TYPICAL SULFUR DIOXIDE EMISSIONS FROM SUBPART D POWER PLANTS FIRING COMPLIANCE COAL

PEDCo ENVIRONMENTAL

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SUMMARY AND CONCLUSIONS

On December 23, 1971, the U.S. Environmental Protection Agency (EPA) adopted New Source Performance Standards (NSPS) for fossil-fuel-fired steam generators that had a heat input greater than 250 x 10^6 Btu/h and which commenced construction after August 17, 1971. The standards limited emissions of sulfur dioxide (SO_2), particulate matter, and nitrogen oxides. Coal-fired steam-generating units at electric utilities are the most significant type of fossil-fuel-fired steam generating units covered under Subpart D.

The purpose of this study was to determine the typical SO_2 emission rates from electric utility steam-generating units firing compliance coal. Before the typical SO_2 emission rates could be determined, an inventory of coal-fired Subpart D units had to be developed. The initial inventory included power plants firing compliance coal and power plants operating flue gas desulfurization (FGD) systems to comply with the Subpart D SO_2 emission standard.

This study identified 140 coal-fired electric utility steam generating units subject to Subpart D that were operating at the end of 1983. The 140 units were divided into two groups. The first group included 78 units that were firing compliance coal, and the second group included 62 units that were operating FGD systems (Table 1). Because continuous SO_2 emission monitoring data were not readily available for many of the 78 compliance coal units, Department of Energy (DOE) monthly coal sulfur content data from January 1982 through June 1983 were used to determine the SO_2 emissions for a subset of the 78 compliance coal units (i.e., this included 49 units where all units at a plant site were subject to Subpart D).

For the compliance-coal-fired units analyzed, 18 months of fuel quality data were reviewed for each power plant. The individual monthly SO_2 emission levels ranged from 0.51 lb $SO_2/10^6$ Btu for one Western power plant to 1.32 lb $SO_2/10^6$ Btu for one Eastern power plant. The 18-month (long-term) average emission levels ranged from 0.60 lb $SO_2/10^6$ Btu to 1.04 lb $SO_2/10^6$ Btu. The

TABLE 1. SUMMARY OF COAL-FIRED SUBPART D UTILITY UNITS[a]

Technology	Number of units
FGD	62
Compliance coal	78[b]
Total	140

[a]Operating as of June 1983.

[b]DOE data are only available on a plant total "as received" basis. The subset analyzed include Subpart D units where all units at a plant were Subpart D units (i.e., 49 out of the 78 compliance coal-fired units were included in the subset analysis).

long-term average emission rate for the compliance-coal-fired units was 0.84 lb $SO_2/10^6$ Btu; the Western units averaged 0.81 and the Eastern units averaged 0.88 lb $SO_2/10^6$ Btu (Table 2).

TABLE 2. SUMMARY OF MONTHLY SO_2 EMISSION LEVELS AT SUBPART D COMPLIANCE-COAL-FIRED UTILITY UNITS

Power plant location	SO_2 emissions, lb/10^6 Btu[b]		
	Minimum month	Maximum month	18-month average
East	0.58	1.32	0.88
West	0.51	1.19	0.81
National	0.51	1.32	0.84

[a]Analysis included 49 compliance-coal-fired units.

[b]Assumes 95 percent of the sulfur is converted to SO_2.

Based on the 18 month average SO_2 emission rates, statistical projections were made for the 3-h, 24-h, 7-day (rolling), and 30-day (rolling) average SO_2 emissions that would be expected at each of the Subpart D units analyzed. The following statistical assumptions were used to project or estimate the 3-h, 24-h, 7-day, and 30-day average SO_2 emissions given the monthly SO_2 emission level: 1) the 1-h emission levels can be represented by an AR(1) process, b) the emission levels are normally distributed, c) the relative standard deviation (RSD) of a rolling average can be estimated by the RSD of the 1-h time series, d) the autocorrelation of the rolling average time series can be estimated from the autocorrelation of the 1-h time series, and e) the 18 month average is equivalent to the long-term mean.

Based on these statistical assumptions, the maximum estimated 3-h, 24-h, 7-day, and 30-day average SO_2 emission levels were projected for each of the Subpart D units analyzed. The maximum projected 3-h average emissions ranged from 0.79 to 2.03 lb $SO_2/10^6$ Btu; the maximum projected 24-h average emissions ranged from 0.76 to 1.76 lb $SO_2/10^6$ Btu; the 7-day rolling average SO_2 emissions ranged from 0.69 to 1.39 lb $SO_2/10^6$ Btu; and the 30-day rolling average SO_2 emissions ranged from 0.65 to 1.22 lb $SO_2/10^6$ Btu. These projections assumed a 24-h autocorrelation of 0.7, a range of RSD's (10, 15, and 20%) and a range of compliance levels (1 exceedance in 10 year, 1 exceedance per year and 99% of the time). A review of these projections indicates that the projections are very sensitive to the statistical assumptions.

Based on the preceding statistical assumptions, several calculations were performed to estimate the long-term SO_2 emissions in lb/10^6 Btu that would be required to meet the Subpart D emission limit of 1.2 lb $SO_2/10^6$ Btu on a 3-h, 24-h, 7-day, and 30-day basis. The results of these calculations indicated that with an RSD of 20 percent and a 24-h autocorrelation 0.7, annual SO_2 emissions would have to be equal to or less than 0.62 lb/10^6 Btu for the unit not to exceed the 1.2 lb/10^6 Btu on a 3-h average more than once in 10 years. The annual SO_2 emissions could be as high as 0.77 lb/10^6 Btu if the unit were permitted to exceed the 3-h limit 29 times per year (99% compliance level). The annual SO_2 emissions necessary to meet the 1.2 lb/10^6 Btu standard on a 3-h basis varied from 0.56 to 0.95 lb/10^6 Btu, depending on the assumed RSD (10, 15, or 20%), 24-h autocorrelation (0.5, 0.7, or 0.8), and whether the unit would be permitted to exceed the limit 29 times per year, once per year or only once in 10 years. The annual SO_2 emissions necessary to meet the 1.2 lb/10^6 Btu standard on a: 24-h basis varied from 0.71 to 0.97 lb/10^6 Btu; 7-day rolling average varied from 0.87 to 1.09 lb/10^6 Btu; and 30-day rolling average varied from 1.00 to 1.14 lb/10^6 Btu depending on the RSD and 24-h autocorrelation that were assumed and whether the unit would be permitted to exceed the limit 4 times per year, once per year, or only once in 10 years.

The above variation in the annual emission limits clearly points out that the ability of a given unit to meet a limit of the 1.2 $lb/10^6$ Btu on a 3-h basis depends a great deal on the variability of the coal sulfur content at the particular plant, the distribution of the emission values, and whether the enforcement policy permits 29 exceedances per year (99% compliance), one exceedance per year or one exceedance in 10 years. A sensitivity analysis was conducted to quantify the extent of this variation and it pointed out that the annual SO_2 emission levels required to meet the 1.2 $lb/10^6$ Btu standard on a 3-h basis could vary from 0.52 $lb/10^6$ Btu (assuming lognormal distribution of data, a 24-h RSD of 20%, 24-h autocorrelation of 0.5, and one permitted exceedance in 10 years) to 0.95 $lb/10^6$ Btu (assuming normal distribution of data, 24-h RSD of 10%, 24-h autocorrelation of 0.8, and 29 exceedances are permitted per year).

The sensitivity analysis also pointed out that the annual SO_2 emission levels required to meet the 1.2 $lb/10^6$ Btu standard on a 24-h basis could vary from 0.67 $lb/10^6$ Btu (assuming that the data are lognormally distributed, 24-h RSD equal 20%, 24-h autocorrelation equals 0.5, and one permitted exceedance in 10 years) to 0.97 $lb/10^6$ Btu (assuming that the data are normally distributed, 24-h RSD equals 10%, 24-h autocorrelation equals 0.8 and 29 exceedances are permitted per year).

SECTION 2

INTRODUCTION

2.1 BACKGROUND

On December 23, 1971, EPA promulgated NSPS for large fossil-fuel-fired steam-generating units (36 FR 24876; 40 CFR Part 60, Subpart D). The standards limit emissions of SO_2, particulate matter, and nitrogen oxides. The SO_2 emission standard for coal is 520 ng/J (1.2 lb per million Btu) heat input; for fuel oil it is 340 ng/J (0.8 lb SO_2, per million Btu) heat input. The SO_2 standard can be met by the use of low sulfur fuels, FGD, or a combination of the two. Subpart D also required the installation and operation of continuous SO_2 emission monitors for FGD equipped units. Continuous SO_2 monitors were not required for facilities using compliance fuel provided fuel sampling and analysis were conducted. The fuel sampling and analysis provisions, however, were reserved in the October 6, 1975 promulgation and were not proposed until October 21, 1983.

When EPA proposed emission standards for large fossil-fuel-fired steam generating units in 1971, EPA indicated that plants could comply with the 520 ng/J (1.2 lb SO_2 per million Btu) emission limit for coal-fired units by using either an FGD system or low-sulfur coal. During the development of the standard, EPA reviewed U.S. coal reserve data to determine the potential impacts of the standard on compliance-coal reserves. As indicated in the background document for the 1971 standard, a high-grade coal with a sulfur content of 0.7 percent or less was judged capable of complying with the standard.

Many facilities subject to Subpart D have elected to use compliance fuel. A survey conducted by EPA in 1978 indicated that approximately 200 coal-fired electric utility boilers subject to Subpart D would begin operation by 1983. Approximately one-half of these planned to use compliance coal; the other half planned to use FGD systems.

In their proposal on October 21, 1983, to complete the SO_2 emission monitoring and fuel sampling and analysis provisions, EPA addressed the appropriate averaging time for enforcing the SO_2 emission standard. The issue of averaging time for the SO_2 standard relates to both the variability of sulfur content of the coal and FGD performance. With regard to compliance coals, the variability of sulfur has been addressed in various EPA studies since 1975. From these studies, it is clear that coal is not homogeneous and that the sulfur content of coal used in a steam generator can vary even when the coal is supplied from the same mine. In addition to geological properties, other factors that affect coal sulfur content variability include mining practices, coal preparation procedures, onsite coal handling procedures (including the onsite mixing of coal from various suppliers), and the chemical characteristics of the coal. These factors can interact and result in complex sulfur variability patterns that are difficult for boiler operators to predict or manage on a short-term basis.

The purpose of this study was to identify units subject to Subpart D that use compliance coal and to determine the typical SO_2 emission levels from the compliance coal-fired electric utility steam generating units subject to Subpart D. The first step in this study was to develop a list of coal-fired electric utility steam generating units subject to Subpart D. The initial list included all coal-fired utility units subject to Subpart D (compliance coal and FGD). This list was then refined to identify those units using compliance coal prior to estimating the typical SO_2 emission levels from the compliance coal units.

2.2 METHODOLOGY

An initial review of available Subpart D data indicated that SO_2 emission data from continuous emission monitoring (CEM) devices were not readily available for a majority of units (i.e., CEM's were not installed on many compliance coal-fired units). The initial review also indicated that no general list of Subpart D units existed. Because CEM data and a list of Subpart D units were generally unavailable, other available emission data bases were investigated that would permit a timely identification of Subpart D units and an estimation of the typical SO_2 emission levels. A review of the available data bases indicated that DOE maintains an up-to-date inventory of power plants in the United States and publishes a summary of the monthly fuel data for all plants. Thus, the DOE data base was selected for use in this study.

Based on the DOE power plant inventory data, a list of coal-fired power plants with a startup date after 1975 was developed. This assumes a 4-year period between initial commencement of construction (1971) and startup. The list of compliance-coal-fired (Subpart D) units was further refined by removing those that were identified as being equipped with FGD systems. The revised list of Subpart D units was verified by comparing it against data submitted by the EPA Regional Offices and EPA's Flue Gas Desulfurization Information System (FGDIS).

After the list of Subpart D units was verified, the SO_2 emission levels from each unit were determined. Because DOE only maintains "as received" monthly fuel data on a total plant basis, a subset of Subpart D units was developed in which all units at a plant site were subject to Subpart D; thus, the plant average "as received" data would be representative of Subpart D emissions. This further refinement was necessary because at power plant sites where some units are subject to Subpart D and others are subject to SIP regulations, the plant average "as received" fuel data would overestimate the Subpart D emissions. The following example illustrates this point. If a power plant has two units (one a Subpart D unit and one an SIP unit) and the plant average sulfur content is 1 percent, use of the 1 percent sulfur content to calculate the emissions from the Subpart D unit would indicate that the SO_2 emissions would be in excess of the allowable Subpart D SO_2 standard. Actually, however, the Subpart D unit could have an average sulfur content of 0.5 percent and the SIP unit an average sulfur content of 1.5 percent. Thus, the emission levels of both units would be consistent with those allowed under Subpart D and the SIP, even though the average plant emissions would be in excess of 1.2 lb $SO_2/10^6$ Btu.

After the subset list of Subpart D was prepared, 18 months of monthly "as received" fuel data were tabulated for each of the power plants. These data were used to calculate both the monthly and long-term (18-month) SO_2 emission levels for each of the power plants in the subset of Subpart D units.

The 3-hour, 24-hour, 7-day rolling, and 30-day rolling average SO_2 emission levels were projected by use of the statistical approach outlined in the October 21, 1983 proposal and the following statistical assumptions: 1) the unknown 1-h emission levels at each plant (unit) can be represented by an AR(1) process with an arithmetic mean μ, relative deviation RSD_1, and an autocorrelation ρ; 2) the arithmetic means of the associated 3-h, 24-h, 7-day (168-h), and 30-day (720-h) average values are also equal to μ; 3) the distribution of the 3-h, 24-h, 7-day rolling, and 30-day rolling average values are normal; 4) the RSD of the 30-day rolling average values is equal to that of the monthly average values for the same period; 5) the RSD of a rolling average of length n can be estimated from the RSD of the 1-h time series; and 6) the autocorrelation of the rolling average time series can be estimated from the autocorrelation of the 1-h time series. The use of a full range of statistical assumptions resulted in a range of projected 3-h, 24-h, 7-day rolling, and 30-day rolling average SO_2 emission levels. The actual 3-h, 24-h, 7-day, and 30-day rolling average SO_2 emission levels occurring at a particular Subpart D unit will depend on the actual SO_2 emission variability at the unit in question.

SECTION 3

SURVEY OF COAL-FIRED SUBPART D UNITS

As noted in Section 2, the first task in this study was to identify coal-fired electricity utility steam generators subject to Subpart D. This included units with and without FGD systems (i.e., those burning compliance coal).

3.1 IDENTIFICATION OF POTENTIAL SUBPART D UNITS

The basic references used to identify those steam generators that are subject to Subpart D were a DOE Inventory of Power Plants in the United States - 1981 Annual[1] and the first condensed version of the Inventory of Power Plants in the United States - 1982 Annual.[2]

The 1981 and 1982 Annual Inventories of Power Plants in the United States are prepared by the Electric Power Division; Office of Coal, Nuclear, Electric and Alternate Fuels; Energy Information Administration; DOE. These reports represent a compilation of data obtained from the following forms:

- o Form EIA-759, Monthly Power Plant Report
- o FPC Form 12, Annual Power Systems Statement
- o EP Form 411, Regional Reliability Council Coordinated Bulk Power Supply Program
- o Form EIA-119A, Annual Projection of System Changes
- o Form EIA-767, Steam Electric Plant Air and Water Quality Control Data.

The data from these forms were used to prepare a summary of the electric generating units by State, company, plant, and county, which was reviewed to identify potential Subpart D units. Figure 1 is an example of the information contained in the Annual inventories.

Although the Inventory of Power Plants in the United States contains a great deal of information, it does not contain any information that would

Electric Generating Units (continued)

Table 7. Electric Generating Units by State, Company, Plant, and County (Continued)

State / Company / Plant / County	Unit Number	Nameplate Rating MW	Unit Type	Primary Energy Source	Alternate Energy Source	In Service Date	Jointly Owned
ALABAMA —Cont.							
SO CO:ALABAMA POWER CO —Cont.							
JORDAN							
ELMORE	1	25.0	HY	WATER	NONE	1928	NO
	2	25.0	HY	WATER	NONE	1928	NO
	3	25.0	HY	WATER	NONE	1928	NO
	4	25.0	HY	WATER	NONE	1928	NO
LAY DAM							
CHILTON	1	30.0	HY	WATER	NONE	1968	NO
	2	30.0	HY	WATER	NONE	1968	NO
	3	30.0	HY	WATER	NONE	1967	NO
	4	30.0	HY	WATER	NONE	1967	NO
	5	30.0	HY	WATER	NONE	1967	NO
	6	30.0	HY	WATER	NONE	1967	NO
LEWIS SMITH DAM							
WALKER	1	79.0	HY	WATER	NONE	1961	NO
	2	79.0	HY	WATER	NONE	1962	NO
LOGAN MARTIN DAM							
TALLADEGA	1	43.0	HY	WATER	NONE	1964	NO
	2	43.0	HY	WATER	NONE	1964	NO
	3	43.0	HY	WATER	NONE	1964	NO
MARTIN DAM							
ELMORE	1	33.0	HY	WATER	NONE	1926	NO
	2	33.0	HY	WATER	NONE	1926	NO
	3	33.0	HY	WATER	NONE	1926	NO
	4	55.0	HY	WATER	NONE	1952	NO
MILLER							
JEFFERSON	1	705.5	ST	BIT	NONE	1978	NO
MITCHELL DAM							
COOSA	1	18.0	HY	WATER	NONE	1923	NO
	2	18.0	HY	WATER	NONE	1923	NO
	3	18.0	HY	WATER	NONE	1923	NO
	4	20.0	HY	WATER	NONE	1949	NO
THURLOW DAM							
ELMORE	1	25.0	HY	WATER	NONE	1930	NO
	2	25.0	HY	WATER	NONE	1930	NO
WEISS DAM							
CHEROKEE	1	29.0	HY	WATER	NONE	1962	NO
	2	29.0	HY	WATER	NONE	1961	NO
	3	29.0	HY	WATER	NONE	1961	NO
YATES DAM							
ELMORE	1	16.0	HY	WATER	NONE	1928	NO
	2	16.0	HY	WATER	NONE	1928	NO
SOUTHEASTERN POWER ADM							
JONES BLUFF							
AUTAUGA	1	17.0	HY	WATER	NONE	1975	NO
	2	17.0	HY	WATER	NONE	1975	NO
	3	17.0	HY	WATER	NONE	1975	NO
	4	17.0	HY	WATER	NONE	1975	NO
TENNESSEE VALLEY AUTHORITY							
BROWNS FERRY							
LIMESTONE	1	1152.0	NB	URAN	NONE	1974	NO
	2	1152.0	NB	URAN	NONE	1975	NO
	3	1152.0	NB	URAN	NONE	1977	NO
COLBERT							
COLBERT	1	200.0	ST	BIT	NONE	1955	NO
	2	200.0	ST	BIT	NONE	1955	NO
	3	200.0	ST	BIT	NONE	1955	NO
	4	200.0	ST	BIT	NONE	1955	NO
	5	550.0	ST	BIT	NONE	1965	NO
	GT1	60.0	GT	NG	FO2	1972	NO
	GT2	60.0	GT	NG	FO2	1972	NO
	GT3	60.0	GT	NG	FO2	1972	NO
	GT4	60.0	GT	NG	FO2	1972	NO
	GT5	60.0	GT	NG	FO2	1972	NO
	GT6	60.0	GT	NG	FO2	1972	NO
	GT7	60.0	GT	NG	FO2	1972	NO

Inventory of Power Plants in the United States
1981 Annual
Energy Information Administration

Figure 1. Example of Table 7 from 1981 Annual report.[1]

directly indicate whether a particular unit at a given plant would be subject to the Subpart D (NSPS) requirements. For this reason, an indirect method was used to identify those units that could be subject to Subpart D. The Subpart D requirements published in 1971 indicated that a unit greater than 250 x 10^6 Btu/h heat input capacity [≈23 megawatt electric output capacity (MW_e)] would be subject to the requirements unless it had commenced construction prior to the publication of the Subpart D requirements. Therefore, all units larger than 250 x 10^6 Btu/h that commenced construction after 1971 would be subject to the Subpart D requirements. Because it can take 4 years or more for a unit to be constructed and placed in service, it was assumed that all units greater than 23 MW_e with an in-service data of 1975 or later would be subject to Subpart D. It should be noted, however, that it may now take from 5 to 8 years for some units to be constructed and placed in service.

Next, the list was compared with available EPA enforcement survey information to ensure consistency. Differences were resolved through contacts with the EPA Regional Offices. This procedure identified units with an in-service date as late as 1979 that were not subject to the Subpart D requirements; however, this was the exception, not the rule.

