ADEQ
OPERATING
AIR PERMIT

Pursuant to the Regulations of the Arkansas Operating Air Permit Program, Regulation 26:

Permit No. : 1995-AOP-R1
IS ISSUED TO:
LSP Services Plum Point, LLC
As operator for the following owners:
Plum Point Energy Associates, LLC
East Texas Electric Cooperative, Inc.
Missouri Joint Municipal Electric Utility Commission
The Empire District Electric Company
2732 S. County Road 623
Osceola, AR 72370
Mississippi County
AFIN: 47-00461

THIS PERMIT AUTHORIZES THE ABOVE REFERENCED PERMITTEE TO INSTALL, OPERATE, AND MAINTAIN THE EQUIPMENT AND EMISSION UNITS DESCRIBED IN THE PERMIT APPLICATION AND ON THE FOLLOWING PAGES. THIS PERMIT IS VALID BETWEEN:

August 20, 2003 AND August 19, 2008

THE PERMITTEE IS SUBJECT TO ALL LIMITS AND CONDITIONS CONTAINED HEREIN.

Signed:

Mike Bates
Chief, Air Division

Date Modified

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List of Acronyms and Abbreviations

A.C.A.	Arkansas Code Annotated
AFIN	ADEQ Facility Identification Number
CFR	Code of Federal Regulations
CO	Carbon Monoxide
HAP	Hazardous Air Pollutant
lb/hr	Pound Per Hour
MVAC	Motor Vehicle Air Conditioner
No.	Number
NO_x	Nitrogen Oxide
PM	Particulate Matter
PM_{10}	Particulate Matter Smaller Than Ten Microns
SNAP	Significant New Alternatives Program (SNAP)
SO_2	Sulfur Dioxide
SSM	Startup, Shutdown, and Malfunction Plan
Tpy	Tons Per Year
UTM	Universal Transverse Mercator
VOC	Volatile Organic Compound

SECTION I: FACILITY INFORMATION

PERMITTEE:	LSP Services Plum Point, LLC As operator for the following owners: Plum Point Energy Associates, LLC East Texas Electric Cooperative, Inc. Missouri Joint Municipal Electric Utility Commission The Empire District Electric Company
AFIN:	47-00461
PERMIT NUMBER:	1995-AOP-R1
FACILITY ADDRESS:	2732 S. County Road 623 Osceola, AR 72370
MAILING ADDRESS:	Two Tower Center 11th Floor East Brunswick, NJ 08816
COUNTY:	Mississippi
CONTACT POSITION:	Samuel Joshi
TELEPHONE NUMBER:	732-249-6750
REVIEWING ENGINEER:	Shawn Hutchings
UTM North South (Y):	Zone 16: 3949.8386
UTM East West (X):	Zone 16: 233.6424

SECTION II: INTRODUCTION

LSP Services Plum Point LLC As operator for the following owners: Plum Point Energy Associates, LLC;East Texas Electric Cooperative, Inc.; Missouri Joint Municipal Electric Utility Commission; and The Empire District Electric Company (permittee) proposes to construct and operate a nominal 665 MW coal fired generating station approximately three miles south of Osceola at 2732 S. County Road 623. The facility will be designed to burn primarily low-sulfur sub-bituminous Powder River Basin Coal, with the flexibility of blending in alternate coals. Low sulfur distillate fuel oil will be used as the start-up fuel for the pulverized coal unit and for operation of the auxiliary boiler.

Summary of Permit Activity

This permit specifies the size of the boiler, SN-01, as 665MW from the 800 to 550 MW range of the initial permit as required in Plantwide Condition 21 of 1995-AOP-R0. Also with this permit the size of the auxiliary boiler, SN-05 is increased to 367 from 175 MMbtu/hr. The cooling tower, SN-03 is reduced from 20 to 18 cells, a carbon silo, SN-38 is added, and the #2 fuel oil storage tank, SN-35 has dropped in size from 330,000 gallons to 250,000 gallons. Emissions from a number of the conveyors and storage piles were also updated due to the facility specifying the main boiler size and having a more finalized plant layout.

During the comment period Plum Point submitted an update to the facility layout. It relocated the railcar unloading equipment from the east side to the west side of the plant site, set the final design parameters for the auxiliary boiler and made minor adjustments to building coordinates to reflect the final design layout. This submittal included a modeling analysis which shows that the maximum modeled concentration of criteria pollutants were less than the impacts predicted with the modeling of the original permit. The Department has reviewed this submittal and these changes will require no updates to any of the language of the permit.

Process Description

The facility uses one pulverized coal-fired boiler to generate steam which drives a condensing steam-turbine generator that generates electricity. The pulverized coal-fired boiler will use low sulfur distillate fuel for startup. In addition, an oil-fired auxiliary boiler may be used to aid in the startup of the pulverized coal-fired boiler. A cooling tower will be used to reject heat from the condenser. Combustion gasses from the pulverized coal-fired boiler will pass through emission control equipment (SCR, scrubber and fabric filters) and then exit through the stack.

Coal will be delivered to the facility by barge and/or railcar. The facility's coal handling system will include unloading facilities, conveyors, active and inactive coal piles, transfer/crusher house, coal silos, pulverizers and other equipment necessary to manage the coal. Distillate fuel oil for use in the facility's boiler for start-up and diesel fuel and gasoline used for plant vehicles will be stored in fuel storage tanks.

Lime for use in the dry scrubber will be delivered by truck and/or rail and be pneumatically transferred into storage silos. Fly ash (which includes economizer ash, air heater ash, fly ash and scrubber waste) will be disposed of either in an on-site disposal facility or hauled off-site. The fly ash handling system may include storage silos; truck, barge and rail loading facilities; pneumatic handling systems; conveyor systems; and an on-site disposal facility.

Particulate emissions from the coal, lime and ash handling systems and roadways will be controlled by enclosures, partial enclosures, fabric filters, water sprays and dust suppressants, as appropriate.

Regulations

The following table contains the regulations applicable to this permit.

Regulations
Arkansas Air Pollution Control Code, Regulation 18, effective February 15, 1999
Regulations of the Arkansas Plan of Implementation for Air Pollution Control, Regulation 19, effective December 19, 2004
Regulations of the Arkansas Operating Air Permit Program, Regulation 26, effective September 26, 2002
Prevention of Significant Deterioration; 40 CFR Part 60, Subpart Da, *Standards of Performance for Electric Utility Steam Generating Units for Which Construction is Commenced After September 18, 1978*
40 CFR Part 60, Subpart Db, *Standards of Performance for Industrial-Commercial-Institutional Steam Generating Units*
40 CFR Part 60, Subpart Kb, *Standards of Performance for Volatile Organic Liquid Storage Vessels (Including Petroleum Liquid Storage Vessels) for Which Construction, Reconstruction, or Modification Commenced after July 23, 1984*
40 CFR Part 60, Subpart Y, *Standards of Performance for Coal Preparation Plants,* and 40 CFR Part 64
Compliance Assurance Monitoring 40 CFR Part 64

The following table is a summary of emissions from the facility. This table, in itself, is not an enforceable condition of the permit.

Emission Summary

EMISSION SUMMARY				
Source Number	Description	Pollutant	Emission Rates	
			lb/hr	tpy

Total Allowable Emissions		PM	154.5	654.5
		PM_{10}	130.4	554.9
		SO_2	1088	4688.8
		VOC	135.1	587.8
		CO	1082	4687.3
		NO_x	639	2644.2
		Lead	0.17	0.75
		H_2SO_4	41.3	179.1
		Fluoride (as HF)	6.1	26.9
HAPs*		HCl	88	386
		Arsenic	0.17	0.73
		Beryllium	0.01	0.04
		Cadmium	0.02	0.10
		Chromium	0.11	0.46
		Formaldehyde	0.10	0.40
		Manganese	0.20	0.87
		Mercury	0.09	0.23
		Nickel	0.11	0.50
		Selenium	0.53	2.32
		Cobalt	0.04	0.18
		PAH	0.01	0.04
		Acetaldehyde	0.24	1.02
		Acrolein	0.12	0.52
		Benzene	0.53	2.32
		benzyl chloride	0.29	1.25
		Bis(2-ethylhexyl)phthalate	0.03	0.13
		carbon disulfide	0.06	0.24
		2-chloroacetophenone	0.01	0.02
		Chloroform	0.03	0.11
		cyanide	0.09	0.39
		dimethylsuflate	0.02	0.09
		ethylene dichloride	0.02	0.08
		isophorone	0.24	1.04
		methyl chloride	0.22	0.95
		methyl hydrazine	0.07	0.31
		methylene chloride	0.12	0.52
		phenol	0.01	0.03
		propionaldehyde	0.16	0.68
		toluene	0.10	0.43
		styrene	0.02	0.05
Air Contaminants **		ammonia	73.0	320.0
SN	Description	Pollutant	lb/hr	tpy
		PM	134	586
		PM_{10}	120	527

		SO_2	1069	4684
		VOC	134	586
		CO	1069	4684
		NO_x	602	2635
		Lead	0.17	0.75
		H_2SO_4	41	179
		Fluoride (as HF)	6.1	26.9
		HCl	88	386
		Arsenic	0.17	0.73
		Beryllium	0.01	0.04
		Cadmium	0.02	0.10
		Chromium	0.11	0.46
		Formaldehyde	0.10	0.40
		Manganese	0.20	0.87
		Mercury	0.09	0.23
		Nickel	0.11	0.50
		Selenium	0.53	2.32
		Cobalt	0.04	0.18
		PAH	0.01	0.04
		Acetaldehyde	0.24	1.02
		acrolein	0.12	0.52
		benzene	0.53	2.32
		benzyl chloride	0.29	1.25
		Bis(2-ethylhexyl)phthalate	0.03	0.13
		carbon disulfide	0.06	0.24
		2-chloroacetophenone	0.01	0.02
		Chloroform	0.03	0.11
		cyanide	0.09	0.39
		dimethylsuflate	0.02	0.09
		ethylene dichloride	0.02	0.08
		isophorone	0.24	1.04
		methyl chloride	0.22	0.95
		methyl hydrazine	0.07	0.31
		methylene chloride	0.12	0.52
		phenol	0.01	0.03
		propionaldehyde	0.16	0.68
		toluene	0.10	0.43
		styrene	0.02	0.05
		ammonia	73.0	320.0
03	Unit 1 Cooling Tower	PM	3.6	15.4
		PM_{10}	0.7	2.8
05	Auxiliary Boiler	PM	3.7	1.0
		PM_{10}	2.7	0.7
			19.0	4.8

		SO_2 VOC CO NO_x H_2SO_4	0.6 13.0 37.0 0.3	0.2 3.3 9.2 0.08
08	Baghouse 1 at Railcar Unloading (Coal)	PM PM_{10}	0.1 0.1	0.5 0.2
09	Stackout Conveyor #1	PM PM_{10}	0.1 0.1	0.4 0.4
10	Barge Unloading Station	PM PM_{10}	0.2 0.1	0.7 0.3
11	Stackout Conveyor #2	PM PM_{10}	0.4 0.4	1.9 1.9
12	Emergency Reclaim Conveyor	PM PM_{10}	0.1 0.1	0.4 0.4
13	Stackout Transfer Point	PM PM_{10}	0.4 0.2	1.6 0.6
14	Active Pile #1	PM PM_{10}	1.2 1.2	5.0 5.0
15	Active Pile #2	PM PM_{10}	1.2 1.2	5.0 5.0
16	Reclaim Conveyor #1	PM PM_{10}	0.1 0.1	0.3 0.3
17	Transfer House	PM PM_{10}	0.2 0.1	0.6 0.3
18	Reclaim Conveyor #2	PM PM_{10}	0.1 0.1	0.4 0.4
19	Reclaim Transfer Point #2	PM PM_{10}	0.1 0.1	0.4 0.2
20	Tripper Deck Conveyor	PM PM_{10}	0.1 0.1	0.1 0.1
21	Reclaim Transfer Point #3	PM PM_{10}	0.1 0.1	0.1 0.1
22	Inactive Coal Pile	PM PM_{10}	0.2 0.2	0.6 0.6

23	Pile Transfer	PM PM_{10}	2.9 0.5	12.4 2.0
24	Fly Ash Silos	PM PM_{10}	0.1 0.1	0.1 0.1
25	Fly Ash Rail Transport	PM PM_{10}	0.1 0.1	0.1 0.1
26	Fly Ash Barge Transport	PM PM_{10}	0.1 0.1	0.1 0.1
27	Fly Ash Pneumatic Transport to Disposal Facility	PM PM_{10}	0.1 0.1	0.1 0.1
28	Fly Ash Transport Point #1	PM PM_{10}	0.1 0.1	0.1 0.1
29	Fly Ash Transfer	PM PM_{10}	0.1 0.1	0.4 0.4
30	Fly Ash Transfer Point #2	PM PM_{10}	0.1 0.1	0.1 0.1
31	Ash Disposal Area	PM PM_{10}	2.2 0.6	9.4 2.5
32	Lime Storage	PM PM_{10}	0.1 0.1	0.1 0.1
33	Unpaved Roadway Travel	PM PM_{10}	2.4 0.7	10.4 2.7
34	Paved Roadway Travel	PM PM_{10}	0.2 0.1	0.7 0.2
35	330,000 Gallon Oil Storage Tank	VOC	0.1	0.1
36	8,000 Gallon Unleaded Gasoline Storage Tank	VOC	0.4	1.5
38	Carbon Storage Silo	PM PM	0.1 0.1	0.1 0.1

*All HAPs except HCl are included in either the VOC or PM totals.
**Air Contaminants such as ammonia, acetone, and certain halogenated solvents are not VOCs or HAPs.

SECTION III: PERMIT HISTORY

Permit 1995-AOP-R0

Permit 1995-AOP-R0 was issued on August 20, 2003. This permit was the initial permit for the facility.

The Plum Point facility will be a new major source under Prevention of Significant Deterioration (PSD) regulations. The facility will result in significant emissions of CO, PM_{10}, NO_x, SO_2, VOC, lead, fluoride emissions, and sulfuric acid mist (H_2SO_4), and is required to undergo PSD review for these pollutants.

Best Available Control Technology

The PSD regulations mandate that a case-by-case Best Available Control Technology (BACT) analysis be performed on all new or modified affected sources at which a net emissions increase will occur. Since all of the sources at the Plum Point facility are new, a case by case BACT analysis was performed for all sources at the facility. A table at the end of this section will summarize the BACT control and BACT limits of the facility.

The following table is a summary of the BACT determinations made in this permit.

BACT Analysis Summary				
Source	Description	Pollutant	Control Technology	BACT Limit
01	Coal Fired Boiler	PM_{10} SO_2 VOC CO NO_x H_2SO_4 lead Fluoride	Fabric Filter Dry FGD Combustion Control Combustion Control Low NO_x burners with overfire air and SCR Dry FGD/fabric filter Fabric Filter Dry FGD/fabric filter	0.018 lb/MMBTU 0.16 lb/MMBTU 0.02 lb/MMBTU 0.16 lb/MMBTU 0.09 lb/MMBTU 0.0061 lb/MMBTU 2.56E-5 lb/MMBTU 0.00044 lb/MMBTU or 90% control efficiency by weight
03	Cooling Tower	PM_{10}	Use of mist eliminators	0.8 lb/hr
05	Auxiliary Boiler	PM_{10} SO_2 VOC CO	Low Ash Fuel Low Sulfur Fuel Oil Combustion Control Combustion Control	0.0071 lb/MMBTU 0.051 lb/MMBTU 0.0015 lb/MMBTU 0.036 lb/MMBTU

BACT Analysis Summary				
Source	Description	Pollutant	Control Technology	BACT Limit
		NO_x	Low NO_x burners and Flue Gas Recirculation	0.10 lb/MMBTU
		H_2SO_4	Low Sulfur Fuel Oil	0.0008 lb/MMBTU

Three different BACT controls were used to control particulate emissions from the dust sources. The following table summarizes the BACT controls level and which sources to which these controls apply.

