) that might not otherwise build storage facilities or hold sufficient strategic stocks, consistent with statutory authorities.
 - ★ The NEPD Group recommends that the President, at such time that exchanged SPR barrels are returned to the SPR, should determine whether offshore Gulf of Mexico royalty oil deposits to the SPR should be resumed, thereby increasing the size of our reserve.
 - ★ The NEPD Group recommends that the President direct the Secretary of Energy to work closely with Congress to ensure that our SPR protection is maintained.
 - ★ The NEPD Group recommends that the President direct the Secretary of Energy to work with producer and consumer country allies and the IEA to craft a more comprehensive and timely world oil data reporting system.

CHAPTER ONE

Taking Stock: Energy Challenges Facing the United States

★ The NEPD Group recommends that the President issue an Executive Order to direct all federal agencies to include in any regulatory action that could significantly and adversely affect energy supplies, distribution, or use, a detailed statement on: (1) the energy impact of the proposed action, (2) any adverse energy effects that cannot be avoided should the proposal be implemented, and (3) alternatives to the proposed action. The agencies would be directed to include this statement in all submissions to the Office of Management and Budget of proposed regulations covered by Executive Order 12866, as well as in all notices of proposed regulations published in the Federal Register.

★ The NEPD Group recommends that the President direct the executive agencies to work closely with Congress to implement the legislative components of a national energy policy.

★ The NEPD Group recommends to the President that the NEPD Group continue to work and meet on the implementation of the National Energy Policy and explore other ways to advance dependable, affordable, and environmentally responsible production and distribution of energy.

Note: All recommendations in this report are subject to execution in accordance with applicable law. Legislation would be sought where needed. Also, any recommendations that involve foreign countries would be executed in accordance with the customs of international relations, including appropriate diplomatic consultation.

CHAPTER TWO

Striking Home The Impacts of High Energy Prices on Families, Communities, and Businesses

★ The NEPD Group recommends that the President direct the Secretary of Energy to explore potential opportunities to develop educational programs related to energy development and use. This should include possible legislation to create public education awareness programs about energy. Such programs should be long-term in nature, should be funded and managed by the respective energy industries, and should include information on energy's compatibility with a clean environment.

★ The NEPD Group recommends that the President take steps to mitigate impacts of high energy costs on low-income consumers. These steps would include:

- Strengthening the Low Income Home Energy Assistance Program by making \$1.7 billion available annually. This is an increase of \$300 million over the regular FY 2001 appropriation.
- Directing the Secretaries of Interior and Health and Human Services to propose legislation to bolster LIHEAP funding by using a portion of oil and gas royalty payments.
- Redirecting royalties above a set trigger price to LIHEAP, whenever crude oil and natural gas prices exceed that trigger price, as determined by the responsible agencies.

★ The NEPD Group recommends that the President increase funding for the Weatherization Assistance Program by \$1.2 billion over ten years. This will roughly double the spending during that period on weatherization. Consistent with that commitment, the FY 2002 Budget includes a \$120 million increase over 2001. The Department of Energy will have the option of using a portion of those funds to test improved implementation approaches for the weatherization program.

★ The NEPD Group recommends that the President support legislation to allow funds dedicated for the Weatherization and State Energy Programs to be transferred to LIHEAP if the Department of Energy deems it appropriate.

★ The NEPD Group recommends the President recognize unique regional energy concerns by working with the National Governors Association and regional governor associations to determine how to better serve the needs of diverse areas of the country.

★ The NEPD Group recommends the President direct FEMA to prepare for potential energy emergencies.

- FEMA should work with states' Offices of Emergency Management as they expand existing emergency operations plans to identify potential problems and address consequences of the power shortages. FEMA should use its current Regional Incident Reporting System to identify any situations that might demand immediate attention.
- Using the structure of the already existing Federal Response Plan, FEMA should conduct Regional Interagency Steering Committee (RISC) meetings for states affected by the energy shortfalls. The RISC is a FEMA-led interagency committee comprised of agencies and departments that support the Federal Response Plan. Either an upcoming, scheduled RISC meeting or a special-focus RISC meeting can be held to identify the short-term energy outlook, as well as any expected consequences, in each of the states during the peak summer season.

CHAPTER THREE

Protecting America's Environment: Sustaining the Nation's Health and Environment

- ★ The NEPD Group recommends that the President direct the Administrator of the Environmental Protection Agency (EPA) to propose multi-pollutant legislation. The NEPD Group recommends that the President direct the EPA Administrator to work with Congress to propose legislation that would establish a flexible, market-based program to significantly reduce and cap emissions of sulfur dioxide, nitrogen oxides, and mercury from electric power generators. Such a program (with appropriate measures to address local concerns) would provide significant public health benefits even as we increase electricity supplies.
 - Establish mandatory reduction targets for emissions of three main pollutants: sulfur dioxide, nitrogen oxides, and mercury.
 - Phase in reductions over a reasonable period of time, similar to the successful acid rain reduction program established by the 1990 amendments to the Clean Air Act.
 - Provide regulatory certainty to allow utilities to make modifications to their plants without fear of new litigation.
 - Provide market-based incentives, such as emissions trading credits to help achieve the required reductions.

- ★ The NEPD Group recommends the President direct the Secretary of the Interior to work with Congress to create the “Royalties Conservation Fund.”
 - This fund will earmark potentially billions of dollars in royalties from new oil and gas production in ANWR to fund land conservation efforts.
 - This fund will also be used to eliminate the maintenance and improvements backlog on federal lands.

- ★ The NEPD Group recommends the President issue an Executive Order to rationalize permitting for energy production in an environmentally sound manner by directing federal agencies to expedite permits and other federal actions necessary for energy related project approvals on a national basis. This order would establish an inter agency task force chaired by the Council on Environmental Quality to ensure that federal agencies responsible for permitting energy-related facilities are coordinating their efforts. The task force will ensure that federal agencies set up appropriate mechanisms to coordinate federal, state, tribal, and local permitting activity in particular regions where increased activity is expected.

CHAPTER FOUR

Using Energy Wisely: Increasing Energy Conservation and Efficiency

★ The NEPD Group recommends that the President direct the Office of Science and Technology Policy and the President's Council of Advisors on Science and Technology to review and make recommendations on using the nation's energy resources more efficiently.

★ The NEPD Group recommends that the President direct the Secretary of Energy to conduct a review of current funding and historic performance of energy efficiency research and development programs in light of the recommendations of this report. Based on this review, the Secretary of Energy is then directed to propose appropriate funding of those research and development programs that are performance-based and are modeled as public-private partnerships.

★ The NEPD Group recommends that the President direct the Secretary of Energy to promote greater energy efficiency.

- Expand the Energy Star program beyond office buildings to include schools, retail buildings, health care facilities, and homes.
- Extend the Energy Star labeling program to additional products, appliances, and services.
- Strengthen Department of Energy public education programs relating to energy efficiency.

★ The NEPD Group recommends that the President direct the Secretary of Energy to improve the energy efficiency of appliances.

- Support the appliance standards program for covered products, setting higher standards where technologically feasible and economically justified.
- Expand the scope of the appliance standards program, setting standards for additional appliances where technologically feasible and economically justified.

★ The NEPD Group recommends that the President direct heads of executive departments and agencies to take appropriate actions to conserve energy use at their facilities to the maximum extent consistent with the effective discharge of public responsibilities. Agencies located in regions where electricity shortages are possible should conserve especially during periods of peak demand. Agencies should report to the President, through the Secretary of Energy, within 30 days on the conservation actions taken.

★ The NEPD Group recommends that the President direct the Secretary of the Treasury to work with Congress to encourage increased energy efficiency through combined heat and power (CHP) projects by shortening the depreciation life for CHP projects or providing investment tax credits.

★ The NEPD Group recommends that the President direct the Administrator of the Environmental Protection Agency (EPA) to work with local and state governments to promote the use of well-designed CHP and other clean power generation at brownfields sites, consistent with the local communities' interests. EPA will also work to clarify liability issues if they are raised at a particular site.

CHAPTER FOUR

- ★ The NEPD Group recommends that the President direct the EPA Administrator to promote CHP through flexibility in environmental permitting.

- ★ The NEPD Group recommends that the President direct the Secretary of Transportation to:
 - Review and provide recommendations on establishing Corporate Average Fuel Economy (CAFE) standards with due consideration of the National Academy of Sciences study to be released in July 2001. Responsibly crafted CAFE standards should increase efficiency without negatively impacting the U.S. automotive industry. The determination of future fuel economy standards must therefore be addressed analytically and based on sound science.
 - Consider passenger safety, economic concerns, and disparate impact on the U.S. versus foreign fleet of automobiles.
 - Look at other market-based approaches to increasing the national average fuel economy of new motor vehicles.

- ★ The new NEPD Group recommends that the President direct the Secretary of Transportation to review and promote congestion mitigation technologies and strategies and work with Congress on legislation to implement these strategies.

- ★ The NEPD Group recommends that the President direct the Secretary of the Treasury to work with Congress on legislation to increase energy efficiency with a tax credit for fuel-efficient vehicles. The NEPD Group recommends that a temporary, efficiency based income tax credit be available for purchase of new hybrid fuel cell vehicles between 2002 and 2007.

- ★ The NEPD Group recommends that the President direct all agencies to use technological advances to better protect our environment.
 - The Administration remains committed to investing in Intelligent Transportation Systems (ITS) and encourages the private sector to invest in ITS applications. This Department of Transportation (DOT) program funds the development of improved transportation infrastructure that will reduce congestion, such as traveler information/navigation systems, freeway management, and electronic toll collection. ITS applications reduce fuel associated with travel.
 - The Administration remains committed to the DOT's fuel-cell-powered transit bus program, authored by the Transportation Equity Act for the 21st Century (TEA-21). This program demonstrates the viability of fuel-cell power plants for transit bus applications.
 - The Administration remains committed to the Clean Buses program. TEA-21 establishes a new clean fuel formula grant program, which provides an opportunity to accelerate the introduction of advanced bus propulsion technologies into the mainstream of the nation's transit fleet.

- ★ The NEPD Group recommends that the President direct the EPA and DOT to develop ways to reduce demand for petroleum transportation fuels by working with the trucking industry to establish a program to reduce emissions and fuel consumption from long-haul trucks at truck stops by implementing alternatives to idling, such as electrification and auxiliary power units at truck stops along interstate highways. EPA and DOT will develop partnership agreements with trucking fleets, truck stops, and manufacturers of idle-reducing technologies (*e.g.*, portable auxiliary packs, electrification) to install and use low emission-idling technologies.