3.2 VERIFICATION OF SUBPART D UNITS

Appendices A and B present listings of coal-fired power plants, based on the 1981 and 1982 Inventory of Power Plants, where units have an in-service date later than 1975 and an electrical output greater than 23 MW_e (i.e., those that are potentially subject to the Subpart D requirements). Appendix A lists coal-fired power plants where all units at the power plant site are Subpart D units. Appendix B lists coal-fired power plants where both Subpart D and SIP units are located at the power plant site. These listings of potential coal-fired Subpart D utility units were compared with information contained in EPA's Compliance Data System (CDS), which is designed to include information on the major stationary sources in the United States, to confirm whether a given unit was subject to Subpart D. The data in CDS are provided by the 10 EPA Regional Offices and the State and local air pollution control agencies. The EPA Regional Offices were contacted via telephone to confirm any units not contained in CDS. The units verified to be subject to Subpart

D based on information contained in CDS are noted with the footnote "d;" those units verified to be subject to Subpart D based on information available from the EPA Regional Offices are noted with the footnotes "f" (Appendix A) and "e" (Appendix B). Appendices A and B contain information on the 140 coal-fired Subpart D utility units that were identified. The 140 units were located at 99 power plants. Figure 2 is an example of the Appendix A listing. Figure 3 is an example of the Appendix B listing.

APPENDIX A

LISTING OF COAL-FIRED POWER PLANTS WITH ALL SUBPART D (NSPS) UNITS (COMPLIANCE COAL AND FGD)[a,b]

Company name	Plant	County	State	Unit number	Capacity, MWe	In service date[a]	Plant location[c]		FGD used	
							E	W	Yes	No
Alabama Power	Miller	Jefferson	AL	1	705.5[d]	1978	x			x
Arizona Electric Power Coop., Inc.	Apache Station	Cochise	AZ	2	194.7[d]	1979		x	x	
				3	204.0[d]	1979		x	x	
Salt River Proj. Agri. Imp. Power Dist.	Coronado	Apache	AZ	1	410.9[d]	1979		x	x	
				2	410.9[d]	1980		x	x	
Arkansas Power and Light Co.	White Bluff	Jefferson	AR	1	800.0[d]	1980	x			x
				2	800.0[d]	1981	x			x
Southwestern Elec. Power Co.	Flint Creek	Benton	AR	1	512.3[d]	1978	x			x
Colorado Springs, City of	Ray D. Nixon	El Paso	CO	1	207.0[d]	1980		x		x
Colorado - UTE Elec. Assn., Inc.	Craig	Moffat	CO	1	447.0[d]	1980		x	x	
				2	447.0[d]	1979		x	x	
Public Service Co. of Colorado	Pawnee	Morgan	CO	1	507.0[d]	1981		x		x
Lakeland, City of Dept. of Electric and Water	Mcintosh, C.D.	Polk	FL	3	364.0[d]	1982	x		x[e]	
Georgia Power Co.	Scherer	Heard	GA	1	891.0[d]	1982	x			x
	Wansley	Heard	GA	1	952.0	1976	x			x
				2	952.0	1978	x			x

[a]Listing only includes Subpart D units located at power plants with all Subpart D units with in-service date of 1975-1982 and a capacity ≥ 23 MWe. Plant sites with both Subpart D and SIP units are not included.

[b]Reference: Inventory of power plants in the United States 1981 and 1982 Annual - DOE and Cost and Quality of Fuels for Electric Utility Plants - DOE.

[c]Eastern locations includes units located in all States east of the Mississippi River and one State west of the Mississippi River. E = Eastern and W = Western.

[d]Subject to Subpart D as listed in EPA's Compliance Data System (CDS).

[e]Per Flue Gas Desulfurization Information System (FGDIS).

[f]Subject to Subpart D per telephone conversation with EPA Regional Office.

Figure 2. Example of Appendix A listing.

APPENDIX B

LISTING OF COAL-FIRED POWER PLANTS WITH BOTH SIP AND SUBPART D (NSPS) UNITS[a,b]

Company name	Plant	County	State	Unit number	Capacity, MWe	In service date	Plant location[c] E	Plant location[c] W	FGD used Yes	FGD used No
Alabama Electric Corp., Inc.	Tombigbee	Washington	AL	1	75	1969	x			x
				2	235[d]	1978	x		x	
				3	235[d]	1980	x		x	
Arizona Public Service Company	Cholla	Navajo	AZ	1	113.6	1962		x	x	
				2	288.9[d]	1978		x	x	
				3	288.9[d]	1980		x		x
				4	414.0[d]	1981		x	x	
Salt River PROJ AGRI IMP PMR DIST	Navajo	Coconino	AZ	1	803.0	1974		x		x
				2	803.0	1975		x		x
				3	803.0	1976		x		x
Colorado-UTE Electric Assn., Inc.	Hayden	Routt	CO	1	190.0	1965		x		x
				2	275.4[d]	1976		x		x
Public Service Company of Colorado	Comanche	Pueblo	CO	1	382.5	1973		x		x
				2	396.0[d]	1976		x		x
Delmarva Power and Light Company of Delaware	Indian River	Sussex	DE	1	81.6	1957	x			x
				2	81.6	1959	x			x
				3	176.8	1970	x			x
				4	403.0[d]	1980	x			x
Florida Power Corp.	Crystal River	Citrus	FL	1	440.5	1966	x			x
				2	523.8	1969	x			x
				4	793.3[d]	1982	x			x
Gainsville-Alachua Company	Deerhaven	Alachua	FL	1	83.0	1972	x			x
				2	243.0[d]	1981	x			x

[a]Listing includes plants with both Subpart D (units with in-service date of 1975 to 1982 and a capacity $\geq$23 MWe) and SIP units. Units marked with footnote "d" or "e" are subject to Subpart D and units that are unmarked are subject to SIP requirements.

[b]References: "Inventory of Power Plants in the United States 1981 and 1982 Annual" and "Cost and Quality of Fuels for Electric Utility Plants."

[c]Eastern locations include units located in all states east of and one state west of the Mississippi River.

[d]Subject to Subpart D as listed in EPA's compliance data system (CDS).

[e]Subject to Subpart D per telephone conversation with EPA Regional Office.

Figure 3. Example of Appendix B listing.

SECTION 4

MONTHLY SULFUR DIOXIDE EMISSIONS

As noted in Section 2, the second task was to determine monthly average SO_2 emissions. Calculation of SO_2 emissions from a coal-fired Subpart D unit require information on the quantity and quality of the coal being burned in each unit. The Office of Coal, Nuclear, Electric, and Alternate Fuels (DOE) is responsible for collecting, reviewing, and summarizing the information on the cost and quality of fuels for electric utility plants. This information is presented in the Federal Power Commission (FPC) Form 423, which is a monthly record of each fuel purchase delivered to electric power generation plants with a combined fossil-fuel capacity of 25 megawatts or larger. The FPC Form 423 is submitted by approximately 281 electric utilities. Data from FPC Form 423 are reviewed, verified, and summarized in the Cost and Quality of Electric Utility Plants Fuels - Monthly[3] (published through the end of 1982) and the Electric Power Quarterly[4], which succeeded the no-longer-published Cost and Quality of the Electric Utility Plants Fuels - Monthly. Data in both of these publications are presented on a plant-by-plant basis. The data of interest for the purpose of calculating SO_2 emissions are:

- o Plant type
- o Fuel type
- o Quantity (heat content): average Btu content
- o Quantity (sulfur content): sulfur content (percentage by weight)
- o Quantity (cost): cents per million Btu.

Figure 4 is an example of Table 33 from the Cost and Quality of Fuels for Electric Utility Plants - Monthly, which summarizes information used to calculate the SO_2 emissions from the Subpart D units.

Because this table only contains monthly information on a plantwide basis (DOE does not report unit-by-unit data), the information should not be used for

TABLE 33. Quantity, Cost, and Quality of Fossil Fuel Receipts by Company and Plant, April 1982

Company Plant (State)	Coal				Oil				Gas			% of Total Btu		
	Quantity 1000 tons	¢ per 10^6 Btu	$ per Ton	% Avg. Sulfur	Quantity 1000 Bbls	¢ per 10^6 Btu	$ per Bbl	% Avg. Sulfur	Quantity 1000 Mcf	¢ per 10^6 Btu	$ per Mcf	Coal	Oil	Gas
Alabama Elec Coop Inc	57.3	196.1	46.22	1.48	-	-	-	-	0.5	445.2	4.58	100	-	*
Tombigbee (AL)	56.9	196.0	46.20	1.48	-	-	-	-	-	-	-	100	-	-
Mc Williams (AL)	.3	202.2	48.58	1.86	-	-	-	-	.5	445.2	4.58	94	-	6
Alabama Power Co (SC)	972.1	195.9	47.34	1.19	8.3	668.6	38.78	0.27	104.1	303.8	3.46	99	*	1
Barry (AL)	-	-	-	-	.2	656.1	37.91	.23	102.2	302.2	3.45	-	1	99
Gadsden (AL)	6.7	211.1	52.97	1.02	.2	663.1	38.33	.25	1.9	398.8	4.12	98	1	1
Gorgas 2 and 3 (AL)	466.1	189.8	46.33	.92	4.0	671.8	39.01	.28	-	-	-	100	*	-
Greene (AL)	38.5	236.1	58.22	1.57	1.5	663.3	38.56	.24	-	-	-	99	1	-
Gaston (AL)	376.1	188.1	44.50	1.62	.8	670.5	38.87	.34	-	-	-	100	*	-
James Miller (AL)	84.8	242.3	60.10	.60	1.7	666.7	38.52	.23	-	-	-	100	*	-
Alexandria, City of	-	-	-	-	-	-	-	-	366.6	390.6	4.08	-	-	100
Alexandria-Hunter (LA)	-	-	-	-	-	-	-	-	366.6	390.6	4.08	-	-	100
Ames, City of	18.0	188.5	32.01	.58	2.1	655.5	37.80	.04	*	394.0	3.94	96	4	*
Ames (IA)	18.0	188.5	32.01	.58	2.1	655.5	37.80	.04	*	394.0	3.94	96	4	*
Appalachian Power (AEP)	969.7	204.7	49.10	.73	-	-	-	-	-	-	-	100	-	-
Clinch River (VA)	104.3	184.6	44.16	.72	-	-	-	-	-	-	-	100	-	-
Glen Lyn (VA)	33.1	185.9	44.57	.86	-	-	-	-	-	-	-	100	-	-
Amos (WV)	505.9	221.5	52.95	.79	-	-	-	-	-	-	-	100	-	-
Kanawha River (WV)	82.6	168.7	38.89	.75	-	-	-	-	-	-	-	100	-	-
Mountaineer (WV)	243.8	193.0	47.32	.60	-	-	-	-	-	-	-	100	-	-
Arizona Elec Power Coop Inc	88.4	260.6	50.34	.46	-	-	-	-	231.3	354.9	3.72	88	-	12
Apache (AZ)	88.4	260.6	50.34	.46	-	-	-	-	231.3	354.9	3.72	88	-	12
Arizona Pub Serv	744.7	88.5	16.40	.68	24.4	527.9	33.04	.51	579.0	376.5	4.03	95	1	4
Cholla (AZ)	309.0	120.7	24.06	.47	-	-	-	-	2.3	305.0	2.82	100	-	*
Ocotillo (AZ)	-	-	-	-	-	-	-	-	364.1	377.0	4.05	-	-	100
Phoenix (AZ)	-	-	-	-	24.4	527.9	33.04	.51	5.9	382.0	4.04	-	96	4
Saguaro (AZ)	-	-	-	-	-	-	-	-	63.8	382.0	4.00	-	-	100
Yucca (AZ)	-	-	-	-	-	-	-	-	9.2	379.0	4.00	-	-	100
Four Corners (NM)	435.7	62.5	10.97	.83	-	-	-	-	113.7	372.0	4.02	98	-	2
Arkansas Elec Coop	-	-	-	-	-	-	-	-	77.7	318.2	3.30	-	-	100
Fitzhugh (AR)	-	-	-	-	-	-	-	-	.1	318.2	3.22	-	-	100
Bailey (AR)	-	-	-	-	-	-	-	-	.3	318.2	3.22	-	-	100
Mcclellan (AR)	-	-	-	-	-	-	-	-	77.3	318.2	3.30	-	-	100
Arkansas Power and Lt (MSU)	356.6	188.7	32.11	.44	8.9	656.0	38.43	.34	1,664.8	283.4	2.92	77	1	22
Lynch (AR)	-	-	-	-	*	636.0	38.11	.30	114.7	322.0	3.27	-	*	100
Moses (AR)	-	-	-	-	*	674.0	38.04	.30	168.2	319.0	3.24	-	*	100
Couch (AR)	-	-	-	-	-	-	-	-	426.3	178.2	1.90	-	-	100
Lake Catherine (AR)	-	-	-	-	-	-	-	-	122.9	319.0	3.24	-	-	100
Mabelvale (GT) (AR)	-	-	-	-	-	-	-	-	.1	322.0	3.25	-	-	100
Ritchie (AR)	-	-	-	-	-	-	-	-	812.5	322.0	3.29	-	-	100
Whitebluff (AR)	356.6	188.7	32.11	.44	8.8	656.0	38.43	.34	-	-	-	99	1	-
Assoc Elec Coop-Missouri	382.5	156.2	33.29	3.33	-	-	-	-	-	-	-	100	-	-
Madrid (MO)	306.6	163.2	34.95	3.17	-	-	-	-	-	-	-	100	-	-
Hill (MO)	75.9	127.0	26.56	3.99	-	-	-	-	-	-	-	100	-	-
Atlantic City Elec	67.3	176.7	45.13	2.79	151.3	430.9	26.91	1.83	-	-	-	65	35	-
England (NJ)	67.3	176.7	45.13	2.79	147.9	423.0	26.47	1.87	-	-	-	65	35	-
Caroll Comr (GT) (NJ)	-	-	-	-	1.4	805.3	45.96	.01	-	-	-	-	100	-
Cedar Sta (GT) (NJ)	-	-	-	-	1.8	809.4	46.19	.01	-	-	-	-	100	-
Missouri Avenue (NJ)	-	-	-	-	.2	808.3	46.13	.01	-	-	-	-	100	-
Austin Elec Dept, City of	-	-	-	-	-	-	-	-	3,233.4	408.6	4.10	-	-	100
Decker Creek (TX)	-	-	-	-	-	-	-	-	1,467.7	407.0	4.11	-	-	100
Holly (TX)	-	-	-	-	-	-	-	-	1,749.2	410.0	4.10	-	-	100
Seaholm (TX)	-	-	-	-	-	-	-	-	16.5	408.0	4.11	-	-	100
Austin Utils	3.7	214.2	54.49	1.68	-	-	-	-	80.1	332.1	3.32	54	-	46
Austin-Northeast (MN)	3.7	214.2	54.49	1.68	-	-	-	-	4.7	344.6	3.44	95	-	5
Downtown-4th Ave (MN)	-	-	-	-	-	-	-	-	75.4	331.3	3.31	-	-	100
Baltimore Gas and Elec	39.0	207.4	54.12	.86	171.0	453.3	28.41	.93	62.0	353.0	3.60	47	50	3
Crane (MD)	-	-	-	-	114.0	454.0	28.40	.94	-	-	-	-	100	-
Gould St (MD)	-	-	-	-	42.0	448.5	28.31	.92	-	-	-	-	100	-
Wagner (MD)	39.0	207.4	54.12	.86	15.0	461.6	28.74	.89	-	-	-	92	8	-
Notch Cliff (GT) (MD)	-	-	-	-	-	-	-	-	41.0	345.8	3.52	-	-	100
Riverside (MD)	-	-	-	-	-	-	-	-	8.0	367.2	3.74	-	-	100
Westport (MD)	-	-	-	-	-	-	-	-	13.0	367.2	3.74	-	-	100

Figure 4. Example of information available from Cost and Quality of Fuels for Electric Utility Plants - Monthly.[3]

calculating the SO_2 emissions unless one is assured that all units are subject only to Subpart D. If there are both SIP and Subpart D units at a plant, the plantwide average information would reflect the sulfur content needed to meet the SIP limits as well as the Subpart D limits for the applicable units. In most cases, depending on the State, the plantwide average sulfur content for plants with a mixture of Subpart D and SIP units would not be representative of the plantwide sulfur content required for plants with all Subpart D units. The plantwide average sulfur content where all units at a plant are subject to Subpart D but some units are using compliance (low-sulfur) coal and others are using an FGD to meet the SO_2 emission limits set forth in Subpart D would also not be representative of the plantwide sulfur content for plants with all Subpart D units. Because the plantwide average information available from DOE cannot be further refined to provide information on a unit-by-unit basis, the calculation of SO_2 emissions was limited to those plants where all units were subject to Subpart D and none of the units were equipped with an FGD. Limiting the analysis to only these plants made it possible to obtain a reasonable representation of the monthly (30-day) SO_2 emissions from Subpart D units.

Based on the information available from the previously noted DOE publications, the following equation was used to calculate the monthly (30-day) average SO_2 emissions for an 18-month period from January 1982 until July 1983:

$$E = \left(\frac{A}{100B}\right)(38S) \qquad \text{(Eq. 4-1)}$$

where E = potential SO_2 emissions (lb $SO_2/10^6$ Btu)

A = fuel cost per heat content (¢/10^6 Btu)

B = fuel cost by weight ($/ton coal)

S = fuel sulfur content (weight percent)

Basis for equation:

$$\left(\frac{A}{100}\right)\left(\frac{1}{B}\right) = \frac{A}{100B} \qquad \text{(Eq. 4-2)}$$

$$\left(\frac{¢/10^6\ \mathrm{Btu}}{100¢/\$}\right)\left(\frac{\mathrm{tons\ coal}}{\$}\right) = \frac{\mathrm{tons\ coal}}{10^6\ \mathrm{Btu}}$$

$$\left(\frac{S}{100}\right)(2000)(2)(0.95) = 38S \qquad \text{(Eq. 4-3)}$$

$$\left(\frac{\mathrm{lb}}{100\ \mathrm{lb\ coal}}\right)\left(\frac{2000\ \mathrm{lb\ coal}}{\mathrm{tons\ coal}}\right)\left(\frac{2\ \mathrm{lb}\ SO_2}{\mathrm{lb}}\right)(0.95\ S\ \mathrm{to}\ SO_2)^* = \frac{\mathrm{lb}\ SO_2}{\mathrm{tons\ coal}}$$

*Assumes 95 percent of sulfur is converted to SO_2. The balance of the sulfur is emitted in the fly ash or combines with the slag or ash in the furnace. This is consistent with October 21, 1983, proposal calculations.

The mean SO_2 emission level (18-month average) was calculated for each unit. Figure 5 is an example of the individual monthly SO_2 emissions for a selected plant. Appendix C lists the 18 monthly SO_2 emission levels for each of the 49 compliance coal-fired units included in this study.

Company name: Alabama Power

Plant name: Miller

Number of units: 1

State: AL

MONTHLY AVERAGE EMISSION RATE: [lb $SO_2/10^6$ Btu][a,b]

Jan. 82:	0.951	Jul. 82:	0.947	Jan. 83:	0.894
Feb. 82:	1.005	Aug. 82:	0.937	Feb. 83:	0.867
Mar. 82:	0.980	Sept. 82:	0.914	Mar. 83:	0.867
Apr. 82:	0.919	Oct. 82:	0.895	Apr. 83:	0.928
May 82:	0.904	Nov. 82:	0.892	May 83:	0.933
Jun. 82:	1.001	Dec. 82:	0.921	Jun. 83:	0.880

[a]Assumes 95 percent sulfur to SO_2 conversion rate.
[b]Mean = 0.924, maximum value = 1.005, and minimum value = 0.867.

Figure 5. Example of individual monthly SO_2 emissions from January 1982 through June 1983.

In order to determine if there was any significant difference between the SO_2 emissions from plants in the East versus those in the West, the list of plants with only Subpart D units was further subdivided into those plants located in the East and those located in the West. The eastern plants were designated as those in States that border the Mississippi River on the west plus all States located east of the Mississippi River. Those designated as western plants are in the States making up the balance of the continiguous United States. A map showing the dividing line for eastern and western plants for the purpose of this study is presented in Appendix D. In general, the plants with the lowest SO_2 emission levels were located in the West and those with the highest SO_2 emission levels were located in the East.

Table 3 summarizes the number of units included in this analysis by location (East versus West). Table 4 also summarizes, by location, the typical SO_2 emissions at the Subpart D compliance-coal-fired units included in this analysis. In general, long-term average emissions from eastern units averaged approximately 0.90 lb $SO_2/10^6$ Btu and emissions from western units averaged approximately 0.80 lb $SO_2/10^6$ Btu. Tables 5 and 6 present the minimum month, maximum month, and average (18-month) SO_2 emission rates for eastern and western units, respectively. Table 7 summarizes the long-term average SO_2 emission rate for eastern and western Subpart D utility units (compliance coal).

TABLE 3. TOTAL SUBPART D COAL-FIRED UNIT INVENTORY[a]

Technology	Number of units by location		
	East	West	Total
Compliance coal	40[b]	38[c]	78
FGD system	33	29	62
Total	73	67	140[d]

[a]Confirmed via CDS or EPA Regional Office.