Type of Control	Sources
Fabric Filtration	Pneumatic Fly Ash Transfer Coal Crushers Crushed Coal Transfer and Coal Storage Silos Pneumatic Lime Receiving and Storage
Partial Enclosures	Barge Unloading Railcar Unloading Coal Transfer Conveyors Ash Conveyors
Water Sprays, Dust Suppressants, etc.	Railcar Unloading Coal Storage Piles Ash Truck Transfer Waste Disposal Area Paved and Unpaved Roadway Travel

Case by Case MACT Determination

Section 112(g) of the Clean Air Act requires that the permitting authority determine a MACT emission limitation on a case-by-case basis for newly constructed major sources of HAPs for which no federal emission limitation has been promulgated. The Plum Point facility will be a new major source for HAPs and is therefore required to undergo a case-by-case MACT determination.

An administrative amendment to permit 1995-AOP-R0 was issued on October 31, 2003. In this amendment, the SO_2 ton per year emission rates were corrected for SN-01 on pages 15 and 26. The emission totals for SO_2 were also corrected on page 14. A number of typographical errors on pages 4 and 5 were corrected. Also, the CSN number of the old permit was converted to the corresponding new AFIN number throughout the permit.

SECTION IV: SPECIFIC CONDITIONS

SN–01

Unit 1 Boiler

Source Description

The Unit 1 Boiler is a 665 MW pulverized coal fired boiler generates steam which drives condensing steam-turbine generators.

Specific Conditions

1. The permittee shall not exceed the emission rates set forth in the following table. Compliance with the lb/hr limit for PM_{10} will be demonstrated by comparison of the limit to the results of the tests conducted pursuant to Specific Condition 13 and compliance with the CAM provisions of Specific Condition 17. Compliance with the ton per year limit for PM_{10} will be demonstrated by compliance with the CAM provisions of Specific Condition 17. Compliance with the lb/hr limit for H_2SO_4 will be demonstrated by comparison of the limit to the results of the tests conducted pursuant to Specific Condition 13 and compliance with the CAM provisions of Specific Condition 18. Compliance with the ton per year limit for H_2SO_4 will be demonstrated by compliance with the CAM provisions of Specific Condition 18. Compliance with the lb/hr limit for CO will be demonstrated by comparison of the limit to the 1 hour average CO reading obtained from the CEMs installed pursuant to Specific Condition 11. Compliance with the tpy limit for CO will be demonstrated by comparison of the limit to the summation over any consecutive 12 month period of the hourly CO readings from the CEMs. To show compliance with the lb/hr limit such comparisons will be made for each hour that the source is in operation excluding periods of startup, shutdown, and malfunction. To show compliance with the ton per year limit such comparisons will be made for each hour that the source is in operation. Compliance with the lb/hr limit for VOC will be demonstrated by comparison of the limit to the results of the tests conducted pursuant to Specific Condition 13. Compliance with the ton per year limit for VOC will be demonstrated by demonstrating compliance with the lb/hr VOC limit. Compliance with the lb/hr limit for SO_2 will be demonstrated by comparison of the limit to the 3 hour rolling average SO_2 reading obtained from the CEMs installed pursuant to Specific Condition 9. Compliance with the ton per year limit for SO_2 will be demonstrated by comparison of the limit to the summation over any consecutive 12 month period of the hourly SO_2 readings from the CEMs. To show compliance with the lb/hr limit such comparisons will be made for each hour that the source is in operation excluding periods of startup, shutdown, and malfunction. To show compliance with the ton per year limit such comparisons will be made for each hour that the source is in operation. Compliance with the lb/hr limit for NO_x will be demonstrated by comparison of the limit to the 30 day rolling average NO_x reading obtained from the CEMS installed pursuant to Specific Condition 9. Compliance with the ton per year limit for NO_x will be demonstrated by

comparison of the limit to the summation over any consecutive 12 month period of the hourly NO_x readings from the CEMs. To show compliance with the lb/hr limit such comparisons will be made for each hour that the source is in operation excluding periods of startup, shutdown, and malfunction. To show compliance with the ton per year limit such comparisons will be made for each hour that the source is in operation. Compliance with the lb/hr limit for PM will be demonstrated by comparison of the limit to the result of the test conducted pursuant to Specific Condition 12. Compliance with the ton per year limit for PM will be demonstrated by complying with the lb/hr limit for PM. Compliance with the lead lb/hr and ton per year limits will be demonstrated by complying with the PM_{10} limits of this condition. Compliance with the lb/hr and ton per year limits for fluoride will be demonstrated by complying with the fluoride BACT limit in Specific Condition 6. [§19.901 et seq of the Regulations of the Arkansas Plan of Implementation for Air Pollution Control (Regulation #19) effective February 15, 1999 and 40 CFR Part 52, Subpart E]

Source	Pollutant	lb/hr	tpy
01	PM	134	586
	PM_{10}	120	527
	SO_2	1069	4684
	VOC	134	586
	CO	1069	4684
	NO_X	602	2635
	Lead	0.17	0.75
	H_2SO_4	41	179
	Fluoride (as HF)	6.1	26.9

2. The permittee shall not exceed the emission rates set forth in the following table. Compliance with the lb/hr limit for HCl will be demonstrated by comparison of the limit to the result of the test conducted pursuant to Specific Condition 15 and demonstrated by compliance with the CAM provisions of Specific Condition 18. Compliance with the ton per year limit for HCl will be demonstrated by compliance with the CAM provisions of Specific Condition 18. Compliance with the lb/hr limit for mercury will be demonstrated by comparison of the limit to the result of the test conducted pursuant to Specific Condition 15. Compliance with the ton per year limit for mercury will be demonstrated by compliance with the lb/hr limit. Compliance with the lb/hr and ton per year limits for arsenic, beryllium, cadmium, chromium, manganese, nickel, selenium, and cobalt will be demonstrated by complying with the lb/hr and ton per year limits for PM_{10} as provided by Specific Condition 1. Compliance with the lb/hr and ton per year limits for the organic

pollutants in the table below will be demonstrated by compliance with the lb/hr and ton per year limits for VOC as provided in Specific Condition 1. [§19.304 and 40 CFR Part 63, Subpart B]

Source	Pollutant	lb/hr	tpy
01	HCl	88	386
	Arsenic	0.17	0.73
	Beryllium	0.01	0.04
	Cadmium	0.02	0.10
	Chromium	0.11	0.46
	Formaldehyde	0.10	0.40
	Manganese	0.20	0.87
	Mercury	0.09	0.23
	Nickel	0.11	0.50
	Selenium	0.53	2.32
	Cobalt	0.04	0.18
	PAH	0.01	0.04
	Acetaldehyde	0.24	1.02
	acrolein	0.12	0.52
	benzene	0.53	2.32
	benzyl chloride	0.29	1.25
	Bis(2-ethylhexyl)phthalate	0.03	0.13
	carbon disulfide	0.06	0.24
	2-chloroacetophenone	0.01	0.02
	Chloroform	0.03	0.11
	cyanide	0.09	0.39
	dimethylsuflate	0.02	0.09
	ethylene dichloride	0.02	0.08
	isophorone	0.24	1.04
	methyl chloride	0.22	0.95
	methyl hydrazine	0.07	0.31
	methylene chloride	0.12	0.52
	phenol	0.01	0.03
	propionaldehyde	0.16	0.68
	toluene	0.10	0.43
	styrene	0.02	0.05

3. The permittee shall not exceed the emission rates set forth in the following table. Compliance with the lb/hr limit for ammonia will be demonstrated by comparison of the limit to the result of the test conducted pursuant to Specific Condition 14. Compliance with the ton per year limit will be demonstrated by complying with the lb/hr limit.

[§18.801 of the Arkansas Air Pollution Control Code (Regulation #18) effective February 15, 1999, and A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311]

Source	Pollutant	lb/hr	tpy
01	Ammonia	73.0	320.0

4. The permittee shall not discharge into the atmosphere any gases from SN-01, exhibiting an opacity greater than 20% opacity (6-minute average), except for one 6-minute period per hour of not more than 27 percent opacity. Compliance with this condition will be demonstrated by complying with the lower opacity limit of Specific Condition 5. If at any time the source is not in compliance with Specific Condition 5, compliance will be demonstrated by comparison of the limit to the 6-minute average opacity reading obtained from the opacity CEMS installed pursuant to Specific Condition 9. [§19.304 and 40 CFR Part 60 Subpart Da]

5. The permittee shall not cause to be discharged to the atmosphere from the SN-01, gases which exhibit an opacity greater than 10% (6-minute average) except for one 6 minute period per hour of not more than 20% as measured in accordance with EPA Reference Method 9 as found in 40 CFR Part 60, Appendix A. Compliance with this condition will be demonstrated by comparison of the limit to the 6-minute average opacity reading obtained from the opacity CEMS installed pursuant to Specific Condition 9. Such comparisons will be made for each hour that the source is in operation excluding periods of startup, shutdown, and malfunction. [§19.901 et seq of the Arkansas State Implementation Plan for Air Pollution Control, (Regulation 19), §18.501, 40 CFR Part 52, Subpart E, and A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311]

6. The permittee shall not emit gases from the source SN-01 which are in excess of the BACT limits in the following table. Compliance with the lb/MMBTU limit for PM_{10} will be demonstrated by comparison of the limit to the results of the tests conducted pursuant to Specific Condition 13 and compliance with the CAM provisions of Specific Condition 17. Compliance with the lb/MMBTU limit for SO_2 will be demonstrated by comparison of the limit to the 3 hour rolling average SO_2 reading obtained from the CEMs installed pursuant to Specific Condition 9. Such comparisons will be made for each hour that the source is in operation excluding periods of startup, shutdown, and malfunction. Compliance with the lb/MMBTU limit for VOC will be demonstrated by comparison of the limit to the results of the tests conducted pursuant to Specific Condition 13. Compliance with the lb/MMBTU limit for CO will be demonstrated by comparison of the limit to the 1 hour average CO reading obtained from the CEMs installed pursuant to Specific Condition 11. Such comparisons will be made for each hour that the source is in operation excluding periods of startup, shutdown, and malfunction. Compliance with the lb/MMBTU limit for NO_x will be demonstrated by comparison of the limit to the 24 hour average NO_x reading obtained from the CEMS installed pursuant to Specific Condition 9.

Such comparisons will be made for each hour that the source is in operation excluding periods of startup, shutdown, and malfunction. Compliance with the lb/MMBTU limit for H_2SO_4 will be demonstrated by comparison of the limit to the results of the tests conducted pursuant to Specific Condition 13 and compliance with the CAM provisions of Specific Condition 18. Compliance with the lb/MMBTU limit for lead will be demonstrated by complying with the PM_{10} limit of this condition. Compliance with the lb/MMBTU limit for fluoride will be demonstrated by comparison of the limit to the result of the test conducted pursuant to Specific Condition 16 and compliance with the CAM provisions of Specific Condition 18. [§19.901 et seq of the Arkansas State Implementation Plan for Air Pollution Control, (Regulation 19) and 40 CFR Part 52, Subpart E]

Source	Description	Pollutant	Control Technology	Bact Limit
SN-01	Pulverized Coal-Fired Boiler	PM_{10}	Fabric Filter	0.018 lb/MMBTU
		SO_2	Dry FGD	0.16 lb/MMBTU
		VOC	Combustion Control	0.02 lb/MMBTU
		CO	Combustion Control	0.16 lb/MMBTU
		NO_x	Low NO_x burners with overfire air and SCR	0.09 lb/MMBTU
		H_2SO_4	Dry FGD/Fabric Filter	0.0061 lb/MMBTU
		Lead	Fabric Filter	2.56E-5 lb/MMBTU
		Fluoride	Dry FGD/Fabric Filter	0.00044 lb/MMBTU or 90% control by weight

7. The permittee shall not emit gases from the source which are in excess of the case-by-case MACT limits in the following table. Compliance with lb/trillion BTU limit for mercury will be demonstrated by comparison of the limit to the result of the test conducted pursuant to Specific Condition 15. Compliance with the lb/MMBTU limit for HCl will be demonstrated by comparison of the limit to the result of the test conducted pursuant to Specific Condition 15 and compliance with the CAM provisions of Specific Condition 18. Compliance with the lb/MMBTU limit for HF will be demonstrated by complying with the fluoride BACT limit in Specific Condition 6. Compliance with the MACT limit for non-metal mercury HAPs will be demonstrated by complying with the PM_{10} BACT limit in Specific Condition 6. Compliance with the MACT limit for organic HAPs will be demonstrated by complying with the VOC BACT limit in Specific Condition 6. [§19.304 and 40 CFR Part 63, Subpart B]

Pollutant	Control Technology	MACT Limit
Mercury	SCR and Fabric Filter	12.8 lb/trillion BTU

HCl	Dry FGD and Fabric Filter	0.013 lb/MMBTU
HF	Dry FGD and Fabric Filter	Control fluoride emissions to 0.00044 lb/MMBTU or 90% control by weight
non-mercury metal HAPs	Fabric Filter to Control Particulate emissions to BACT level	0.018 lb PM_{10}/MMBTU
Organic HAPs	Combustion Control to Control VOC emissions to BACT control level	0.02 lb VOC/MMBTU

8. On or after the date on which the performance test is required to be conducted under §60.8 the permittee shall not discharge into the atmosphere any gases from SN-01 which contain pollutants in excess of the amounts in the following table. Compliance with this condition will be shown by Specific Conditions 12. [§19.304 and 40 CFR Part 60 Subpart Da]

Pollutant	Emission limit	Compliance Averaging Time
Particulate matter	0.03 lb/MMBTU	3-hour average
SO_2	1.2 lb/MMBTU	30-day rolling average
NO_x	0.5 lb/MMBTU	30-day rolling average

9. The permittee shall install, calibrate, maintain, and operate continuous emission monitoring systems (CEMS) for SN-01 and record the output of the system to measure opacity, SO_2, and NO_x. The permittee shall install, calibrate, maintain, and operate continuous emission monitoring systems and record the output of the system to measure O_2 or CO_2 at each location where SO_2 or NO_x emissions are monitored. The CEMS shall comply with the Department "Continuous Emissions Monitoring Systems Conditions." [§19.304 and 40 CFR Part 60 Subpart Da]

10. The permittee shall submit reports as required under 60.49a. These reports include initial test reports, CEM performance evaluation reports, and quarterly reports. [§19.304 and 40 CFR Part 60 Subpart Da]

11. The permittee shall install, calibrate, maintain, and operate continuous emission monitoring systems (CEMS) for SN-01 and record the output of the system to measure CO. The CEMS shall comply with the Department "Continuous Emissions Monitoring Systems Conditions." The CEMS data may be used by the Department for enforcement

purposes. [§19.702 et seq, 40 CFR Part 52, Subpart E, and A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311]

12. The permittee shall conduct initial compliance tests on SN-01 for the pollutants in the following table using the test method for the pollutant listed in the table and in accordance with Plantwide Condition 3. These tests shall be conducted at 90% capacity of the boiler or greater and within 180 days of startup of the source and annually thereafter. [§19.304 and 40 CFR Part 60 Subpart Da]