- ★ The NEPD Group recommends that the President direct the Secretary of Energy to establish a national priority for improving energy efficiency. The priority would be to improve the energy intensity of the U.S. economy as measured by the amount of energy required for each dollar of economic productivity. This increased efficiency should be pursued through the combined efforts of industry, consumers, and federal, state, and local governments.

- ★ The NEPD Group recommends that the President direct the EPA Administrator to develop and implement a strategy to increase public awareness of the sizable savings that energy efficiency offers to homeowners across the country. Typical homeowners can save about 30 percent (about \$400) a year on their home energy bill by using Energy Star labeled products.

Chapter Five Energy for a New Century: Increasing Domestic Energy Supplies

- ★ The NEPD Group recommends that the President direct the Secretaries of Energy and the Interior to promote enhanced oil and gas recovery from existing wells through new technology.
- ★ The NEPD Group recommends that the President direct the Secretary of Energy to improve oil and gas exploration technology through continued partnership with public and private entities.
- ★ The NEPD Group recommends that the President direct the Secretary of the Interior to examine land status and lease stipulation impediments to federal oil and gas leasing, and review and modify those where opportunities exist (consistent with the law, good environmental practice, and balanced use of other resources).
 - Expedite the ongoing Energy Policy and Conservation Act study of impediments to federal oil and gas exploration and development.
 - Review public lands withdrawals and lease stipulations, with full public consultation, especially with the people in the region, to consider modifications where appropriate.
- ★ The NEPD Group recommends that the President direct the Secretary of the Interior to consider economic incentives for environmentally sound offshore oil and gas development where warranted by specific circumstances: explore opportunities for royalty reductions, consistent with ensuring a fair return to the public where warranted for enhanced oil and gas recovery; for reduction of risk associated with production in frontier areas or deep gas formations; and for development of small fields that would otherwise be uneconomic.
- ★ The NEPD Group recommends that the President direct the Secretaries of Commerce and Interior to re-examine the current federal legal and policy regime (statutes, regulations, and Executive Orders) to determine if changes are needed regarding energy-related activities and the siting of energy facilities in the coastal zone and on the Outer Continental Shelf (OCS).
- ★ The NEPD Group recommends that the President direct the Secretary of the Interior to continue OCS oil and gas leasing and approval of exploration and development plans on predictable schedules.
- ★ The NEPD Group recommends that the President direct the Secretary of the Interior to consider additional environmentally responsible oil and gas development, based on sound science and the best available technology, through further lease sales in the National Petroleum Reserve-Alaska. Such consideration should include areas not currently leased within the Northeast corner of the Reserve.
- ★ The NEPD Group recommends that the President direct the Secretary of the Interior to work with Congress to authorize exploration and, if resources are discovered, development of the 1002 Area of ANWR. Congress should require the use of the best available technology and should require that activities will result in no significant adverse impact to the surrounding environment.
- ★ The NEPD Group recommends that the President direct the Secretary of the Interior to work with Congress and the State of Alaska to put in place the most expeditious process for renewal of the Trans-Alaska Pipeline System rights-of-way to ensure that Alaskan oil continues to flow uninterrupted to the West Coast of the United States.

★ The NEPD Group recommends that the President direct the Secretary of Energy to propose comprehensive electricity legislation that promotes competition, protects consumers, enhances reliability, promotes renewable energy, improves efficiency repeals the Public Utility Holding Company Act, and reforms the Public Utility Regulatory Policies Act.

★ The NEPD Group recommends that the President encourage FERC to use its existing statutory authority to promote competition and encourage investment in transmission facilities.

★ The NEPD Group recognizes the importance of looking to technology to help us meet the goals of increasing electricity generation while protecting our environment. To that end, the NEPD Group recommends that the President direct the Department of Energy to continue to develop advanced clean coal technology by:

- Investing \$2 billion over 10 years to fund research in clean coal technologies.
- Supporting a permanent extension of the existing research and development tax credit.
- Directing federal agencies to explore regulatory approaches that will encourage advancements in environmental technology.

★ The NEPD Group recommends that the President direct federal agencies to provide greater regulatory certainty relating to coal electricity generation through clear policies that are easily applied to business decisions.

★ The NEPD Group recommends that the President support the expansion of nuclear energy in the United States as a major component of our national energy policy. Following are specific components of the recommendation:

- Encourage the Nuclear Regulatory Commission (NRC) to ensure that safety and environmental protection are high priorities as they prepare to evaluate and expedite applications for licensing new advanced-technology nuclear reactors.
- Encourage the NRC to facilitate efforts by utilities to expand nuclear energy generation in the United States by uprating existing nuclear plants safely.
- Encourage the NRC to relicense existing nuclear plants that meet or exceed safety standards.
- Direct the Secretary of Energy and the Administrator of the Environmental Protection Agency to assess the potential of nuclear energy to improve air quality.
- Increase resources as necessary for nuclear safety enforcement in light of the potential increase in generation.
- Use the best science to provide a deep geologic repository for nuclear waste.
- Support legislation clarifying that qualified funds set aside by plant owners for eventual decommissioning will not be taxed as part of the transaction.
- Support legislation to extend the Price–Anderson Act.

★ The NEPD Group recommends that, in the context of developing advanced nuclear fuel cycles and next generation technologies for nuclear energy, the United States should reexamine its policies to allow for research, development and deployment of fuel conditioning methods (such as pyroprocessing) that reduce waste streams and enhance proliferation resistance. In doing so, the United States will continue to discourage the accumulation of separated plutonium, worldwide.

★ The United States should also consider technologies (in collaboration with international partners with highly developed fuel cycles and a record of close cooperation) to develop reprocessing and fuel treatment technologies that are cleaner, more efficient, less waste intensive, and more proliferation-resistant.

CHAPTER FIVE

★ The NEPD Group recognizes there is a need to reduce the time and cost of the hydro power licensing process. The NEPD Group recommends that the President encourage the Federal Energy Regulatory Commission (FERC) and direct federal resource agencies to make the licensing process more clear and efficient, while preserving environmental goals. In addition, the NEPD Group recognizes the importance of optimizing the efficiency and reliability of existing hydropower facilities and will encourage the Administration to adopt efforts to ward that end.

- Support administrative and legislative reform of the hydropower licensing process.
- Direct federal resource agencies to reach interagency agreement on conflicting mandatory license conditions before they submit their conditions to FERC for inclusion in a license.
- Encourage FERC to adopt appropriate deadlines for its own actions during the licensing process.

CHAPTER SIX

Nature's Power: Increasing America's Use of Renewable and Alternative Energy

- ★ The NEPD Group recommends that the President direct the Secretaries of the Interior and Energy to re-evaluate access limitations to federal lands in order to increase renewable energy production, such as biomass, wind, geothermal, and solar.
- ★ The NEPD Group supports the increase of \$39.2 million in the FY 2002 budget amendment for the Department of Energy's Energy Supply account that would provide increased support for research and development of renewable energy resources.
- ★ The NEPD Group recommends that the President direct the Secretary of Energy to conduct a review of current funding and historic performance of renewable energy and alternative energy research and development programs in light of the recommendations of this report. Based on this review, the Secretary of Energy is then directed to propose appropriate funding of those research and development programs that are performance-based and are modeled as public-private partnerships.
- ★ The NEPD Group recommends that the President direct the Secretary of the Treasury to work with Congress on legislation to expand the section 29 tax credit to make it available for new landfill methane projects. The credit could be tiered, depending on whether a landfill is already required by federal law to collect and flare its methane emissions due to local air pollution concerns.
- ★ The NEPD Group recommends that the President direct the Secretary of the Interior to determine ways to reduce the delays in geothermal lease processing as part of the permitting review process.
- ★ The NEPD Group recommends that the President direct the Administrator of the Environmental Protection Agency to develop a new renewable energy partnership program to help companies more easily buy renewable energy, as well as receive recognition for the environmental benefits of their purchase, and help consumers by promoting consumer choice programs that increase their knowledge about the environmental benefits of purchasing renewable energy.
- ★ The NEPD Group recommends that the President direct the Secretary of the Treasury to work with Congress on legislation to extend and expand tax credits for electricity produced using wind and biomass. The President's budget request extends the present 1.7 cents per kilowatt hour tax credit for electricity produced from wind and biomass; expands eligible biomass sources to include forest-related sources, agricultural sources, and certain urban sources; and allows a credit for electricity produced from biomass co-fired with coal.
- ★ The NEPD Group recommends that the President direct the Secretary of the Treasury to work with Congress on legislation to provide a new 15 percent tax credit for residential solar energy property, up to a maximum credit of \$2,000.
- ★ The NEPD Group recommends that the President direct the Secretaries of the Interior and Energy to work with Congress on legislation to use an estimated \$1.2 billion of bid bonuses from the environmentally responsible leasing of ANWR for funding research into alternative and renewable energy resources, including wind, solar, geothermal, and biomass.
- ★ The NEPD Group recommends that the President direct the Secretary of the Treasury to work with Congress to continue the ethanol excise tax exemption.

CHAPTER SIX

- ★ The NEPD Group recommends that the President direct the Secretary of Energy to develop next-generation technology—including hydrogen and fusion.
 - Develop an education campaign that communicates the benefits of alternative forms of energy, including hydrogen and fusion.
 - Focus research and development efforts on integrating current programs regarding hydrogen, fuel cells, and distributed energy.
 - Support legislation reauthorizing the Hydrogen Energy Act.
- ★ The NEPD Group recommends that the President direct the Secretary of the Treasury to work with Congress to develop legislation to provide for a temporary income tax credit available for the purchase of new hybrid or fuel-cell vehicles between 2002 and 2007.
- ★ The NEPD Group recommends that the President direct the Administrator of the Environmental Protection Agency to issue guidance to encourage the development of well-designed combined heat and power (CHP) units that are both highly efficient and have low emissions. The goal of this guidance would be to shorten the time needed to obtain each permit, provide certainty to industry by ensuring consistent implementation across the country, and encourage the use of these cleaner, more efficient technologies.