[b]Sixteen of the 40 units are at plant sites where all units are compliance-coal-fired Subpart D units.

[c]Thirty-three of the 38 units are at plant sites where all units are compliance-coal-fired Subpart D units.

[d]The 140 coal-fired Subpart D units are located at 99 power plants.

TABLE 4. MONTHLY SO_2 EMISSIONS AT SUBPART D (COMPLIANCE COAL) UNITS[a,b]

Unit location	Number of units	Emissions, lb $SO_2/10^6$ Btu[c]		
		Combined average of all 18 monthly values	Range of 18-month average values	Range of maximum monthly values
East	16	0.88	0.68 to 0.98	0.72 to 1.32
West	33	0.81	0.60 to 1.04	0.65 to 1.19
Total	49	0.84	0.60 to 1.04	0.65 to 1.32

[a]Non-FGD. Based on published DOE "as received" fuel data.

[b]Only includes SO_2 emissions data from power plants where all units at the plant are subject to Subpart D and all units are using complying coal. Does not include any Subpart D units at any power plants where any units at the plant site are subject to SIP regulations. Therefore, the analysis focused on only 49 units out of the 78 compliance-coal-units originally identified.

[c]Assumes 95 percent sulfur-to-SO_2 conversion.

TABLE 5. MONTHLY SO_2 EMISSIONS FOR EASTERN COMPLIANCE COAL-FIRED UNITS SUBJECT TO SUBPART D[a]

Company name	Plant	No. of units	State	Type coal	No. in sample[c]	Monthly emissions,[b] lb $SO_2/10^6$ Btu: Minimum	Maximum	Average	Average sulfur, %
Alabama Power Company	Miller	1	AL	BIT	18	0.867	1.005	0.924	0.61
Arkansas Power & Light Co.	White Bluff	2	AR	BIT	18	0.759	1.070	0.962	0.44
Southwestern Electric Power Co.	Flint Creek	1	AR	BIT	18	0.621	0.841	0.777	0.35
Georgia Power Co.	Scherer	1	GA	BIT	18	0.864	1.052	0.951	0.66
Iowa Southern Utilities Co.	Ottumwa	1	IA	SUB	18	0.660	0.719	0.681	0.30
Cajun Electric Power Coop., Inc.	Big Cajun 2	2	LA	SUB	14	0.801	1.036	0.968	0.41
Mississippi Power Co.	Daniel, Victor J.	2	MS	BIT	18	0.874	0.968	0.919	0.57
Kansas City Power and Light Company	Iatan	1	MO	BIT	17	0.581	0.794	0.727	0.34
Dayton Power and Light Company, The	Killen Station	1	OH	BIT	18	0.852	0.930	0.887	0.59
Appalachian Power Co.	Mountaineer (1301)	1	WV	BIT	18	0.884	0.969	0.925	0.60
Wisconsin Electric Power Company	Pleasant Prairie	1	WI	SUB	18	0.716	0.890	0.830	0.33
Central Louisiana Electric Co., Inc.	Rodemacher	1	LA	SUB	18	0.736	1.069	0.962	0.44

(continued)

TABLE 5 (continued)

Company name	Plant	No. of units	State	Type coal	No. in sample[c]	Monthly emissions,[b] lb $SO_2/10^6$ Btu			
						Minimum	Maximum	Average	Average sulfur, %
Gulf States Utilities Company	Nelson, R.S.	1	LA	SUB	18	0.858	1.315	0.981	0.45

[a]In-service date of 1975 or later and a capacity $\geq$ 23 MW_e and confirmed via CDS or EPA Regional Office.

[b]Plant average SO_2 emissions were calculated because only plant average fuel data are available. The emission calculations assumes a 95 percent sulfur to SO_2 conversion as provided in October 21, 1983 proposal.

[c]Number of monthly values included in the average percent sulfur and average emission calculation.

TABLE 6. MONTHLY SO_2 EMISSIONS FOR WESTERN COMPLIANCE COAL-FIRED UNITS SUBJECT TO SUBPART D[a]

Company name	Plant	No. of units	State	Type coal	No. in sample[c]	Monthly emissions,[b] lb $SO_2/10^6$ Btu: Minimum	Maximum	Average	Average sulfur, %
Colorado Springs, City of	Ray D. Nixon	1	CO	BIT	18	0.629	0.750	0.684	0.38
Kansas City Board of Public Utilities	Nearman Creek	1	KS	BIT	17	0.695	0.940	0.821	0.36
Hastings Utilities	Hastings Energy Ctr.	1	NE	BIT	15	0.857	1.188	0.981	0.41
Nebraska Public Power District	Gentleman	2	NE	BIT	18	0.668	0.796	0.750	0.35
Omaha Public Power District	Nebraska City	1	NE	BIT	18	0.628	0.952	0.806	0.35
Sierra Pacific Power Company	North Valmy	1	NV	BIT	18	0.510	0.726	0.621	0.37
Grand River Dam Authority	GRDA 1	1	OK	BIT	15	0.628	0.958	0.841	0.36
Oklahoma Gas and Electric Company	Muskogee	2	OK	BIT	18	0.685	0.802	0.743	0.35
	Sooner	2	OK	BIT	18	0.667	0.796	0.750	0.35
Public Service Co. of Oklahoma	Northeastern	2	OK	BIT	18	0.846	1.041	0.959	0.42
Western Farmers Electric Coop.	Hugo	1	OK	SUB	18	0.876	1.129	1.043	0.45
Portland General Electric Co.	Boardman	1	OK	BIT	12	0.733	1.076	0.856	0.36

(continued)

TABLE 6 (continued)

Company name	Plant	No. of units	State	Type coal	No. in sample[c]	Monthly emissions,[b] lb $SO_2/10^6$ Btu Minimum	Maximum	Average	Average sulfur, %
Central Power and Light Company	Coleto Creek	1	TX	BIT	18	0.524	0.650	0.597	0.34
Houston Lighting and Power	Parish, W.A.	4	TX	BIT	18	0.710	0.985	0.868	0.39
Lower Colorado River Authority	Sam K. Seymour, Jr.	2	TX	BIT	18	0.725	0.824	0.776	0.37
San Antonio Public Service Board	Deely, J.T.	1	TX	BIT	15	0.677	0.890	0.748	0.33
Southwestern Electric Power Company	Welsh	3	TX	BIT	17	0.745	0.802	0.780	0.34
Southwestern Public Service Company	Harrington	3	TX	BIT	18	0.652	0.895	0.819	0.39
Grand Island Water and Light Dept.	Platte	1	NE	SUB	11	0.736	1.134	0.956	0.41
Southwestern Public Service Company	Tolk	1	TX	BIT	10	0.648	0.863	0.751	0.35
Public Service Co. of Colorado	Pawnee	1	CO	BIT	17	0.657	0.865	0.767	0.34

[a] In-service date of 1975 or later and a capacity $\geq$ 23 MW_e and confirmed via CDS or EPA Regional Office.

[b] Plant average SO_2 emissions were calculated because only plant average fuel data are available. The emission calculations assumes a 95 percent sulfur to SO_2 conversion as provided in October 21, 1983 proposal.

[c] Number of monthly values included in the average percent sulfur and average emission calculation.

TABLE 7. LONG-TERM AVERAGE SO_2 EMISSION RATE FOR EASTERN AND WESTERN SUBPART D UTILITY UNITS (COMPLIANCE COAL)

Long-term average SO_2 emission rate, lbs SO_2/million Btu[a]	Unit location[b]	
	Eastern	Western
0.60		1-unit
0.62		1-unit
0.68	1-unit	1-unit
0.73	1-unit	
0.74		2-units
0.75		6-units
0.77		1-unit
0.78	1-unit	5-units
0.81		1-unit
0.82		4-units
0.83	1-unit	
0.84		1-unit
0.86		1-unit
0.87		4-units
0.89	1-unit	
0.92	3-units	
0.93	1-unit	
0.95	1-unit	
0.96	3-units	3-units
0.97	2-units	
0.98	1-unit	1-unit
1.04		1-unit

[a]Based upon 18 months of DOE fuel quality data per unit (coal sampling and data analysis data, not CEM data).

[b]Eastern units include all units located in States east of the Mississippi River plus one State west of the Mississippi River.

SECTION 5

ESTIMATED SULFUR DIOXIDE EMISSION

Estimates of the 3-h, 24-h, 7-day rolling, and 30-day rolling average SO_2 emissions are based on a series of statistical procedures and assumptions associated with previously developed relationships for the 3-h, 24-h, 7-day, and 30-day SO_2 emission levels.[5]

5.1 ESTIMATION OF 3-H, 24-H, 7-DAY ROLLING, AND 30-DAY ROLLING AVERAGE SO_2 EMISSIONS

The SO_2 emissions generated by the direct combustion of compliance (low-sulfur) coal vary naturally, in part because of fluctuations in sulfur content and heating value of the coal resulting from the manner in which the coal was formed. Normally, a unit operates at a predetermined average level of SO_2 emissions and the actual minute-by-minute or hour-by-hour operation varies above and below the average level. Figure 6 shows a hypothetical SO_2 emission variability curve.[5]

Two terms are used to describe the variability of SO_2 emissions: standard deviation and autocorrelation. Standard deviation is loosely described as the size of a typical difference between a set of observations and the average of these observations, assuming a random system variability. The standard deviation is often expressed as a percentage of the average value, or the RSD. The RSD (i.e., standard deviation divided by the mean) is a relative measure of system variability.

Autocorrelation is a measure of the association or dependence between periodic observations or measurements taken one after another in time. An autocorrelation near 1.0 indicates that successive observations are similar in value. An autocorrelation near zero indicates there is little relationship between successive observations or measurements.[5]

Ideally, when a series of 1-h average SO_2 emission levels are available, calculation of the 3-h, 24-h, 7-day, and 30-day average SO_2 emission levels

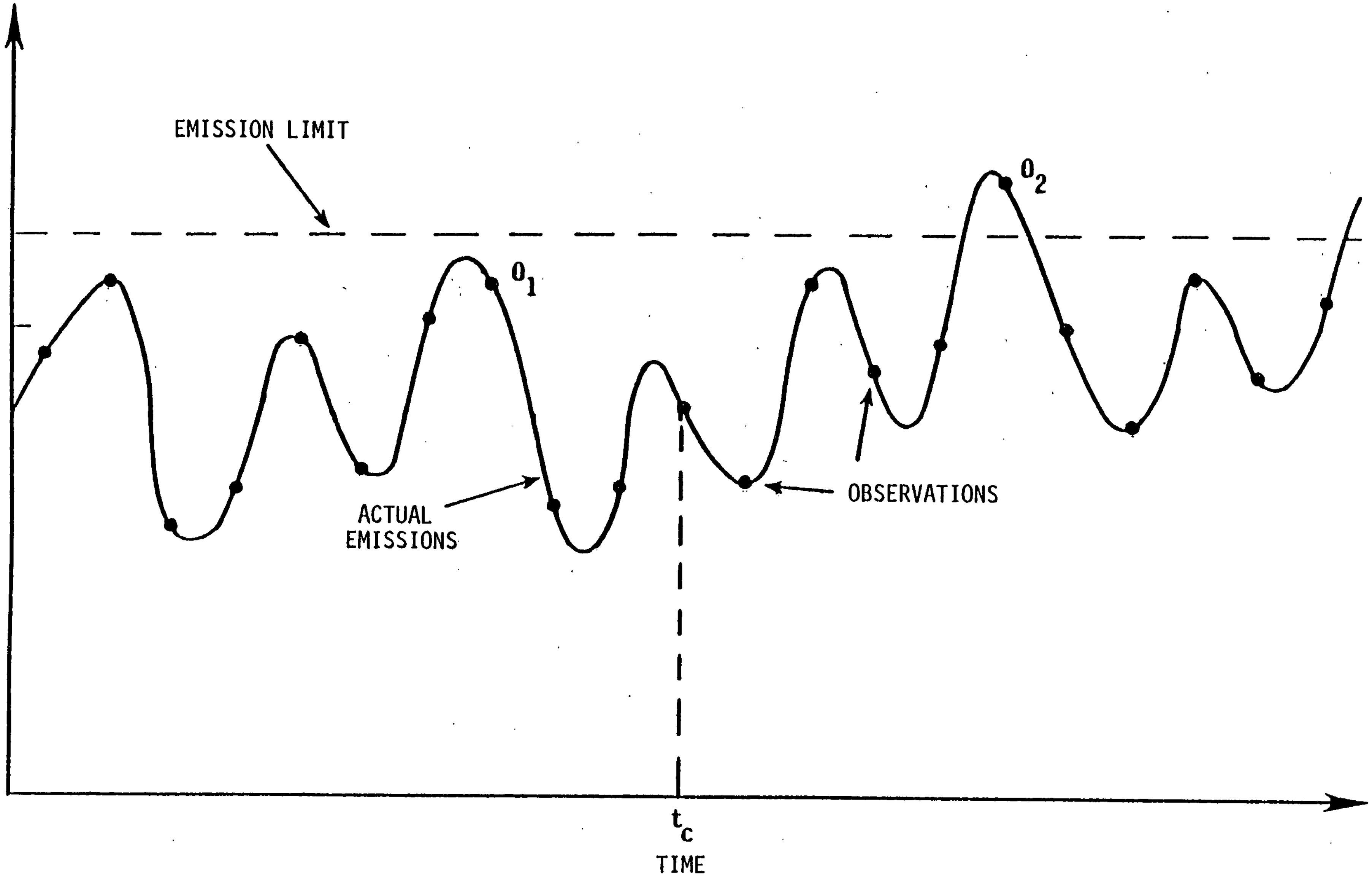

Figure 6. Typical SO_2 emission variability.[5]

for a given unit is relatively straightforward. With these data, one can calculate the mean, standard deviation, RSD, and autocorrelation for the data set. It is, however, more difficult to estimate the 3-h, 24-h, and 7-day emission levels given only the 30-day or monthly SO_2 emission levels and the 30-day average RSD. Lacking information on the relationships that may exist with respect to a given data set, one must use theory and a series of assumptions to describe the expected relationship.

The basic assumptions used in estimating 3-h, 24-h, and 7-day average SO_2 emissions, given a 30-day emission level, are as follows:

1. The unknown 1-h emission levels at each plant (unit) can be represented by an AR(1) process with an arithmetic mean μ, relative deviation RSD_1, and an autocorrelation ρ.

2. The arithmetic means of the associated 3-h, 24-h, 168-h (7-day), and 720-h (30-day) average values are also equal to μ.

3. The distributions of the 3-h, 24-h, and 7-day average values are normal.

4. The RSD of the 30-day rolling average values is equal to that of the monthly average values for the same period.

5. The RSD of a rolling average of length n can be estimated from the RSD of the 1-h time series:

$$RSD_n = f_n(\rho)^{\frac{1}{2}} RSD_1.$$

6. The autocorrelation of the rolling average time series can be estimated from the autocorrelation of the 1-h time series:

$$\rho_n = \frac{(n)(1-\rho^2) - (1+\rho^2)(1-\rho^h)}{(n^2)(1-\rho)^2 \; f_n(\rho)}$$

7. The function $f_n(\rho)$ can be estimated as:

$$f_n(\rho) = \frac{1+\rho}{(n)(1-\rho)}$$

8. The 18 month average is equivalent to the long-term mean.

Based on the assumptions presented, the maximum estimated 3-h, 24-h, 7-day rolling, and 30-day rolling average emission levels were calculated for each of the eastern and western plants where all units at the plant were subject to Subpart D. The estimates are based on one exceedance in 10 years, one exceedance per year, four exceedances per year for the 24-h, 7-day rolling, and 30-day rolling averages (99% compliance level), and 29 exceedances per year for the 3-h average (99% compliance level). Tables 8 and 9 summarize the estimated or projected 3-h average emission levels assuming 24-h RSD's of 10, 15, and 20 percent, a 24-h autocorrelation of 0.7; 29 exceedances per year (99% compliance level); one exceedance per year; and one exceedance in 10 years for the eastern and western units. Three projected SO_2 emission levels are presented for each unit based on a range of statistical assumptions. The projected 3-h average SO_2 emissions ranged from 0.76 to 1.32 lb $SO_2/10^6$ Btu for a 24-h RSD of 10 percent, a 24-h autocorrelation of 0.7, and 29 exceedances per year; from 0.84 to 1.46 lb $SO_2/10^6$ Btu for a 24-h RSD of 15 percent, a 24-h autocorrelation of 0.7, and one exceedance per year; and from 1.17 to 2.03 lb $SO_2/10^6$ Btu for a 24-h RSD of 20 percent, a 24-h autocorrelation of 0.7 and one exceedance in 10 years.

Tables 10 and 11 summarize the estimated or projected 24-h average emission levels based on assumed 24-h RSD's of 10, 15, and 20 percent; a 24-h autocorrelation of 0.7; four exceedances per year (99% compliance level); one exceedance per year; and one exceedance in 10 years for the eastern and western units. The 24-h average SO_2 emissions ranged from 0.74 to 1.28 lb $SO_2/10^6$ Btu for a 24-h RSD of 10 percent, a 24-h autocorrelation of 0.7, and four exceedances per year; from 0.77 to 1.33 lb $SO_2/10^6$ Btu for a 24-h RSD of 10 percent, a 24-h autocorrelation of 0.7, and one exceedance per year; and from 1.01 to 1.76 lb $SO_2/10^6$ Btu for a 24-h RSD of 20 percent, a 24-h autocorrelation of 0.7, and one exceedance in 10 years.

Tables 12 and 13 summarize the estimated or projected 7-day rolling average emission levels based on assumed RSD's of 10, 15, and 20 percent, a 24-h autocorrelation of 0.7; and four exceedances per year; one exceedance per year; and one exceedance in 10 years for the eastern and western units. The 7-day rolling average for SO_2 emissions ranged from 0.67 to 1.16 lb $SO_2/10^6$ Btu for a 24-h RSD of 10 percent, a 24-h autocorrelation of 0.7, and four exceedances per year; from 0.68 to 1.19 lb $SO_2/10^6$ Btu for a 24-h RSD of 10 percent, a 24-h autocorrelation of 0.7, and one exceedance per year; and from 0.80 to 1.39 lb $SO_2/10^6$ Btu for a 24-h RSD of 20 percent, a 24-h autocorrelation of 0.7, and one exceedance in 10 years.

TABLE 8. MONTHLY AVERAGE AND PROJECTED 3-H AVERAGE SO_2 EMISSIONS FOR EASTERN ELECTRIC GENERATING UNITS SUBJECT TO SUBPART D[a]

Company name	Plant	No. of units	State	SO_2 emissions, lb/10^6 Btu			
				Avg. of 18 monthly values[b,c]	Maximum projected 3-h SO_2 emissions, lb/10^6 Btu[d]		
					RSD = 10 percent	RSD = 15 percent	RSD = 20 percent
Alabama Power Co.	Miller	1	AL	0.92[e]	1.17[f] 1.29[g] 1.35[h]	1.30[f] 1.47[g] 1.59[h]	1.43[f] 1.67[g] 1.79[h]
Arkansas Power & Light Co.	White Bluff	2	AR	0.96[e]	1.04[f] 1.15[g] 1.21[h]	1.16[f] 1.31[g] 1.40[h]	1.27[f] 1.48[g] 1.60[h]
Southwestern Electric Power Co.	Flint Creek	1	AR	0.78[e]	0.99[f] 1.09[g] 1.15[h]	1.10[f] 1.25[g] 1.33[h]	1.21[f] 1.41[g] 1.52[h]
Georgia Power Co.	Scherer	1	GA	0.95[e]	1.21[f] 1.33[g] 1.40[h]	1.34[f] 1.52[g] 1.62[h]	1.47[f] 1.72[g] 1.85[h]
Iowa Southern Utilities Co.	Ottumwa	1	IA	0.68[e]	0.86[f] 0.95[g] 1.00[h]	0.96[f] 1.09[g] 1.16[h]	1.05[f] 1.23[g] 1.33[h]
Cajun Electric Power Coop., Inc.	Big Cajun 2	2	LA	0.97[e]	1.23[f] 1.36[g] 1.43[h]	1.37[f] 1.55[g] 1.66[h]	1.50[f] 1.76[g] 1.89[h]
Mississippi Power Co.	Daniel, Victor J.	2	MS	0.92[e]	1.17[f] 1.29[g] 1.35[h]	1.30[f] 1.47[g] 1.57[h]	1.43[f] 1.67[g] 1.79[h]
Kansas City Power & Light Co.	Iatan	1	MO	0.73[e]	0.93[f] 1.02[g] 1.07[h]	1.03[f] 1.17[g] 1.25[h]	1.13[f] 1.32[g] 1.42[h]

(continued)

TABLE 8 (continued)

Company name	Plant	No. of units	State	SO_2 emissions, lb/10^6 Btu			
				Avg. of 18 monthly values[b,c]	Maximum projected 3-h SO_2 emissions, lb/10^6 Btu[d]		
					RSD = 10 percent	RSD = 15 percent	RSD = 20 percent
Dayton Power & Light Co., The	Killen Station	1	OH	0.89[e]	1.13[f] 1.25[g] 1.31[h]	1.25[f] 1.42[g] 1.52[h]	1.38[f] 1.61[g] 1.74[h]
Appalachian Power Co.	Mountaineer (1301)	1	WV	0.93[e]	1.18[f] 1.30[g] 1.37[h]	1.31[f] 1.49[g] 1.59[h]	1.44[f] 1.68[g] 1.81[h]
Wisconsin Electric Power Co.	Pleasant Prairie	1	WI	0.83[e]	1.05[f] 1.16[g] 1.22[h]	1.17[f] 1.33[g] 1.42[h]	1.29[f] 1.50[g] 1.62[h]
Central Louisiana Electric Co., Inc.	Rodemacher	1	LA	0.96[e]	1.22[f] 1.34[g] 1.41[h]	1.35[f] 1.54[g] 1.64[h]	1.49[f] 1.74[g] 1.87[h]
Gulf States Utilities Co.	Nelson, R.S.	1	LA	0.98[e]	1.24[f] 1.37[g] 1.44[h]	1.38[f] 1.57[g] 1.68[h]	1.52[f] 1.77[g] 1.91[h]

[a]In-service date of 1975 or later and a capacity $\geq$ 23 MW_e.