Pollutant	EPA Reference Method
Particulate Matter	5 with 202
Opacity	9
SO_2	6C
NO_x	7E

13. The permittee shall test SN-01 for CO, VOC, $PM_{10,}$ and H_2SO_4. These tests shall be conducted within 180 days of startup of the source and annually thereafter. These tests shall also be conducted at 90% capacity or greater, using the test method for the pollutant listed in the table, and in accordance with Plantwide Condition 3. [Pursuant to §19.702 et seq and 40 CFR Part 52, Subpart E]

Pollutant	EPA Reference Method
PM_{10}	201A/202
CO	10
VOC	25A/18
H_2SO_4	8

14. The permittee shall test SN-01 for ammonia emissions. This test shall be conducted within 180 days of startup of the source using test method CTM-027 with the source operating at 90% capacity or greater, and in accordance with Plantwide Condition 3. [Pursuant to §19.702 et seq and 40 CFR Part 52, Subpart E]

15. The permittee shall test SN-01 for mercury and hydrochloric acid emissions. These tests shall be conducted within 180 days of startup of the source using the Test Methods specified in the following table, with the source operating at 90% capacity or greater, and in accordance with Plantwide Condition 3. [§19.304 and 40 CFR Part 63, Subpart B]

Pollutant	Test Method
Mercury	ASTM D6784-02
HCl	EPA Reference Method 26

16. The permittee shall test SN-01 for fluoride emissions. The permittee shall test the outlet from the boiler and the outlet from the fabric filter. In case emissions are above 0.00044 lb/MMBtu, the permittee would be required to demonstrate 90% control efficiency across the control devices. This test shall be conducted within 180 days of startup of the source using EPA test method 13A with the source operating at 90% capacity or greater, and in accordance with Plantwide Condition 3. [§19.702 et seq and 40 CFR Part 52, Subpart E]

17. To show compliance with the PM_{10} emission limits for source SN-01 the permittee shall install, operate, and maintain a continuous opacity monitor for SN-01 and insure that the opacity does not exceed the limit set forth in Specific Condition 5. The permittee shall also conduct daily inspections of the baghouse for SN-01 to insure the baghouse is not in need of repair or in faulty operation, and the permittee shall maintain a daily log of those inspections. [§19.304 and 40 CFR Part 64]

18. To show compliance with the HCl, HF, and H_2SO_4 limits for source SN-01 the permittee shall monitor the SO_2 CEMs required for SN-01 by Specific Condition 9 to insure that SO_2 emissions are below the 0.16 lb/MMBTU limit of Specific Condition 6. During the any compliance test for HCl, HF, and/or H_2SO_4 emissions the permittee shall validate using the SO_2 CEM data as a basis for monitoring the tested pollutant. [§19.304 and 40 CFR Part 64]

Acid Rain Program

19. The affected unit (SN-01) is subject to and shall comply with applicable provisions of the Acid Rain Program (40 CFR Parts 72, 73, and 75).

20. The submission of the NO_X, SO_2, and O_2 or CO_2 monitoring plan is required at least 45 days prior to the CEMS certification testing. Notice of CEMS certification testing is required at least 45 days prior to the CEMS certification testing. [40 CFR Part 75-Continuous Emission Monitoring Subpart G]

21. The initial NO_X, and O_2 or CO_2 CEMS certification testing is to occur no later than 90 days after the unit commences commercial operation except the testing must occur prior to the date this unit is declared commercial in accordance with DOE Form EIA-860. [40 CFR Part 75 Subpart A]

22. The permittee shall ensure that the continuous emissions monitoring systems are in operation and monitoring all unit emissions at all times, except during periods of calibration, quality assurance, preventative maintenance or repair. [40 CFR §75.10]

SN–03

Unit One Cooling Tower

Source Description

Circulating water from the condenser cooling operations will be cooled in a multi-cell mechanical draft cooling tower. Particulate emissions from the cooling tower result from minerals in the cooling tower water that exit in the tower in drift. As the drift water later evaporates, the material remains as PM emissions.

Specific Conditions

23. The permittee shall not exceed the emission rates set forth in the following table. Compliance with this condition will be demonstrated by compliance with Plantwide Condition 5. [§19.901 et seq of the Regulations of the Arkansas Plan of Implementation for Air Pollution Control (Regulation #19) effective February 15, 1999 and 40 CFR Part 52, Subpart E,]

Source	Pollutant	lb/hr	tpy
03	PM PM_{10}	3.6 0.7	15.4 2.8

SN–05

Auxiliary Boiler

Source Description

The facility includes a 367 MMBtu/hr #2, oil-fired auxiliary boiler that would be used less than 500 hours per year. The auxiliary boiler operates during periods when the entire plant is off line, or to assist with the startup of the coal fired boiler.

Specific Conditions

24. The permittee shall not exceed the emission rates set forth in the following table. Compliance with all PM, PM_{10}, VOC, and CO will be demonstrated by compliance with Plantwide Condition 5 and Specific Condition 27. Compliance with the limits for SO_2 and H_2SO_4 will be demonstrated by compliance with Specific Conditions 29 and 32. Compliance with the lb/hr limit for NO_x will be demonstrated by comparison of the limit to the 30 day rolling average NO_x reading obtained from the CEMS installed pursuant to Specific Condition 31. Compliance with the ton per year limit for NO_x will be demonstrated by comparison of the limit to the summation over any consecutive 12 month period of the hourly NO_x readings from the CEMs. To show compliance with the lb/hr limit such comparisons will be made for each hour that the source is in operation excluding periods of startup, shutdown, and malfunction. To show compliance with the ton per year limit such comparisons will be made for each hour that the source is in operation. [§19.901 et seq of the Regulations of the Arkansas Plan of Implementation for Air Pollution Control (Regulation #19) effective February 15, 1999 and 40 CFR Part 52, Subpart E,]

Pollutant	lb/hr	tpy
PM	3.7	1.0
PM_{10}	2.7	0.7
SO_2	19.0	4.8
VOC	0.6	0.2
CO	13.0	3.3
NO_x	37.0	9.2
H_2SO_4	0.3	0.08

25. The permittee shall not cause to be discharged to the atmosphere from the auxiliary boiler, SN-05, any gasses which exceed 20% opacity (6-minute average) except for one 6-minute period per hour of not more than 27%. Compliance with this condition will be demonstrated by comparison of the limit to the 6-minute rolling average opacity reading obtained from the CEMS installed pursuant to Specific Condition 31. Such comparison will be made for each hour that the source is in operation excluding startup, shutdown, and malfunction. [Pursuant to §19.901, §19.503, and 40 CFR Part 52, Subpart E]

26. The permittee shall not cause to be discharged to the atmosphere from the auxiliary boiler, SN-05, any gasses which contain pollutants in excess of the amounts in the following table. Compliance with the $PM_{10,}$ VOC, and CO limits will be demonstrated by compliance with Plantwide Condition 5. Compliance with the limits for SO_2 and H_2SO_4 will be demonstrated by compliance with Specific Condition 29. Compliance with the lb/MMBTU limit for NO_x will be demonstrated by comparison of the limit to the 30 day rolling average NO_x reading obtained from the CEMS installed pursuant to Specific Condition 31. Such comparisons will be made for each hour that the source is in operation excluding periods of startup, shutdown, and malfunction. [§19.901 and 40 CFR Part 52, Subpart E]

Pollutant	Control Technology	Bact Limit
PM_{10}	No Control	0.0071 lb/MMBTU
SO_2	Low Sulfur Fuel Oil	0.051 lb/MMBTU
VOC	Combustion Control	0.0015 lb/MMBTU
CO	Combustion Control	0.036 lb/MMBTU
NO_x	Low NO_x burners with flue gas recirculation	0.1 lb/MMBTU
H_2SO_4	Low Sulfur Fuel Oil	0.0008 lb/MMBTU

27. The auxiliary boiler, SN-05, shall only be operated a total time not to exceed 500 hours during any consecutive 12 month period. Compliance with this condition will be demonstrated by the operational records maintained pursuant to Specific Condition 28. [to §19.901, A.C.A.§8-4-203 as referenced by A.C.A.§8-4-304, and 40 CFR 70.6]

28. The permittee shall maintain monthly records of the hours of operation of the auxiliary boiler, SN-05. These records shall include the hours of operation each month and the hours operated in the previous consecutive 12 month period. These records shall be updated by the 15^{th} day of the month after the month which the records represent, be kept on site, and be made available to Department personnel upon request. Reports of these records shall be submitted in accordance with General Provision 7. [§19.705 and 40 CFR 70.6]

29. The permittee shall not combust in the auxiliary boiler, SN-05, a fuel oil with a sulfur content greater than 0.05% by weight. Compliance with this condition will be shown by the fuel records required by Specific Condition 32 pursuant to NSPS Subpart Db and by Specific Condition 34. [§19.901 and 40 CFR Part 52, Subpart E]

30. The permittee shall not cause to be discharged to the atmosphere from the auxiliary boiler, SN-05, any gasses which contain nitrogen oxides in excess of 0.2 lb/MMBTU. This standard applies at all times including periods of startup, shutdown, and malfunction. Compliance with this condition will be demonstrated by comparison of the

limit to the 30-day rolling average obtained from the CEMS installed pursuant to Specific Condition 31. Such comparisons will be made for each hour that the source is in operation. [§19.304 and 40 CFR Part 60 Subpart Db]

31. The permittee shall install, calibrate, maintain, and operate continuous emission monitoring systems (CEMS) for measuring opacity and the NO_x discharged to the atmosphere from the Auxiliary Boiler, SN-05, and record the output of the systems. [§19.304 and 40 CFR Part 60 Subpart Db]

32. The permittee shall maintain records of the amount of fuel combusted in the Auxiliary Boiler, SN-05, each day and the annual capacity factor for distillate oil for each calendar quarter. The annual capacity factor is calculated on a 12 month rolling average basis with a new factor calculated at the end of each calendar month. [§19.304 and 40 CFR Part 60 Subpart Db]

33. The permittee shall submit reports as required by Subpart Db. These reports include the initial startup report, Initial Compliance test reports, and quarterly reports. [§19.304 and 40 CFR Part 60 Subpart Db]

34. To demonstrate that the auxiliary boiler, SN-05, combusts only very low sulfur oil under §60.42b(j)(2), the permittee shall obtain and maintain fuel receipts from the fuel supplier which certify that the oil meets the fuel definition of distillate oil as defined in §60.41b. Quarterly reports shall be submitted to the Administrator certifying that only very low sulfur oil meeting this definition was combusted in the auxiliary boiler during the preceding quarter. [§19.304 and 40 CFR Part 60 Subpart Db]

SN-08 and 10

Railcar Unloading Station and Barge Unloading Station

Source Description

Coal is received at the plant by rail and barge. At the railcar unloading station, railcars are brought into a partially enclosed railcar unloading structure. The railcars will have doors on the bottom which will open to dump the coal, or the cars will be connected with a swivel connection so they can be tipped to dump the coal. The coal is dumped to an underground hopper. From the underground hopper the coal will be transferred to a short conveyor and then on to the Stackout Conveyor #1. A dust suppression system will be used to control dust emissions from the railcar unloader.

The barges will be unloaded in a partially enclosed structure using a clamshell bucket or rotary unloader. The coal will be transferred to a hopper and then onto Stackout Conveyor #2.

Specific Conditions

35. The permittee shall not exceed the emission rates set forth in the following table. Compliance with this condition will be demonstrated by compliance with Specific Conditions 37 and 39. [§19.901 et seq of the Regulations of the Arkansas Plan of Implementation for Air Pollution Control (Regulation #19) effective February 15, 1999 and 40 CFR Part 52, Subpart E]

Source	Pollutant	lb/hr	tpy
08	PM PM_{10}	0.1 0.1	0.5 0.2
10	PM PM_{10}	0.2 0.1	0.7 0.3

36. The permittee shall not discharge into the atmosphere any gases from SN-08 or SN-10 exhibiting an opacity greater than 20% opacity. Compliance with this condition will be demonstrated by compliance with Plantwide Condition 8. [19.901 and 40 CFR Part 52, Subpart E]

37. The permittee shall not receive more than 54,000 tons of coal at the railcar unloading station, SN-08, in any day, and the permittee shall not receive more than 54,000 tons of coal at the barge unloading station, SN-10, in any day. Compliance with this condition will be demonstrated by the coal receipt records required by Specific Condition 38. [to §19.705, A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311, and 40 CFR 70.6]

38. The permittee shall maintain daily records showing the amount of coal received at both the railcar and barge unloading station. These records shall include the daily totals of coal received at each of the sources. These records shall be updated daily. [§19.705 and 40 CFR Part 52, Subpart E]

39. The permittee shall not operate the railcar unloading station without the water sprays being in service. The permittee shall also maintain daily records which certify that the water sprays were operating for each day that coal unloading at the railcar unloading station occurs. [§19.705 and 40 CFR Part 52, Subpart E]

SN-09, 11, 12, 13, 16, 18, and 19

Stackout Conveyor #1, #2, Emergency Reclaim Conveyor, Stackout Transfer Point, Reclaim Conveyor #1 and #2, and Reclaim Transfer Point #2

Source Description

Stackout Conveyor #1 transfers coal from the railcar unloading station to the transfer house. Stackout Conveyor #2 transfers coal from the barge unloading station to the transfer house. Emergency Reclaim Conveyor transfers coal from the Transfer House to the active piles. The Stackout Transfer Point is the point of transfer of coal from Stackout Conveyor #3 to the Active Piles. Two rotary plows are located directly beneath the Active Piles. Coal is transferred from the piles onto the active pile conveyor and then onto the Reclaim Conveyor #1. Reclaim Conveyor #1 transfers coal from the Active Piles back to the Transfer House. Reclaim Conveyor #2 transports coal from the Transfer House to the Tripper Deck Conveyor by drop operation at Reclaim Transfer Point #2.

Specific Conditions

40. The permittee shall not exceed the emission rates set forth in the following table. Compliance with this condition will be demonstrated by compliance with Specific Conditions 37 and 42. [§19.901 et seq of the Regulations of the Arkansas Plan of Implementation for Air Pollution Control (Regulation #19) effective February 15, 1999 and 40 CFR Part 52, Subpart E]

Source	Pollutant	lb/hr	tpy
09	PM PM_{10}	0.1 0.1	0.4 0.4
11	PM PM_{10}	0.4 0.4	1.9 1.9
12	PM PM_{10}	0.1 0.1	0.4 0.4
13	PM PM_{10}	0.4 0.2	1.6 0.6
16	PM PM_{10}	0.1 0.1	0.3 0.3
18	PM PM_{10}	0.1 0.1	0.4 0.4

Source	Pollutant	lb/hr	tpy
19	PM PM_{10}	0.1 0.1	0.4 0.2

41. The permittee shall not discharge gasses into the atmosphere from sources 09, 11, 12, 13, 16, 18, and 19 which exhibit an opacity of 20 percent or greater. The permittee shall also conduct initial test for opacity from sources 09, 11, 12, and, 13 within 180 days of start-up of the sources. These tests shall be conducted in accordance with EPA Reference Method 9 and §60.254 of Subpart Y. Compliance with the opacity limit of this condition will be demonstrated by the initial test required by this condition and by compliance with Plantwide Condition 8. [to §19.901, §19.304, and 40 CFR Part 60, Subpart Y]

42. The permittee shall operate the Stackout Transfer Point, SN-13, using a stackout tube to control fugitive emissions. [§19.705 and 40 CFR Part 52, Subpart E]

SN–14, 15, 22, and 23

Active Pile #1, Active Pile #2, Inactive Coal Pile, and Pile Transfer

Source Description

The Active Storage Piles will be in the approximate shape of a cone with a diameter of 300 feet at the base and a height of 100ft. Fugitive dust emissions from the Active Piles will be controlled by dust suppression spray water on an as needed basis. Coal is transferred as necessary from the Active Piles to the Inactive Coal Pile by operation of bull dozers and scrapers. Fugitive dust emissions from the Inactive Coal Pile will be controlled by dust suppression spray water plus chemical suppressant on freshly disturbed areas, on an as needed basis.