CHAPTER SEVEN

America's Energy Infrastructure: A Comprehensive Delivery System

- ★ The NEPD Group recommends that the President direct the Secretary of Energy to work with the Federal Energy Regulatory Commission (FERC) to improve the reliability of the interstate transmission system and to develop legislation providing for enforcement by a self-regulatory organization subject to FERC oversight.
- ★ The NEPD Group recommends that the President direct the Secretary of Energy to expand the Department's research and development on transmission reliability and superconductivity.
- ★ The NEPD Group recommends that the President direct the Secretary of Energy to authorize the Western Area Power Administration to explore relieving the "Path 15" bottle neck through transmission expansion financed by nonfederal contributions.
- ★ The NEPD Group recommends that the President direct the appropriate federal agencies to take actions to remove constraints on the interstate transmission grid and allow our nation's electricity supply to meet the growing needs of our economy.
 - Direct the Secretary of Energy, by December 31, 2001, to examine the benefits of establishing a national grid, identify transmission bottlenecks, and identify measures to remove transmission bottlenecks.
 - Direct the Secretary of Energy to work with FERC to relieve transmission constraints by encouraging the use of incentive rate-making proposals.
 - Direct the federal utilities to determine whether transmission expansions are necessary to remove constraints. The Administration should review the Bonneville Power Administration's (BPA's) capital and financing requirements in the context of its membership in a regional RTO, and if additional Treasury financing appears warranted or necessary in the future, the Administration should seek an increase in BPA's borrowing authority at that time.
 - Direct the Secretary of Energy, in consultation with appropriate federal agencies and state and local government officials, to develop legislation to grant authority to obtain rights-of-way for electricity transmission lines, with the goal of creating a reliable national transmission grid. Similar authority already exists for natural gas pipelines in recognition of their role in interstate commerce.
- ★ The NEPD Group recommends that the President direct the Secretary of the Interior to work with Congress and the State of Alaska to put in place the most expeditious process for renewal of the Trans-Alaskan Pipeline System lease to ensure that Alaskan oil continues to flow uninterrupted to the West Coast of the United States.
- ★ The NEPD Group recommends that the President direct the Secretaries of Energy and State, coordinating with the Secretary of the Interior and the Federal Energy Regulatory Commission, to work closely with Canada, the State of Alaska, and all other interested parties to expedite the construction of a pipeline to deliver natural gas to the lower 48 states. This should include proposing to Congress any changes or waivers of law pursuant to the Alaska Natural Gas Transportation Act of 1976 that may be required.
- ★ The NEPD Group recommends that the President support legislation to improve the safety of natural gas pipelines, protect the environment, strengthen emergency preparedness and inspections and bolster enforcement.

CHAPTER SEVEN

- ★ The NEPD Group recommends that the President direct agencies to continue their interagency efforts to improve pipeline safety and expedite pipeline permitting in an environmentally sound manner and encourage FERC to consider improvements in the regulatory process governing approval of interstate natural gas pipeline projects.
- ★ The NEPD Group recommends that the President direct the Administrator of the EPA to study opportunities to maintain or improve the environmental benefits of state and local “boutique” clean fuel programs while exploring ways to increase the flexibility of the fuels distribution infrastructure, improve fungibility, and provide added gasoline market liquidity. In concluding this study, the Administrator shall consult with the Departments of Energy and Agriculture, and other agencies as needed.
- ★ The NEPD Group recommends that the President direct the Administrator of the Environmental Protection Agency and the Secretary of Energy to take steps to ensure America has adequate refining capacity to meet the needs of consumers.
 - Provide more regulatory certainty to refinery owners and streamline the permitting process where possible to ensure that regulatory overlap is limited.
 - Adopt comprehensive regulations (covering more than one pollutant and require ment) and consider the rules’ cumulative impacts and benefits.
- ★ The NEPD Group recommends that the President direct the Administrator of the Environmental Protection Agency, in consultation with the Secretary of Energy and other relevant agencies, to review New Source Review regulations, including administrative interpretation and implementation, and report to the President within 90 days on the impact of the regulations on investment in new utility and refinery generation capacity, energy efficiency, and environmental protection.
- ★ The NEPD Group recommends that the President direct the Attorney General to review existing enforcement actions regarding New Source Review to ensure that the enforcement actions are consistent with the Clean Air Act and its regulations.
- ★ The NEPD Group supports the President’s budget proposal to provide \$8 million to maintain the two-million-barrel Northeast Heating Oil Reserve. Operated by the private sector, the Reserve helps ensure adequate supplies of heating oil in the event that colder than normal winters occur in the Northeast United States.

CHAPTER 8

Strengthening Global Alliances: Enhancing National Energy Security and International Relationships

- ★ The NEPD Group recommends that the President make energy security a priority of our trade and foreign policy.
- ★ The NEPD Group recommends the President support initiatives by Saudi Arabia, Kuwait, Algeria, Qatar, the UAE, and other suppliers to open up areas of their energy sectors to foreign investment.
- ★ The NEPD Group recommends that the President direct the Secretaries of State, Energy and Commerce work to improve dialogue among energy producing and consuming nations.
- ★ The NEPD Group recommends that the President direct the Secretaries of State, Commerce, and Energy to continue supporting American energy firms competing in markets abroad and use our membership in multilateral organizations, such as the Asia-Pacific Economic Cooperation (APEC) forum, the Organization for Economic Cooperation and Development (OECD), the World Trade Organization (WTO) Energy Services Negotiations, the Free Trade Area of the Americas (FTAA), and our bilateral relationships to implement a system of clear, open, and transparent rules and procedures governing foreign investment; to level the playing field for U.S. companies overseas; and to reduce barriers to trade and investment.
- ★ The NEPD Group recommends that the President direct the Secretaries of Commerce and Energy, and the U.S. Trade Representative, to support a sectoral trade initiative to expand investment and trade in energy-related goods and services that will enhance exploration, production, and refining, as well as the development of new technologies.
- ★ The NEPD Group recommends that the President direct the Secretaries of State, Treasury, and Commerce to initiate a comprehensive review of sanctions. Energy security should be one of the factors considered in such a review.
- ★ The NEPD Group recommends that the President direct the Secretaries of State, Commerce, and Energy to engage in a dialogue through the North American Energy Working Group to develop closer energy integration among Canada, Mexico, and the United States and identify areas of cooperation, fully consistent with the countries' respective sovereignties.
- ★ The NEPD Group recommends that the President direct the Secretaries of Energy and State, in consultation with the Federal Energy Regulatory Commission, to review their respective oil, natural gas, and electricity cross-boundary "Presidential Permitting" authorities, and to propose reforms as necessary in order to make their own regulatory regimes more compatible for cross-border trade.
- ★ The NEPD Group recommends that the President direct the Secretaries of Energy and State, coordinating with the Secretary of the Interior and the Federal Energy Regulatory Commission, to work closely with Canada, the State of Alaska, and all other interested parties to expedite the construction of a pipeline to deliver natural gas to the lower 48 states. This should include proposing to Congress any changes or waivers of law pursuant to the Alaska Natural Gas Transportation Act of 1976 that

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may be required.

★ The NEPD Group recommends that the President direct the Secretaries of State and Commerce to conclude negotiations with Venezuela on a Bilateral Investment Treaty, and propose formal energy consultations with Brazil, to improve the energy investment climate for the growing level of energy investment flows between the United States and each of these countries.

★ The NEPD Group recommends that the President direct the Secretaries of Energy, Commerce, and State to work through the Summit of the Americas Hemispheric Energy Initiative to develop effective and stable regulatory frameworks and foster reliable supply sources of all fuels within the region.

★ The NEPD Group recommends that the President direct the Secretaries of State, Energy, and Commerce to reinvigorate the U.S.-Africa Trade and Economic Cooperation Forum and the U.S.-African Energy Ministerial process; deepen bilateral and multilateral engagement to promote a more receptive environment for U.S. oil and gas trade, investment, and operations; and promote geographic diversification of energy supplies, addressing such issues as transparency, sanctity of contracts, and security.

★ The NEPD Group recommends that the President direct the Secretaries of State, Commerce, and Energy to support more transparent, accountable, and responsible use of oil resources in African producer countries to enhance the stability and security of trade and investment environments.

★ The NEPD Group recommends that the President direct the Secretaries of State, Commerce, and Energy to support the BTC oil pipeline as it demonstrates its commercial viability.

★ The NEPD Group recommends that the President direct the Secretaries of Commerce, State, and Energy to continue working with relevant companies and countries to establish the commercial conditions that will allow oil companies operating in Kazakhstan the option of exporting their oil via the BTC pipeline.

★ The NEPD Group recommends that the President direct the Secretaries of State, Commerce, and Energy to support the efforts of private investors and regional governments to develop the Shah Deniz gas pipeline as a way to help Turkey and Georgia diversify their natural gas supplies and help Azerbaijan export its gas via a pipeline that will continue diversification of secure energy supply routes.

★ The NEPD Group recommends that the President direct appropriate federal agencies to complete the current cycle of oil spill response readiness workshops and to consider further appropriate steps to ensure the implementation of the workshops' recommendations.

★ The NEPD Group recommends that the President direct the Secretary of State to encourage Greece and Turkey to link their gas pipeline systems to allow European consumers to diversify their gas supplies by purchasing Caspian gas.

★ The NEPD Group recommends that the President direct the Secretaries of Commerce, Energy, and State to deepen their commercial dialogue with Kazakhstan, Azerbaijan, and other Caspian states to provide a strong, transparent, and stable-business climate for energy and related infrastructure projects.-

★ The NEPD Group recommends that the President direct the Secretaries of State, Commerce, and Energy to deepen the focus of the discussions with Russia on energy and the investment climate.-

★ The NEPD Group recommends that the President direct the Secretaries of Commerce, State, and Energy to assist U.S. companies in their dialogue on the investment and trade climate with Russian officials, to encourage reform of the PSA law and other regulations and related tax provisions, as well as general improvements in the overall investment climate. This will help expand private investment opportunities in Russia and will increase the international role of Russian firms.-

★ The NEPD Group recommends that the President direct the Secretaries of State, Commerce, and Energy to continue to work in the APEC Energy Working Group to examine oil market data transparency issues and the variety of ways petroleum stocks can be used as an option to address oil market disruptions.-

★ The NEPD Group recommends that the President direct the Secretaries of State and Energy to work with India's Ministry of Petroleum and Natural Gas to help India maximize its domestic oil and gas production.-

★ The NEPD Group recommends that the President direct the Secretaries of Commerce, State, and Energy to promote market-based solutions to environmental concerns; support exports of U.S. clean energy technologies and encourage their overseas development; engage bilaterally and multilaterally to promote best practices; explore collaborative international basic research and development in energy alternatives and energy-efficient technologies; and explore innovative programs to support the global adoption of these technologies.-

★ The NEPD Group recommends that the President direct federal agencies to support continued research into global climate change; continue efforts to identify environmentally and cost-effective ways to use market mechanisms and incentives; continue development of new technologies; and cooperate with allies, including through international processes, to develop technologies, market-based incentives, and other innovative approaches to address the issue of global climate change.-