[b]Measured arithmetic mean.

[c]Data from January 1982 through June 1983.

[d]Projections are based on 24-h RSD's of 10, 15, 20 percent, 24-h autocorrelation of 0.7 and 29 exceedances per year, one exceedance per year and one exceedance in 10 years.

[e]Subject to Subpart D as listed in CDS or based on conversation with EPA Regional Office.

[f]Assumes 29 exceedances per year (99% compliance level).

[g]Assumes one exceedance per year.

[h]Assumes one exceedance in 10 years.

TABLE 9. MONTHLY AVERAGE AND PROJECTED 3-H AVERAGE SO_2 EMISSIONS FOR WESTERN ELECTRIC GENERATING UNITS SUBJECT TO SUBPART D[a]

Company name	Plant	No. of units	State	SO_2 emissions, $lb/10^6$ Btu: Avg. of 18 monthly values[b,c]	Maximum projected 3-h SO_2 emissions, $lb/10^6$ Btu[d]: RSD = 10 percent	RSD = 15 percent	RSD = 20 percent
Colorado Springs, City of	Ray D. Nixon	1	CO	0.68[e]	0.86[f] 0.95[g] 1.00[h]	0.96[f] 1.09[g] 1.16[h]	1.05[f] 1.23[g] 1.33[h]
Kansas City Board of Public Utilities	Nearman Creek	1	KS	0.82[e]	1.04[f] 1.15[g] 1.21[h]	1.16[f] 1.31[g] 1.40[h]	1.27[f] 1.48[g] 1.60[h]
Hastings Utilities	Hastings Energy Center	1	NE	0.98[e]	1.24[f] 1.37[g] 1.44[h]	1.38[f] 1.57[g] 1.68[h]	1.52[f] 1.77[g] 1.91[h]
Nebraska Public Power District	Gentleman	2	NE	0.75[e]	0.95[f] 1.05[g] 1.10[h]	1.06[f] 1.20[g] 1.28[h]	1.16[f] 1.36[g] 1.46[h]
Omaha Public Power District	Nebraska City	1	NE	0.81[e]	1.03[f] 1.13[g] 1.19[h]	1.14[f] 1.30[g] 1.39[h]	1.26[f] 1.47[g] 1.58[h]
Sierra Pacific Power Company	North Valmy	1	NV	0.62[e]	0.79[f] 0.87[g] 0.91[h]	0.87[f] 0.99[g] 1.06[h]	0.96[f] 1.12[g] 1.21[h]
Grand River Dam Authority	GRDA 1	1	OK	0.84[e]	1.07[f] 1.18[g] 1.23[h]	1.18[f] 1.34[g] 1.44[h]	1.30[f] 1.52[g] 1.64[h]
Oklahoma Gas & Electric Co.	Muskogee	2	OK	0.74[e]	0.94[f] 1.04[g] 1.09[h]	1.04[f] 1.18[g] 1.27[h]	1.15[f] 1.33[g] 1.44[h]

(continued)

TABLE 9 (continued)

				SO_2 emissions, $lb/10^6$ Btu			
					Maximum projected 3-h SO_2 emissions, $lb/10^6$ Btu[d]		
Company name	Plant	No. of units	State	Avg. of 18 monthly values[b,c]	RSD = 10 percent	RSD = 15 percent	RSD = 20 percent
	Sooner	2	OK	0.75[e]	0.95[f] 1.05[g] 1.10[h]	1.06[f] 1.20[g] 1.28[h]	1.16[f] 1.36[g] 1.46[h]
Public Service Co. of Oklahoma	North-eastern	2	OK	0.96[e]	1.22[f] 1.34[g] 1.41[h]	1.35[f] 1.54[g] 1.64[h]	1.49[f] 1.74[g] 1.87[h]
Western Farmers Electric Coop.	Hugo	1	OK	1.04[e]	1.32[f] 1.46[g] 1.53[h]	1.47[f] 1.66[g] 1.77[h]	1.61[f] 1.88[g] 2.03[h]
Portland General Electric Co.	Boardman	1	OR	0.86[e]	1.09[f] 1.20[g] 1.26[h]	1.21[f] 1.38[g] 1.47[h]	1.33[f] 1.56[g] 1.68[h]
Central Power & Light Co.	Coleto Creek	1	TX	0.60[e]	0.76[f] 0.84[g] 0.88[h]	0.85[f] 0.96[g] 1.02[h]	0.93[f] 1.09[g] 1.17[h]
Houston Lighting & Power	Parish, W.A.	4	TX	0.87[e]	1.10[f] 1.22[g] 1.28[h]	1.23[f] 1.39[g] 1.49[h]	1.35[f] 1.57[g] 1.70[h]
Lower Colorado River Authority	Sam K. Seymour, Jr.	2	TX	0.78[e]	0.99[f] 1.09[g] 1.15[h]	1.10[f] 1.25[g] 1.33[h]	1.21[f] 1.41[g] 1.52[h]
San Antonio Public Service Board	Deely, J.T.	1	TX	0.75[e]	0.95[f] 1.05[g] 1.10[h]	1.06[f] 1.20[g] 1.28[h]	1.16[f] 1.36[g] 1.46[h]
Southwestern Electric Power Co.	Welsh	3	TX	0.78[e]	0.99[f] 1.09[g] 1.15[h]	1.10[f] 1.25[g] 1.33[h]	1.21[f] 1.41[g] 1.52[h]

(continued)

TABLE 9 (continued)

Company name	Plant	No. of units	State	SO_2 emissions, lb/10^6 Btu Avg. of 18 monthly values[b,c]	Maximum projected 3-h SO_2 emissions, lb/10^6 Btu[d] RSD = 10 percent	 RSD = 15 percent	 RSD = 20 percent
Southwestern Public Service Company	Harrington	3	TX	0.82[e]	1.04[f] 1.15[g] 1.21[h]	1.16[f] 1.31[g] 1.40[h]	1.27[f] 1.48[g] 1.60[h]
Grand Island Water & Light Dept.	Platte	1	NE	0.96[e]	1.04[f] 1.15[g] 1.21[h]	1.16[f] 1.31[g] 1.40[h]	1.27[f] 1.48[g] 1.60[h]
Southwestern Public Service Co.	Tolk	1	TX	0.75[e]	0.95[f] 1.05[g] 1.10[h]	1.06[f] 1.20[g] 1.28[h]	1.16[f] 1.36[g] 1.46[h]
Public Service Co. of Colorado	Pawnee	1	CO	0.77[e]	0.98[f] 1.08[g] 1.13[h]	1.09[f] 1.23[g] 1.32[h]	1.19[f] 1.39[g] 1.50[h]

[a]In-service date of 1975 or later and a capacity $\geq$ 23 MW_e.

[b]Measured arithmetic mean.

[c]Data from January 1982 through June 1983.

[d]Projections are based on 24-h RSD's of 10, 15, 20 percent, 24-h autocorrelation of 0.7, and 29 exceedances per year, one exceedance per year, and one exceedance in 10 years.

[e]Subject to Subpart D as listed in CDS or based on conversation with EPA Regional Office.

[f]Assumes 29 exceedances per year (99% compliance level).

[g]Assumes 1 exceedance per year.

[h]Assumes 1 exceedance in 10 years.

TABLE 10. MONTHLY AVERAGE AND PROJECTED 24-H AVERAGE SO_2 EMISSIONS FOR EASTERN ELECTRIC GENERATING UNITS SUBJECT TO SUBPART D[a]

Company name	Plant	No. of units	State	SO_2 emissions, lb/10^6 Btu: Avg. of 18 monthly values[b,c]	Maximum projected 24-h SO_2 emissions, lb/10^6 Btu[d]: RSD = 10 percent	RSD = 15 percent	RSD = 20 percent
Alabama Power Co.	Miller	1	AL	0.92[e]	1.13[f] 1.18[g] 1.24[h]	1.24[f] 1.31[g] 1.40[h]	1.35[f] 1.45[g] 1.56[h]
Arkansas Power & Light Co.	White Bluff	2	AR	0.96[e]	1.18[f] 1.23[g] 1.30[h]	1.30[f] 1.37[g] 1.46[h]	1.41[f] 1.50[g] 1.62[h]
Southwestern Electric Power Co.	Flint Creek	1	AR	0.78[e]	0.96[f] 1.00[g] 1.05[h]	1.05[f] 1.11[g] 1.18[h]	1.15[f] 1.22[g] 1.31[h]
Georgia Power Co.	Scherer	1	GA	0.95[e]	1.17[f] 1.22[g] 1.28[h]	1.28[f] 1.35[g] 1.44[h]	1.40[f] 1.50[g] 1.61[h]
Iowa Southern Utilities Co.	Ottumwa	1	IA	0.68[e]	0.84[f] 0.87[g] 0.92[h]	0.92[f] 0.97[g] 1.03[h]	1.00[f] 1.07[g] 1.15[h]
Cajun Electric Power Coop., Inc.	Big Cajun 2	2	LA	0.97[e]	1.19[f] 1.24[g] 1.31[h]	1.31[f] 1.38[g] 1.47[h]	1.43[f] 1.53[g] 1.64[h]
Mississippi Power Co.	Daniel, Victor J.	2	MS	0.92[e]	1.13[f] 1.18[g] 1.24[h]	1.24[f] 1.31[g] 1.40[h]	1.35[f] 1.45[g] 1.56[h]
Kansas City Power & Light Co.	Iatan	1	MO	0.73[e]	0.90[f] 0.93[g] 0.98[h]	0.99[f] 1.04[g] 1.11[h]	1.07[f] 1.14[g] 1.23[h]

(continued)

TABLE 10 (continued)

Company name	Plant	No. of units	State	SO_2 emissions, lb/10^6 Btu			
				Avg. of 18 monthly values[b,c]	Maximum projected 24-h SO_2 emissions, lb/10^6 Btu[d]		
					RSD = 10 percent	RSD = 15 percent	RSD = 20 percent
Dayton Power & Light Co., The	Killen Station	1	OH	0.89[e]	1.09[f] 1.14[g] 1.20[h]	1.20[f] 1.27[g] 1.35[h]	1.31[f] 1.40[g] 1.50[h]
Appalachian Power Co.	Mountaineer (1301)	1	WV	0.93[e]	1.14[f] 1.19[g] 1.25[h]	1.26[f] 1.33[g] 1.41[h]	1.37[f] 1.45[g] 1.56[h]
Wisconsin Electric Power Co.	Pleasant Prairie	1	WI	0.83[e]	1.02[f] 1.06[g] 1.12[h]	1.12[f] 1.18[g] 1.26[h]	1.22[f] 1.30[g] 1.40[h]
Central Louisiana Electric Co., Inc.	Rodemacher	1	LA	0.96[e]	1.18[f] 1.23[g] 1.30[h]	1.30[f] 1.37[g] 1.46[h]	1.41[f] 1.50[g] 1.62[h]
Gulf States Utilities Co.	Nelson, R.S.	1	LA	0.98[e]	1.21[f] 1.25[g] 1.32[h]	1.32[f] 1.40[g] 1.49[h]	1.44[f] 1.54[g] 1.66[h]

[a]In-service date of 1975 or later and a capacity $\geq$ 23 MW_e.

[b]Measured arithmetic mean.

[c]Data from January 1982 through June 1983.

[d]Projections are based on 24-h RSD's of 10, 15, 20 percent, 24-h autocorrelation of 0.7, and four exceedances per year, one exceedance per year, and one exceedance in 10 years.

[e]Subject to Subpart D as listed in CDS or based on conversation with EPA Regional Office.

[f]Assumes 4 exceedances per year (99% compliance level).

[g]Assumes one exceedance per year.

[h]Assumes one exceedance in 10 years.

TABLE 11. MONTHLY AVERAGE AND PROJECTED 24-H AVERAGE SO_2 EMISSIONS FOR WESTERN ELECTRIC GENERATING UNITS SUBJECT TO SUBPART D[a]

Company name	Plant	No. of units	State	SO_2 emissions, $lb/10^6$ Btu: Avg. of 18 monthly values[b,c]	Maximum projected 24-h SO_2 emissions, $lb/10^6$ Btu[d]: RSD = 10 percent	RSD = 15 percent	RSD = 20 percent
Colorado Springs, City of	Ray D. Nixon	1	CO	0.68[e]	0.84[f] 0.87[g] 0.92[h]	0.92[f] 0.97[g] 1.03[h]	1.00[f] 1.08[g] 1.16[h]
Kansas City Board of Public Utilities	Nearman Creek	1	KS	0.82[e]	1.01[f] 1.05[g] 1.11[h]	1.11[f] 1.18[g] 1.25[h]	1.21[f] 1.29[g] 1.39[h]
Hastings Utilities	Hastings Energy Center	1	NE	0.98[e]	1.21[f] 1.25[g] 1.32[h]	1.32[f] 1.40[g] 1.49[h]	1.44[f] 1.54[g] 1.66[h]
Nebraska Public Power District	Gentleman	2	NE	0.75[e]	0.92[f] 0.96[g] 1.01[h]	1.01[f] 1.07[g] 1.14[h]	1.10[f] 1.18[g] 1.27[h]
Omaha Public Power District	Nebraska City	1	NE	0.81[e]	1.00[f] 1.04[g] 1.09[h]	1.09[f] 1.16[g] 1.23[h]	1.19[f] 1.26[g] 1.36[h]
Sierra Pacific Power Company	North Valmy	1	NV	0.62[e]	0.76[f] 0.79[g] 0.83[h]	0.83[f] 0.88[g] 0.94[h]	0.91[f] 0.98[g] 1.05[h]
Grand River Dam Authority	GRDA 1	1	OK	0.84[e]	1.03[f] 1.07[g] 1.13[h]	1.13[f] 1.20[g] 1.28[h]	1.23[f] 1.32[g] 1.42[h]
Oklahoma Gas & Electric Co.	Muskogee	2	OK	0.74[e]	0.91[f] 0.95[g] 1.00[h]	1.00[f] 1.05[g] 1.12[h]	1.09[f] 1.17[g] 1.26[h]

(continued)

TABLE 11 (continued)

Company name	Plant	No. of units	State	SO_2 emissions, lb/10^6 Btu: Avg. of 18 monthly values[b,c]	Maximum projected 24-h SO_2 emissions, lb/10^6 Btu[d]: RSD = 10 percent	RSD = 15 percent	RSD = 20 percent
	Sooner	2	OK	0.75[e]	0.92[f] 0.96[g] 1.01[h]	1.01[f] 1.07[g] 1.14[h]	1.16[f] 1.18[g] 1.27[h]
Public Service Co. of Oklahoma	North-eastern	2	OK	0.96[e]	1.18[f] 1.23[g] 1.30[h]	1.30[f] 1.37[g] 1.46[h]	1.41[f] 1.50[g] 1.62[h]
Western Farmers Electric Coop.	Hugo	1	OK	1.04[e]	1.28[f] 1.33[g] 1.40[h]	1.40[f] 1.49[g] 1.58[h]	1.53[f] 1.64[g] 1.76[h]
Portland General Electric Co.	Boardman	1	OR	0.86[e]	1.06[f] 1.10[g] 1.16[h]	1.16[f] 1.23[g] 1.31[h]	1.26[f] 1.35[g] 1.45[h]
Central Power & Light Co.	Coleto Creek	1	TX	0.60[e]	0.74[f] 0.77[g] 0.81[h]	0.81[f] 0.86[g] 0.91[h]	0.88[f] 0.94[g] 1.01[h]
Houston Lighting & Power	Parish, W.A.	4	TX	0.87[e]	1.07[f] 1.11[g] 1.17[h]	1.17[f] 1.24[g] 1.32[h]	1.29[f] 1.37[g] 1.47[h]
Lower Colorado River Authority	Sam K. Seymour, Jr.	2	TX	0.78[e]	0.96[f] 1.00[g] 1.05[h]	1.05[f] 1.11[g] 1.18[h]	1.14[f] 1.22[g] 1.31[h]
San Antonio Public Service Board	Deely, J.T.	1	TX	0.75[e]	0.92[f] 0.96[g] 1.01[h]	1.01[f] 1.07[g] 1.14[h]	1.10[f] 1.18[g] 1.27[h]
Southwestern Electric Power Co.	Welsh	3	TX	0.78[e]	0.96[f] 1.00[g] 1.05[h]	1.05[f] 1.11[g] 1.18[h]	1.15[f] 1.22[g] 1.31[h]

(continued)

TABLE 11 (continued)

Company name	Plant	No. of units	State	SO_2 emissions, $lb/10^6$ Btu: Avg. of 18 monthly values[b,c]	Maximum projected 24-h SO_2 emissions, $lb/10^6$ Btu[d]: RSD = 10 percent	RSD = 15 percent	RSD = 20 percent
Southwestern Public Service Company	Harrington	3	TX	0.82[e]	1.01[f] 1.05[g] 1.10[h]	1.10[f] 1.18[g] 1.25[h]	1.21[f] 1.29[g] 1.39[h]
Grand Island Water & Light Dept.	Platte	1	NE	0.96[e]	1.18[f] 1.23[g] 1.30[h]	1.30[f] 1.37[g] 1.46[h]	1.41[f] 1.50[g] 1.62[h]
Southwestern Public Service Co.	Tolk	1	TX	0.75[e]	0.92[f] 0.96[g] 1.01[h]	1.01[f] 1.07[g] 1.14[h]	1.10[f] 1.18[g] 1.27[h]
Public Service Co. of Colorado	Pawnee	1	CO	0.77[e]	0.95[f] 0.99[g] 1.04[h]	1.04[f] 1.10[g] 1.17[h]	1.13[f] 1.26[g] 1.30[h]

[a]In-service date of 1975 or later and a capacity $\geq$ 23 MW_e.

[b]Measured arithmetic mean.

[c]Data from January 1982 through June 1983.

[d]Projections are based on 24-h RSD's of 10, 15, 20 percent, 24-h autocorrelation of 0.7, and four exceedances per year, one exceedance per year, and one exceedance in 10 years.

[e]Subject to Subpart D as listed in CDS or based on conversation with EPA Regional Office.

[f]Assumes four exceedances per year (99% compliance level).

[g]Assumes one exceedance per year.

[h]Assumes one exceedance in 10 years.