Specific Conditions

43. The permittee shall not exceed the emission rates set forth in the following table. Compliance with this condition will be demonstrated by compliance with Specific Condition 44. [§19.901 et seq of the Regulations of the Arkansas Plan of Implementation for Air Pollution Control (Regulation #19) effective February 15, 1999 and 40 CFR Part 52, Subpart E]

Source	Pollutant	lb/hr	tpy
14	PM PM_{10}	1.2 1.2	5.0 5.0
15	PM PM_{10}	1.2 1.2	5.0 5.0
22	PM PM_{10}	0.2 0.2	0.6 0.6
23	PM PM_{10}	2.9 0.5	12.4 2.0

44. The permittee shall treat the Active Piles #1 and #2, SN-14 and SN-15, with water each day that precipitation is less than 0.1 inches. Water treatment is also not required when the ambient temperature is below 40 degrees F. The permittee shall also maintain a daily log which shows if water was applied to the Active Piles, SN-14 and SN-15, and the precipitation amounts or temperature on days it was not applied. The permittee shall treat the freshly disturbed areas of the Inactive Pile, SN-22 with water or chemical dust suppressant sprays on a daily basis. These treatments shall not be required if the ambient temperature is below 40 degrees F or if the precipitation is greater that 0.1 inch. The permittee shall maintain a daily log of the water and dust suppressant treatment to the

Inactive Pile. On days where no treatment occurs the log shall document either that no new areas were disturbed, the ambient temperature on that day was below 40 degrees F, or that precipitation on that day was greater than 0.1 inch. [§19.705 and 40 CFR Part 52, Subpart E]

SN-17, 20, and 21

Transfer House, Tripper Deck Conveyor, and Reclaim Transfer Point #3

Source Description

The Transfer House receives coal from Stackout Conveyor #1 and Stackout Conveyor #2, and from Reclaim Conveyor #1. The Transfer House will also transfer coal onto Stackout Conveyor #3. The Transfer House may contain a crusher for crushing any large pieces of coal. For the transfer of coal to the boilers, coal is transferred onto the Reclaim Conveyor #2. The Tripper Deck Conveyor will transport coal from Reclaim Conveyor #2 to the Storage Silos. Both the transfer House and the Tripper Deck Conveyor will be totally enclosed within a building and each building will exhaust through a baghouse. Coal is transferred from the Tripper Deck Conveyor to multiple storage silos at Reclaim Transfer Point #3. The silos and Reclaim Transfer Point #3 are enclosed and vented through one or more baghouses.

Specific Conditions

45. The permittee shall not exceed the emission rates set forth in the following table. Compliance with this condition will be demonstrated by compliance with Specific Condition 48. [§19.901 et seq of the Regulations of the Arkansas Plan of Implementation for Air Pollution Control (Regulation #19) effective February 15, 1999 and 40 CFR Part 52, Subpart E]

Source	Pollutant	lb/hr	tpy
17	PM PM_{10}	0.2 0.1	0.6 0.3
20	PM PM_{10}	0.1 0.1	0.1 0.1
21	PM PM_{10}	0.1 0.1	0.1 0.1

46. The permittee shall not cause to be discharged to the atmosphere from the Transfer House, Tipper Deck Conveyor or Reclaim Transfer Point #3, SN-17, 20 and 21, gases which exhibit an opacity greater than 5% as measured in accordance with EPA Reference Method 9 as found in 40 CFR Part 60, Appendix A. Compliance with this Condition will be shown by compliance with Plantwide Condition 7. [§19.901 and 40 CFR Part 52, Subpart E]

47. The permittee shall not discharge gasses into the atmosphere from sources SN-17, 20, and 21 which exhibit an opacity of 20 percent or greater. The permittee shall also conduct initial test for opacity from sources SN-17, 20, and 21 within 180 days of start-

up of the sources. These tests shall be conducted in accordance with EPA Reference Method 9 and §60.254 of Subpart Y. Compliance with the opacity limit of this condition will be demonstrated by the initial test required by this condition and by compliance with Plantwide Condition 7. [§19.304 and 40 CFR Part 60, Subpart Y]

48. The permittee shall install, operate, and maintain baghouse leak detectors for SN-17, 20, and 21. These detectors shall alarm to the operator if a leak is detected. The permittee shall maintain a log of all alarms, the cause for the alarm, and what was done to correct the cause for the alarm. This log shall be maintained on a daily basis, kept on site and made available to Department personnel upon request. [§19.705 and 40 CFR Part 52, Subpart E]

SN–24

Fly Ash Silos

Source Description

The term fly ash is used to refer to the ash from the economizer and air heater and the fly ash scrubber waste from the baghouse. The waste will be transferred in pipes from the boiler economizer and air heater hoppers and from the boiler baghouse to one or more Fly Ash Silos by pneumatic means.

Specific Conditions

49. The permittee shall not exceed the emission rates set forth in the following table. Compliance with this condition will be demonstrated by compliance with Specific Condition 51. [to §19.901 et seq of the Regulations of the Arkansas Plan of Implementation for Air Pollution Control (Regulation #19) effective February 15, 1999 and 40 CFR Part 52, Subpart E]

Pollutant	lb/hr	tpy
PM_{10}	0.1	0.1
PM	0.1	0.1

50. The permittee shall not cause to be discharged to the atmosphere from the Fly Ash Silo, SN-24, gases which exhibit an opacity greater than 5% as measured in accordance with EPA Reference Method 9 as found in 40 CFR Part 60, Appendix A. Compliance with this condition will be demonstrated by compliance with Plantwide Condition 7. [to §19.901 and 40 CFR Part 52, Subpart E]

51. The permittee shall install, operate, and maintain baghouse leak detectors for the Fly Ash Silos SN-24. These detectors shall alarm to the operator if a leak is detected. The permittee shall maintain a log of all alarms, the cause for the alarm, and what was done to correct the cause for the alarm. This log shall be maintained on a daily basis, kept on site and made available to Department personnel upon request. [§19.705 and 40 CFR Part 52, Subpart E]

SN–25, 26, 27, 28, 29 and 30

Fly Ash Rail Transport, Barge Transport, Fly Ash Pneumatic Transport, and Fly Ash Transport Point #1, Fly Ash Transfer, and Fly Ash Transfer #2

Source Description

Since this permit was written before the construction of the facility, the exact method of fly ash disposal is not set. This permit is written with flexibility to dispose of fly ash offsite by truck, rail, or barge, or in an on-site disposal facility. For onsite disposal, additional flexibility allows for transfer of fly ash to the disposal site by pneumatic transport, truck, or conveyor.

Fly Ash Rail Transport, SN-25. For fly ash disposal by railcar, the fly ash would be conveyed pneumatically to the enclosed rail cars for disposal or reuse.

Fly Ash Barge Transport, SN-26. For fly ash disposal by barge, the fly ash would be conveyed pneumatically to the enclosed rail cars for disposal or reuse.

Fly Ash Pneumatic Transport, SN-27. For onsite disposal of fly ash transferred pneumatically, a baghouse would be used at the disposal facility ash-water mixing station for emissions control. The mixing station would mix the fly ash with water to create a dough-like mixture for subsequent disposal.

Fly Ash Transfer Point #1, SN-28. For onsite disposal of fly ash to be transferred by conveyor or truck, this source will account for emissions from the drop into the truck or onto the conveyor.

Fly Ash Transfer, SN-29. For onsite disposal of fly ash to be transferred by conveyor or truck, this source will account for emissions from the conveyor or truck transport.

Fly Ash Transfer Point #2, SN-30. For onsite disposal of fly ash to be transferred by conveyor or truck, this source will account for emissions from the transfer from the truck or conveyor to the Ash Disposal Area.

Specific Conditions

52. The permittee shall not exceed the emission rates set forth in the following table. Compliance with this condition will be demonstrated by compliance with Specific Condition 55. [§19.901 et seq of the Regulations of the Arkansas Plan of Implementation for Air Pollution Control (Regulation #19) effective February 15, 1999 and 40 CFR Part 52, Subpart E]

Source	Pollutant	lb/hr	tpy
25	PM	0.1	0.1

Source	Pollutant	lb/hr	tpy
	PM_{10}	0.1	0.1
26	PM PM_{10}	0.1 0.1	0.1 0.1
27	PM PM_{10}	0.1 0.1	0.1 0.1
28	PM PM_{10}	0.1 0.1	0.1 0.1
29	PM PM_{10}	0.1 0.1	0.4 0.4
30	PM PM_{10}	0.1 0.1	0.1 0.1

53. The permittee shall not discharge into the atmosphere any gases from SN-28, SN-29, and SN-30 exhibiting an opacity greater than 20% opacity. Compliance with this condition will be demonstrated by compliance with Plantwide Condition 8. [§19.901 and 40 CFR Part 52, Subpart E]

54. The permittee shall not discharge into the atmosphere any gases from SN-25, SN-26, and SN-27 exhibiting an opacity greater than 5% opacity. Compliance with this condition will be demonstrated by compliance with Plantwide Condition 7. [§19.901 and 40 CFR Part 52, Subpart E]

55. The permittee shall install, operate, and maintain baghouse leak detectors for SN-25, 26, and 27. These detectors shall alarm to the operator if a leak is detected. The permittee shall maintain a log of all alarms, the cause for the alarm, and what was done to correct the cause for the alarm. This log shall be maintained on a daily basis, kept on site and made available to Department personnel upon request. The permittee shall also process only wetted fly ash at sources SN-28, SN-29, and SN-30. The permittee shall maintain a log of the amount of fly ash processed through SN-28, SN-29, and SN-30 and the amount of water added to the fly ash. These logs shall be maintained on a daily basis, kept on site and made available to Department personnel upon request. [§19.705 and 40 CFR Part 52, Subpart E]

SN-31
Ash Disposal Area

Source Description

The wet dough-like fly ash mixture will be deposited into the Ash Disposal Area for permanent disposal. The mixture tends to solidify into a concrete-like substance thereby greatly reducing the potential for fugitive emissions.

Specific Conditions

56. The permittee shall not exceed the emission rates set forth in the following table. Compliance with this condition will be demonstrated by compliance with Specific Condition 57. [§19.901 et seq of the Regulations of the Arkansas Plan of Implementation for Air Pollution Control (Regulation #19) effective February 15, 1999 and 40 CFR Part 52, Subpart E]

Pollutant	lb/hr	tpy
PM	2.2	9.4
PM_{10}	0.6	2.5

57. The permittee shall treat the freshly disturbed areas of the Ash Disposal Area, SN-31 with water sprays on a daily basis, as needed. These treatments shall not be required if the ambient temperature is below 40 degrees F or precipitation exceeds 0.1 inch. The permittee shall maintain a daily log of the water sprays applied to the Ash Disposal Area. On days where no treatment occurs the log shall document either that no new areas were disturbed, treatment was not needed, the ambient temperature on that day was below 40 degrees F, or precipitation on that day was greater than 0.1 inch. [§19.705 and 40 CFR Part 52, Subpart E]

SN-32
Lime Storage

Source Description

Lime will be delivered to the facility in trucks or by rail and pneumatically transferred into one or more storage silos, SN-32. The silos will be exhausted through a baghouse.

Specific Conditions

58. The permittee shall not exceed the emission rates set forth in the following table for SN-32. Compliance with this condition will be demonstrated by compliance with Specific Condition 60. [§19.901 et seq of the Regulations of the Arkansas Plan of Implementation for Air Pollution Control (Regulation #19) effective February 15, 1999 and 40 CFR Part 52, Subpart E]

Pollutant	lb/hr	tpy
PM	0.1	0.1
PM_{10}	0.1	0.1

59. The permittee shall not cause to be discharged to the atmosphere from the Lime Storage, (SN-32) gases which exhibit an opacity greater than 5% as measured in accordance with EPA Reference Method 9 as found in 40 CFR Part 60, Appendix A. Compliance with this condition will be demonstrated by compliance with Plantwide Condition 7. [§19.901 and 40 CFR Part 52, Subpart E]

60. The permittee shall install, operate, and maintain baghouse leak detectors for the Lime Storage SN-32. These detectors shall alarm to the operator if a leak is detected. The permittee shall maintain a log of all alarms, the cause for the alarm, and what was done to correct the cause for the alarm. This log shall be maintained on a daily basis, kept on site and made available to Department personnel upon request. [§19.705 and 40 CFR Part 52, Subpart E]

SN-33 and 34
Unpaved and Paved Roadway Travel

Source Description

These sources account for emissions from roadway travel.

Specific Conditions

61. The permittee shall not exceed the emission rates set forth in the following table. Compliance with this condition will be demonstrated by compliance with Plantwide Condition 5. [§19.901 et seq of the Regulations of the Arkansas Plan of Implementation for Air Pollution Control (Regulation #19) effective February 15, 1999 and 40 CFR Part 52, Subpart E]

Source	Pollutant	lb/hr	tpy
33	PM PM_{10}	2.4 0.7	10.4 2.7
34	PM PM_{10}	0.2 0.1	0.7 0.2

SN-35 and 36
330,000 Gallon Oil Storage Tank and 8,000 Gallon Unleaded Gasoline Storage Tank

Source Description

The 330,000 gallon oil storage tank stores #2 fuel oil for use in boiler startups, the auxiliary boiler, diesel generator, and the diesel fuel fire pump. The 8,000 gallon gasoline tank stores unleaded gasoline for use by plant vehicles.

Specific Conditions

62. The permittee shall not exceed the emission rates set forth in the following table. Compliance with this condition will be demonstrated by compliance with Specific Condition 64. [§19.901 et seq of the Regulations of the Arkansas Plan of Implementation for Air Pollution Control (Regulation #19) effective February 15, 1999 and 40 CFR Part 52, Subpart E]

Source	Pollutant	lb/hr	tpy
35	VOC	0.1	0.1
36	VOC	0.4	1.5

63. The facility shall maintain readily accessible records showing the dimension of the Oil Storage Tank, SN-35, and an analysis of the storage capacity of the vessels. [§19.304 and 40 CFR Part 60 Subpart Kb]

64. The permittee shall not receive more than 1,000,000 gallons of #2 fuel oil in the Oil Storage Tank, SN-35, and more than 160,000 gallons of gasoline in the gasoline storage tank, SN-36, in any consecutive 12 month period. The permittee shall maintain records which show the amount of fuel received for storage in SN-35 and 36 and the consecutive 12 month total of fuel received for each source. These records shall be updated daily with each shipment. The record of the consecutive 12 month total received shall be updated by the 10th day of the month following the month to which the records pertain. [§19.901 and 40 CFR Part 52, Subpart E]

SN-38
Carbon Storage

Source Description

Carbon for the carbon injection system will be stored in the Carbon Storage, SN-38. The carbon injection system will be used to control mercury emissions from the main boiler, SN-01.