★ The NEPD Group recommends that the President seek to increase international cooperation on finding alternatives to oil, especially for the transportation sector.-

★ The NEPD Group recommends that the President direct the Secretary of State to reinvigorate its dialogue with the European Union on energy issues, and resume the consultative process this year in Washington.-

★ The NEPD Group recommends that the President promote a coordinated approach to energy security by calling for an annual meeting of G-8 Energy Ministers or their equivalents.-

CHAPTER EIGHT

- ★ The NEPD Group recommends that the President reaffirm that the SPR is designed for addressing an imminent or actual disruption in oil supplies, and not for managing prices.
- ★ The NEPD Group recommend that the President direct the Secretary of Energy to work within the International Energy Agency (IEA) to ensure that member states fulfill their stockholding.
- ★ The NEPD Group recommends that the President direct the Secretary of Energy to encourage major oil-consuming countries that are not IEA members to consider strategic stocks as an option for addressing potential supply disruptions. In this regard, we should work closely with Asian economies, especially through APEC.
- ★ The NEPD Group recommends that the President direct the Secretary of Energy offer to lease excess SPR storage facilities to countries (both IEA and non-IEA members) that might not otherwise build storage facilities or hold sufficient strategic stocks, consistent with statutory authorities.
- ★ The NEPD Group recommends that the President, at such time that exchanged SPR barrels are returned to the SPR, should determine whether offshore Gulf of Mexico royalty oil deposits to the SPR should be resumed, thereby increasing the size of our reserve.
- ★ The NEPD Group recommends that the President direct the Secretary of Energy to work closely with Congress to ensure that our SPR protection is maintained.
- ★ The NEPD Group recommends that the President direct the Secretary of Energy to work with producer and consumer country allies and the IEA to craft a more comprehensive and timely world oil data reporting system.

Glossary

Barrel (Oil): A unit of volume equal to 42 U.S. gallons.

Barrels per Day (Operable Refinery Capacity): The maximum number of barrels of input that can be processed during a 24-hour period after making allowances for the following limitations: the capability of downstream facilities to absorb the output of crude oil processing facilities of a given refinery (no reduction is made when a planned distribution of intermediate streams through other than downstream facilities is part of a refinery's normal operation); the types and grades of inputs to be processed; the types and grades of products to be manufactured; the environmental constraints associated with refinery operations; the reduction of capacity for scheduled downtime, such as routine inspection, mechanical problems, maintenance, repairs, and turnaround; and the reduction of capacity for unscheduled downtime, such as mechanical problems, repairs, and slowdowns.

Biomass: Organic nonfossil material of biological origin constituting a renewable energy source.

British Thermal Unit (Btu): The quantity of heat needed to raise the temperature of 1 pound of water by 1°F at or near 39.2°F.

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

Cogeneration: The production of electricity and another form of useful energy (such as heat or steam) used for industrial, commercial, heating, or cooling purposes.

Commercial Building: A building with more than 50 percent of its floor space used for commercial activities. Commercial buildings include stores, offices, schools, churches, gymnasiums, libraries, museums, hospitals, clinics, warehouses, and jails. Government buildings are also included, except buildings on military bases or reservations.

Commercial Sector: Business establishments that are not engaged in transportation or in manufacturing or other types of industrial activity (agriculture, mining, or construction). Commercial establishments include hotels, motels, restaurants, wholesale businesses, retail stores, laundries, and other service enterprises; religious and nonprofit organizations; health, social, and educational institutions; and federal, state, and local governments. Streetlights, pumps, bridges, and public services are also included if the establishment operating them is considered commercial.

Conversion Factor: A number that translates units of one system into corresponding values of another system. Conversion factors can be used to translate physical units of measure for various fuels into Btu equivalents.

Crude Oil: A mixture of hydrocarbons that exists in liquid phase in natural underground reservoirs and remains liquid at atmospheric pressure after passing through surface separating facilities. Crude oil may also include:

- Small amounts of hydrocarbons that exist in the gaseous phase in natural underground reservoirs but are liquid at atmospheric pressure after being recovered from oil well (casing head) gas in lease separators and that subsequently are commingled with the crude stream without being separately measured.
- Small amounts of nonhydrocarbons produced with the oil, such as sulfur and other compounds

Crude Oil Stocks: Stocks of crude oil and lease condensate held at refineries, in pipelines, at pipeline terminals, and on leases.

District Heat: Steam or hot water from an outside source used as an energy source in a building. The steam or hot water is produced in a central plant and is piped into the building. District heat may be purchased from a utility or provided by a physical plant in a separate building that is part of the same facility (for example, a hospital complex or university).

Electric Power Plant: A station containing prime movers, electric generators, and auxiliary equipment for converting mechanical, chemical, and/or fission energy into electric energy.

Electricity Generation: The process of producing electric energy or transforming other forms of energy into electric energy. Also, the amount of electric energy produced or expressed in watt-hours (Wh).

End-Use Sectors: The residential, commercial, industrial, and transportation sectors of the economy.

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

Energy Consumption: The use of energy as a source of heat or power or as an input in the manufacturing process.

Energy Source: A substance, such as oil, natural gas, or coal, that supplies heat or power. Electricity and renewable forms of energy, such as wood, waste, geothermal, wind, and solar, are considered to be energy sources.

Exports: Shipments of goods from the 50 states and the District of Columbia to foreign countries and to Puerto Rico, the Virgin Islands, and other U.S. possessions and territories.

Federal Energy Regulatory Commission (FERC): The federal agency with jurisdiction over interstate electricity sales, wholesale electric rates, hydroelectric licensing, natural gas pricing, oil pipeline rates, and gas pipeline certification. FERC is an independent regulatory agency within the Department of Energy and is the successor to the Federal Power Commission.

Fossil Fuel: Any naturally occurring organic fuel formed in the Earth's crust, such as oil, coal, and natural gas.

Fuel Ethanol: An anhydrous, denatured aliphatic alcohol intended for motor gasoline blending.

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

Geothermal Energy: Energy from the internal heat of the Earth, which may be residual heat, friction heat, or a result of radioactive decay. The heat is found in rocks and fluids at various depths and can be extracted by drilling or pumping.

Gross Domestic Product (GDP): The total value of goods and services produced by labor and property located in the United States.

Hydrocarbon: An organic chemical compound of hydrogen and carbon in the gaseous, liquid, or solid phase. The molecular structure of hydrocarbon compounds varies from the simplest (methane, a constituent of natural gas) to the very heavy and very complex.

Hydropower: The production of electricity from the kinetic energy of falling water.

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

Independent Power Producer: Wholesale electricity producers (other than qualifying facilities under the Public Utilities Regulatory Policies Act of 1978) that are unaffiliated with franchised utilities in the area in which the independent power producers are selling power and that lack significant marketing power. Unlike traditional electric utilities, independent power producers do not possess transmission facilities that are essential to their customers and do not sell power in any retail service territory where they have a franchise.

Industrial Sector: Manufacturing industries, which make up the largest part of the sector, along with mining, construction, agriculture, fisheries, and forestry. Establishments in this sector range from steel mills, to small farms, to companies assembling electronic components.

Jet Fuel: A refined petroleum product used in jet aircraft engines. It includes kerosene type jet fuel and naphtha-type jet fuel.

Methane: Hydrocarbon gas, which is the major component of natural gas.

Methanol: A light, volatile alcohol eligible for motor gasoline blending.

Methyl Tertiary Butyl Ether (MTBE): An ether, intended for motor gasoline blending.

Natural Gas: A gaseous mixture of hydrocarbon compounds, primarily methane, delivered via pipeline for consumption. It is used as a fuel for electricity generation, a variety of uses in buildings, and as raw material input and fuel for industrial processes. *Note:* This product, also referred to as *dry natural gas* or *consumer-grade natural gas*, is the product that remains after *wet natural gas* has been processed at lease facilities and/or natural gas processing plants. This processing removes nonhydrocarbon gases (e.g., water vapor, carbon dioxide, helium, hydrogen sulfide, and nitrogen) that would otherwise make the gas unmarketable and natural gas liquids.

Natural Gas, Dry: The marketable portion of natural gas production, which is obtained by subtracting extraction losses, including natural gas liquids removed at natural gas processing plants, from total production.

Natural Gas, Wet: A mixture of hydrocarbon compounds and small quantities of various nonhydrocarbons existing in the gaseous phase or in solution with crude oil in porous rock formations at reservoir conditions. The principal hydrocarbons normally contained in the mixture are methane, ethane, propane, butane, and pentanes. Typical nonhydrocarbon gases that may be present in reservoir natural gas are water vapor, carbon dioxide, helium, hydrogen sulfide, and nitrogen. Under reservoir conditions, natural gas and the liquefiable portions occur either in a single gaseous phase in the reservoir or in solution with oil and are not distinguishable at the time as separate substances.

Nitrogen Oxides (NO_x): Compounds of nitrogen and oxygen produced by the burning of fossil fuels.

North American Electric Reliability Council (NERC): A council formed in 1968 by the electric utility industry to promote the reliability and adequacy of bulk power supply in the electric utility systems of North America. The NERC consists of ten regional reliability councils and encompasses essentially all the power systems of the contiguous United States and Canada.

Nuclear Electric Power: Electricity generated by an electric power plant whose turbines are driven by steam generated in a reactor by heat from the fissioning of nuclear fuel.

Organization for Economic Cooperation and Development (OECD): Current members are Australia, Austria, Belgium, Canada, Czech Republic, Denmark and its territories (Faroe Islands and Greenland), Finland, France, Germany, Greece, Greenland, Hungary, Iceland, Ireland, Italy, Japan, Luxembourg, Mexico, the Netherlands, New Zealand, Norway, Poland, Portugal, South Korea, Spain, Sweden, Switzerland, Turkey, United Kingdom, and United States and its territories (Guam, Puerto Rico, and Virgin Islands).

Organization of Petroleum Exporting Countries (OPEC): Countries that have organized for the purpose of negotiating with oil companies on matters of oil production, prices, and future concession rights. Current members are Algeria, Indonesia, Iran, Iraq, Kuwait, Libya, Nigeria, Qatar, Saudi Arabia, United Arab Emirates, and Venezuela.

Photovoltaic Energy: Direct-current electricity generated from sunlight through solid state semiconductor devices that have no moving parts.

Pipeline, Natural Gas: A continuous pipe conduit, complete with such equipment as valves, compressor stations, communications systems, and meters, for transporting natural gas and/or supplemental gaseous fuels from one point to another, usually from a point in or beyond the producing field or processing plant to another pipeline or to points of use. Also refers to a company operating such facilities.