TABLE 12. MONTHLY AVERAGE AND PROJECTED 7-DAY (ROLLING) SO_2 EMISSIONS FOR EASTERN ELECTRIC GENERATING UNITS SUBJECT TO SUBPART D[a]

Company name	Plant	No. units	State	SO_2 emissions, lb/10^6 Btu: Avg. of 18 monthly values[b,c]	Maximum projected 7-day SO_2 emissions, lb/10^6 Btu[d]: RSD = 10 percent	RSD = 15 percent	RSD = 20 percent
Alabama Power Co.	Miller	1	AL	0.92[e]	1.03[f] 1.05[g] 1.08[h]	1.08[f] 1.11[g] 1.16[h]	1.13[f] 1.18[g] 1.23[h]
Arkansas Power & Light Co.	White Bluff	2	AR	0.96[e]	1.08[f] 1.09[g] 1.12[h]	1.12[f] 1.16[g] 1.21[h]	1.18[f] 1.23[g] 1.29[h]
Southwestern Electric Power Co.	Flint Creek	1	AR	0.78[e]	0.87[f] 0.89[g] 0.91[h]	0.91[f] 0.94[g] 0.98[h]	0.96[f] 1.00[g] 1.05[h]
Georgia Power Co.	Scherer	1	GA	0.95[e]	1.06[f] 1.08[g] 1.11[h]	1.11[f] 1.15[g] 1.20[h]	1.17[f] 1.22[g] 1.27[h]
Iowa Southern Utilities Co.	Ottumwa	1	IA	0.68[e]	0.76[f] 0.78[g] 0.80[h]	0.80[f] 0.82[g] 0.86[h]	0.84[f] 0.87[g] 0.91[h]
Cajun Electric Power Coop., Inc.	Big Cajun 2	2	LA	0.97[e]	1.09[f] 1.11[g] 1.13[h]	1.13[f] 1.17[g] 1.22[h]	1.19[f] 1.24[g] 1.30[h]
Mississippi Power Co.	Daniel, Victor J.	2	MS	0.92[e]	1.03[f] 1.05[g] 1.98[h]	1.08[f] 1.11[g] 1.16[h]	1.13[f] 1.18[g] 1.23[h]
Kansas City Power & Light Co.	Iatan	1	MO	0.73[e]	0.82[f] 0.83[g] 0.85[h]	0.85[f] 0.88[g] 0.92[h]	0.90[f] 0.93[g] 0.98[h]

(continued)

TABLE 12 (continued)

Company name	Plant	No. units	State	SO_2 emissions, lb/10^6 Btu: Avg. of 18 monthly values[b,c]	Maximum projected 7-day SO_2 emissions, lb/10^6 Btu[d]: RSD = 10 percent	RSD = 15 percent	RSD = 20 percent
Dayton Power & Light Co., The	Killen Station	1	OH	0.89[e]	1.00[f] 1.01[g] 1.04[h]	1.04[f] 1.08[g] 1.12[h]	1.09[f] 1.14[g] 1.19[h]
Appalachian Power Co.	Mountaineer (1301)	1	MV	0.93[e]	1.04[f] 1.06[g] 1.09[h]	1.09[f] 1.13[g] 1.17[h]	1.14[f] 1.19[g] 1.25[h]
Wisconsin Electric Power Co.	Pleasant Prairie	1	WI	0.83[e]	0.93[f] 0.94[g] 0.97[h]	0.97[f] 1.00[g] 1.05[h]	1.02[f] 1.06[g] 1.11[h]
Central Louisiana Electric Co., Inc.	Rodemacher	1	LA	0.96[e]	1.08[f] 1.09[g] 1.12[h]	1.12[f] 1.16[g] 1.21[h]	1.18[f] 1.23[g] 1.29[h]
Gulf States Utilities Co.	Nelson, R.S.	1	LA	0.98[e]	1.10[f] 1.12[g] 1.15[h]	1.15[f] 1.19[g] 1.23[h]	1.21[f] 1.25[g] 1.31[h]

[a]In-service date of 1975 or later and a capacity $\geq$ 23 MW_e.

[b]Measured arithmetic mean.

[c]Data from January 1982 through June 1983.

[d]Projections are based on 24-h RSD's of 10, 15, 20 percent, 24-h autocorrelation of 0.7, and four exceedances per year, one exceedance per year, and one exceedance in 10 years.

[e]Subject to Subpart D as listed in CDS or based on conversation with EPA Regional Office.

[f]Assumes four exceedances per year (99% compliance level).

[g]Assumes one exceedance per year.

[h]Assumes one exceedance in 10 years.

TABLE 13. MONTHLY AVERAGE AND PROJECTED 7-DAY (ROLLING) AVERAGE SO_2 EMISSIONS FOR WESTERN ELECTRIC GENERATING UNITS SUBJECT TO SUBPART D[a]

Company name	Plant	No. units	State	SO_2 emissions, $lb/10^6$ Btu			
				Avg. of 18 monthly values[b,c]	Maximum projected 7-day SO_2 emissions, $lb/10^6$ Btu[d]		
					RSD = 10 percent	RSD = 15 percent	RSD = 20 percent
Colorado Springs, City of	Ray D. Nixon	1	CO	0.68[e]	0.76[f] 0.78[g] 0.80[h]	0.80[f] 0.82[g] 0.86[h]	0.84[f] 0.87[g] 0.91[h]
Kansas City Board of Public Utilities	Nearman Creek	1	KS	0.82[e]	0.92[f] 0.93[g] 0.96[h]	0.96[f] 0.99[g] 1.03[h]	1.01[f] 1.05[g] 1.10[h]
Hastings Utilities	Hastings Energy Center	1	NE	0.98[e]	1.10[f] 1.12[g] 1.15[h]	1.15[f] 1.19[g] 1.23[h]	1.21[f] 1.25[g] 1.31[h]
Nebraska Public Power District	Gentleman	2	NE	0.75[e]	0.84[f] 0.86[g] 0.88[h]	0.88[f] 0.91[g] 0.95[h]	0.92[f] 0.96[g] 1.01[h]
Omaha Public Power District	Nebraska City	1	NE	0.81[e]	0.91[f] 0.92[g] 0.95[h]	0.95[f] 0.98[g] 1.02[h]	1.00[f] 1.04[g] 1.09[h]
Sierra Pacific Power Company	North Valmy	1	NV	0.62[e]	0.69[f] 0.71[g] 0.73[h]	0.73[f] 0.75[g] 0.78[h]	0.76[f] 0.79[g] 0.83[h]
Grand River Dam Authority	GRDA 1	1	OK	0.84[e]	0.94[f] 0.96[g] 0.98[h]	0.98[f] 1.02[g] 1.06[h]	1.03[f] 1.08[g] 1.13[h]
Oklahoma Gas & Electric Co.	Muskogee	2	OK	0.74[e]	0.83[f] 0.84[g] 0.87[h]	0.87[f] 0.90[g] 0.93[h]	0.91[f] 0.95[g] 0.99[h]

(continued)

TABLE 13 (continued)

Company name	Plant	No. units	State	SO_2 emissions, $lb/10^6$ Btu: Avg. of 18 monthly values[b,c]	Maximum projected 7-day SO_2 emissions, $lb/10^6$ Btu[d]: RSD = 10 percent	RSD = 15 percent	RSD = 20 percent
	Sooner	2	OK	0.75[e]	0.84[f] 0.86[g] 0.88[h]	0.88[f] 0.91[g] 0.95[h]	0.92[f] 0.96[g] 1.01[h]
Public Service Co. of Oklahoma	North-eastern	2	OK	0.96[e]	1.08[f] 1.09[g] 1.12[h]	1.12[f] 1.16[g] 1.21[h]	1.18[f] 1.23[g] 1.29[h]
Western Farmers Electric Coop.	Hugo	1	OK	1.04[e]	1.16[f] 1.19[g] 1.22[h]	1.22[f] 1.26[g] 1.31[h]	1.28[f] 1.33[g] 1.39[h]
Portland General Electric Co.	Boardman	1	OR	0.86[e]	0.96[f] 0.98[g] 1.01[h]	1.01[f] 1.04[g] 1.08[h]	1.05[f] 1.10[g] 1.15[h]
Central Power & Light Co.	Coleto Creek	1	TX	0.60[e]	0.67[f] 0.68[g] 0.70[h]	0.70[f] 0.73[g] 0.76[h]	0.74[f] 0.77[g] 0.80[h]
Houston Lighting & Power	Parish, W.A.	4	TX	0.87[e]	0.97[f] 0.99[g] 1.02[h]	1.02[f] 1.05[g] 1.10[h]	1.07[f] 1.11[g] 1.17[h]
Lower Colorado River Authority	Sam K. Seymour, Jr.	2	TX	0.78[e]	0.87[f] 0.89[g] 0.91[h]	0.91[f] 0.94[g] 0.98[h]	0.96[f] 1.00[g] 1.05[h]
San Antonio Public Service Board	Deely, J.T.	1	TX	0.75[e]	0.84[f] 0.86[g] 0.88[h]	0.88[f] 0.91[g] 0.95[h]	0.92[f] 0.96[g] 1.01[h]
Southwestern Electric Power Co.	Welsh	3	TX	0.78[e]	0.87[f] 0.89[g] 0.91[h]	0.91[f] 0.94[g] 0.98[h]	0.96[f] 1.00[g] 1.04[h]

(continued)

TABLE 13 (continued)

Company name	Plant	No. units	State	SO_2 emissions, lb/10^6 Btu: Avg. of 18 monthly values[b,c]	Maximum projected 7-day SO_2 emissions, lb/10^6 Btu[d]: RSD = 10 percent	RSD = 15 percent	RSD = 20 percent
Southwestern Public Service Company	Harrington	3	TX	0.82[e]	0.92[f] 0.93[g] 0.96[h]	0.96[f] 0.99[g] 1.03[h]	1.01[f] 1.05[g] 1.10[h]
Grand Island Water & Light Dept.	Platte	1	NE	0.96[e]	1.08[f] 1.09[g] 1.12[h]	1.12[f] 1.16[g] 1.21[h]	1.18[f] 1.23[g] 1.29[h]
Southwestern Public Service Co.	Tolk	1	TX	0.75[e]	0.84[f] 0.86[g] 0.88[h]	0.88[f] 0.91[g] 0.95[h]	0.92[f] 0.96[g] 1.01[h]
Public Service Co. of Colorado	Pawnee	1	CO	0.77[e]	0.86[f] 0.88[g] 0.91[h]	0.91[f] 0.93[g] 0.97[h]	0.95[f] 0.99[g] 1.03[h]

[a]In-service date of 1975 or later and a capacity $\geq$ 23 MW_e.

[b]Measured arithmetic mean.

[c]Data from January 1982 through June 1983.

[d]Projections are based on 24-h RSD's of 10, 15, 20 percent, 24-h autocorrelation of 0.7, and four exceedances per year, one exceedance per year, and one exceedance in 10 years.

[e]Subject to Subpart D as listed in CDS or based on conversation with EPA Regional Office.

[f]Assumes four exceedances per year (99% compliance level).

[g]Assumes one exceedance per year.

[h]Assumes one exceedance in 10 years.

Tables 14 and 15 summarize the estimated or projected 30-day rolling average emission levels based on assumed RSD's of 10, 15, and 20 percent, a 24-h autocorrelation of 0.7; four exceedances per year; one exceedance per year; and one exceedance in 10 years for the eastern and western units. The 30-day rolling average for SO_2 emissions ranged from 0.63 to 1.09 lb $SO_2/10^6$ Btu for a 24-h RSD of 10 percent, a 24-h autocorrelation of 0.7, and four exceedances per year; from 0.64 to 1.11 lb $SO_2/10^6$ Btu for a 24-h RSD of 10 percent, a 24-h autocorrelation of 0.7, and one exceedance per year; and from 0.70 to 1.22 lb $SO_2/10^6$ Btu for a 24-h RSD of 20 percent, a 24-h autocorrelation of 0.7, and one exceedance in 10 years.

5.2 EVALUATION OF COMPLIANCE WITH SUBPART D LIMITS ON A 3-H, 24-H, 7-DAY, AND 30-DAY BASIS

Based on the statistical assumptions and procedures presented in Section 5.1, several calculations were performed to estimate the mean SO_2 emissions in lb/10^6 Btu that would be required to meet the Subpart D limit of 1.2 lb/10^6 Btu on a 30-day, 7-day, 24-h, and 3-h basis. Table 15 summarizes the results of these calculations. These calculations are based on a 24-h RSD of 0.20 and a 24-h autocorrelation of 0.7. For a 24-h RSD of 20 percent, a 24-h autocorrelation of 0.7, and one exceedance in 10 years, long-term averages of 1.02, 0.89, 0.72, and 0.62 lb $SO_2/10^6$ Btu are needed to ensure compliance with a 30-day, 7-day, 24-h, and 3-h average emission limit of 1.2 lb 10^6/Btu, respectively. For a 24-h RSD of 10 percent, a 24-h autocorrelation of 0.7, and one exceedance in 10 years, long-term averages of 1.10, 1.02, 0.89, and 0.81 lb $SO_2/10^6$ Btu are needed to ensure compliance with a 30 day, 7-day, 24-h, and 3-h average emission limit of 1.2 lb $SO_2/10^6$ Btu, respectively. If one exceedance per year is permitted, the projected annual SO_2 emission levels required to meet the 1.2 lb $SO_2/10^6$ Btu standard at the various averaging times are approximately 2 to 8 percent higher depending on the averaging time and the RSD. If a 99 percent compliance level is assumed, the projected annual SO_2 emission levels required to meet the 1.2 lb $SO_2/10^6$ Btu standard at various averaging times are approximately 3 to 24 percent higher depending on the averaging time and the RSD.

Because the assumptions used in the projections presented in Table 15 were based on limited data, a sensitivity analysis was conducted to determine

TABLE 14. MONTHLY AVERAGE AND PROJECTED 30-DAY (ROLLING AVERAGE) SO_2 EMISSIONS FOR EASTERN ELECTRIC GENERATING UNITS SUBJECT TO SUBPART D[a]

Company name	Plant	No. of units	State	SO_2 emissions, lb/10^6 Btu: Avg. of 18 monthly values[b,c]	Maximum projected 30-day SO_2 emissions, lb/10^6 Btu[d]: RSD = 10 percent	RSD = 15 percent	RSD = 20 percent
Alabama Power Co.	Miller	1	AL	0.92[e]	0.97[f] 0.98[g] 1.00[h]	1.00[f] 1.01[g] 1.04[h]	1.03[f] 1.05[g] 1.08[h]
Arkansas Power & Light Co.	White Bluff	2	AR	0.96[e]	1.01[f] 1.03[g] 1.05[h]	1.05[f] 1.06[g] 1.08[h]	1.08[f] 1.09[g] 1.12[h]
Southwestern Electric Power Co.	Flint Creek	1	AR	0.78[e]	0.82[f] 0.83[g] 0.85[h]	0.85[f] 0.86[g] 0.88[h]	0.87[f] 0.89[g] 0.91[h]
Georgia Power Co.	Scherer	1	GA	0.95[e]	1.00[f] 1.02[g] 1.04[h]	1.04[f] 1.05[g] 1.07[h]	1.06[f] 1.08[g] 1.11[h]
Iowa Southern Utilities Co.	Ottumwa	1	IA	0.68[e]	0.71[f] 0.73[g] 0.74[h]	0.74[f] 0.75[g] 0.77[h]	0.76[f] 0.78[g] 0.80[h]
Cajun Electric Power Coop., Inc.	Big Cajun 2	2	LA	0.97[e]	1.02[f] 1.04[g] 1.06[h]	1.06[f] 1.07[g] 1.10[h]	1.09[f] 1.11[g] 1.13[h]
Mississippi Power Co.	Daniel, Victor J.	2	MS	0.92[e]	0.97[f] 0.98[g] 1.00[h]	1.00[f] 1.01[g] 1.04[h]	1.03[f] 1.05[g] 1.08[h]
Kansas City Power & Light Co.	Iatan	1	MO	0.73[e]	0.77[f] 0.78[g] 0.80[h]	0.80[f] 0.81[g] 0.82[h]	0.82[f] 0.83[g] 0.85[h]

(continued)

TABLE 14 (continued)

Company name	Plant	No. of units	State	SO_2 emissions, lb/10^6 Btu: Avg. of 18 monthly values[b,c]	Maximum projected 30-day SO_2 emissions, lb/10^6 Btu[d]: RSD = 10 percent	RSD = 15 percent	RSD = 20 percent
Dayton Power & Light Co., The	Killen Station	1	OH	0.89[e]	0.93[f] 0.95[g] 0.97[h]	0.97[f] 0.98[g] 1.01[h]	1.00[f] 1.01[g] 1.04[h]
Appalachian Power Co.	Mountaineer (1301)	1	WV	0.93[e]	0.98[f] 1.00[g] 1.01[h]	1.01[f] 1.02[g] 1.05[h]	1.04[f] 1.06[g] 1.09[h]
Wisconsin Electric Power Co.	Pleasant Prairie	1	WI	0.83[e]	0.87[f] 0.89[g] 0.90[h]	0.90[f] 0.91[g] 0.94[h]	0.93[f] 0.95[g] 0.97[h]
Central Louisiana Electric Co., Inc.	Rodemacher	1	LA	0.96[e]	1.01[f] 1.03[g] 1.05[h]	1.05[f] 1.06[g] 1.08[h]	1.08[f] 1.09[g] 1.12[h]
Gulf States Utilities Co.	Nelson, R.S.	1	LA	0.98[e]	1.03[f] 1.05[g] 1.07[h]	1.07[f] 1.08[g] 1.11[h]	1.10[f] 1.12[g] 1.15[h]

[a]In-service date of 1975 or later and a capacity $\geq$ 23 MW_e.

[b]Measured arithmetic mean.

[c]Data from January 1982 through June 1983.

[d]Projections are based on RSD's of 10, 15, 20 percent, autocorrelation of 0.7 and four exceedances per year, one exceedance per year, and one exceedance in 10 years.

[e]Subject to Subpart D as listed in CDS or based on conversation with EPA Regional Office.

[f]Assumes four exceedances per year (99% compliance level).

[g]Assumes one exceedance per year.

[h]Assumes one exceedance per 10 years.

TABLE 15. MONTHLY AVERAGE AND PROJECTED 30-DAY (ROLLING AVERAGE) SO EMISSIONS FOR WESTERN ELECTRIC GENERATING UNITS SUBJECT TO SUBPART D[a]

				SO_2 emissions, lb/10^6 Btu			
					Maximum projected 30-day SO_2 emissions, lb/10^6 Btu[d]		
Company name	Plant	No. of units	State	Avg. of 18 monthly values[b,c]	RSD = 10 percent	RSD = 15 percent	RSD = 20 percent
Colorado Springs, City of	Ray D. Nixon	1	CO	0.68[e]	0.71[f] 0.73[g] 0.74[h]	0.74[f] 0.75[g] 0.77[h]	0.76[f] 0.78[g] 0.80[h]
Kansas City Board of Public Utilities	Nearman Creek	1	KS	0.82[e]	0.86[f] 0.88[g] 0.89[h]	0.89[f] 0.90[g] 0.93[h]	0.92[f] 0.93[g] 0.96[h]
Hastings Utilities	Hastings Energy Center	1	NE	0.98[e]	1.03[f] 1.05[g] 1.07[h]	1.07[f] 1.08[g] 1.11[h]	1.10[f] 1.12[g] 1.15[h]
Nebraska Public Power District	Gentleman	2	NE	0.75[e]	0.79[f] 0.80[g] 0.82[h]	0.82[f] 0.83[g] 0.85[h]	0.84[f] 0.86[g] 0.88[h]
Omaha Public Power District	Nebraska City	1	NE	0.81[e]	0.85[f] 0.87[g] 0.88[h]	0.88[f] 0.89[g] 0.92[h]	0.91[f] 0.92[g] 0.95[h]
Sierra Pacific Power Company	North Valmy	1	NV	0.62[e]	0.65[f] 0.66[g] 0.68[h]	0.68[f] 0.69[g] 0.70[h]	0.69[f] 0.71[g] 0.73[h]
Grand River Dam Authority	GRDA 1	1	OK	0.84[e]	0.88[f] 0.90[g] 0.92[h]	0.92[f] 0.92[g] 0.95[h]	0.94[f] 0.96[g] 0.98[h]
Oklahoma Gas & Electric Co.	Muskogee	2	OK	0.74[e]	0.78[f] 0.79[g] 0.81[h]	0.81[f] 0.82[g] 0.84[h]	0.83[f] 0.84[g] 0.87[h]

(continued)

TABLE 15 (continued)

Company name	Plant	No. of units	State	SO_2 emissions, lb/10^6 Btu: Avg. of 18 monthly values[b,c]	Maximum projected 30-day SO_2 emissions, lb/10^6 Btu[d]: RSD = 10 percent	RSD = 15 percent	RSD = 20 percent
	Sooner	2	OK	0.75[e]	0.79[f] 0.80[g] 0.82[h]	0.82[f] 0.83[g] 0.85[h]	0.84[f] 0.86[g] 0.88[h]
Public Service Co. of Oklahoma	North-eastern	2	OK	0.96[e]	1.01[f] 1.03[g] 1.05[h]	1.05[f] 1.06[g] 1.08[h]	1.08[f] 1.09[g] 1.12[h]
Western Farmers Electric Coop.	Hugo	1	OK	1.04[e]	1.09[f] 1.11[g] 1.13[h]	1.13[f] 1.14[g] 1.18[h]	1.16[f] 1.19[g] 1.22[h]
Portland General Electric Co.	Boardman	1	OR	0.86[e]	0.90[f] 0.92[g] 0.94[h]	0.94[f] 0.95[g] 0.97[h]	0.96[f] 0.98[g] 1.01[h]
Central Power & Light Co.	Coleto Creek	1	TX	0.60[e]	0.63[f] 0.64[g] 0.65[h]	0.64[f] 0.66[g] 0.68[h]	0.67[f] 0.68[g] 0.70[h]
Houston Lighting & Power	Parish, W.A.	4	TX	0.87[e]	0.91[f] 0.93[g] 0.95[h]	0.95[f] 0.96[g] 0.98[h]	0.97[f] 0.99[g] 1.02[h]
Lower Colorado River Authority	Sam K. Seymour, Jr.	2	TX	0.78[e]	0.82[f] 0.83[g] 0.85[h]	0.85[f] 0.86[g] 0.88[h]	0.87[f] 0.89[g] 0.91[h]
San Antonio Public Service Board	Deely, J.T.	1	TX	0.75[e]	0.79[f] 0.80[g] 0.82[h]	0.82[f] 0.83[g] 0.85[h]	0.84[f] 0.86[g] 0.88[h]
Southwestern Electric Power Co.	Welsh	3	TX	0.78[e]	0.82[f] 0.83[g] 0.85[h]	0.85[f] 0.86[g] 0.88[h]	0.87[f] 0.89[g] 0.91[h]

(continued)

TABLE 15 (continued)

Company name	Plant	No. of units	State	SO_2 emissions, $lb/10^6$ Btu: Avg. of 18 monthly values[b,c]	Maximum projected 30-day SO_2 emissions, $lb/10^6$ Btu[d]		
					RSD = 10 percent	RSD = 15 percent	RSD = 20 percent
Southwestern Public Service Company	Harrington	3	TX	0.82[e]	0.86[f] 0.88[g] 0.89[h]	0.89[f] 0.90[g] 0.93[h]	0.92[f] 0.93[g] 0.96[h]
Grand Island Water & Light Dept.	Platte	1	NE	0.96[e]	1.01[f] 1.03[g] 1.05[h]	1.05[f] 1.06[g] 1.08[h]	1.08[f] 1.09[g] 1.12[h]
Southwestern Public Service Co.	Tolk	1	TX	0.75[e]	0.79[f] 0.80[g] 0.82[h]	0.82[f] 0.83[g] 0.85[h]	0.84[f] 0.86[g] 0.88[h]
Public Service Co. of Colorado	Pawnee	1	CO	0.77[e]	0.81[f] 0.82[g] 0.84[h]	0.84[f] 0.85[g] 0.87[h]	0.86[f] 0.88[g] 0.90[h]

[a]In-service date of 1975 or later and a capacity $\geq$ 23 MW_e.