Specific Conditions

65. The permittee shall not exceed the emission rates set forth in the following table. Compliance with this condition will be shown by compliance with Plantwide Condition 5. [Regulation 19, §19.501 et seq. and 40 CFR Part 52, Subpart E]

Pollutant	lb/hr	tpy
PM_{10}	0.1	0.1

66. The permittee shall not exceed the emission rates set forth in the following table. Compliance with this condition will be shown by compliance with Plantwide Condition 5. [Regulation 18, §18.801, and A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311]

Pollutant	lb/hr	tpy
PM	0.1	0.1

67. The permittee shall not cause to be discharged to the atmosphere from the Carbon Storage, (SN-38) gases which exhibit an opacity greater than 5% as measured in accordance with EPA Reference Method 9 as found in 40 CFR Part 60, Appendix A. Compliance with this condition will be demonstrated by compliance with Plantwide Condition 7. [Regulation 18, §18.501, and A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311]

68. The permittee shall 18 months prior to the initial startup of the facility submit a permit application to incorporate the new mercury standards in NSPS subpart Da into the permit and update the standards for other pollutants. [§26.1011(A)(1) of Regulation 26]

SECTION V: COMPLIANCE PLAN AND SCHEDULE

LSP Services Plum Point, LLC will continue to operate in compliance with those identified regulatory provisions. The facility will examine and analyze future regulations that may apply and determine their applicability with any necessary action taken on a timely basis.

SECTION VI: PLANTWIDE CONDITIONS

1. The permittee shall notify the Director in writing within thirty (30) days after commencing construction, completing construction, first placing the equipment and/or facility in operation, and reaching the equipment and/or facility target production rate. [Regulation 19, §19.704, 40 CFR Part 52, Subpart E, and A.C.A. §8-4-203 as referenced by A.C.A. §8-4-304 and §8-4-311]

2. If the permittee fails to start construction within eighteen months or suspends construction for eighteen months or more, the Director may cancel all or part of this permit. [Regulation 19, §19.410(B) and 40 CFR Part 52, Subpart E]

3. The permittee must test any equipment scheduled for testing, unless stated in the Specific Conditions of this permit or by any federally regulated requirements, within the following time frames: (1) new equipment or newly modified equipment within sixty (60) days of achieving the maximum production rate, but no later than 180 days after initial start up of the permitted source or (2) operating equipment according to the time frames set forth by the Department or within 180 days of permit issuance if no date is specified. The permittee must notify the Department of the scheduled date of compliance testing at least fifteen (15) days in advance of such test. The permittee shall submit the compliance test results to the Department within thirty (30) days after completing the testing. [Regulation 19, §19.702 and/or Regulation 18 §18.1002 and A.C.A. §8-4-203 as referenced by A.C.A. §8-4-304 and §8-4-311]

4. The permittee must provide: [Regulation 19, §19.702 and/or Regulation 18, §18.1002 and A.C.A. §8-4-203 as referenced by A.C.A. §8-4-304 and §8-4-311]

    a. Sampling ports adequate for applicable test methods;
    b. Safe sampling platforms;
    c. Safe access to sampling platforms; and
    d. Utilities for sampling and testing equipment.

5. The permittee must operate the equipment, control apparatus and emission monitoring equipment within the design limitations. The permittee shall maintain the equipment in good condition at all times. [Regulation 19, §19.303 and A.C.A. §8-4-203 as referenced by A.C.A. §8-4-304 and §8-4-311]

6. This permit subsumes and incorporates all previously issued air permits for this facility. [Regulation 26 and A.C.A. §8-4-203 as referenced by A.C.A. §8-4-304 and §8-4-311]

7. The permittee shall conduct weekly observations of the opacity from the following sources SN-17, 20, 21, 24, 25, 26, 27 and 32. These weekly observations shall be conducted by someone trained in EPA Reference Method 9. If visible emissions in excess of the permitted opacity are detected, the permittee shall immediately take action to identify the cause of the excess visible emissions, implement corrective action, and

document that the visible emissions did not exceed the permitted opacity following the corrective action. [§19.705, 40 CFR Part 52, Subpart E, and A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311

8. The permittee shall conduct daily observations of the opacity from the following sources SN-8, 9, 10, 11, 12, 13, 16, 18, 19, 28, 29, and 30. These daily observations shall be conducted in accordance with EPA Reference Method 22. If visible emissions are detected, the permittee shall immediately conduct an observation using EPA Reference Method 9. If with the Method 9 observation an opacity above the permitted limit is detected, the permittee shall immediately take action to identify the cause of the excess visible emissions, implement corrective action, and document that the visible emissions did not exceed the permitted opacity following the corrective action. [§19.705, 40 CFR Part 52, Subpart E, and A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311]

9. The permittee shall maintain records which demonstrate compliance with Plantwide Conditions 7 and 8. These records shall contain the following items.

    i. The date and time of the observation;
    ii. if visible emissions above the permitted limit were detected;
    iii. if visible emissions above the permitted limits, list the cause of the exceedance of the opacity limits, the corrective action taken, and if the visible emissions are below the permitted limit after the corrective actions was taken; and
    iv. the person conducting the opacity observations.

    These records shall be updated weekly, kept on site, and made available to Department personnel upon request. These records shall not be required when the EPA Reference Method 9 training sessions offered by the Department are in session. [§19.705, 40 CFR Part 52, Subpart E, and A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311]

10. The permittee shall install, operate, and maintain ambient air monitors for PM_{10} and SO_2. The permittee shall submit a monitoring protocol to the Department within 180 days of the anticipated start up date of the facility. The Department must approve of the monitoring protocol prior to installation of the monitors. The monitors shall be installed and operating within 180 days of the startup of the source. After 2 years of data is collected if the monitored concentrations are below 50% of the NAAQS and PSD increment standards the permittee may submit a permit application to have the monitors removed. [§19.901 et seq of the Regulations of the Arkansas Plan of Implementation for Air Pollution Control (Regulation #19) effective February 15, 1999 and 40 CFR Part 52, Subpart E]

11. The permittee shall for the period of time prior to the fifth anniversary of the issuance of permit 1995-AOP-R0 limit the emissions from SN-01 to the emission levels in the following table by limiting the sum of the hours of operation for SN-01 to 1500 hours or less on a 12 month rolling total basis. These limits will be removed with the Title V

renewal of this permit. Compliance with this condition will be demonstrated by the operational records required pursuant to Plantwide Condition 18. [§18.801, and A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311]

Pollutant	Tons per year
PM	125.4
SO_2	1002.8
VOC	125.4
NO_x	564.1
H_2SO_4	38.4
HCl	82.6
HF	5.9

12. The permittee shall maintain monthly records of the hours of operation of SN-01 for the period of time prior to the fifth anniversary of the issuance of permit 1995-AOP-R0. These records shall contain the number of hours SN-01 was operated during the month and during the consecutive 12 month period. These records shall be updated by the 15th day of the month following the month the records are to represent, kept on site, and made available to Department personnel upon request. [§18.801, and A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311]

SECTION VII: INSIGNIFICANT ACTIVITIES

The following sources are insignificant activities. Any activity that has a state or federal applicable requirement shall be considered a significant activity even if this activity meets the criteria of §26.304 of Regulation 26 or listed in the table below. Insignificant activity determinations rely upon the information submitted by the permittee in an application dated April 20, 2001.

Description	Category
Emergency Fire Pump	A-12
8,000 Gallon Diesel Fuel Storage Tank	A-3
Emergency Diesel Fuel-Fired Generator	A-12

SECTION VIII: GENERAL PROVISIONS

1. Any terms or conditions included in this permit which specify and reference Arkansas Pollution Control & Ecology Commission Regulation 18 or the Arkansas Water and Air Pollution Control Act (A.C.A. §8-4-101 et seq.) as the sole origin of and authority for the terms or conditions are not required under the Clean Air Act or any of its applicable requirements, and are not federally enforceable under the Clean Air Act. Arkansas Pollution Control & Ecology Commission Regulation 18 was adopted pursuant to the Arkansas Water and Air Pollution Control Act (A.C.A. §8-4-101 et seq.). Any terms or conditions included in this permit which specify and reference Arkansas Pollution Control & Ecology Commission Regulation 18 or the Arkansas Water and Air Pollution Control Act (A.C.A. §8-4-101 et seq.) as the origin of and authority for the terms or conditions are enforceable under this Arkansas statute. [40 CFR 70.6(b)(2)]

2. This permit shall be valid for a period of five (5) years beginning on the date this permit becomes effective and ending five (5) years later. [40 CFR 70.6(a)(2) and §26.701(B) of the Regulations of the Arkansas Operating Air Permit Program (Regulation 26), effective September 26, 2002]

3. The permittee must submit a complete application for permit renewal at least six (6) months before permit expiration. Permit expiration terminates the permittee's right to operate unless the permittee submitted a complete renewal application at least six (6) months before permit expiration. If the permittee submits a complete application, the existing permit will remain in effect until the Department takes final action on the renewal application. The Department will not necessarily notify the permittee when the permit renewal application is due. [Regulation 26, §26.406]

4. Where an applicable requirement of the Clean Air Act, as amended, 42 U.S.C. 7401, et seq. (Act) is more stringent than an applicable requirement of regulations promulgated under Title IV of the Act, the permit incorporates both provisions into the permit, and the Director or the Administrator can enforce both provisions. [40 CFR 70.6(a)(1)(ii) and Regulation 26, §26.701(A)(2)]

5. The permittee must maintain the following records of monitoring information as required by this permit. [40 CFR 70.6(a)(3)(ii)(A) and Regulation 26, §26.701(C)(2)]

    a. The date, place as defined in this permit, and time of sampling or measurements;
    b. The date(s) analyses performed;
    c. The company or entity performing the analyses;
    d. The analytical techniques or methods used;
    e. The results of such analyses; and
    f. The operating conditions existing at the time of sampling or measurement.

6. The permittee must retain the records of all required monitoring data and support information for at least five (5) years from the date of the monitoring sample,

measurement, report, or application. Support information includes all calibration and maintenance records and all original strip chart recordings for continuous monitoring instrumentation, and copies of all reports required by this permit. [40 CFR 70.6(a)(3)(ii)(B) and Regulation 26, §26.701(C)(2)(b)]

7. The permittee must submit reports of all required monitoring every six (6) months. If permit establishes no other reporting period, the reporting period shall end on the last day of the anniversary month of the initial Title V permit. The report is due within thirty (30) days of the end of the reporting period. Although the reports are due every six months, each report shall contain a full year of data. The report must clearly identify all instances of deviations from permit requirements. A responsible official as defined in Regulation No. 26, §26.2 must certify all required reports. The permittee will send the reports to the address below: [40 C.F.R. 70.6(a)(3)(iii)(A) and Regulation 26, §26.701(C)(3)(a)]

    Arkansas Department of Environmental Quality
    Air Division
    ATTN: Compliance Inspector Supervisor
    Post Office Box 8913
    Little Rock, AR 72219

8. The permittee shall report to the Department all deviations from permit requirements, including those attributable to upset conditions as defined in the permit.

    a. For all upset conditions (as defined in Regulation19, § 19.601), the permittee will make an initial report to the Department by the next business day after the discovery of the occurrence. The initial report my be made by telephone and shall include:

        i. The facility name and location
        ii. The process unit or emission source deviating from the permit limit,
        iii. The permit limit, including the identification of pollutants, from which deviation occurs,
        iv. The date and time the deviation started,
        v. The duration of the deviation,
        vi. The average emissions during the deviation,
        vii. The probable cause of such deviations,
        viii. Any corrective actions or preventive measures taken or being taken to prevent such deviations in the future, and
        ix. The name of the person submitting the report.

    The permittee shall make a full report in writing to the Department within five (5) business days of discovery of the occurrence. The report must include, in addition to the information required by the initial report, a schedule of actions taken or planned to eliminate future occurrences and/or to minimize the amount the permit's limits were exceeded and to reduce the length of time the limits were exceeded. The

permittee may submit a full report in writing (by facsimile, overnight courier, or other means) by the next business day after discovery of the occurrence, and the report will serve as both the initial report and full report.

b. For all deviations, the permittee shall report such events in semi-annual reporting and annual certifications required in this permit. This includes all upset conditions reported in 8a above. The semi-annual report must include all the information as required by the initial and full reports required in 8a.

[Regulation 19, §19.601 and §19.602, Regulation 26, §26.701(C)(3)(b), and 40 CFR 70.6(a)(3)(iii)(B)]

9. If any provision of the permit or the application thereof to any person or circumstance is held invalid, such invalidity will not affect other provisions or applications hereof which can be given effect without the invalid provision or application, and to this end, provisions of this Regulation are declared to be separable and severable. [40 CFR 70.6(a)(5), Regulation 26, §26.701(E), and A.C.A. §8-4-203 as referenced by A.C.A. §8-4-304 and §8-4-311]

10. The permittee must comply with all conditions of this Part 70 permit. Any permit noncompliance with applicable requirements as defined in Regulation 26 constitutes a violation of the Clean Air Act, as amended, 42 U.S.C. §7401, et seq. and is grounds for enforcement action; for permit termination, revocation and reissuance, for permit modification; or for denial of a permit renewal application. [40 CFR 70.6(a)(6)(i) and Regulation 26, §26.701(F)(1)]

11. It shall not be a defense for a permittee in an enforcement action that it would have been necessary to halt or reduce the permitted activity to maintain compliance with the conditions of this permit. [40 CFR 70.6(a)(6)(ii) and Regulation 26, §26.701(F)(2)]

12. The Department may modify, revoke, reopen and reissue the permit or terminate the permit for cause. The filing of a request by the permittee for a permit modification, revocation and reissuance, termination, or of a notification of planned changes or anticipated noncompliance does not stay any permit condition. [40 CFR 70.6(a)(6)(iii) and Regulation 26, §26.701(F)(3)]

13. This permit does not convey any property rights of any sort, or any exclusive privilege. [40 CFR 70.6(a)(6)(iv) and Regulation 26, §26.701(F)(4)]

14. The permittee must furnish to the Director, within the time specified by the Director, any information that the Director may request in writing to determine whether cause exists for modifying, revoking and reissuing, or terminating the permit or to determine compliance with the permit. Upon request, the permittee must also furnish to the Director copies of records required by the permit. For information the permittee claims confidentiality, the Department may require the permittee to furnish such records directly to the Director

along with a claim of confidentiality. [40 CFR 70.6(a)(6)(v) and Regulation 26, §26.701(F)(5)]

15. The permittee must pay all permit fees in accordance with the procedures established in Regulation 9. [40 CFR 70.6(a)(7) and Regulation 26, §26.701(G)]

16. No permit revision shall be required, under any approved economic incentives, marketable permits, emissions trading and other similar programs or processes for changes provided for elsewhere in this permit. [40 CFR 70.6(a)(8) and Regulation 26, §26.701(H)]

17. If the permit allows different operating scenarios, the permittee shall, contemporaneously with making a change from one operating scenario to another, record in a log at the permitted facility a record of the operational scenario. [40 CFR 70.6(a)(9)(i) and Regulation 26, §26.701(I)(1)]

18. The Administrator and citizens may enforce under the Act all terms and conditions in this permit, including any provisions designed to limit a source's potential to emit, unless the Department specifically designates terms and conditions of the permit as being federally unenforceable under the Act or under any of its applicable requirements. [40 CFR 70.6(b) and Regulation 26, §26.702(A) and (B)]

19. Any document (including reports) required by this permit must contain a certification by a responsible official as defined in Regulation 26, §26.2. [40 CFR 70.6(c)(1) and Regulation 26, §26.703(A)]

20. The permittee must allow an authorized representative of the Department, upon presentation of credentials, to perform the following: [40 CFR 70.6(c)(2) and Regulation 26, §26.703(B)]

    a. Enter upon the permittee's premises where the permitted source is located or emissions related activity is conducted, or where records must be kept under the conditions of this permit;
    b. Have access to and copy, at reasonable times, any records required under the conditions of this permit;
    c. Inspect at reasonable times any facilities, equipment (including monitoring and air pollution control equipment), practices, or operations regulated or required under this permit; and
    d. As authorized by the Act, sample or monitor at reasonable times substances or parameters for assuring compliance with this permit or applicable requirements.