Pipeline, Oil: Oil and product pipelines (including interstate, intrastate, and intracompany pipelines) used to transport oil and petroleum products, respectively, within the 50 states and the District of Columbia.

Proved Reserves, Oil: The estimated quantities of all liquids defined as crude oil that geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions.

Proved Reserves, Natural Gas: The estimated quantities of natural gas that analysis of geological and engineering data demonstrates with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions.

Refinery (Oil): An installation that manufactures finished fuels from oil, unfinished oils, natural gas liquids, other hydrocarbons, and alcohol.

Renewable Energy: Energy obtained from sources that are essentially inexhaustible (unlike, for example, fossil fuels, of which there is a finite supply). Renewable sources of energy include conventional hydroelectric power, wood, waste, geothermal, wind, photovoltaic, and solar thermal energy.

Spot Price: The price for a one-time open market transaction for immediate delivery of the specific quantity of product at a specific location where the commodity is purchased “on the spot” at current market rates.

Strategic Petroleum Reserve (SPR): Petroleum stocks maintained by the federal government for use during periods of major supply interruption.

Stocks: Supplies of fuel or other energy source(s) stored for future use. Stocks are reported as of the end of the reporting period.

Sulfur Dioxide (SO₂): A toxic, colorless gas soluble in water, alcohol, and ether. Used as a chemical intermediate in paper pulping and ore refining, and as a solvent.

Transportation Sector: Private and public vehicles that move people and commodities. Included are automobiles, trucks, buses, motorcycles, railroads, and railways (including streetcars), aircraft, ships, barges, and natural gas pipelines.

Wellhead Price: The price of oil or natural gas at the mouth of the well.

Wind Energy: The kinetic energy of wind converted into mechanical energy by wind turbines (i.e., blades rotating from a hub) that drive generators to produce electricity.

Wood Energy: Wood and wood products used as fuel, including round wood (cord wood), limb wood, wood chips, bark, sawdust, forest residues, charcoal, pulp waste, and spent pulping liquor.



BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c)	)	
Emergency Order: Tri-State	)	Order No. 202-25-14
Generation and Transmission	)	
Association, Platte River Power	)	
Authority, Salt River Project,	)	
<u>PacifiCorp, and Xcel Energy</u>	)	

Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
Public Interest Organizations

Filed January 28, 2026

Exhibit 1-120:
Department Export Authorization EA-365-C (Oct. 21, 2025)

United States
Department of Energy

Grid Deployment Office

Research Power Corporation
(formerly known as Centre Lane Trading Ltd.)
GDO Docket No. EA-365-C



Order Authorizing Electricity Exports to Canada

Order No. EA-365-C

October 21, 2025

Research Power Corporation
(formerly known as Centre Lane Trading Ltd.)
Order No. EA-365-C
Authorizing Electricity Exports to Canada

I. BACKGROUND

The Department of Energy (DOE or Department) regulates electricity exports from the United States to a foreign country in accordance with Federal Power Act (FPA) § 202(e) (16 U.S.C. § 824a(e)) and regulations thereunder (10 C.F.R. §§ 205.300 *et seq.*). This authority was transferred to DOE under §§ 301(b) and 402(f) of the DOE Organization Act (42 U.S.C. §§ 7151(b) and 7172(f)). On April 10, 2023, this authority was delegated to the DOE’s Grid Deployment Office (GDO) by Redelegation Order No. S3-DEL-GD1-2023.

An entity that seeks to export electricity must obtain an order from DOE authorizing it to do so. Under FPA § 202(e), DOE “shall issue such order upon application unless, after opportunity for hearing, it finds that the proposed transmission would impair the sufficiency of electric supply within the United States or would impede or tend to impede the coordination in the public interest of facilities subject to the jurisdiction of [DOE].” 16 U.S.C. § 824a(e). DOE has discretion to condition the order as necessary or appropriate; the Department “may by its order grant such application in whole or in part, with such modifications and upon such terms and conditions as [DOE] may find necessary or appropriate, and may from time to time, after opportunity for hearing and for good cause shown, make such supplemental orders in the premises as it may find necessary or appropriate.” *Id.*

A. Application for Export Authorization

Research Power Corporation (the Applicant) is a power marketer seeking renewal of its authorization to export electric energy to Canada, which was originally granted in Order No. EA-365-A on June 29, 2015, and subsequently renewed (EA-365-B) on April 29, 2020. On December 26, 2024, Centre Lane filed an application with DOE (Application or App.) requesting renewal of its export authority for a five-year term. App. at 1. On July 7, 2025, the Applicant notified DOE of its corporate name change from Centre Lane Trading Ltd. to Research Power Corporation.

According to the Application, Research Power Corporation (formerly known as Centre Lane Trading Ltd.) “is a Canadian Corporation with its principal place of business in Toronto, Ontario” that is “organized under the *Business Corporations Act* of the Province of Ontario, Canada.” *Id.* The Applicant states that it “does not own, operate or control any generation or transmission facilities in any region, nor is it affiliated with any entity that owns, operates or controls generation or transmission facilities, and is not affiliated with any franchised public utility.” *Id.* at 1-2. The applicant further represents that it is a “[Federal Energy Regulatory Commission]-authorized power marketer engaging in the purchase and sale of physical and/or

virtual energy in the Day-ahead and Real-time Markets of various Independent System Operators and Regional Transmission Organizations.” App at 2.

Research Power Corporation represents that it “has no electric power supply system on which the proposed exports could have a reliability, fuel use system or stability impact.” App. at 3. The Applicant states that it “has no obligation to serve native load usually associated with a franchised service area, and, thus, the exports proposed by [Research Power Corporation] will not impair its ability to meet current and prospective power supply obligations.” *Id.* The Applicant further affirms that it “will purchase power to be exported from a variety of sources such as power marketers, independent power producers, or U.S. electric utilities and federal power marketing entities as those terms are defined in Sections 3(22) and 3(19) of the FPA” and that “such power is surplus to the system of the generator and, therefore, the electric power that [Research Power Corporation] will export on either a firm or interruptible basis will not impair the sufficiency of the electric power supply within the U.S.” *Id.*

The applicant states that it “will make all necessary commercial arrangements and will obtain any and all other regulatory approvals required in order to schedule and deliver power exports.” *Id.* The Applicant further states that it will “schedule its transactions with the appropriate balancing authority areas in compliance with the reliability criteria standards and guidelines established by the North American Electric Reliability Corporation[.]” *Id.* Research Power Corporation also attests to not exceed the export limits for the facilities, or otherwise cause a violation of the terms and conditions set forth in the export authorizations for each. App at 4.

B. Procedural History

On December 26, 2024, Centre Lane filed a renewal application with DOE for export authority for a five-year term. *Id.* at 1. On June 16, 2025, DOE published notice of Centre Lane’s Application in the Federal Register (90 Fed. Reg. 25252) and asked for any interested parties to submit comments on the Application by July 16, 2025. On July 7, 2025, DOE received notice of Centre Lane’s corporate name change to Research Power Corporation.

C. Public Comments

No public comments were received.

II. DISCUSSION AND ANALYSIS

DOE is statutorily obligated under FPA § 202(e) to grant requests for export authorization unless the Department finds that the proposed export would negatively impact either: (i) the sufficiency of electric supply, or (ii) the coordination of the electric grid. Regarding the first exception criterion, DOE shall approve an electricity export application “unless, after opportunity for hearing, it finds that the proposed transmission would impair the sufficiency of electric supply within the United States” 16 U.S.C. § 824a(e). DOE has interpreted this criterion to mean that sufficient generating capacity and electric energy must exist such that the export could be made without compromising the energy needs of the exporting region, including

serving all load obligations in the region while maintaining appropriate reserve levels. *See, e.g., BP Energy Co.*, Order No. EA-314, at 1-2 (Feb. 22, 2007), *renewed*, Order No. EA-314-A, at 2 (May 3, 2012), Order No. EA-314-B, at 2 (Feb. 28, 2017), *renewed*, Order No. EA-314-C, at 4 (Dec. 20, 2021).

Under the second exception criterion, DOE shall approve an electricity export application “unless, after opportunity for hearing, it finds that the proposed transmission would ... impede or tend to impede the coordination in the public interest of facilities subject to the jurisdiction of [DOE].” 16 U.S.C. § 824a(e). DOE has interpreted this criterion primarily as an issue of the operational reliability of the domestic electric transmission system. Accordingly, the export must not compromise transmission system security and reliability. *See, e.g., Order No. EA-314-C*, at 4.

A. Research Power Corporation Will Not Impair the Sufficiency of the Electric Supply in the United States

Sufficiency of supply, the first exception criterion, addresses whether regional electricity needs are met in the current market. DOE has analyzed this issue from both an economic and a reliability perspective. The economic perspective concerns the supply available to wholesale market participants. The reliability perspective focuses on preventing problems that could result from inadequate supplies. Taken together, DOE examines whether existing electric supply is available via market mechanisms, and whether potential reliability issues linked to supply problems are mitigated by reliability enforcement mechanisms.

From an economic perspective, DOE finds that the wholesale energy markets are sufficiently robust to make supplies available to exporters and other market participants serving United States regions along the Canadian and Mexican borders. Following enactment of the Energy Policy Act of 1992, Pub. L. No. 102-486, which encouraged the Federal Energy Regulatory Commission (FERC) to foster competition in the wholesale energy markets through open access to transmission facilities, energy markets developed across the United States to provide opportunities for a more efficient availability of supply. Subsequently, the Energy Policy Act of 2005, Pub. L. No. 109-58, reaffirmed the Government’s commitment to competition in wholesale energy markets as national policy. FERC has continued to encourage the expansion of wholesale energy markets through its orders to remove barriers¹ and to ensure that these markets are functioning properly.² As a result, market participants have access to traditional bilateral contracts, as well as organized electricity markets run by regional transmission organizations (RTOs) or independent system operators (ISOs). FERC oversees these interstate wholesale electricity markets across most of the lower 48 states. Absent an indication in the record that the geographic markets relevant to this export authorization analysis are flawed and result in

¹ *See, e.g., Preventing Undue Discrimination and Preference in Transmission Service*, Order No. 890, 72 Fed. Reg. 12,266 (Mar. 15, 2007), FERC Stats. & Regs. ¶ 31,241, *order on reh’g*, Order No. 890-A, FERC Stats. & Regs. ¶ 31,261 (2007), *order on reh’g*, Order No. 890-B, 123 FERC ¶ 61,299 (2008), *order on reh’g*, Order No. 890-C, 126 FERC ¶ 61,228 (2009).