[b]Measured arithmetic mean.

[c]Data from January 1982 through June 1983.

[d]Projections are based on RSD's of 10, 15, 20 percent, autocorrelation of 0.7, and four exceedances per year, one exceedance per year, and one exceedance in 10 years.

[e]Subject to Subpart D as listed in CDS or based on conversation with EPA Regional Office.

[f]Assumes four exceedances per year (99% compliance level).

[g]Assumes one exceedance per year.

[h]Assumes one exceedance in 10 years.

TABLE 16. PROJECTED ANNUAL SO_2 EMISSION LEVELS REQUIRED TO MEET 1.2 lb $SO_2/10^6$ Btu AT VARIOUS AVERAGING TIMES[a]

Averaging time	Annual average SO_2 emission (lb $SO_2/10^6$ Btu)		
	RSD = 10%	RSD = 15%	RSD = 20%
30-day[e]	1.13[b] 1.12[c] 1.10[d]	1.10[b] 1.09[c] 1.06[d]	1.07[b] 1.05[c] 1.02[d]
7-day[e]	1.08[b] 1.05[c] 1.02[d]	1.02[b] 0.99[c] 0.95[d]	0.97[b] 0.94[c] 0.89[d]
24-hour[f]	0.97[b] 0.94[c] 0.89[d]	0.89[b] 0.85[c] 0.79[d]	0.82[b] 0.77[c] 0.71[d]
3-hour[f]	0.94[b] 0.86[c] 0.81[d]	0.85[b] 0.75[c] 0.70[d]	0.77[b] 0.66[c] 0.62[d]

[a]RSD and autocorrelation are for 24-h average. Autocorrelation is 0.7.

[b]For 3-h, 29 exceedances per year are assumed and for 24-h, 7-day, and 30-day, four exceedances per year are assumed (99% compliance level).

[c]One exceedance per year.

[d]One exceedance in 10 years.

[e]Rolling average.

[f]Discrete nonoverlapping average.

what effect (if any) the RSD, autocorrelation, the one exceedance criteria, and the assumption that the 3-h and 24-h SO_2 values are normally distributed versus lognormally distributed, might have on these estimates.

The results in Table 16 clearly indicate that RSD has a significant impact on the projected long-term average that would be needed to meet the Subpart D limit on a 3-h or 24-h basis. For example, a unit firing coal that has an RSD of 10 percent (low variability) could emit 0.81 and 0.89 lb $SO_2/10^6$ Btu (long-term average) if it wanted to ensure that it would not exceed the 1.2 lb/10^6 Btu limit more than once in 10 years on a 3-h or 24-h basis, respectively. A unit firing coal that has an RSD of 20 percent (relatively high variability), however, could only emit 0.62 and 0.71 lb $SO_2/10^6$ Btu (long-term average) without exceeding the 1.2 $lb/10^6$ Btu limit more than once in 10 years on a 3-h or 24-h basis, respectively.

The results in Table 16 also indicate that whether the unit is allowed to exceed the 1.2 $lb/10^6$ Btu limit once per year, more than once per year or only once in 10 years has an impact on the projected long-term average that would be needed to meet the Subpart D limit on a 3-h and 24-h basis. Even when the variability is relatively low (i.e., 10%), a unit could only emit 0.81 lb $SO_2/10^6$ Btu or less without exceeding the 1.2 $lb/10^6$ Btu limit on a 3-h basis more than once in 10 years. A unit could emit 0.86 or 0.94 lb $SO_2/10^6$ Btu on a 3-h basis, however, if it were allowed to exceed the limit once per year or 29 times per year (99% compliance level), respectively.

As noted in Table 16, the calculations are based on the assumption that the 24-h autocorrelation is 0.7. This autocorrelation indicates that the 1-h values are reasonably well correlated. For determination of impact of the autocorrelation assumption of 0.7, two additional autocorrelation assumptions were evaluated: 0.5 and 0.8.

Tables 17, 18, 19, and 20 summarize the projected annual SO_2 emission levels required to meet 1.2 lb $SO_2/10^6$ Btu on a 3-h, 24-h, 7-day, and 30-day rolling average basis, respectively, assuming autocorrelations of 0.5, 0.7, and 0.8; 24-h, RSD's of 10, 15, and 20 percent; one exceedance in 10 years, one exceedance per year and 99 percent compliance level. The results in Tables 17, 18, 19, and 20 indicate that the projected emissions are less sensitive to the autocorrelation assumptions than to the RSD and the exceedance criteria assumptions.

The last assumption to be tested in terms of its impact on the projected long-term emissions needed to meet the 1.2 lb $SO_2/10^6$ Btu standard on a 3-h, 24-h, 7-day, and 30-day rolling average basis is that the data are normally distributed. As a test of the significance of this assumption, the values in Tables 17, and 18 were recalculated on the assumption that the 3-h and 24-h data are lognormally distributed. Tables 21 and 22 summarize the results of the recalculation and compare these results with the values based on the assumption that the data are normally distributed. A review of Table 21 indicates that a unit can only emit 0.52 lb $SO_2/10^6$ Btu and still meet 1.2 $lb/10^6$ Btu on a 3-h basis if the data are lognormally distributed, the 24-h RSD is 20 percent, the 24-h autocorrelation is 0.5, and the unit is permitted to exceed

TABLE 17. PROJECTED ANNUAL SO_2 EMISSION LEVELS REQUIRED TO MEET 1.2 LB $SO_2/10^6$ BTU ON A 3-H BASIS

Exceedance criteria	Annual average SO_2 emissions (lb $SO_2/10^6$ Btu)[a]								
	RSD = 10 percent			RSD = 15 percent			RSD = 20 percent		
	ρ=0.5	ρ=0.7	ρ=0.8	ρ=0.5	ρ=0.7	ρ=0.8	ρ=0.5	ρ=0.7	ρ=0.8
Once in 10 years	0.77	0.81	0.83	0.65	0.70	0.72	0.56	0.62	0.64
Once per year	0.81	0.86	0.87	0.70	0.75	0.77	0.61	0.66	0.68
29 per year	0.90	0.94	0.95	0.80	0.85	0.87	0.72	0.77	0.79

[a]Normal distribution.

TABLE 18. PROJECTED ANNUAL SO_2 EMISSION LEVELS REQUIRED TO MEET 1.2 LB $SO_2/10^6$ BTU ON A 24-H BASIS

Exceedance criteria	Annual average SO_2 emissions (lb $SO_2/10^6$ Btu)[a]								
	RSD = 10 percent			RSD = 15 percent			RSD = 20 percent		
	ρ=0.5	ρ=0.7	ρ=0.8	ρ=0.5	ρ=0.7	ρ=0.8	ρ=0.5	ρ=0.7	ρ=0.8
Once in 10 years	0.89	0.89	0.89	0.79	0.79	0.79	0.71	0.71	0.71
Once per year	0.94	0.94	0.94	0.85	0.85	0.85	0.77	0.77	0.77
4 per year	0.97	0.97	0.97	0.89	0.89	0.89	0.82	0.82	0.82

[a]Normal distribution.

TABLE 19. PROJECTED ANNUAL SO_2 EMISSION LEVELS REQUIRED TO MEET 1.2 LB SO_2 ON A 7-DAY (ROLLING AVERAGE) BASIS

Exceedance criteria	Annual average SO_2 emissions (lb $SO_2/10^6$ Btu)[a]								
	RSD = 10 percent			RSD = 15 percent			RSD = 20 percent		
	ρ=0.5	ρ=0.7	ρ=0.8	ρ=0.5	ρ=0.7	ρ=0.8	ρ=0.5	ρ=0.7	ρ=0.8
Once in 10 years	1.04	1.02	1.01	0.98	0.95	0.93	0.92	0.89	0.87
Once per year	1.07	1.05	1.02	1.02	0.99	0.97	0.97	0.94	0.92
4 per year	1.09	1.08	1.07	1.04	1.02	1.00	1.00	0.97	0.95

[a]Normal distribution.

TABLE 20. PROJECTED ANNUAL SO_2 EMISSION LEVELS REQUIRED TO MEET 1.2 LB $SO_2/10^6$ BTU ON A 30-DAY (ROLLING AVERAGE) BASIS

Exceedance criteria	Annual average SO_2 emissions (lb $SO_2/10^6$ Btu)[a]								
	RSD = 10 percent			RSD = 15 percent			RSD = 20 percent		
	ρ=0.5	ρ=0.7	ρ=0.8	ρ=0.5	ρ=0.7	ρ=0.8	ρ=0.5	ρ=0.7	ρ=0.8
Once in 10 years	1.12	1.10	1.09	1.08	1.06	1.04	1.04	1.02	1.00
Once per year	1.13	1.12	1.11	1.10	1.09	1.07	1.09	1.07	1.06
4 per year	1.14	1.13	1.12	1.12	1.10	1.09	1.09	1.07	1.06

[a]Normal distribution.

TABLE 21. PROJECTED ANNUAL SO_2 EMISSION LEVELS REQUIRED TO MEET 1.2 LB $SO_2/10^6$ BTU ON A 3-H BASIS ASSUMING NORMAL VERSUS A LOGNORMAL DISTRIBUTION

Exceedance criteria	Distribution	Annual average SO_2 emissions (lb $SO_2/10^6$ Btu)								
		RSD = 10 percent			RSD = 15 percent			RSD = 20 percent		
		ρ=0.5	ρ=0.7	ρ=0.8	ρ=0.5	ρ=0.7	ρ=0.8	ρ=0.5	ρ=0.7	ρ=0.8
Once in 10 years	Normal	0.77	0.81	0.83	0.65	0.70	0.72	0.56	0.62	0.64
Once in 10 years	Lognormal	0.72	0.76	0.78	0.61	0.65	0.68	0.52	0.58	0.60
Once per year	Normal	0.81	0.86	0.87	0.70	0.75	0.77	0.61	0.66	0.68
Once per year	Lognormal	0.76	0.81	0.82	0.65	0.71	0.72	0.57	0.62	0.64
29 per year	Normal	0.90	0.94	0.95	0.80	0.85	0.87	0.72	0.77	0.79
29 per year	Lognormal	0.85	0.88	0.89	0.75	0.80	0.82	0.68	0.72	0.74

TABLE 22. PROJECTED ANNUAL SO_2 EMISSION LEVELS REQUIRED TO MEET 1.2 LB $SO_2/10^6$ BTU ON A 24-H BASIS ASSUMING NORMAL VERSUS A LOGNORMAL DISTRIBUTION

Exceedance criteria	Distribution	Annual average SO_2 emissions (lb $SO_2/10^6$ Btu)								
		RSD = 10 percent			RSD = 15 percent			RSD = 20 percent		
		ρ=0.5	ρ=0.7	ρ=0.8	ρ=0.5	ρ=0.7	ρ=0.8	ρ=0.5	ρ=0.7	ρ=0.8
Once in 10 years	Normal	0.89	0.89	0.89	0.79	0.79	0.79	0.71	0.71	0.71
Once in 10 years	Lognormal	0.89	0.89	0.89	0.77	0.77	0.77	0.67	0.67	0.67
Once per year	Normal	0.94	0.94	0.94	0.85	0.85	0.85	0.77	0.77	0.77
Once per year	Lognormal	0.94	0.94	0.94	0.85	0.85	0.85	0.76	0.76	0.76
4 per year	Normal	0.97	0.97	0.97	0.89	0.89	0.89	0.82	0.82	0.82
4 per year	Lognormal	0.97	0.97	0.97	0.89	0.89	0.89	0.81	0.81	0.81

the 1.2 lb/10^6 Btu limit once in 10 years. On the other hand, a unit could emit as much as 0.87 lb $SO_2/10^6$ Btu if the data were normally distributed, the 24-h RSD is 10 percent, the 24-h autocorrelation is 0.8, and the unit is permitted to exceed the limit once per year and 0.95 lb $SO_2/10^6$ if the data were normally distributed, the 24-h RSD is 10 percent, the 24-h autocorrelation is 0.8, and the unit were permitted to exceed the limit 29 times per year.

A review of Table 22 indicates that a unit can emit 0.67 lb $SO_2/10^6$ Btu and still meet 1.2 lb $SO_2/10^6$ Btu on a 24-h basis if the data are lognormally distributed, the 24-h RSD is 20 percent, the 24-h autocorrelation is 0.5, and the unit is permitted to exceed the 1.2 lb $SO_2/10^6$ Btu limit once in 10 years. On the other hand, a unit could emit as much as 0.94 lb $SO_2/10^6$ Btu if the data were normally distributed, the 24-h RSD is 10 percent, the 24-h autocorrelation is 0.8, and the unit is permitted to exceed the limit once per year and 0.97 lb $SO_2/10^6$ Btu if the data were normally distributed, the 24-h RSD is 10 percent, the 24-h autocorrelation is 0.8 and the unit were permitted to exceed the limit four times per year (99% compliance level).

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5. DuBose, D. A., W. D. Kwapil, and E. F. Aul, Jr. Statistical Analysis of Wet Flue Gas Desulfurization Systems and Coal Sulfur Content. Volumes I and II. Prepared by Radian Corporation for the U.S. Environmental Protection Agency under Contract No. 68-02-3816, August 1983.

APPENDIX A

LISTING OF COAL-FIRED POWER PLANTS WITH ALL SUBPART D (NSPS) UNITS (COMPLIANCE COAL AND FGD)[a,b]

Company name	Plant	County	State	Unit number	Capacity, MWe	In service date[a]	Plant location[c] E	Plant location[c] W	FGD used Yes	FGD used No
Alabama Power	Miller	Jefferson	AL	1	705.5[d]	1978	x			x
Arizona Electric Power Coop., Inc.	Apache Station	Cochise	AZ	2	194.7[d]	1979		x	x	
				3	204.0[d]	1979		x	x	
Salt River Proj. Agri. Imp. Power Dist.	Coronado	Apache	AZ	1	410.9[d]	1979		x	x	
				2	410.9[d]	1980		x	x	
Arkansas Power and Light Co.	White Bluff	Jefferson	AR	1	800.0[d]	1980	x			x
				2	800.0[d]	1981	x			x
Southwestern Elec. Power Co.	Flint Creek	Benton	AR	1	512.3[d]	1978	x			x
Colorado Springs, City of	Ray D. Nixon	El Paso	CO	1	207.0[d]	1980		x		x
Colorado - UTE Elec. Assn., Inc.	Craig	Moffat	CO	1	447.0[d]	1980		x	x	
				2	447.0[d]	1979		x	x	
Public Service Co. of Colorado	Pawnee	Morgan	CO	1	507.0[d]	1981		x		x
Lakeland, City of Dept. of Electric and Water	Mcintosh, C.D.	Polk	FL	3	364.0[d]	1982	x		x[e]	
Georgia Power Co.	Scherer	Heard	GA	1	891.0[d]	1982	x			x
	Wansley	Heard	GA	1	952.0	1976	x			x
				2	952.0	1978	x			x

(continued)

Company name	Plant	County	State	Unit number	Capacity, MWe	In service date[a]	Plant location[c]		FGD used	
							E	W	Yes	No
Central Illinois Light Co.	Duck Creek	Fulton	IL	1	441.0[d]	1976	x		x	
Central Illinois Public Service Co.	Newton	Jasper	IL	1	617.4[d]	1977	x		x	
				2	617.4[d]	1982	x			x
Hoosier Energy, Ind. Statewide Rec.	Merom	Sullivan	IN	1	490.0[d]	1982	x		x[e]	
				2	490.0[d]	1982	x		x	
Southern Indiana Gas and Electric	A. B. Brown	Posey	IN	1	265.2[d]	1979	x		x	
Iowa Southern Utilities Co.	Ottumwa	Wapello	IA	1	726.0[d]	1981	x			x
Kansas City Board of Public Util. (KS)	Nearman Creek	Wyandotte	KS	1	262.0[d]	1981		x		x
Kansas Power and Light Co.	Jeffrey	Pottawatomie	KS	1	720.0[d]	1978		x	x	
				2	720.0[d]	1980		x	x	
Big Rivers Electric Corp.	Green	Webster	KY	1	242.1[d]	1979	x		x	
				2	242.1[d]	1980	x		x	
Cincinnati Gas and Electric Co.	East Bend	Boone	KY	2	669.0[d]	1981	x		x[e]	
Cajun Electric Power Coop. Inc.	Big Cajun 2	Pointe Coupee	LA	1	559.0[d]	1981	x			x
				2	559.0[d]	1981	x			x
Central Louisiana Electric Co., Inc.	Rodemacher	Rapides	LA	2	558.0[d]	1982	x			x

(continued)

Company name	Plant	County	State	Unit number	Capacity, MWe	In service date[a]	Plant location[c]		FGD used	
							E	W	Yes	No
Gulf States Utilities Company	Nelson, RS	Calcasieu	LA	6	614.0[f]	1982	x			x
Northern States Power Co.	Sherburne	Sherburne	MN	1	720.0[d]	1976	x		x	
				2	720.0[d]	1977	x		x	
Mississippi Power Co.	Daniel, Victor J JR.	Jackson	MS	1	548.3[d]	1977	x			x
				2	548.3[d]	1981	x			x
South Mississippi Elec. Power Assn.	Morrow	Lamar	MS	1	200.0[d]	1978	x		x	
				2	200.0[d]	1978	x		x	
Independence, City of	Missouri City	Clay	MO	1	23.0	1982	x			x
				2	23.0	1982	x			x
Kansas City Power and Light Co.	Iatan	Platte	MO	1	725.8[d]	1980	x			x
Sikeston Board of Municipal Utilities	Sikeston	Scott	MO	1	251.0[d]	1981	x		x	
Springfield Utilities (MO)	Southwest	Greene	MO	1	194.0[d]	1976	x		x	
Union Electric Co. (MO)	Rush Island	Jefferson	MO	1	620.5	1976	x			x
				2	620.5	1977	x			x
Montana Power Co., The	Colstrip	Rosebud	MT	1	358.0[d]	1975		x	x	
				2	358.0[d]	1976		x	x	
Grand Island Water and Light Dept.	Platte	Hall	NE	1	109.8[d]	1982		x		x

(continued)

Company name	Plant	County	State	Unit number	Capacity, MWe	In service date[a]	Plant location[c] E	Plant location[c] W	FGD used Yes	FGD used No
Hastings Utilities	Hastings Energy Ctr.	Adams	NE	1	76.3[d]	1981		x		x
Nebraska Public Power District	Gentleman	Lincoln	NE	1	650.0[f]	1979		x		x
				2	628.0[f]	1982		x		x
Omaha Public Power District	Nebraska City	Otoe	NE	1	565.0[d]	1979		x		x
Sierra Pacific Power Co.	North Valmy	Humboldt	NV	1	270.0[d]	1981		x		x
Cooperative Power Association	Coal Creek	Mclean	ND	1	550.0[d]	1979		x	x	
				2	550.0[d]	1981		x	x	
Montana-Dakota Utilities Co.	Coyote	Mercer	ND	1	450.0[d]	1981		x	x	
Dayton Power and Light Co., The	Killen Station	Adams	OH	2	661.0[d]	1982	x			x
Grand River Dam Authority	GRDA 1	Mayes	OK	1	490.0[d]	1981		x		x
Oklahoma Gas and Electric Co.	Muskogee	Muskogee	OK	4	550.0[d]	1977		x		x
				5	550.0[d]	1978		x		x
	Sooner	Noble	OK	1	568.8[d]	1979		x		x
				2	568.8[d]	1980		x		x
Public Service Co. of Oklahoma	North-eastern	Rogers	OK	3	472.5[d]	1979		x		x
				4	472.5[d]	1980		x		x
Western Farmers Electric Coop. (OK)	Hugo	Choctaw	OK	1	445.5[d]	1982		x		x