21. The permittee shall submit a compliance certification with the terms and conditions contained in the permit, including emission limitations, standards, or work practices. The permittee must submit the compliance certification annually within 30 days following the last day of the anniversary month of the initial Title V permit. The permittee must also

submit the compliance certification to the Administrator as well as to the Department. All compliance certifications required by this permit must include the following: [40 CFR 70.6(c)(5) and Regulation 26, §26.703(E)(3)]

a. The identification of each term or condition of the permit that is the basis of the certification;
b. The compliance status;
c. Whether compliance was continuous or intermittent;
d. The method(s) used for determining the compliance status of the source, currently and over the reporting period established by the monitoring requirements of this permit;
e. and Such other facts as the Department may require elsewhere in this permit or by §114(a)(3) and §504(b) of the Act.

22. Nothing in this permit will alter or affect the following: [Regulation 26, §26.704(C)]

a. The provisions of Section 303 of the Act (emergency orders), including the authority of the Administrator under that section;
b. The liability of the permittee for any violation of applicable requirements prior to or at the time of permit issuance;
c. The applicable requirements of the acid rain program, consistent with §408(a) of the Act or,
d. The ability of EPA to obtain information from a source pursuant to §114 of the Act.

23. This permit authorizes only those pollutant emitting activities addressed in this permit. [A.C.A. §8-4-203 as referenced by A.C.A. §8-4-304 and §8-4-311]

APPENDIX A

Continuous Emission Monitoring Systems Conditions

Arkansas Department of Environmental Quality

CONTINUOUS EMISSION MONITORING SYSTEMS

CONDITIONS

Revised August 2004

PREAMBLE

These conditions are intended to outline the requirements for facilities required to operate Continuous Emission Monitoring Systems/Continuous Opacity Monitoring Systems (CEMS)/(COMS). Generally there are three types of sources required to operate CEMS/COMS:

1. CEMS/COMS required by 40 CFR Part 60 or 63,
2. CEMS required by 40 CFR Part 75,
3. CEMS/COMS required by ADEQ permit for reasons other that Part 60, 63 or 75.

These CEMS/COMS conditions are not intended to supercede Part 60, 63 or 75 requirements.

- Only CEMS/COMS in the third category (those required by ADEQ permit for reasons other than Part 60, 63 or 75) shall comply with SECTION II, MONITORING REQUIREMENTS and SECTION IV, QUALITY ASSURANCE/QUALITY CONTROL.

- All CEMS/COMS shall comply with Section III, NOTIFICATION AND RECORDKEEPING.

SECTION I

DEFINITIONS

Continuous Emission Monitoring System (CEMS) - The total equipment required for the determination of a gas concentration and/or emission rate so as to include sampling, analysis and recording of emission data.

Continuous Opacity Monitoring System (COMS) - The total equipment required for the determination of opacity as to include sampling, analysis and recording of emission data.

Calibration Drift (CD) - The difference in the CEMS output reading from the established reference value after a stated period of operation during which no unscheduled maintenance, repair, or adjustments took place.

Back-up CEMS (Secondary CEMS) - A CEMS with the ability to sample, analyze and record stack pollutant to determine gas concentration and/or emission rate. This CEMS is to serve as a back-up to the primary CEMS to minimize monitor downtime.

Excess Emissions - Any period in which the emissions exceed the permit limits.

Monitor Downtime - Any period during which the CEMS/COMS is unable to sample, analyze and record a minimum of four evenly spaced data points over an hour, except during one daily zero-span check during which two data points per hour are sufficient.

Out-of-Control Period - Begins with the time corresponding to the completion of the fifth, consecutive, daily CD check with a CD in excess of two times the allowable limit, or the time corresponding to the completion of the daily CD check preceding the daily CD check that results in a CD in excess of four times the allowable limit and the time corresponding to the completion of the sampling for the RATA, RAA, or CGA which exceeds the limits outlined in Section IV. Out-of-Control Period ends with the time corresponding to the completion of the CD check following corrective action with the results being within the allowable CD limit or the completion of the sampling of the subsequent successful RATA, RAA, or CGA.

Primary CEMS - The main reporting CEMS with the ability to sample, analyze and record stack pollutant to determine gas concentration and/or emission rate.

Relative Accuracy (RA) - The absolute mean difference between the gas concentration or emission rate determined by the CEMS and the value determined by the reference method plus the 2.5 percent error confidence coefficient of a series of tests divided by the mean of the reference method tests of the applicable emission limit.

Span Value – The upper limit of a gas concentration measurement range.

SECTION II

MONITORING REQUIREMENTS

A. For new sources, the installation date for the CEMS/COMS shall be no later than thirty (30) days from the date of start-up of the source.

B. For existing sources, the installation date for the CEMS/COMS shall be no later than sixty (60) days from the issuance of the permit unless the permit requires a specific date.

C. Within sixty (60) days of installation of a CEMS/COMS, a performance specification test (PST) must be completed. PST's are defined in 40 CFR, Part 60, Appendix B, PS 1-9. The Department may accept alternate PSTs for pollutants not covered by Appendix B on a case-by-case basis. Alternate PST's shall be approved, in writing, by the ADEQ CEM Coordinator prior to testing.

D. Each CEMS/COMS shall have, as a minimum, a daily zero-span check. The zero-span shall be adjusted whenever the 24-hour zero or 24-hour span drift exceeds two times the limits in the applicable performance specification in 40 CFR, Part 60, Appendix B. Before any adjustments are made to either the zero or span drifts measured at the 24-hour interval the excess zero and span drifts measured must be quantified and recorded.

E. All CEMS/COMS shall be in continuous operation and shall meet minimum frequency of operation requirements of 95% up-time for each quarter for each pollutant measured. Percent of monitor down-time is calculated by dividing the total minutes the monitor is not in operation by the total time in the calendar quarter and multiplying by one hundred. Failure to maintain operation time shall constitute a violation of the CEMS conditions.

F. Percent of excess emissions are calculated by dividing the total minutes of excess emissions by the total time the source operated and multiplying by one hundred. Failure to maintain compliance may constitute a violation of the CEMS conditions.

F. All CEMS measuring emissions shall complete a minimum of one cycle of operation (sampling, analyzing, and data recording) for each successive fifteen minute period unless more cycles are required by the permit. For each CEMS, one-hour averages shall be computed from four or more data points equally spaced over each one hour period unless more data points are required by the permit.

H. All COMS shall complete a minimum of one cycle of sampling and analyzing for each successive 10-second period and one cycle of data recording for each successive 6-minute period.

J. When the pollutant from a single affected facility is released through more than one point, a CEMS/COMS shall be installed on each point unless installation of fewer systems is approved, in writing, by the ADEQ CEM Coordinator. When more than one CEM/COM is used to monitor emissions from one affected facility the owner or operator shall report the results as required from each CEMS/COMS.

SECTION III

NOTIFICATION AND RECORD KEEPING

A. When requested to do so by an owner or operator, the ADEQ CEM Coordinator will review plans for installation or modification for the purpose of providing technical advice to the owner or operator.

B. Each facility which operates a CEMS/COMS shall notify the ADEQ CEM Coordinator of the date for which the demonstration of the CEMS/COMS performance will commence (i.e. PST, RATA, RAA, CGA). Notification shall be received in writing no less than 15 days prior to testing. Performance test results shall be submitted to the Department within thirty days after completion of testing.

C. Each facility which operates a CEMS/COMS shall maintain records of the occurrence and duration of start up/shut down, cleaning/soot blowing, process problems, fuel problems, or other malfunction in the operation of the affected facility which causes excess emissions. This includes any malfunction of the air pollution control equipment or any period during which a continuous monitoring device/system is inoperative.

D. Except for Part 75 CEMs, each facility required to install a CEMS/COMS shall submit an excess emission and monitoring system performance report to the Department (Attention: Air Division, CEM Coordinator) at least quarterly, unless more frequent submittals are warranted to assess the compliance status of the facility. Quarterly reports shall be postmarked no later than the 30th day of the month following the end of each calendar quarter. Part 75 CEMs shall submit this information semi-annually and as part of Title V six (6) month reporting requirement if the facility is a Title V facility.

E. All excess emissions shall be reported in terms of the applicable standard. Each report shall be submitted on ADEQ Quarterly Excess Emission Report Forms. Alternate forms may be used with prior written approval from the Department.

F. Each facility which operates a CEMS/COMS must maintain on site a file of CEMS/COMS data including all raw data, corrected and adjusted, repair logs, calibration checks, adjustments, and test audits. This file must be retained for a period of at least five years, and is required to be maintained in such a condition that it can easily be audited by an inspector.

G. Except for Part 75 CEMs, quarterly reports shall be used by the Department to determine compliance with the permit. For Part 75 CEMs, the semi-annual report shall be used.

SECTION IV

QUALITY ASSURANCE/QUALITY CONTROL

A. For each CEMS/COMS a Quality Assurance/Quality Control (QA/QC) plan shall be submitted to the Department (Attn.: Air Division, CEM Coordinator). CEMS quality assurance procedures are defined in 40 CFR, Part 60, Appendix F. This plan shall be submitted within 180 days of the CEMS/COMS installation. A QA/QC plan shall consist of procedure and practices which assures acceptable level of monitor data accuracy, precision, representativeness, and availability.

B. The submitted QA/QC plan for each CEMS/COMS shall not be considered as accepted until the facility receives a written notification of acceptance from the Department.

C. Facilities responsible for one, or more, CEMS/COMS used for compliance monitoring shall meet these minimum requirements and are encouraged to develop and implement a more extensive QA/QC program, or to continue such programs where they already exist. Each QA/QC program must include written procedures which should describe in detail, complete, step-by-step procedures and operations for each of the following activities:

1. Calibration of CEMS/COMS
    a. Daily calibrations (including the approximate time(s) that the daily zero and span drifts will be checked and the time required to perform these checks and return to stable operation)
2. Calibration drift determination and adjustment of CEMS/COMS
    a. Out-of-control period determination
    b. Steps of corrective action
3. Preventive maintenance of CEMS/COMS
    a. CEMS/COMS information
        1) Manufacture
        2) Model number
        3) Serial number
    b. Scheduled activities (check list)
    c. Spare part inventory
4. Data recording, calculations, and reporting
5. Accuracy audit procedures including sampling and analysis methods
6. Program of corrective action for malfunctioning CEMS/COMS

D. A Relative Accuracy Test Audit (RATA), shall be conducted at least once every four calendar quarters. A Relative Accuracy Audit (RAA), or a Cylinder Gas Audit (CGA), may be conducted in the other three quarters but in no more than three quarters in succession. The RATA should be conducted in accordance with the applicable test procedure in 40 CFR Part 60 Appendix A and calculated in accordance with the applicable performance specification in 40 CFR Part 60 Appendix B. CGA's and RAA's should be conducted and the data calculated in accordance with the procedures outlined on 40 CFR Part 60 Appendix F.

If alternative testing procedures or methods of calculation are to be used in the RATA, RAA or CGA audits prior authorization must be obtained from the ADEQ CEM Coordinator.

E. Criteria for excessive audit inaccuracy.

RATA

All Pollutants except Carbon Monoxide	> 20% Relative Accuracy
Carbon Monoxide	> 10% Relative Accuracy
All Pollutants except Carbon Monoxide	> 10% of the Applicable Standard
Carbon Monoxide	> 5% of the Applicable Standard
Diluent (O_2 & CO_2)	> 1.0 % O2 or CO2
Flow	> 20% Relative Accuracy

CGA

Pollutant	> 15% of average audit value or 5 ppm difference
Diluent (O_2 & CO_2)	> 15% of average audit value or 5 ppm difference

RAA

Pollutant	> 15% of the three run average or > 7.5 % of the applicable standard
Diluent (O_2 & CO_2)	> 15% of the three run average or > 7.5 % of the applicable standard

F. If either the zero or span drift results exceed two times the applicable drift specification in 40 CFR, Part 60, Appendix B for five consecutive, daily periods, the CEMS is out-of-control. If either the zero or span drift results exceed four times the applicable drift specification in Appendix B during a calibration drift check, the CEMS is out-of-control. If the CEMS exceeds the audit inaccuracies listed above, the CEMS is out-of-control. If a CEMS is out-of-control, the data from that out-of-control period is not counted towards meeting the minimum data availability as required and described in the applicable subpart. The end of the out-of-control period is the time corresponding to the completion of the successful daily zero or span drift or completion of the successful CGA, RAA or RATA.

G. A back-up monitor may be placed on an emission source to minimize monitor downtime. This back-up CEMS is subject to the same QA/QC procedure and practices as the primary CEMS. The back-up CEMS shall be certified by a PST. Daily zero-span checks must be performed and recorded in accordance with standard practices. When the primary CEMS goes down, the back-up CEMS may then be engaged to sample, analyze and record the emission source pollutant until repairs are made and the primary unit is placed back in service. Records must be maintained on site when the back-up CEMS is placed in service, these records shall include at a minimum the reason the primary CEMS is out of service, the date and time the primary CEMS was out of service and the date and time the primary CEMS was placed back in service.

APPENDIX B

40 CFR Part 75
Acid Rain Program - Continuous Emission Monitoring

APPENDIX C

40 CFR Part 60, Subpart Da

[Last updated 2/27/06]

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40 CFR 60: Subpart Da--Standards of Performance for Electric Utility Steam Generating Units for Which Construction is Commenced After September 18, 1978

Sec.

60.40Da Applicability and designation of affected facility.
60.41Da Definitions.
60.42Da Standard for particulate matter.
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60.44Da Standard for nitrogen oxide.
60.45Da Commerical demonstration permit.
60.46Da Compliance provisions.
60.47Da Emissions monitoring.
60.48Da Compliance determination procedures and methods.
60.49Da Reporting requirements.

Subpart Da--Standards of Performance for Electric Utility Steam Generating Units for Which Construction is Commenced After September 18, 1978

Sec. 60.40Da Applicability and designation of affected facility.

(a) The affected facility to which this subpart applies is each electric utility steam generating unit:

(1) That is capable of combusting more than 73 megawatts (250 million Btu/hour) heat input of fossil fuel (either alone or in combination with any other fuel); and

(2) For which construction or modification is commenced after September 18, 1978.

(b) Heat recovery steam generators that are associated with stationary combustion turbines burning fuels other than 75 percent (by heat input) or more synthetic-coal gas on a 12-month rolling average and that meet the applicability requirements of subpart KKKK of this part are not subject to this subpart. Heat recovery steam generators and the associated stationary combustion turbine(s) burning fuels containing 75 percent (by heat input) or more synthetic-coal gas on a 12-month rolling average are subject to this part and are not subject to subpart KKKK of this part. This subpart will continue to apply to all other electric utility combined cycle gas turbines that are capable of combusting more than 73 MW (250 MMBtu/h) heat input of fossil fuel in the heat recovery steam generator. If the heat recovery steam generator is subject to this subpart and the combined cycle gas turbine burn fuels other than synthetic-coal gas, only emissions resulting from combustion of fuels in the steam-generating unit are subject to this subpart. (The combustion turbine emissions are subject to subpart GG or KKKK, as applicable, of this part).