² *See, e.g., Wholesale Competition in Regions with Organized Electric Markets*, Order No. 719, FERC Stats. & Regs. ¶ 31,281 (2008), *as amended*, 126 FERC ¶ 61,261, *order on reh’g*, Order No. 719-A, FERC Stats. & Regs. ¶ 31,292, *reh’g denied*, Order No. 719-B, 129 FERC ¶ 61,252 (2009).

uneconomic exports that jeopardize regional supply, DOE finds that the proposed transmission for export does not impair the sufficiency of electric supply within the United States.

From a reliability perspective,³ DOE focuses on the prevention of cascading outages and other problems that could result from inadequate resources.⁴ Reliability oversight is addressed by the authority granted to FERC through the Energy Policy Act of 2005. That Act added section 215 to the FPA, which directed FERC to certify an electric reliability organization and develop procedures for establishing, approving, and enforcing mandatory electric reliability standards. 16 U.S.C. § 824o. FERC certified the North American Electric Reliability Corporation (NERC) in 2006 to develop and enforce reliability standards for the bulk-power system in the United States. *Order Certifying NERC as the Electric Reliability Organization and Ordering Compliance Filing*, FERC Docket No. RR06-1-000, 116 FERC ¶ 61,062 (July 20, 2006). FERC approves these standards, at which point they become mandatory and enforceable. NERC Reliability Standards address areas such as resource and demand balancing, critical infrastructure protection, communications, emergency preparedness and operations, facilities design, transmission operations, transmission planning, modelling, nuclear, personnel performance and training, protection and controls, voltage and reactive, interchange scheduling and coordination, and interconnection reliability operations and coordination.

NERC Reliability Standards are enforceable throughout the continental United States, most of Canada south of the 60th parallel, and the Mexican state of Baja California Norte. Through enforcement by FERC, NERC, and six Regional Entities overseen by NERC,⁵ all bulk-power system owners, operators, and users are held responsible for complying with reliability standards. The reliability standards are structured so that many entities have overlapping responsibility for the electric grid, thereby resulting in several layers of reliability monitoring. Entities such as reliability coordinators and balancing authorities coordinate power generation and transmission among multiple utilities to serve demand within an integrated regional wholesale market. One of the principal functions of these entities is to schedule adequate generating and reserve capacity. This allows them to serve demand at the regional level and to ensure that there is sufficient power supply to maintain system reliability. Reliability Standard IRO-001-4 “establish[es] the responsibility of Reliability Coordinators to act or direct other entities to act.”⁶ Requirement R1 states that “[e]ach Reliability Coordinator shall act to address the reliability of its Reliability Coordinator Area via direct actions or by issuing Operating Instructions.”⁷ Reliability oversight is designed through coordinated efforts amongst Reliability Coordinators to preserve the benefits of interconnected operations and ensure that operations in one area will not adversely impact other areas.⁸ Reliability Standard IRO-014-3 R1 provides that “[e]ach Reliability Coordinator shall have and implement Operating Procedures, Operating

³ A related reliability analysis follows in the next section of this Order.

⁴ This focus should not be confused with resource adequacy planning and capacity requirements that have traditionally been the domain of state regulatory commissions, NERC-certified Regional Entities, and RTOs/ISOs.

⁵ The six entities are the Midwest Reliability Organization, Northeast Power Coordinating Council, ReliabilityFirst Corporation, SERC Reliability Corporation, Texas Reliability Entity, and Western Electricity Coordinating Council.

⁶ Standard IRO-001-4 (Reliability Coordination – Responsibilities), at ¶ A.3.

⁷ *Id.* ¶ B.R1.

⁸ See Standard IRO-014-3 (Coordination Among Reliability Coordinators), at ¶ A.3.

Processes, or Operating Plans, for activities that require notification or coordination of actions that may impact adjacent Reliability Coordinator Areas, to support Interconnection reliability.”⁹

DOE finds that NERC’s FERC-approved comprehensive enforcement mechanism ensures that bulk-power system owners, operators, and users have a strong incentive both to maintain system resources and to prevent reliability problems that could result from movement of electric supplies through export. As a result of this reliability oversight, DOE finds that the sufficiency of supply is not impaired by Research Power Corporation’s proposed export authorization.

DOE’s sufficiency of supply findings are further supported by the fact that power marketers, such as Research Power Corporation, do not have an obligation to serve a franchised territory. Before the current role of power marketers emerged in the industry, the FPA § 202(e) inquiry into sufficiency of supply had a narrower focus and was designed for an applicant that was a vertically integrated utility¹⁰ with an obligation to serve native load. Under that traditional scenario, the inquiry regarding sufficiency of supply logically sought to confirm that exports would be surplus to the needs of a vertically-integrated utility’s native load obligations and reserve margins. As explained in DOE’s notice of the first application by a power marketer for export authorization, the sufficiency of supply inquiry became unnecessary when applied to power marketers:

The Applicant also is required to demonstrate that it would have sufficient generating capacity to sustain the proposed export under the terms and conditions of its export agreement, while still complying with any established reserve criteria.

Since marketers generally could not be seen as having any “native load” requirements, the latter criterion of maintaining sufficient reserve margins appears inappropriate and unnecessary in this instance.

59 Fed. Reg. 54900 (Nov. 2, 1994). Power marketers do not have franchised service areas and, consequently, do not have native load obligations like a traditional local distribution utility that could be impaired by exports.

In sum, market mechanisms and reliability oversight protect against the possibility that Research Power Corporation’s exports would jeopardize domestic sufficiency of supply. Therefore, an export by Research Power Corporation would not trigger the first exception criterion of FPA § 202(e) regarding the sufficiency of electric supply within the United States.

⁹ *Id.* ¶ B.R1.

¹⁰ The Supreme Court of the United States has explained: “In 1935, when the FPA became law, most electricity was sold by vertically integrated utilities that had constructed their own power plants, transmission lines, and local delivery systems...[M]ost operated as separate, local monopolies subject to state or local regulation. Their sales were ‘bundled,’ meaning that consumers paid a single charge that included both the cost of the electric energy and the cost of its delivery. Competition among utilities was not prevalent.” *New York v. FERC*, 535 US 1, 5 (2002).

B. Research Power Corporation's Requested Authorization Will Not Adversely Affect Either the Reliability or the Security of the United States Electric Transmission System

Reliability, the second exception criterion under FPA § 202(e), addresses operational reliability and security of the domestic electric transmission system. In evaluating the operational reliability impacts of export proposals, DOE has used a variety of methodologies and information, including established industry guidelines, operating procedures, and technical studies where available and appropriate. When determining these impacts, it is convenient to separate the export transaction into two parts: (i) moving the export from the source to a border system that owns the international transmission connection, and (ii) moving the export through that border system and across the border.

Moving Electricity to a Border System. Moving electricity for export to a border system necessarily involves the use of the bulk-power system. As noted in the preceding section, bulk-power system reliability concerns are addressed under the FPA by FERC and NERC and involve the enforcement of mandatory reliability standards. These standards ensure that all owners, operators, and users of the bulk-power system have an obligation to maintain system security and reliability. The standards are structured so that there are always entities with broader responsibilities than the applicant, such as reliability coordinators and balancing authorities, to keep a constant watch over the domestic transmission system.

To deliver the export from the source to a border system, the applicant must make the necessary commercial arrangements and obtain sufficient transmission capacity to wheel the exported energy to the border system. The applicant would be expected to follow FERC orders regarding open transmission access and to schedule delivery of the export with the appropriate RTO, ISO, and/or balancing authority (formerly the control area operator).

It is the responsibility of the RTO, ISO, and/or balancing authority to schedule the delivery of the export consistent with established and mandatory operational reliability criteria. During each step of the process of obtaining transmission service, the owners and/or operators of the transmission facilities will evaluate the impact on the system and schedule the movement of the export *only* if it would not violate established operating reliability standards. As a failsafe, the reliability coordinator in each region has the authority and responsibility to curtail, cancel, or deny scheduled flows to avoid shortages or to restore necessary energy and capacity reserves. Reliability Standard EOP-011-1 R2 provides that “[e]ach Balancing Authority shall develop, maintain, and implement one or more Reliability Coordinator-reviewed Operating Plan(s) to mitigate Capacity Emergencies and Energy Emergencies within its Balancing Authority Area.”¹¹

Specifically, the reliability coordinator has the authority to suspend exports if the electric energy would be needed to support the regional power grid. *See* Reliability Standard IRO-001-4 R1 (“Each Reliability Coordinator shall act to address the reliability of its Reliability Coordinator Area via direct actions or by issuing Operating Instructions”), R2 (“Each Transmission Operator, Balancing Authority, Generator Operator, and Distribution Provider shall comply with its Reliability Coordinator’s Operating Instructions unless compliance with the

¹¹ EOP-011-1 (Emergency Operations), at ¶ B.R2.

Operating Instructions cannot be physically implemented or unless such actions would violate safety, equipment, regulatory, or statutory requirements”), and R3 (“Each Transmission Operator, Balancing Authority, Generator Operator, and Distribution Provider shall inform its Reliability Coordinator of its inability to perform the Operating Instruction issued by its Reliability Coordinator in Requirement R1”).

DOE has determined that the existing industry procedures for obtaining transmission capacity on the domestic transmission system (described above) provide adequate assurance that any export will not cause an operational reliability problem. Therefore, Research Power Corporation’s export authorization has been conditioned to ensure that the export will not cause operational issues on regional transmission systems to fall outside of established industry reliability criteria, or cause or exacerbate a transmission operating problem on the United States’ electric power supply system (*see* Order below, Section VII, paragraphs C, D, and I).

Moving Electricity Through a Border System. The second part of DOE’s reliability inquiry, addressing the transmission of the export through a border system and across the border, is a question of whether the border system is reliable and secure. To a large extent, this question is addressed by the jurisdiction of NERC. NERC and Regional Entities—including the Midwest Reliability Organization, the Northeast Power Coordinating Council, and the Western Electricity Coordinating Council—oversee the United States-Canadian border system and a significant part of the United States-Mexican border system. Those border systems are generally subject to the same reliability standards as domestic systems. *See, e.g.,* <http://www.ieso.ca/sector-participants/system-reliability/reliability-standards-framework>.