(continued)

Company name	Plant	County	State	Unit number	Capacity, MWe	In service date[a]	Plant location[c]		FGD used	
							E	W	Yes	No
Portland General Electric Co.	Boardman	Morrow	OR	1	560.5[d]	1980		x		x
Otter Tail Power Co.	Big Stone	Grant	SD	1	456.0	1976		x		x
Central Power and Light Co.	Coleto Creek	Goliad	TX	1	600.4[d]	1980		x		x
Houston Lighting and Power	Parish, W.A.	Fort Bend	TX	5	636.1[d]	1977		x		x
				6	636.1[d]	1979		x		x
				7	551.1[d]	1980		x		x
				8	614.6[d]	1982		x		x
Lower Colorado River Authority	Sam K. Seymour, Jr.	Fayette	TX	1	600.0[d]	1979		x		x
				2	600.0[d]	1980		x		x
San Antonio Public Service Board	Deely, J.T.	Bexar	TX	2	447.0[d]	1978		x		x
Southwestern Electric Power Co.	Welsh	Titus	TX	1	512.3[d]	1977		x		x
				2	512.3[d]	1980		x		x
				3	558.0[d]	1982		x		x
Southwestern Public Service Co.	Tolk Station	Lamb	TX	1	568.0[d]	1982		x		x
Southwestern Public Service Co.	Celanese	Hutchinson	TX	2	37.0	1979		x		x
Southwestern Public Service Co.	Harrington	Potter	TX	1	360.01[d]	1976		x		x
				2	360.0[d]	1978		x		x
				3	360.0[d]	1980		x		x

(continued)

Company name	Plant	County	State	Unit number	Capacity, MWe	In service date[a]	Plant location[c]		FGD used	
							E	W	Yes	No
Texas Power and Light Co.	Sandow	Milan	TX	4	591.0[d]	1981		x	x	
Texas Utilities Co.	Martin Lake	Rusk	TX	1	793.3	1977		x	x	
				2	793.3	1978		x	x	
				3	793.3	1978		x	x	
San Miguel Electric Coop.	San Miguel	Atascosa	TX	1	448.0[d]	1982		x	x	
Utah Power and Light Co.	Hunter (Emery)	Emery	UT	1	446.4[d]	1978		x	x	
				2	446.4[d]	1980		x	x	
Appalachian Power Co.	Mountaineer (1301)	Mason	WV	1	1300.0[d]	1980	x			
Monongahela Power Co.	Pleasants	Pleasants	WV	1	684.0[d]	1979	x		x	
				2	684.0[d]	1980	x		x	
Wisconsin Electric Power Co.	Pleasant Prairie	Kenosha	WI	1	617.0[d]	1980	x			
Basin Electric Power Coop., Inc.	Laramie River	Platte	WY	1	570.0[d]	1980		x	x	
				2	570.0[d]	1981		x	x	
				3	570.0[d]	1982		x	x[e]	

(continued)

Company name	Plant	County	State	Unit number	Capacity, MWe	In service date[a]	Plant location[c]		FGD used	
							E	W	Yes	No
Pacific Power and Light Co.	WYODAK	Campbell	WY	1	331.9	1978		x		x

[a]Listing only includes Subpart D units located at power plants with all Subpart D units with in-service date of 1975-1982 and a capacity $\geq$ 23 MWe. Plant sites with both Subpart D and SIP units are not included.

[b]Reference: Inventory of power plants in the United States 1981 and 1982 Annual - DOE and Cost and Quality of Fuels for Electric Utility Plants - DOE.

[c]Eastern locations includes units located in all States east of the Mississippi River and one State west of the Mississippi River. E = Eastern and W = Western.

[d]Subject to Subpart D as listed in EPA's Compliance Data System (CDS).

[e]Per Flue Gas Desulfurization Information System (FGDIS).

[f]Subject to Subpart D per telephone conversation with EPA Regional Office.

APPENDIX B

LISTING OF COAL-FIRED POWER PLANTS WITH BOTH SIP AND SUBPART D (NSPS) UNITS[a,b]

Company name	Plant	County	State	Unit number	Capacity, MWe	In service date	Plant location[c] E	Plant location[c] W	FGD used Yes	FGD used No
Alabama Electric Corp., Inc.	Tombigbee	Washington	AL	1	75	1969	x			x
				2	235[d]	1978	x		x	
				3	235[d]	1980	x		x	
Arizona Public Service Company	Cholla	Navajo	AZ	1	113.6	1962		x	x	
				2	288.9	1978		x	x	
				3	288.9[d]	1980		x		x
				4	414.0[d]	1981		x	x	
Salt River PROJ AGRI IMP PMR DIST	Navajo	Coconino	AZ	1	803.0	1974		x		x
				2	803.0	1975		x		x
				3	803.0	1976		x		x
Colorado-UTE Electric Assn., Inc.	Hayden	Routt	CO	1	190.0	1965		x		x
				2	275.4[d]	1976		x		x
Public Service Company of Colorado	Comanche	Pueblo	CO	1	382.5	1973		x		x
				2	396.0[d]	1976		x		x
Delmarva Power and Light Company of Delaware	Indian River	Sussex	DE	1	81.6	1957	x			x
				2	81.6	1959	x			x
				3	176.8	1970	x			x
				4	403.0[d]	1980	x			x
Florida Power Corp.	Crystal River	Citrus	FL	1	440.5	1966	x			x
				2	523.8	1969	x			x
				4	793.3[d]	1982	x			x
Gainsville-Alachua Company	Deerhaven	Alachua	FL	1	83.0	1972	x			x
				2	243.0[d]	1981	x			x

(continued)

Company name	Plant	County	State	Unit number	Capacity, MWe	In service date	Plant location[c] E	W	FGD used Yes	No
Tampa Electric Company	Big Bend	Hillsborough	FL	1	445.5	1970	x			x
				2	445.5	1973	x			x
				3	445.5	1976	x			x
Georgia Power Company	Bowen	Bartow	GA	1	805.8	1971	x			x
				2	788.8	1972	x			x
				3	952.0	1974	x			x
				4	952.0	1975	x			x
Commonwealth Edison Company	Powerton	Tazewell	IL	5	893.0	1972	x			x
				6	893.0	1975	x			x
Illinois Power Company	Baldwin	Randolph	IL	1	623.0	1970	x			x
				2	634.5	1973	x			x
				3	634.5	1975	x			x
Illinois Power Company	Havana	Mason	IL	1	46.0	1947	x			x
				2	46.0	1947	x			x
				3	46.0	1948	x			x
				4	46.0	1950	x			x
				5	46.0	1950	x			x
				6	488.5[d]	1978	x			x
Southern Illinois Power Coop.	Marion	Williamson	IL	1	33.0	1963	x			x
				2	33.0	1963	x			x
				3	33.0	1963	x			x
				4	211.0[d]	1978	x		x	
City of Springfield	Dallman	Sangamon	IL	1	90.3	1967	x			x
				2	90.3	1972	x			x
				3	207.4[d]	1978	x		x	

(continued)

Company name	Plant	County	State	Unit number	Capacity, MWe	In service date	Plant location[c] E	W	FGD used Yes	No
Indianapolis Power and Light Company	Petersburg	Pike	IN	1	253.4	1967	x			x
				2	471.0	1969	x			x
				3	574.4[d]	1977	x		x	
Northern Indiana Public Service Company	Schahfer, R.M.	Jasper	IN	14	521.0	1976	x			x
				15	511.0[d]	1979	x			x
Public Service Co. of Indiana, Inc.	Gibson	Gibson	IN	1	668.1	1976	x			x
				2	668.1	1975	x			x
				3	668.0	1978	x			x
				4	668.0	1979	x			x
				5	668.0[d]	1982	x		x	
Interstate Power Company	Lansing	Allamakee	IA	1	15.0	1948	x			x
				2	11.5	1949	x			x
				3	37.5	1957	x			x
				4	274.5[d]	1977	x			x
Ames, City of Electric Utilities	Ames	Story	IA	5	7.5	1950	x			x
				6	12.6	1958	x			x
				7	33.0	1968	x			x
				8	65.0[d]	1982	x			x
Iowa Power and Light Company	Council Bluffs	Pottawattamie	IA	1	49.0	1954	x			x
				2	81.6	1958	x			x
				3	650.0[d]	1978	x			x
Iowa Public Service Company	Neal, George	Woodbury	IA	1	147.0	1964	x			x
				2	349.0	1972	x			x
				3	550.0	1975	x			x
				4	640.0[d]	1979	x			x

(continued)

Company name	Plant	County	State	Unit number	Capacity, MWe	In service date	Plant location[c] E	Plant location[c] W	FGD used Yes	FGD used No
Kansas City Power and Light Company	La Cygne	Linn	KS	1	873.0	1973		x	x	
				2	686.0[d]	1977		x		x
East Kentucky Power Coop.	Spurlock, H.L.	Mason	KY	1	305.5	1977	x		x	
				2	508.0[d]	1981	x			x
Kentucky Utilities Company	Ghent	Carroll	KY	1	556.9	1974	x			x
				2	556.4[d]	1977	x			x
				3	556.4[d]	1981	x			x
Louisville Gas and Electric Company	Mill Creek	Jefferson	KY	1	355.5	1972	x		x	
				2	355.5	1974	x		x	
				3	462.6[e]	1978	x		x	
				4	543.6[e]	1982	x		x	
Consumers Power Company	Campbell, J.H.	Ottawa	MI	1	267.0	1962	x			x
				2	385.0	1967	x			x
				3	718.5[d]	1980	x			x
Upper Penisula Generating Company	Presque Isle	Marquette	MI	1	25.0	1955	x			x
				2	37.5	1962	x			x
				3	57.8	1964	x			x
				4	57.8	1966	x			x
				5	90.0	1974	x			x
				6	90.0	1975	x			x
				7	90.0[d]	1978	x			x
				8	90.0[d]	1978	x			x
				9	90.0[d]	1979	x			x

(continued)

Company name	Plant	County	State	Unit number	Capacity, MWe	In service date	Plant location[c] E	Plant location[c] W	FGD used Yes	FGD used No
Minnesota Power and Light Company	Boswell, Clay	Itasca	MN	1	75.0	1958	x			x
				2	75.0	1960	x			x
				3	364.5	1973	x			x
				4	558.0[d]	1980	x		x	
Associated Electric Coop., Inc.	New Madrid	New Madrid	MO	1	600.0	1972	x			x
				2	600.0	1977	x			x
	Thomas Hill	Randolf	MO	1	171.7	1966	x			x
				2	272.0	1969	x			x
				3	630.0[d]	1982	x		x	
Fremont Dept. of Utilities	Fremont #2	Dodge	NE	6	16.0	1957		x		x
				7	22.0	1963		x		x
				8	91.0[d]	1977		x		x
Nevada Power Company	Gardner, Reid	Clark	NV	1	114.0	1965		x	x	
				2	114.0	1968		x	x	
				3	114.0[d]	1976		x	x	
Public Service Company of New Mexico	San Juan	San Juan	NM	1	347.4	1976		x	x	
				2	328.7[d]	1973		x	x	
				3	517.0[d]	1979		x	x	
				4	534.0[d]	1982		x	x	
Carolina Power and Light Company	Roxboro	Person	NC	1	410.9	1966	x			x
				2	657.0	1968	x			x
				3	745.2	1973	x			x
				4	745.0[d]	1976	x			x
Duke Power Company	Belews Creek	Stokes	NC	1	1080.0	1974	x			x
				2	1080.0	1975	x			x

(continued)

Company name	Plant	County	State	Unit number	Capacity, MWe	In service date	Plant location[c] E	Plant location[c] W	FGD used Yes	FGD used No
Basin Electric Power Coop., Inc.	Lelands Olds	Mercer	ND	1	216.0	1966		x		x
				2	440.0	1975		x		x
Minnkota Power Coop., Inc.	Young, Milton R.	Oliver	ND	1	257.0	1970		x		x
				2	416.2[d]	1977		x	x	
Buckeye Power, Inc.	Cardinal	Jefferson	OH	1	590.0	1967	x			x
				2	590.0	1968	x			x
				3	615.0	1977	x			x
Cincinnati Gas and Electric Company	Miami Fort	Hamilton	OH	5	100.0	1949	x			x
				6	163.2	1960	x			x
				7	557.1	1975	x			x
				8	557.0[d]	1978	x			x
Columbus and Southern Ohio Electric Company	Conesville	Coshocton	OH	1	148.0	1959	x			x
				2	136.0	1957	x			x
				3	162.0	1962	x			x
				4	842.0	1973	x			x
				5	444.0[d]	1976	x		x	
				6	444.0[d]	1978	x		x	
Painsville Municipal Light Plant (OH)	Painsville	Lake	OH	1	3.0	1941	x			x
				2	3.0	1946	x			x
				3	8.0	1953	x			x
				4	8.0	1953	x			x
				5	17.0	1965	x			x
				6	25.0[d]	1976	x			x
AEP: Ohio Power Company	Gavin Gen. J.M.	Gallia	OH	1	1300.0	1974	x			x
				2	1300.0	1975	x			x

(continued)

Company name	Plant	County	State	Unit number	Capacity, MWe	In service date	Plant location[c] E	W	FGD used Yes	No
GPU: Pennsylvania Electric Company	Homer City	Indiana	PA	1	660.0	1969	x			x
				2	660.0	1971	x			x
				3	692.0[d]	1977	x			x
Pennsylvania Power Company	Mansfield, Bruce	Beaver	PA	1	934.9	1976	x		x	
				2	934.9	1977	x		x	
				3	871.4[d]	1980	x		x	
South Carolina Public Service Authority	Winyah	Georgetown	SC	1	315.0	1975	x			x
				2	315.0[d]	1977	x		x	
				3	315.0[d]	1981	x		x	
				4	315.0[d]	1981	x		x	
Texas Utilities Company	Monticello	Titus	TX	1	593.4	1974		x		x
				2	593.4	1975		x		x
				3	793.3[e]	1978		x	x	
Utah Power and Light Company	Huntington Canyon	Emery	UT	1	446.4[e]	1977		x	x	
				2	446.4	1974		x		x
Dairyland Power Coop.	Alma (J.P. Madgett)	Buffalo	WI	1	17.3	1947	x			x
				2	17.3	1947	x			x
				3	17.3	1951	x			x
				4	54.4	1957	x			x
				5	81.6	1960	x			x
				6	387.0[d]	1979	x			x
Wisconsin Power and Light Company	Columbia	Columbia	WI	1	556.0	1975	x			x
				2	556.0[d]	1978	x			x
Wisconsin Public Service Corp.	Weston	Marathon	WI	1	60.0	1954	x			x
				2	75.0	1960	x			x
				3	321.6[d]	1981	x			x

(continued)

Company name	Plant	County	State	Unit number	Capacity, MWe	In service date	Plant location[c] E	W	FGD used Yes	No
Pacific Power and Light Company	Bridger, Jim	Sweetwater	WY	1	508.6	1974		x		x
				2	508.6	1975		x		x
				3	508.6	1976		x		x
				4	508.6[d]	1979		x	x	

[a]Listing includes plants with both Subpart D (units with in-service date of 1975 to 1982 and a capacity >23 MWe) and SIP units. Units marked with footnote "d" or "e" are subject to Subpart D and units that are unmarked are subject to SIP requirements.

[b]References: "Inventory of Power Plants in the United States 1981 and 1982 Annual" and "Cost and Quality of Fuels for Electric Utility Plants."

[c]Eastern locations include units located in all states east of and one state west of the Mississippi River.

[d]Subject to Subpart D as listed in EPA's compliance data system (CDS).

[e]Subject to Subpart D per telephone conversation with EPA Regional Office.

APPENDIX C

MONTHLY SO_2 EMISSIONS FOR SUBPART D UNITS

Company name	Plant	No. of units	State	Type coal	SO_2 emissions ($lb/10^6$ Btu) 1/82 Percent sulfur	1/82 Emissions	2/82 Percent sulfur	2/82 Emissions	3/82 Percent sulfur	3/82 Emissions	4/82 Percent sulfur	4/82 Emissions	5/82 Percent sulfur	5/82 Emissions	6/82 Percent sulfur	6/82 Emissions
Alabama Power Co.	Miller	1	AL	BIT	0.62	0.951	0.65	1.005	0.64	0.980	0.60	0.919	0.61	0.904	0.66	1.001
Arkansas Power & Light Co.	White Bluff	2	AR	BIT	0.44	0.995	0.47	1.042	0.48	1.070	0.44	0.983	0.44	0.969	0.42	0.928
Southwestern Elec. Power Co.	Flint Creek	1	AR	BIT	0.33	0.746	0.33	0.758	0.33	0.753	0.33	0.748	0.33	0.759	0.33	0.800
Colorado Springs, City of	Ray D. Nixon	1	CO	BIT	0.41	0.725	0.37	0.668	0.36	0.656	0.37	0.678	0.39	0.711	0.41	0.750
Georgia Power Co.	Scherer	1	GA	BIT	0.67	0.971	0.70	1.028	0.65	0.946	0.63	0.911	0.64	0.924	0.65	0.934
Iowa Southern Utilities Co.	Ottumwa	1	IA	SUB	0.30	0.680	0.30	0.681	0.30	0.672	0.30	0.673	0.30	0.675	0.30	0.676
Kansas City (KANS) BD of Public Utilities	Nearman	1	KS	BIT			0.35	0.825	0.40	0.933	0.39	0.896	0.30	0.701	0.31	0.723

Company name	Plant	No. of units	State	Type coal	7/82 Percent sulfur	7/82 Emissions	8/82 Percent sulfur	8/82 Emissions	9/82 Percent sulfur	9/82 Emissions	10/82 Percent sulfur	10/82 Emissions	11/82 Percent sulfur	11/82 Emissions	12/82 Percent sulfur	12/82 Emissions
					SO_2 emissions (lb/10^6 Btu)											
Alabama Power Co.	Miller	1	AL	BIT	0.63	0.947	0.62	0.937	0.63	0.914	0.60	0.895	0.59	0.892	0.61	0.921
Arkansas Power & Light Co.	White Bluff	2	AR	BIT	0.46	1.014	0.46	1.012	0.42	0.937	0.46	1.008	0.46	1.008	0.45	0.999
Southwestern Elec. Power Co.	Flint Creek	1	AR	BIT	0.35	0.798	0.35	0.795	0.35	0.799	0.35	0.621	0.35	0.787	0.35	0.790
Colorado Springs, City of	Ray D. Nixon	1	CO	BIT	0.39	0.704	0.42	0.752	0.36	0.656	0.37	0.665	0.37	0.658	0.38	0.679
Georgia Power Co.	Scherer	1	GA	BIT	0.66	0.956	0.67	0.967	0.65	0.948	0.63	0.887	0.63	0.864	0.64	0.896
Iowa Southern	Ottumwa	1	IA	SUB	0.30	0.667	0.30	0.671	0.30	0.676	0.30	0.660	0.30	0.674	0.30	0.676
Kansas City (KANS) BD of Public Utilities	Nearman	1	KS	BIT	0.37	0.862	0.31	0.718	0.39	0.907	0.36	0.837	0.36	0.828	0.31	0.695

Company name	Plant	No. of units	State	Type coal	1/83 Percent sulfur	1/83 Emissions	2/83 Percent sulfur	2/83 Emissions	3/83 Percent sulfur	3/83 Emissions	4/83 Percent sulfur	4/83 Emissions	5/83 Percent sulfur	5/83 Emissions	6/83 Percent sulfur	6/83 Emissions
					SO_2 emissions (lb/10^6 Btu)											
Alabama Power Co.	Miller	1	AL	BIT	0.59	0.894	0.57	0.867	0.57	0.867	0.61	0.928	0.62	0.933	0.58	0.880
Arkansas Power & Light Co.	White Bluff	2	AR	BIT	0.35	0.759	0.38	0.815	0:46	0.992	0.44	0.940	0.43	0.917	0.43	0.920
Southwestern Elec. Power Co.	Flint Creek	1	AR	BIT	0.35	0.796	0.35	0.799	0.35	0.799	0.35	0.801	0.35	0.797	0.37	0.841
Colorado Springs, City of	Ray D. Nixon	1	CO	BIT	0.36	0.647	0.35	0.629	0.38	0.676	0.39	0.695	0.40	0.717	0.36	0.650
Georgia Power Co.	Scherer	1	GA	BIT	0.64	0.904	0.67	0.950	0.69	0.990	0.72	1.052	0.70	1.019	0.67	0.974
Iowa Southern Utilities Co.	Ottumwa	1	IA	SUB	0.32	0.718	0.31	0.697	0.30	0.675	0.30	0.673	0.32	0.719	0.31	0.698
Kansas City (KANS) BD of Public Utilities	Nearman	1	KS	BIT	0.32	0.744	0.38	0.882	0.35	0.812	0.33	0.759	0.39	0.900	0.41	0.940