(c) Any change to an existing fossil-fuel-fired steam generating unit to accommodate the use of combustible materials, other than fossil fuels, shall not bring that unit under the applicability of this

subpart.

(d) Any change to an existing steam generating unit originally designed to fire gaseous or liquid fossil fuels, to accommodate the use of any other fuel (fossil or nonfossil) shall not bring that unit under the applicability of this subpart.

§ 60.41Da Definitions.

As used in this subpart, all terms not defined herein shall have the meaning given them in the Act and in subpart A of this part.

Anthracite means coal that is classified as anthracite according to the American Society of Testing and Materials' (ASTM) Standard Specification for Classification of Coals by Rank D388-77 (incorporated by reference -- see §60.17).

Available purchase power means the lesser of the following:

(a) The sum of available system capacity in all neighboring companies.

(b) The sum of the rated capacities of the power interconnection devices between the principal company and all neighboring companies, minus the sum of the electric power load on these interconnections.

(c) The rated capacity of the power transmission lines between the power interconnection devices and the electric generating units (the unit in the principal company that has the malfunctioning flue gas desulfurization system and the unit(s) in the neighboring company supplying replacement electrical power) less the electric power load on these transmission lines.

Available system capacity means the capacity determined by subtracting the system load and the system emergency reserves from the net system capacity.

Bituminous coal means coal that is classified as bituminous according to the American Society of Testing and Materials (ASTM) Standard Specification for Classification of Coals by Rank D388-77, 90, 91, 95, 98a, or 99 (Reapproved 2004)[e1] (incorporated by reference, see Sec. 60.17).

Boiler operating day for units constructed, reconstructed, or modified on or before February 28, 2005, means a 24-hour period during which fossil fuel is combusted in a steam-generating unit for the entire 24 hours. For units constructed, reconstructed, or modified after February 28, 2005, boiler operating day means a 24-hour period between 12 midnight and the following midnight during which any fuel is combusted at any time in the steam-generating unit. It is not necessary for fuel to be combusted the entire 24-hour period.

Coal means all solid fuels classified as anthracite, bituminous, subbituminous, or lignite by the American Society of Testing and Materials (ASTM) Standard Specification for Classification of Coals by Rank D388-77, 90, 91, 95, 98a, or 99 (Reapproved 2004)[epsiv]\1\ (incorporated by reference, see Sec. 60.17), coal refuse, and petroleum coke. Synthetic fuels derived from coal for the purpose of creating useful heat, including but not limited to solvent-refined coal, gasified coal, coal-oil mixtures, and coal-water mixtures are included in this definition for the purposes of this subpart.

Coal-fired electric utility steam generating unit means an electric utility steam generating unit that burns coal, coal refuse, or a synthetic gas derived from coal either exclusively, in any combination together, or in any combination with other supplemental fuels in any amount. Examples of supplemental fuels include, but are not limited to, petroleum coke and tire-derived fuels.

Coal refuse means waste products of coal mining, physical coal cleaning, and coal preparation operations (e.g. culm, gob, etc.) containing coal, matrix material, clay, and other organic and inorganic material.

Cogeneration, also known as ``combined heat and power," means a steam-generating unit that simultaneously produces both electric (or mechanical) and useful thermal energy from the same primary energy source.

Combined cycle gas turbine means a stationary turbine combustion system where heat from the turbine exhaust gases is recovered by a steam generating unit.

Dry flue gas desulfurization technology or dry FGD means a sulfur dioxide control system that is located downstream of the steam generating unit and removes sulfur oxides from the combustion gases of the steam generating unit by contacting the combustion gases with an alkaline slurry or solution and forming a dry powder material. This definition includes devices where the dry powder material is subsequently converted to another form. Alkaline slurries or solutions used in dry FGD technology include, but are not limited to, lime and sodium.

Duct burner means a device that combusts fuel and that is placed in the exhaust duct from another source, such as a stationary gas turbine, internal combustion engine, kiln, etc., to allow the firing of additional fuel to heat the exhaust gases before the exhaust gases enter a heat recovery steam generating unit.

Electric utility combined cycle gas turbine means any combined cycle gas turbine used for electric generation that is constructed for the purpose of supplying more than one-third of its potential electric output capacity and more than 25 MW electrical output to any utility power distribution system for sale. Any steam distribution system that is constructed for the purpose of providing steam to a steam electric generator that would produce electrical power for sale is also considered in determining the electrical energy output capacity of the affected facility.

Electric utility company means the largest interconnected organization, business, or governmental entity that generates electric power for sale (e.g., a holding company with operating subsidiary companies).

Electric utility steam generating unit means any steam electric generating unit that is constructed for the purpose of supplying more than one-third of its potential electric output capacity and more than 25 MW net-electrical output to any utility power distribution system for sale. For the purpose of this subpart, net-electric output is the gross electric sales to the utility power distribution system minus purchased power on a 12-month rolling average. Also, any steam supplied to a steam distribution system for the purpose of providing steam to a steam-electric generator that would produce electrical energy for sale is considered in determining the electrical energy output capacity of the affected facility.

Electrostatic precipitator or ESP means an add-on air pollution control device used to capture particulate matter by charging the particles using an electrostatic field, collecting the particles using a grounded collecting surface, and transporting the particles into a hopper.

Emergency condition means that period of time when:

(a) The electric generation output of an affected facility with a malfunctioning flue gas desulfurization system cannot be reduced or electrical output must be increased because:

(1) All available system capacity in the principal company interconnected with the affected facility is being operated, and

(2) All available purchase power interconnected with the affected facility is being obtained, or

(b) The electric generation demand is being shifted as quickly as possible from an affected facility with a malfunctioning flue gas desulfurization system to one or more electrical generating units held in reserve by the principal company or by a neighboring company, or

(c) An affected facility with a malfunctioning flue gas desulfurization system becomes the only available unit to maintain a part or all of the principal company's system emergency reserves and the unit is operated in spinning reserve at the lowest practical electric generation

load consistent with not causing significant physical damage to the unit. If the unit is operated at a higher load to meet load demand, an emergency condition would not exist unless the conditions under (a) of this definition apply.

Emission limitation means any emissions limit or operating limit.

Emission rate period means any calendar month included in a 12-month rolling average period.

Federally enforceable means all limitations and conditions that are enforceable by the Administrator, including the requirements of 40 CFR parts 60 and 61, requirements within any applicable State implementation plan, and any permit requirements established under 40 CFR 52.21 or 40 CFR 51.18 and 40 CFR 51.24.

Fossil fuel means natural gas, petroleum, coal, and any form of solid, liquid, or gaseous fuel derived from such material for the purpose of creating useful heat.

Gaseous fuel means any fuel derived from coal or petroleum that is present as a gas at standard conditions and includes, but is not limited to, refinery fuel gas, process gas, and coke-oven gas.

Gross output means the gross useful work performed by the steam generated. For units generating only electricity, the gross useful work performed is the gross electrical output from the turbine/generator set. For cogeneration units, the gross useful work performed is the gross electrical output plus 75 percent of the useful thermal output measured relative to ISO conditions that is not used to generate additional electrical or mechanical output (i.e., steam delivered to an industrial process).

24-hour period means the period of time between 12:01 a.m. and 12:00 midnight.

Interconnected means that two or more electric generating units are electrically tied together by a network of power transmission lines, and other power transmission equipment.

Integrated gasification combined cycle electric utility steam generating unit or IGCC means a coal-fired electric utility steam generating unit that burns a synthetic gas derived from coal in a combined-cycle gas turbine. No coal is directly burned in the unit during operation.

ISO conditions means a temperature of 288 Kelvin, a relative humidity of 60 percent, and a pressure of 101.3 kilopascals.

Lignite means coal that is classified as lignite A or B according to the American Society of Testing and Materials' (ASTM) Standard Specification for Classification of Coals by Rank D388-77, 90, 91, 95, or 98a (incorporated by reference -- see §60.17).

Natural gas means:

(1) A naturally occurring mixture of hydrocarbon and nonhydrocarbon gases found in geologic formations beneath the earth's surface, of which the principal constituent is methane; or

(2) Liquid petroleum gas, as defined by the American Society of Testing and Materials (ASTM) Standard Specification for Liquid Petroleum Gases D1835-87, 91, 97, or 03a (incorporated by reference, see Sec. 60.17).

Neighboring company means any one of those electric utility companies with one or more electric power interconnections to the principal company and which have geographically adjoining service areas.

Net system capacity means the sum of the net electric generating capability (not necessarily equal to rated capacity) of all electric generating equipment owned by an electric utility company (including steam generating units, internal combustion engines, gas turbines, nuclear units, hydroelectric units, and all other electric generating equipment) plus firm contractual purchases that are interconnected to the affected facility that has the malfunctioning flue gas desulfurization system. The electric generating capability of equipment under multiple ownership is prorated based on ownership unless the proportional entitlement to electric output is otherwise established by contractual arrangement.

Noncontinental area means the State of Hawaii, the Virgin Islands, Guam, American Samoa, the Commonwealth of Puerto Rico, or the Northern Mariana Islands.

Petroleum means crude oil or petroleum or a fuel derived from crude oil or petroleum, including distillate, residual oil, and petroleum coke.

Potential combustion concentration means the theoretical emissions (ng/J, lb/million Btu heat input) that would result from combustion of a fuel in an uncleaned state without emission control systems) and:

(a) For particulate matter is:

(1) 3,000 ng/J (7.0 lb/million Btu) heat input for solid fuel; and

(2) 73 ng/J (0.17 lb/million Btu) heat input for liquid fuels.

(b) For sulfur dioxide is determined under § 60.48Da(b).

(c) For nitrogen oxides is:

(1) 290 ng/J (0.67 lb/million Btu) heat input for gaseous fuels;

(2) 310 ng/J (0.72 lb/million Btu) heat input for liquid fuels; and

(3) 990 ng/J (2.30 lb/million Btu) heat input for solid fuels.

Potential electrical output capacity is defined as 33 percent of the maximum design heat input capacity of the steam generating unit (e.g., a steam generating unit with a 100-MW (340 million Btu/hr) fossil-fuel heat input capacity would have a 33-MW potential electrical output capacity). For electric utility combined cycle gas turbines the potential electrical output capacity is determined on the basis of the fossil-fuel firing capacity of the steam generator exclusive of the heat input and electrical power contribution by the gas turbine.

Principal company means the electric utility company or companies which own the affected facility.

Resource recovery unit means a facility that combusts more than 75 percent non-fossil fuel on a quarterly (calendar) heat input basis.

Responsible official means responsible official as defined in 40 CFR 70.2.

Solid-derived fuel means any solid, liquid, or gaseous fuel derived from solid fuel for the purpose of creating useful heat and includes, but is not limited to, solvent refined coal, liquified coal, and gasified coal.

Spare flue gas desulfurization system module means a separate system of sulfur dioxide emission control equipment capable of treating an amount of flue gas equal to the total amount of flue gas generated by an affected facility when operated at maximum capacity divided by the total number of nonspare flue gas desulfurization modules in the system.

Spinning reserve means the sum of the unutilized net generating capability of all units of the electric utility company that are synchronized to the power distribution system and that are capable of immediately accepting additional load. The electric generating capability of equipment under multiple ownership is prorated based on ownership unless the proportional entitlement to electric output is otherwise established by contractual arrangement.

Steam generating unit means any furnace, boiler, or other device used for combusting fuel for the purpose of producing steam (including fossil-fuel-fired steam generators associated with combined cycle gas turbines; nuclear steam generators are not included).

Subbituminous coal means coal that is classified as subbituminous A, B, or C according to the American Society of Testing and Materials (ASTM) Standard Specification for Classification of Coals by Rank D388-77, 90, 91, 95, or 98a (incorporated by reference -- see §60.17).

System emergency reserves means an amount of electric generating capacity equivalent to the rated capacity of the single largest electric generating unit in the electric utility company (including steam generating units, internal combustion engines, gas turbines, nuclear units, hydroelectric units, and all other electric generating equipment) which is interconnected with the affected facility that has the malfunctioning flue gas desulfurization system. The electric generating capability of equipment under multiple ownership is prorated based on ownership unless the proportional entitlement to electric output is otherwise established by contractual arrangement.

System load means the entire electric demand of an electric utility company's service area interconnected with the affected facility that has the malfunctioning flue gas desulfurization system plus firm contractual sales to other electric utility companies. Sales to other electric utility companies (e.g., emergency power) not on a firm contractual basis may also be included in the system load when no available system capacity exists in the electric utility company to which the power is supplied for sale.

Wet flue gas desulfurization technology or wet FGD means a sulfur dioxide control system that is located downstream of the steam generating unit and removes sulfur oxides from the combustion gases of the steam generating unit by contacting the combustion gases with an alkaline slurry or solution and forming a liquid material. This definition applies to devices where the aqueous liquid material product of this contact is subsequently converted to other forms. Alkaline reagents used in wet FGD technology include, but are not limited to, lime, limestone, and sodium.

Sec. 60.42Da Standard for particulate matter.

(a) On and after the date on which the performance test required to be conducted under Sec. 60.8 is completed, no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any affected facility for which construction, reconstruction, or modification commenced before or on February 28, 2005, any gases that contain particulate matter in excess of:

(1) 13 ng/J (0.03 lb/million Btu) heat input derived from the combustion of solid, liquid, or gaseous fuel;

(2) 1 percent of the potential combustion concentration (99 percent reduction) when combusting solid fuel; and

(3) 30 percent of potential combustion concentration (70 percent reduction) when combusting liquid fuel.

(b) On and after the date the particulate matter performance test required to be conducted under Sec. 60.8 is completed, no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any affected facility any gases which exhibit greater than 20 percent opacity (6-minute average), except for one 6-minute period per hour of not more than 27 percent opacity.

(c) On and after the date on which the performance test required to be conducted under Sec. 60.8 is completed, no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any affected facility for which construction, reconstruction, or modification is commenced after February 28, 2005, except for modified affected facilities meeting the requirements of paragraph (d) of this section, any gases that contain particulate matter in excess of either:

(1) 18 ng/J (0.14 lb/MWh) gross energy output; or

(2) 6.4 ng/J (0.015 lb/MMBtu) heat input derived from the combustion of solid, liquid, or gaseous fuel.

(d) As an alternative to meeting the requirements of paragraph (c) of this section, the owner or operator of an affected facility for which construction, reconstruction, or modification commenced after February 28, 2005, may elect to meet the requirements of this paragraph. On and after the date on which the performance test required to be conducted under Sec. 60.8 is completed, the owner or operator subject to the provisions of this subpart shall not cause to be discharged into the atmosphere from any affected facility for which construction, reconstruction, or modification commenced after February 28, 2005, any gases that contain particulate matter in excess of:

(1) 13 ng/J (0.03 lb/MMBtu) heat input derived from the combustion of solid, liquid, or gaseous fuel, and

(2) 0.1 percent of the combustion concentration determined according to the procedure in Sec. 60.48Da(o)(5) (99.9 percent reduction) for an affected facility for which construction or reconstruction commenced after February 28, 2005 when combusting solid fuel or solid-derived fuel, or

(3) 0.2 percent of the combustion concentration determined according to the procedure in Sec. 60.48Da(o)(5) (99.8 percent reduction) for an affected facility for which modification commenced after February 28, 2005 when combusting solid fuel or solid-derived fuel.