DOE also relies on the System Impact Studies submitted in conjunction with an application for a DOE-issued Presidential permit¹² to construct a new international transmission line. As DOE has previously reviewed System Impact Studies submitted with Presidential permit applications,¹³ DOE does not need to perform additional impact assessments here, provided the maximum rate of transmission for all exports through a border system does not exceed the authorized limit of the system (*see* Order below, Section VII, paragraph (A)). In its application, Research Power Corporation committed to complying with all reliability limits on border facilities. *See* App. at 3. The second part of the reliability inquiry is therefore satisfied by DOE regulatory oversight, in addition to NERC’s reliability enforcement.

III. FINDINGS AND DECISION

A. Research Power Corporation Meets the Statutory Requirements to Export Electric Energy to Canada

¹² DOE issues Presidential permits pursuant to Executive Order 10,485, as amended by Executive Order 12,038. *See* 10 C.F.R. §§ 205.320-205.329.

¹³ *See, e.g., AEP Tex. Cent. Co.*, Order No. PP-317, at 2-3 (Jan. 22, 2007); *Mont. Alta. Tie Ltd.*, Order No. PP-305, at 2-4 (Nov. 17, 2008).

As explained above, DOE has assessed the impact that the proposed export would have on the reliability of the United States electric power supply system. DOE has determined that the export of electric energy to Canada by Research Power Corporation, as ordered below, would not impair the sufficiency of electric power supply within the United States and would not impede or tend to impede the coordination in the public interest of facilities within the meaning of FPA § 202(e).

B. Research Power Corporation Qualifies for a NEPA Categorical Exclusion for Exports of Electric Energy

Research Power Corporation's Application qualifies for DOE's categorical exclusion for exports of electric energy under the National Environmental Policy Act of 1969, as amended (NEPA), 42 U.S.C. § 4321 *et seq.* DOE's NEPA [Implementing](#) Procedures (June 2025) set forth this categorical exclusion, codified as "B4.2," as follows:

Export of electric energy as provided by Section 202(e) of the Federal Power Act over existing transmission lines or using transmission system changes that are themselves categorically excluded.

10 C.F.R. Part 1021, App. B, § B4.2.

DOE has determined that actions in this category do not normally have a significant effect on the human environment and that, therefore, neither an environmental assessment nor an environmental impact statement normally is required. 10 C.F.R. § 1021.102(a).

To invoke this categorical exclusion, DOE must determine that, in relevant part, "[t]here are no extraordinary circumstances related to the proposal that may affect the significance of the environmental effects of the proposal." 10 C.F.R. § 1021.102(b)(2). "Extraordinary circumstances" include "unique situations" such as "scientific controversy about the environmental effects of the proposal; uncertain effects or effects involving unique or unknown risks; and unresolved conflicts concerning alternative uses of available resources." *Id.* DOE finds that granting Research Power Corporation's request for export authorization does not present such extraordinary circumstances. Research Power Corporation seeks to deliver electricity over existing international electric transmission facilities, which fits squarely within the B4.2 categorical exclusion. For these reasons, DOE will not require more detailed NEPA review in connection with this Application.

C. Conclusion

DOE grants Research Power Corporation's request for export authorization. Research Power Corporation is authorized to export electricity to Canada over any authorized international transmission facility that is appropriate for open access transmission by third parties, subject to the limitations and conditions described in this Order. The authorization shall be effective for a five (5) year term consistent with DOE's standard term for new electricity export authorizations.

IV. DATA COLLECTION AND REPORTING REQUIREMENTS

The responsibility for the data collection and reporting under orders authorizing electricity exports to a foreign country currently rests with the U.S. Energy Information Administration (EIA) within DOE. The Applicant is instructed to follow EIA instructions in completing this data exchange. Questions regarding the data collection and reporting requirements can be directed to EIA by email at EIA4USA@eia.gov or by phone at 1-855-342-4872.

Additionally, any change to the tariff of an entity with an export authorization must be provided to DOE's Grid Deployment Office via email at electricity.exports@hq.doe.gov. 10 C.F.R. § 205.308(b).

V. COMPLIANCE

Obtaining a valid order from DOE authorizing the export of electricity under FPA § 202(e) is a necessary condition before engaging in the export. Failure to obtain such an order or continuing to export after the expiration of such an order may result in a denial of authorization to export in the future and subject the exporter to sanctions and penalties under the FPA. DOE expects transmitting utilities owning border facilities and entities charged with the operational control of those border facilities, such as ISOs, RTOs, or balancing authorities, to verify that companies seeking to schedule an electricity export have the requisite authority from DOE to export such energy.

DOE expects Research Power Corporation to abide by the terms and conditions established for its authority to export electric energy to Canada, as set forth below. DOE intends to monitor Research Power Corporation compliance with these terms and conditions, including the requirement in paragraph G of this Order that Research Power Corporation create and preserve full and complete records and file reports with EIA as discussed above.

A violation of any of these terms and conditions, including the failure to submit timely and accurate reports, may result in the loss of authority to export electricity and subject Research Power Corporation to any applicable sanctions and penalties under the FPA.

VI. OPEN ACCESS POLICY

An export authorization issued under FPA § 202(e) does not impose a requirement on transmitting utilities to provide service. However, DOE expects transmitting utilities that own border facilities to provide open access transmission service across the border in accordance with the principles of comparable open access and non-discrimination contained in the FPA and articulated in FERC Order No. 888 (Promoting Wholesale Competition Through Open Access Non-Discriminatory Transmission Services by Public Utilities, FERC Statutes and Regulations ¶ 31,036 (1996)), as amended. The actual rates, terms, and conditions of transmission service should be consistent with the non-discrimination principles of the FPA and the transmitting utility's Open-Access Transmission Tariff on file with FERC.

All recipients of export authorizations, including owners of border facilities for which Presidential permits have been issued, are required by their export authorization to conduct operations in accordance with the applicable principles of the FPA and any pertinent rules, regulations, directives, policy statements, and orders adopted or issued thereunder, including the comparable open access provisions of FERC Order No. 888, as amended. Cross-border electric trade ought to be subject to the same principles of comparable open access and non-discrimination that apply to transmission in interstate commerce. *See Enron Power Mktg., Inc. v. El Paso Elec. Co.*, 77 FERC ¶ 61,013 (1996), *reh'g denied*, 83 FERC ¶ 61,213 (1998). Thus, DOE expects owners of border facilities to comply with the same principles of comparable open access and non-discrimination that apply to the domestic, interstate transmission of electricity.

VII. ORDER

Accordingly, pursuant to FPA § 202(e) and the Rules and Regulations issued thereunder (10 C.F.R. §§ 205.300-309), it is hereby ordered that Research Power Corporation is authorized to export electric energy to Canada under the following terms and conditions:

- (A) The electric energy exported by Research Power Corporation pursuant to this Order may be delivered to Canada over any authorized international transmission facility that is appropriate for open access transmission by third parties in accordance with the export limits authorized by DOE.

(1) The following international transmission facilities located at the United States border with Canada are currently authorized by Presidential permit and available for open access transmission:^{14, 15}

<u>Owner</u>	<u>Location</u>	<u>Voltage</u>	<u>Permit No.</u> ¹⁶
Bangor Hydro-Electric Company	Baileyville, ME	345 kV	PP-89
Basin Electric Power Cooperative	Tioga, ND	230 kV	PP-64
Bonneville Power Administration (BPA)	Blaine, WA	2x 500 kV	PP-10
	Nelway, WA	230 kV	PP-36
	Nelway, WA	230 kV	PP-46
CHPE, LLC	Champlain, NY	±230 kV DC	PP-481 ¹⁷

¹⁴ This Order authorizes the export of electricity over any “authorized international transmission facility,” which is intended to include both large transmission lines and smaller distribution lines that have received a Presidential permit. However, the list in subparagraph (A)(1) of current facilities only includes transmission lines.

¹⁵ The Applicant submitted a list identifying currently authorized transmission facilities (Attachment 1 of the Application). However, as information about some of those facilities may have changed since the Application was submitted, the table of transmission facilities in this Order may differ from the Applicant’s submission to reflect those changes.

¹⁶ These Presidential permit numbers refer to the generic DOE permit number and are intended to include any subsequent amendments to the permit authorizing the facility.

¹⁷ Currently under construction and not yet operational as of September 2025.

Eastern Maine Electric Cooperative	Calais, ME	69 kV	PP-32
International Transmission Company	Detroit, MI	230 kV	PP-230
	Marysville, MI	230 kV	PP-230
	St. Claire, MI	230 kV	PP-230
	St. Claire, MI	345 kV	PP-230
Lake Erie Connector Transmission, LLC	Erie County, PA	320 kV	PP-412 ¹⁸
Long Sault, Inc.	Massena, NY	2x 115 kV	PP-24
Maine Electric Power Company	Houlton, ME	345 kV	PP-43
Minnesota Power, Inc.	International Falls, MN	115 kV	PP-78
Minnesota Power, Inc.	Roseau County, MN	500 kV	PP-398
Minnkota Power Cooperative	Roseau County, MN	230 kV	PP-61
Montana Alberta Tie Ltd.	Cut Bank, MT	230 kV	PP-399
NECEC Transmission LLC	Beattie Twp, ME	±320 kV	PP-438 ¹⁹
New York Power Authority	Massena, NY	765 kV	PP-56
	Massena, NY	2x 230 kV	PP-25
	Niagara Falls, NY	2x 345 kV	PP-74
	Devils Hole, NY	230 kV	PP-30
Niagara Mohawk Power Corp.	Devils Hole, NY	230 kV	PP-190
Northern States Power Company	Red River, ND	230 kV	PP-45
	Roseau County, MN	500 kV	PP-63
	Rugby, ND	230 kV	PP-231
Sea Breeze Olympic Converter LP	Port Angeles, WA	±450 kV DC	PP-299 ²⁰
TDI New England	Alburgh, VT	±320 kV DC	PP-400 ²¹

¹⁸ These transmission facilities have been authorized but not yet constructed or placed into operation.

¹⁹ These transmission facilities have been authorized but not yet constructed or placed into operation.

²⁰ These transmission facilities have been authorized but not yet constructed or placed into operation.

²¹ These transmission facilities have been authorized but not yet constructed or placed into operation.