Company name	Plant	No. of units	State	Type coal	SO_2 emissions [lb/10^6 Btu] 1/82 Percent sulfur	1/82 Emissions	2/82 Percent sulfur	2/82 Emissions	3/82 Percent sulfur	3/82 Emissions	4/82 Percent sulfur	4/82 Emissions	5/82 Percent sulfur	5/82 Emissions	6/82 Percent sulfur	6/82 Emissions
Cajun Elect. Power Coop., Inc.	Big Cajun 2	2	LA	SUB									0.44	1.036	0.40	0.938
Mississippi Power Co.	Daniel, Victor J., Jr.	2	MS	BIT	0.59	0.962	0.60	0.968	0.58	0.932	0.58	0.933	0.56	0.891	0.58	0.933
Kansas City Power and Light Co.	Iatan	1	MO	BIT	0.36	0.780	0.37	0.794	0.36	0.779			0.35	0.751	0.34	0.725
Hastings Utilities	Hastings Energy Ctr.	1	NE	BIT	0.50	1.188	0.48	1.143	0.44	1.052					0.44	1.052
Nebraska Public Power District	Gentleman	2	NE	BIT	0.36	0.783	0.37	0.796	0.35	0.756	0.36	0.784	0.35	0.750	0.35	0.745
Omaha Public Power District	Nebraska City	1	NE	BIT	0.35	0.819	0.32	0.752	0.37	0.860	0.36	0.841	0.27	0.629	0.27	0.628
Sierra Pacific Power Co.	North Valmey	1	NV	BIT	0.30	0.510	0.38	0.635	0.37	0.623	0.38	0.635	0.39	0.654	0.39	0.663

Company name	Plant	No. of units	State	Type coal	SO_2 emissions [lb/10^6 Btu]											
					7/82		8/82		9/82		10/82		11/82		12/82	
					Percent sulfur	Emissions	Percent sulfur	Emissions	Percent sulfur	Emissions	Percent sulfur	Emissions	Percent sulfur	Emissions	Percent sulfur	Emissions
Cajun Elect. Power Coop., Inc.	Big Cajun 2	2	LA	SUB	0.34	0.801	0.42	0.992	0.39	0.918	0.43	1.010	0.39	0.918	0.41	0.963
Mississippi Power Co.	Daniel, Victor J., Jr.	2	MS	BIT	0.57	0.907	0.57	0.916	0.55	0.874	0.56	0.904	0.56	0.902	0.56	0.900
Kansas City Power and Light Co.	Iatan	1	MO	BIT	0.35	0.748	0.35	0.744	0.36	0.773	0.36	0.581	0.33	0.720	0.34	0.754
Hastings Utilities	Hastings Energy Ctr.	1	NE	BIT	0.43	1.028	0.45	1.076	0.39	0.932	0.38	0.907	0.39	0.928		
Nebraska Public Power District	Gentleman	2	NE	BIT	0.35	0.744	0.35	0.751	0.36	0.774	0.36	0.773	0.36	0.771	0.35	0.752
Omaha Public Power District	Nebraska City	1	NE	BIT	0.36	0.838	0.35	0.807	0.36	0.833	0.37	0.860	0.36	0.834	0.38	0.882
Sierra Pacific Power Co.	North Valmey	1	NV	BIT	0.38	0.637	0.36	0.602	0.36	0.604	0.35	0.586	0.37	0.623	0.40	0.677

Company name	Plant	No. of units	State	Type coal	SO2 emissions (lb/10^6 Btu) 1/83 Percent sulfur	1/83 Emissions	2/83 Percent sulfur	2/83 Emissions	3/83 Percent sulfur	3/83 Emissions	4/83 Percent sulfur	4/83 Emissions	5/83 Percent sulfur	5/83 Emissions	6/83 Percent sulfur	6/83 Emissions
Cajun Elect. Power Coop., Inc.	Big Cajun 2	2	LA	SUB	0.40	0.942	0.43	1.014	0.44	1.032	0.41	0.975	0.43	1.008	0.43	1.007
Mississippi Power Co.	Daniel, Victor J., Jr.	2	MS	BIT	0.58	0.936	0.56	0.903	0.56	0.901	0.56	0.897	0.58	0.928	0.60	0.962
Kansas City Power and Light Co.	Iatan	1	MO	BIT	0.34	0.726	0.33	0.709	0.35	0.760	0.31	0.670	0.33	0.709	0.30	0.641
Hastings Utilities	Hastings Energy Ctr.	1	NE	BIT	0.38	0.905	0.38	0.904	0.38	0.904	0.37	0.881	0.36	0.857	0.40	0.952
Nebraska Public Power District	Gentleman	2	NE	BIT	0.35	0.748	0.35	0.751	0.33	0.706	0.33	0.710	0.34	0.732	0.31	0.668
Omaha Public Power District	Nebraska City	1	NE	BIT	0.34	0.789	0.41	0.952	0.33	0.767	0.32	0.737	0.36	0.826	0.37	0.852
Sierra Pacific Power Co.	North Valmey	1	NV	BIT	0.39	0.661	0.43	0.726	0.38	0.649	0.38	0.649	0.32	0.536	0.31	0.517

Company name	Plant	No. of units	State	Type coal	SO_2 emissions (lb/10^6 Btu) 1/82 Percent sulfur	1/82 Emissions	2/82 Percent sulfur	2/82 Emissions	3/82 Percent sulfur	3/82 Emissions	4/82 Percent sulfur	4/82 Emissions	5/82 Percent sulfur	5/82 Emissions	6/82 Percent sulfur	6/82 Emissions
Dayton Power & Light Co., The	Killen Station	1	OH	BIT	0.60	0.906	0.58	0.909	0.57	0.884	0.57	0.881	0.57	0.865	0.59	0.883
Grand River Dam Authority	GRDA 1	1	OK	BIT							0.34	0.797	0.27	0.628	0.31	0.721
Oklahoma Gas & Electric Co.	Muskogee	2	OK	BIT	0.35	0.760	0.37	0.791	0.36	0.782	0.37	0.802	0.36	0.773	0.34	0.722
	Sooner	2	OK	BIT	0.35	0.759	0.36	0.772	0.36	0.781	0.34	0.738	0.37	0.796	0.35	0.743
Public Service Co. of Oklahoma	North-eastern	2	OK	BIT	0.42	0.977	0.44	1.022	0.45	1.041	0.43	1.001	0.45	1.035	0.39	0.909
Western Farmers Elec. Coop (OK)	HUGO	1	OK	SUB	0.44	1.024	0.47	1.097	0.46	1.069	0.42	0.967	0.38	0.876	0.45	1.064
Portland General Electric Co.	Boardman	1	OR	COAL	0.34	0.770	0.39	0.893	0.37	0.851	0.36	0.819	0.39	0.896	0.39	0.887
Central Power & Light Co.	Coleto Creek	1	TX	BIT	0.36	0.636	0.36	0.644	0.29	0.524	0.31	0.561	0.32	0.569	0.37	0.650

					SO_2 emissions (lb/10^6 Btu)											
					7/82		8/82		9/82		10/82		11/82		12/82	
Company name	Plant	No. of units	State	Type coal	Percent sulfur	Emissions	Percent sulfur	Emissions	Percent sulfur	Emissions	Percent sulfur	Emissions	Percent sulfur	Emissions	Percent sulfur	Emissions
Dayton Power & Light Co., The	Killen Station	1	OH	BIT	0.57	0.877	0.63	0.930	0.58	0.867	0.59	0.892	0.60	0.895	0.59	0.886
Grand River Dam Authority	GRDA 1	1	OK	BIT	0.39	0.907	0.33	0.764	0.38	0.883	0.40	0.927	0.36	0.830	0.35	0.813
Oklahoma Gas & Electric Co.	Muskogee	2	OK	BIT	0.33	0.701	0.36	0.775	0.35	0.750	0.36	0.770	0.35	0.750	0.35	0.753
	Sooner	2	OK	BIT	0.36	0.768	0.36	0.772	0.36	0.776	0.37	0.792	0.34	0.730	0.36	0.771
Public Service Co. of Oklahoma	North-eastern	2	OK	BIT	0.40	0.914	0.43	0.992	0.40	0.926	0.41	0.934	0.41	0.937	0.42	0.962
Western Farmers Elec. Coop (OK)	HUGO	1	OK	SUB	0.48	1.097	0.46	1.048	0.45	1.027	0.42	0.983	0.43	0.994	0.42	0.965
Portland General Electric Co.	Boardman	1	OR	COAL	0.32	0.733	0.38	0.877	0.35	1.076	0.39	0.885	0.33	0.758	0.36	0.823
Central Power & Light Co.	Coleto Creek	1	TX	BIT	0.36	0.638	0.32	0.573	0.31	0.557	0.32	0.570	0.37	0.650	0.36	0.633

Company name	Plant	No. of units	State	Type coal	SO$_2$ emissions (lb/10^6 Btu) 1/83 Percent sulfur	1/83 Emissions	2/83 Percent sulfur	2/83 Emissions	3/83 Percent sulfur	3/83 Emissions	4/83 Percent sulfur	4/83 Emissions	5/83 Percent sulfur	5/83 Emissions	6/83 Percent sulfur	6/83 Emissions
Dayton Power & Light Co., The	Killen Station	1	OH	BIT	0.58	0.858	0.56	0.852	0.57	0.865	0.59	0.897	0.59	0.902	0.60	0.916
Grand River Dam Authority	GRDA 1	1	OK	BIT	0.38	0.878	0.41	0.958	0.34	0.793	0.39	0.895	0.41	0.944	0.38	0.873
Oklahoma Gas & Electric Co.	Muskogee	2	OK	BIT	0.35	0.748	0.34	0.725	0.33	0.708	0.32	0.688	0.32	0.685	0.32	0.688
	Sooner	2	OK	BIT	0.37	0.795	0.34	0.729	0.34	0.727	0.32	0.691	0.32	0.686	0.31	0.667
Public Service Co. of Oklahoma	North-eastern	2	OK	BIT	0.39	0.889	0.38	0.846	0.42	0.947	0.43	0.975	0.43	0.969	0.44	0.988
Western Farmers Elec. Coop (OK)	HUGO	1	OK	SUB	0.44	1.014	0.47	1.076	0.49	1.116	0.47	1.099	0.48	1.127	0.49	1.129
Portland General Electric Co.	Boardman	1	OR	COAL												
Central Power & Light Co.	Coleto Creek	1	TX	BIT	0.31	0.552	0.31	0.550	0.35	0.621	0.37	0.646	0.33	0.586	0.33	0.592

Company name	Plant	No. of units	State	Type coal	SO$_2$ emissions (lb/10^6 Btu) 1/82 Percent sulfur	1/82 Emissions	2/82 Percent sulfur	2/82 Emissions	3/82 Percent sulfur	3/82 Emissions	4/82 Percent sulfur	4/82 Emissions	5/82 Percent sulfur	5/82 Emissions	6/82 Percent sulfur	6/82 Emissions
Houston Lighting & Power	Parish, W.A.	4	TX	BIT	0.40	0.930	0.40	0.903	0.40	0.867	0.39	0.859	0.39	0.852	0.39	0.867
Lower Colorado River Authority	Sam K. Seymour, Jr.	2	TX	BIT	0.38	0.779	0.39	0.796	0.36	0.739	0.38	0.780	0.35	0.725	0.37	0.774
San Antonio Public Service BD	Deely, J. T.	1	TX	BIT							0.32	0.720	0.31	0.699	0.32	0.729
Southwestern Elec. Power Co.	Welsh	3	TX	BIT	0.33	0.745	0.33	0.757	0.33	0.755	0.33	0.747	0.33	0.751	0.35	0.798
Southwestern Public Service Co.	Harrington	3	TX	BIT	0.42	0.895	0.41	0.869	0.41	0.873	0.36	0.760	0.40	0.859	0.37	0.794
Appalachian Power Co.	Mountaineer (1301)	1	WV	BIT	0.59	0.922	0.60	0.918	0.60	0.928	0.60	0.930	0.62	0.948	0.61	0.938
Wisconsin Elec. Power Co.	Pleasant Prairie	1	WI	COAL	0.37	0.852	0.38	0.871	0.36	0.828	0.39	0.890	0.39	0.889	0.38	0.868

Company name	Plant	No. of units	State	Type coal	SO$_2$ emissions (lb/10^6 Btu) 7/82 Percent sulfur	7/82 Emissions	8/82 Percent sulfur	8/82 Emissions	9/82 Percent sulfur	9/82 Emissions	10/82 Percent sulfur	10/82 Emissions	11/82 Percent sulfur	11/82 Emissions	12/82 Percent sulfur	12/82 Emissions
Houston Lighting & Power	Parish, W.A.	4	TX	BIT	0.39	0.866	0.38	0.865	0.37	0.829	0.37	0.832	0.40	0.911	0.40	0.904
Lower Colorado River Authority	Sam K. Seymour, Jr.	2	TX	BIT	0.37	0.759	0.37	0.760	0.37	0.769	0.38	0.788	0.35	0.731	0.39	0.823
San Antonio Public Service BD	Deely, J. T.	1	TX	BIT	0.33	0.732	0.31	0.699	0.40	0.890	0.38	0.855	0.31	0.698	0.39	0.883
Southwestern Elec. Power Co.	Welsh	3	TX	BIT			0.35	0.796	0.35	0.802	0.35	0.794	0.35	0.792	0.35	0.797
Southwestern Public Service Co.	Harrington	3	TX	BIT	0.37	0.778	0.38	0.800	0.42	0.886	0.38	0.812	0.39	0.823	0.40	0.842
Appalachian Power Co.	Mountaineer (1301)	1	WV	BIT	0.61	0.944	0.58	0.923	0.59	0.910	0.61	0.930	0.61	0.926	0.60	0.914
Wisconsin Elec. Power Co.	Pleasant Prairie	1	WI	COAL	0.39	0.822	0.31	0.716	0.38	0.879	0.38	0.876	0.34	0.784	0.33	0.769

Company name	Plant	No. of units	State	Type coal	SO_2 emissions [lb/10^6 Btu]											
					1/83		2/83		3/83		4/83		5/83		6/83	
					Percent sulfur	Emissions	Percent sulfur	Emissions	Percent sulfur	Emissions	Percent sulfur	Emissions	Percent sulfur	Emissions	Percent sulfur	Emissions
Houston Lighting & Power	Parish, W.A.	4	TX	BIT	0.36	0.806	0.36	0.800	0.44	0.985	0.43	0.958	0.39	0.872	0.32	0.710
Lower Colorado River Authority	Sam K. Seymour, Jr.	2	TX	BIT	0.38	0.794	0.36	0.751	0.37	0.771	0.38	0.802	0.38	0.801	0.39	0.824
San Antonio Public Service BD	Deely, J. T.	1	TX	BIT	0.37	0.838	0.32	0.719	0.31	0.700	0.30	0.677	0.30	0.682	0.31	0.700
Southwestern Elec. Power Co.	Welsh	3	TX	BIT	0.35	0.796	0.35	0.798	0.35	0.795	0.35	0.801	0.33	0.747	0.35	0.794
Southwestern Public Service Co.	Harrington	3	TX	BIT	0.40	0.844	0.40	0.851	0.40	0.840	0.40	0.848	0.34	0.724	0.31	0.652
Appalachian Power Co.	Mountaineer (1301)	1	WV	BIT	0.60	0.908	0.60	0.905	0.60	0.916	0.58	0.884	0.61	0.931	0.64	0.969
Wisconsin Elec. Power Co.	Pleasant Prairie	1	WI	COAL	0.32	0.742	0.35	0.818	0.37	0.866	0.33	0.767	0.37	0.853	0.34	0.787

Company name	Plant	No. of units	State	Type coal	SO_2 emissions (lb/10^6 Btu) 7/82 Percent sulfur	7/82 Emissions	8/82 Percent sulfur	8/82 Emissions	9/82 Percent sulfur	9/82 Emissions	10/82 Percent sulfur	10/82 Emissions	11/82 Percent sulfur	11/82 Emissions	12/82 Percent sulfur	12/82 Emissions
Central Louisiana Elec. Co., Inc.	Rodemacher	1	LA	SUB	0.44	0.968	0.47	1.026	0.39	0.871	0.44	0.891	0.41	0.903	0.38	0.845
Gulf States Utilities Co.	Nelson, R. S.	1	LA	SUB	0.49	1.084	0.47	1.035	0.40	0.888	0.40	0.885	0.40	0.0880	0.40	0.925
Grand Island Water & Light Dept.	Platte	1	NE	SUB	0.31	0.736	0.40	0.948	0.38	0.898			0.42	0.987	0.45	1.067
Southwestern Public Service Co.	Tolk	1	TX	BIT			0.36	0.775	0.36	0.765	0.38	0.812	0.37	0.803	0.37	0.816
Public Service Co. of Colorado	Pawnee	1	CO	BIT	0.34	0.774	0.36	0.812	0.29	0.657	0.33	0.746	0.33	0.747	0.35	0.791

Company name	Plant	No. of units	State	Type coal	SO$_2$ emissions (lb/10^6 Btu) 1/82 Percent sulfur	1/82 Emissions	2/82 Percent sulfur	2/82 Emissions	3/82 Percent sulfur	3/82 Emissions	4/82 Percent sulfur	4/82 Emissions	5/82 Percent sulfur	5/82 Emissions	6/82 Percent sulfur	6/82 Emissions
Central Louisiana Elec. Co., Inc.	Rodemacher	1	LA	SUB	0.48	1.069	0.48	1.061	0.44	0.976	0.44	0.981	0.48	1.062	0.46	1.018
Gulf States Utilities Co.	Nelson, R. S.	1	LA	SUB	0.40	0.890	0.47	1.041	0.45	0.995	0.40	0.894	0.60	1.315	0.55	1.203
Grand Island Water & Light Dept.	Platte	1	NE	SUB												
Southwestern Public Service Co.	Tolk	1	TX	BIT												
Public Service Co. of Colorado	Pawnee	1	CO	BIT	0.36	0.812	0.38	0.865	0.33	0.752	0.37	0.833	0.33	0.752	0.37	0.836

Company name	Plant	No. of units	State	Type coal	SO_2 emissions ($lb/10^6$ Btu)											
					1/83		2/83		3/83		4/83		5/83		6/83	
					Percent sulfur	Emissions	Percent sulfur	Emissions	Percent sulfur	Emissions	Percent sulfur	Emissions	Percent sulfur	Emissions	Percent sulfur	Emissions
Central Louisiana Elec. Co., Inc.	Rodemacher	1	LA	SUB	0.34	0.736	0.45	0.966	0.47	1.013	0.45	0.961	0.47	1.002	0.45	0.961
Gulf States Utilities Co.	Nelson, R. S.	1	LA	SUB	0.40	0.863	0.40	0.860	0.40	0.858	0.46	0.982	0.48	1.024	0.48	1.035
Grand Island Water & Light Dept.	Platte	1	NE	SUB	0.48	1.134	0.41	0.957	0.36	0.852	0.41	0.970	0.40	0.939	0.44	1.024
Southwestern Public Service Co.	Tolk	1	TX	BIT	0.30	0.656	0.30	0.652	0.40	0.863	0.30	0.648			0.33	0.717
Public Service Co. of Colorado	Pawnee	1	CO	BIT	0.33	0.746	0.32	0.716			0.34	0.765	0.32	0.718	0.32	0.718

APPENDIX D

MAP DENOTING BOUNDARY BETWEEN EASTERN AND WESTERN UNITS


WESTERN
EASTERN
WASHINGTON
OREGON
CALIFORNIA
IDAHO
NEVADA
MONTANA
WYOMING
UTAH
ARIZONA
COLORADO
NEW MEXICO
NORTH DAKOTA
SOUTH DAKOTA
NEBRASKA
KANSAS
OKLAHOMA
TEXAS
MINNESOTA
IOWA
MISSOURI
ARKANSAS
LOUISIANA
WISCONSIN
ILLINOIS
MICHIGAN
INDIANA
OHIO
KENTUCKY
TENNESSEE
MISSISSIPPI
ALABAMA
GEORGIA
FLORIDA
SOUTH CAROLINA
NORTH CAROLINA
VIRGINIA
WEST VIRGINIA
PENNSYLVANIA
NEW YORK
MD.
DEL.
NJ
CONN.
RI
MASS.
VT.
N.H.
MAINE