Vermont Electric Power Co.	Derby Line, VT	120 kV	PP-66
Vermont Electric Transmission Co.	Norton, VT	±450 kV DC	PP-76
Vermont Transco LLC	Highgate, VT	120 kV	PP-82
Versant Power	Fort Fairfield, ME	69 kV	PP-497
	Madawaska, ME	138 kV	PP-498
	Easton, ME	7.2 kV	PP-499
	Baileyville, ME	345kV	PP-500

(2) The following are the authorized export limits for the international transmission lines listed above in subparagraph (A)(1):

- (a) Exports by Research Power Corporation made pursuant to this Order shall not cause the total exports on facilities authorized by Presidential Permit PP-64 (issued to Basin Electric Power Coop.) to exceed an instantaneous transmission rate of 150 megawatts (MW). The gross amount of energy that Research Power Corporation may export over the PP-64 facilities shall not exceed 900,000 megawatt-hours (MWH) during any consecutive 12-month period.
- (b) Exports by Research Power Corporation made pursuant to this Order shall not cause the total exports on the facilities authorized by Presidential Permit PP-32 (issued to Eastern Maine Electric Coop.) to exceed an instantaneous transmission rate of 15 MW. The gross amount of energy that Research Power Corporation may export over the PP-32 facilities shall not exceed 7,500 MWH annually.
- (c) Exports by Research Power Corporation made pursuant to this Order shall not cause the total exports on a combination of the facilities authorized by Presidential Permit PP-481-2 (issued to CHPE, LLC) to exceed an instantaneous transmission rate of 1,250 MW.
- (d) Exports by Research Power Corporation made pursuant to this Order shall not cause the total exports on a combination of the facilities authorized by Presidential Permit PP-230 (issued to International Transmission Company) to exceed a coincident, instantaneous transmission rate of 2.2 billion volt-amperes (2,200 MVA).
- (e) Exports by Research Power Corporation made pursuant to this Order shall not cause the total exports on a combination of the facilities authorized by Presidential Permit PP-412-1 (issued to Lake Erie Connector Transmission, LLC) to exceed an instantaneous transmission rate of 1,000 MW.
- (f) Exports by Research Power Corporation made pursuant to this Order shall not cause the scheduled rate of transmission over a combination of facilities

authorized by Presidential Permits PP-43 (issued to Maine Electric Power Company) and PP-500 (issued to Bangor Hydro-Electric) to exceed 550 MW.

- (g) Exports by Research Power Corporation made pursuant to this Order shall not cause the total exports on the combination of facilities authorized by Presidential Permits PP-497 and PP-498 (issued to Versant Power) to exceed a coincident, instantaneous transmission rate of 134 MW.
- (h) Exports by Research Power Corporation made pursuant to this Order shall not cause total exports on the facilities authorized by Presidential Permit PP-78-1 (issued to Minnesota Power, Inc.) to exceed an instantaneous transmission rate of 100 MW. Exports by Research Power Corporation may cause total exports on the PP-78-1 facilities to exceed 100 MW only when total exports between the Mid-Continent Area Power Pool (MAPP) and Manitoba Hydro are below maximum transfer limits and/or whenever operating conditions within the MAPP system permit exports on the PP-78-1 facilities above the 100-MW level without violating established MAPP reliability criteria. However, under no circumstances shall exports by Research Power Corporation cause the total exports on the PP-78-1 facilities to exceed 150 MW.
- (i) Exports made by Research Power Corporation pursuant to this Order shall not cause total exports on the facilities authorized by Presidential Permit PP-398 (issued to Minnesota Power, Inc.) to exceed an instantaneous transmission rate of 750 MW.
- (j) Exports by Research Power Corporation made pursuant to this Order shall not cause total exports on a combination of the international transmission lines authorized by Presidential Permits PP-45 and PP-63 (issued to Northern States Power Company), PP-61 (issued to Minnkota Power), and PP-231 (issued to Northern States Power Company, d/b/a Excel Energy Inc. (Xcel)), to exceed an instantaneous transmission rate of 700 MW on a firm basis and 1,050 MW on a non-firm basis.
- (k) Exports by Research Power Corporation made pursuant to this Order shall not cause the total exports on the facilities authorized by Presidential Permit PP-66 (issued to Vermont Electric Power Co.) to exceed an instantaneous transmission rate of 50 MW. The gross amount of energy that Research Power Corporation may export over the PP-66 facilities shall not exceed 50,000 MWH annually.
- (l) Exports by Research Power Corporation made pursuant to this Order shall not cause the total exports on the facilities authorized by Presidential Permit PP-56 (issued to NYPA) to exceed an instantaneous transmission rate of 1,000 MW.
- (m) Exports by Research Power Corporation made pursuant to this Order shall not cause: (a) the total exports on the facilities authorized by Presidential Permits PP-25, PP-30, PP-74 (issued to NYPA), and PP-190 (issued to Niagara Mohawk Power Corp.) to exceed a combined instantaneous transmission rate of 1,650

MW; and (b) the total exports on the 115-kV facilities authorized by Presidential Permit PP-24 (issued to Long Sault, Inc.) to exceed an instantaneous transmission rate of 100 MW. In addition, the gross amount of energy that Research Power Corporation may export over the PP-24 facilities shall not exceed 300,000 MWH annually.

- (n) Exports by Research Power Corporation made pursuant to this Order shall not cause total exports on the two 500-kV lines authorized by Presidential Permit PP-10, the 230-kV line authorized by Presidential Permit PP-36, and the 230-kV line authorized by Presidential Permit PP-46 (issued to BPA) to exceed the following limits:

Condition	PP-36 & PP-46 Limit	PP-10 Limit	Total Export Limit
All lines in service	400 MW	1500 MW	1900 MW
1-500 kV line out	400 MW	300 MW	700 MW
2-500 kV lines out	400 MW	0 MW	400 MW
1-230 kV line out	400 MW	1500 MW	1900 MW
2-230 kV line out	0 MW	1500 MW	1500 MW

- (o) Exports by Research Power Corporation made pursuant to this Order shall not cause a violation of the following conditions as they apply to exports over the facilities authorized by Presidential Permit PP-76-1, as amended (issued to the Vermont Electric Transmission Company):

NEPOOL		
Exports Through	Load Condition	Export Limit
Comerford converter	Summer, Heavy	650 MW
Comerford converter	Winter, Heavy	660 MW
Comerford converter	Summer, Light	690 MW
Comerford converter	Winter, Light	690 MW
Comerford & Sandy Pond converters	All	2,000 MW

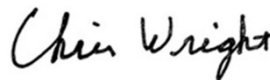
- (p) Exports by Research Power Corporation made pursuant to this Order over the international transmission facilities authorized by Presidential Permit PP-399 (issued to Montana Alberta Tie Ltd.) shall not exceed an instantaneous transmission rate of 300 MW.
- (q) Exports by Research Power Corporation made pursuant to this Order over the international transmission facilities authorized by Presidential Permit PP-438 (issued to NECEC Transmission LLC) shall not exceed an instantaneous transmission rate of 1,200 MW.
- (r) Exports by Research Power Corporation made pursuant to this Order over the international transmission facilities authorized by Presidential Permit PP-299

(issued to Sea Breeze Olympic Converter LP) shall not exceed an instantaneous transmission rate of 550 MW.

- (s) Exports by Research Power Corporation made pursuant to this Order shall not cause the total exports on a combination of the facilities authorized by Presidential Permit PP-400 (issued to TDI-New England) to exceed an instantaneous transmission rate of 1,000 MW.
 - (t) Exports by Research Power Corporation made pursuant to this Order shall neither cause the total exports on the facilities authorized by Presidential Permit PP-82-6 (issued to Vermont Transco LLC) to exceed an instantaneous transmission rate of 250 MW.
- (B) Changes by DOE to the export limits in other orders shall result in a concomitant change to the export limits contained in subparagraph (A)(2) of this Order. Changes to the export limits contained in subparagraphs (A)(2)(l), (m), and (n) will be made by DOE after submission of appropriate information demonstrating a change in the transmission transfer capability between the electric systems in New York State and Ontario and New York State and Quebec, and between BPA and BC Hydro or BPA and West Kootenay Power. Notice of these changes will be provided to Research Power Corporation.
- (C) Research Power Corporation shall obtain any and all other Federal and state regulatory approvals required to execute any power exports to Canada. The scheduling and delivery of electricity exports to Canada shall comply with all reliability criteria, standards, and guidelines of NERC, reliability coordinators, Regional Entities, RTOs, ISOs or balancing authorities, or their successors, as appropriate, on such terms as expressed therein, and as such criteria, standards, and guidelines may be amended from time to time.
- (D) Exports made pursuant to this authorization shall be conducted in accordance with the applicable provisions of the FPA and any pertinent rules, regulations, directives, policy statements, and orders adopted or issued thereunder, including the comparable open access provisions of FERC Order No. 888, as amended.
- (E) The authorization herein granted may be modified from time to time or terminated by further order of DOE. In no event shall such authorization to export over a particular transmission facility identified in subparagraphs (A)(1) and (2) extend beyond the date of termination of the Presidential permit or treaty authorizing such facility.
- (F) This authorization shall be without prejudice to the authority of any state or state regulatory commission for the exercise of any lawful authority vested in such state or state regulatory commission.
- (G) Research Power Corporation shall make and preserve full and complete records with respect to the electric energy transactions between the United States and Canada. Research Power Corporation shall collect and submit the data to EIA as required by and in accordance with the procedures of Form EIA-111, "Quarterly Electricity Imports and Exports Report," and all successor forms.

- (H) In accordance with 10 C.F.R. § 205.305, this export authorization is not transferable or assignable, except in the event of involuntary transfer by operation of law. Provided written notice of the involuntary transfer is given to DOE within 30 days, this authorization shall remain in effect temporarily. The authorization shall terminate unless an application for a new export authorization has been received by DOE within 60 days of the involuntary transfer. Upon receipt by DOE of such an application, this existing authorization shall continue in effect pending a decision on the new application. In the event of a proposed voluntary transfer of this authority to export electricity, the transferee and the transferor shall file a joint application for a new export authorization, together with a statement of the reasons for the transfer.
- (I) Nothing in this Order is intended to prevent the transmission system operator from being able to reduce or suspend the exports authorized herein, as necessary and appropriate, whenever a continuation of those exports would cause or exacerbate a transmission operating problem or would negatively impact the security or reliability of the transmission system.
- (J) Research Power Corporation has a continuing obligation to give DOE written notification as soon as practicable of any prospective or actual changes of a substantive nature in the circumstances upon which this Order was based, including but not limited to changes in authorized entity contact information or NERC compliance registry status.
- (K) This authorization shall be effective as of October 21, 2025 and shall remain in effect for a period of five (5) years from that date. Application for renewal of this authorization may be filed within six (6) months prior to its expiration. Failure to provide DOE with at least one hundred and twenty (120) days to process a renewal application and provide adequate opportunity for public comment may result in a gap in Research Power Corporation's authority to export electricity.

Issued in Washington, D.C., on October 21, 2025.



Chris Wright
Secretary of Energy
U.S. Department of Energy