Sec. 60.43Da Standard for sulfur dioxide.

(a) On and after the date on which the initial performance test required to be conducted under Sec. 60.8 is completed, no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any affected facility which combusts solid fuel or solid-derived fuel and for which construction, reconstruction, or modification commenced before or on February 28, 2005, except as provided under paragraphs (c), (d), (f) or (h) of this section, any gases that contain sulfur dioxide in excess of:

(1) 520 ng/J (1.20 lb/million Btu) heat input and 10 percent of the potential combustion concentration (90 percent reduction), or

(2) 30 percent of the potential combustion concentration (70 percent reduction), when emissions are less than 260 ng/J (0.60 lb/million Btu) heat input.

(b) On and after the date on which the initial performance test required to be conducted under Sec. 60.8 is completed, no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any affected facility which combusts liquid or gaseous fuels (except for liquid or gaseous fuels derived from solid fuels and as provided under paragraphs (e) or (h) of this section) and for which construction, reconstruction, or modification commenced before or on February 28, 2005, any gases that contain sulfur dioxide in excess of:

(1) 340 ng/J (0.80 lb/million Btu) heat input and 10 percent of the potential combustion concentration (90 percent reduction), or

(2) 100 percent of the potential combustion concentration (zero percent reduction) when emissions are less than 86 ng/J (0.20 lb/million Btu) heat input.

(c) On and after the date on which the initial performance test required to be conducted under Sec. 60.8 is complete, no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any affected facility which combusts solid solvent refined coal (SRC-I) any gases which contain sulfur dioxide in excess of 520 ng/J (1.20 lb/million Btu) heat input and 15 percent of the potential combustion concentration (85 percent reduction) except as provided under paragraph (f) of this section; compliance with the emission limitation is determined on a 30-day rolling average basis and compliance with the percent reduction requirement is determined on a 24-hour basis.

(d) Sulfur dioxide emissions are limited to 520 ng/J (1.20 lb/million Btu) heat input from any affected facility which: (1) Combusts 100 percent anthracite,

(2) Is classified as a resource recovery unit, or

(3) Is located in a noncontinental area and combusts solid fuel or solid-derived fuel.

(e) Sulfur dioxide emissions are limited to 340 ng/J (0.80 lb/million Btu) heat input from any affected facility which is located in a noncontinental area and combusts liquid or gaseous fuels (excluding solid-derived fuels).

(f) The emission reduction requirements under this section do not apply to any affected facility that is operated under an SO_2 commercial demonstration permit issued by the Administrator in accordance with the provisions of Sec. 60.45Da.

(g) Compliance with the emission limitation and percent reduction requirements under this section are both determined on a 30-day rolling average basis except as provided under paragraph (c) of this section.

(h) When different fuels are combusted simultaneously, the applicable standard is determined by proration using the following formula:

(1) If emissions of sulfur dioxide to the atmosphere are greater than 260 ng/J (0.60 lb/million Btu) heat input

$E_s = (340x+520\ y)/100$ and
$\%P_s = 10$

(2) If emissions of sulfur dioxide to the atmosphere are equal to or less than 260 ng/J (0.60 lb/million Btu) heat input:

$E_s = (340x+520\ y)/100$ and
$\%Ps = (10x+30\ y)/100$

where:
Es is the prorated sulfur dioxide emission limit (ng/J heat input),
%Ps is the percentage of potential sulfur dioxide emission allowed.
x is the percentage of total heat input derived from the combustion of liquid or gaseous fuels (excluding solid-derived fuels)
y is the percentage of total heat input derived from the combustion of solid fuel (including solid-derived fuels)
[44 FR 33613, June 11, 1979, as amended at 54 FR 6663, Feb. 14, 1989; 54 FR 21344, May 17, 1989]

(i) On and after the date on which the performance test required to be conducted under Sec. 60.8 is completed, no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any affected facility for which construction, reconstruction, or modification commenced after February 28, 2005, except as provided for under paragraphs (j) or (k) of this section, any gases that contain sulfur dioxide in excess of the applicable emission limitation specified in paragraphs (i)(1) through (3) of this section.

(1) For an affected facility for which construction commenced after February 28, 2005, any gases that contain sulfur dioxide in excess of either:

(i) 180 ng/J (1.4 lb/MWh) gross energy output on a 30-day rolling average basis, or

(ii) 5 percent of the potential combustion concentration (95 percent reduction) on a 30-day rolling average basis.

(2) For an affected facility for which reconstruction commenced after February 28, 2005, any gases that contain sulfur dioxide in excess of either:

(i) 180 ng/J (1.4 lb/MWh) gross energy output on a 30-day rolling average basis,

(ii) 65 ng/J (0.15 lb/MMBtu) heat input on a 30-day rolling average basis, or

(iii) 5 percent of the potential combustion concentration (95 percent reduction) on a 30-day rolling average basis.

(3) For an affected facility for which modification commenced after February 28, 2005, any gases that contain sulfur dioxide in excess of either:

(i) 180 ng/J (1.4 lb/MWh) gross energy output on a 30-day rolling average basis,

(ii) 65 ng/J (0.15 lb/MMBtu) heat input on a 30-day rolling average basis, or

(iii) 10 percent of the potential combustion concentration (90 percent reduction) on a 30-day rolling average basis.

(j) On and after the date on which the performance test required to be conducted under Sec. 60.8 is completed, no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any affected facility for which construction, reconstruction, or modification commenced after February 28, 2005, and that burns 75 percent or more (by heat input) coal refuse on a 12-month rolling average basis, any gases that contain sulfur dioxide in excess of the applicable emission limitation specified in paragraphs (j)(1) through (3) of this section.

(1) For an affected facility for which construction commenced after February 28, 2005, any gases that contain sulfur dioxide in excess of either:

(i) 180 ng/J (1.4 lb/MWh) gross energy output on a 30-day rolling average basis, or

(ii) 6 percent of the potential combustion concentration (94 percent reduction) on a 30-day rolling average basis.

(2) For an affected facility for which reconstruction commenced after February 28, 2005, any gases that contain sulfur dioxide in excess of either:

(i) 180 ng/J (1.4 lb/MWh) gross energy output on a 30-day rolling average basis,

(ii) 65 ng/J (0.15 lb/MMBtu) heat input on a 30-day rolling average basis, or

(iii) 6 percent of the potential combustion concentration (94 percent reduction) on a 30-day rolling average basis.

(3) For an affected facility for which modification commenced after February 28, 2005, any gases that contain sulfur dioxide in excess of either:

(i) 180 ng/J (1.4 lb/MWh) gross energy output on a 30-day rolling average basis,

(ii) 65 ng/J (0.15 lb/MMBtu) heat input on a 30-day rolling average basis, or

(iii) 10 percent of the potential combustion concentration (90 percent reduction) on a 30-day rolling average basis.

(k) On and after the date on which the performance test required to be conducted under Sec. 60.8 is completed, no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any affected facility for which construction, reconstruction, or modification commenced after February 28, 2005, and that is located in a noncontinental area, any gases that contain sulfur dioxide in excess of the applicable emission limitation specified in paragraphs (k)(1) and (2) of this section.

(1) For an affected facility that burns solid or solid-derived fuel, the owner or operator shall not cause to be discharged into the atmosphere any gases that contain sulfur dioxide in excess of 520 ng/J (1.2 lb/MMBtu) heat input on a 30-day rolling average basis.

(2) For an affected facility that burns other than solid or solid-derived fuel, the owner or operator shall not cause to be discharged into the atmosphere any gases that contain sulfur dioxide in excess of if the affected facility or 230 ng/J (0.54 lb/MMBtu) heat input on a 30-day rolling average basis.

Sec. 60.44Da Standard for nitrogen oxides.

(a) On and after the date on which the initial performance test required to be conducted under Sec. 60.8 is completed, no owner or operator subject to the provisions of this subpart shall cause to be discharged into

the atmosphere from any affected facility, except as provided under paragraphs (b) and (d) of this section, any gases which contain nitrogen oxides (expressed as NO_2) in excess of the following emission limits, based on a 30-day rolling average, except as provided under § 60.46Da(j)(1):

(1) NO_x emission limits.

Fuel type	Emission limit for heat input	
	ng/J	(lb/million Btu)
Gaseous fuels:		
Coal-derived fuels	210	0.50
All other fuels	86	0.20
Liquid fuels:		
Coal-derived fuels	210	0.50
Shale oil	210	0.50
All other fuels	130	0.30
Solid fuels:		
Coal-derived fuels	210	0.50
Any fuel containing more than 25%, by weight, coal refuse	([1])	([1])
Any fuel containing more than 25%, by weight, lignite if the lignite is mined in North Dakota, South Dakota, or Montana, and is combusted in a slag tap furnace[2]	340	0.80
Any fuel containing more than 25%, by weight, lignite not subject to the 340 ng/J heat input emission limit[2]		
Subbituminous coal	210	0.50
Bituminous coal	260	0.60
Anthracite coal	260	0.60
All other fuels	260	0.60

[1] Exempt from NO_x standards and NO_x monitoring requirements.

[2] Any fuel containing less than 25%, by weight, lignite is not prorated but its percentage is added to the percentage of the predominant fuel.

(2) NO_x reduction requirement.

Fuel type	Percent reduction of potential combustion concentration

Gaseous fuels.....	25
Liquid fuels.....	30
Solid fuels.....	65

(b) The emission limitations under paragraph (a) of this section do not apply to any affected facility which is combusting coal-derived liquid fuel and is operating under a commercial demonstration permit issued by the Administrator in accordance with the provisions of Sec. 60.45Da.

(c) Except as provided under paragraph (d) of this section, when two or more fuels are combusted simultaneously, the applicable standard is determined by proration using the following formula:

$E_n = [86\ w+130\ x\ +210\ y+260\ z+340\ v]/100$

where:
E_n is the applicable standard for nitrogen oxides when multiple fuels are combusted simultaneously (ng/J heat input);
w is the percentage of total heat input derived from the combustion of fuels subject to the 86 ng/J heat input standard;
x is the percentage of total heat input derived from the combustion of fuels subject to the 130 ng/J heat input standard;
y is the percentage of total heat input derived from the combustion of fuels subject to the 210 ng/J heat input standard;
z is the percentage of total heat input derived from the combustion of fuels subject to the 260 ng/J heat input standard; and
v is the percentage of total heat input delivered from the combustion of fuels subject to the 340 ng/J heat input standard.
[44 FR 33613, June 11, 1979, as amended at 54 FR 6664, Feb. 14, 1989]

(d) (1) On and after the date on which the initial performance test required to be conducted under Sec. 60.8 is completed, no new source owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any affected facility for which construction commenced after July 9, 1997, but before or on February 28, 2005, any gases that contain nitrogen oxides (expressed as NO2) in excess of 200 ng/J (1.6 lb/MWh) gross energy output, based on a 30-day rolling average, except as provided under Sec. 60.48Da(k).

(2) On and after the date on which the initial performance test required to be conducted under Sec. 60.8 is completed, no existing source owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any affected facility for which reconstruction commenced after July 9, 1997, but before or on February 28, 2005, any gases that contain nitrogen oxides (expressed as NO2) in excess of 65 ng/J (0.15 lb/MMBtu) heat input, based on a 30-day rolling average.

(e) On and after the date on which the performance test required to be conducted under Sec. 60.8 is completed, no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any affected facility for which construction, reconstruction, or modification commenced after February 28, 2005, except for an IGCC meeting the requirements of paragraph (f) of

this section, any gases that contain nitrogen oxides (expressed as NO2) in excess of the applicable emission limitation specified in paragraphs (e)(1) through (3) of this section.

(1) For an affected facility for which construction commenced after February 28, 2005, the owner or operator shall not cause to be discharged into the atmosphere any gases that contain nitrogen oxides (expressed as NO2) in excess of 130 ng/J (1.0 lb/MWh) gross energy output on a 30-day rolling average basis, except as provided under Sec. 60.48Da(k).

(2) For an affected facility for which reconstruction commenced after February 28, 2005, the owner or operator shall not cause to be discharged into the atmosphere any gases that contain nitrogen oxides (expressed as NO2) in excess of either:

(i) 130 ng/J (1.0 lb/MWh) gross energy output on a 30-day rolling average basis, or

(ii) 47 ng/J (0.11 lb/MMBtu) heat input on a 30-day rolling average basis.

(3) For an affected facility for which modification commenced after February 28, 2005, the owner or operator shall not cause to be discharged into the atmosphere any gases that contain nitrogen oxides (expressed as NO2) in excess of either:

(i) 180 ng/J (1.4 lb/MWh) gross energy output on a 30-day rolling average basis, or

(ii) 65 ng/J (0.15 lb/MMBtu) heat input on a 30-day rolling average basis.

(f) On and after the date on which the performance test required to be conducted under Sec. 60.8 is completed, the owner or operator of an IGCC subject to the provisions of this subpart that burns liquid fuel as a supplemental fuel and for which construction, reconstruction, or modification commenced after February 28, 2005, shall meet the requirements specified in paragraphs (f)(1) through (3) of this section.

(1) The owner or operator shall not cause to be discharged into the atmosphere any gases that contain nitrogen oxides (expressed as NO2) in excess of 130 ng/J (1.0 lb/MWh) gross energy output on a 30-day rolling average basis, except as provided for in paragraphs (f)(2) and (3) of this section.

(2) When burning liquid fuel exclusively or in combination with synthetic gas derived from coal such that the liquid fuel contributes 50 percent or more of the total heat input to the combined cycle combustion turbine, the owner or operator shall not cause to be discharged into the atmosphere any gases that contain nitrogen oxides (expressed as NO2) in excess of 190 ng/J (1.5 lb/MWh) gross energy output on a 30-day rolling average basis.

(3) In cases when during a 30-day rolling average compliance period liquid fuel is burned in such a manner to meet the conditions in paragraph (f)(2) of this section for only a portion of the 30-day period, the owner or operator shall not cause to be discharged into the atmosphere any gases that contain nitrogen oxides (expressed as NO2) in excess of the computed weighted-average emissions limit based on the proportion of gross energy output (in MWh) generated during the compliance period for each of emissions limits in paragraphs (f)(1) and (2) of this section.

Sec. 60.45Da Standard for mercury.

(a) For each coal-fired electric utility steam generating unit other than an integrated gasification combined cycle (IGCC) electric utility steam generating unit, on and after the date on which the initial performance test required to be conducted under Sec. 60.8 is completed, no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any affected facility for which construction or reconstruction commenced after January 30, 2004, any gases which contain mercury (Hg) emissions in excess of each Hg emissions limit in paragraphs (a)(1) through (5) of this section that applies to you. The Hg emissions limits in paragraphs (a)(1) through (5) of this section are based on a 12-month rolling average using the procedures in Sec. 60.50Da(h).

(1) For each coal-fired electric utility steam generating unit that burns only bituminous coal, you must not discharge into the atmosphere any gases from a new affected source which contain Hg in

excess of 21 x 10^{-6} pound per megawatt hour (lb/MWh) or 0.021 lb/gigawatt-hour (GWh) on an output basis. The International System of Units (SI) equivalent is 0.0026 nanograms per joule (ng/J).

(2) For each coal-fired electric utility steam generating unit that burns only subbituminous coal:

(i) If you utilize wet FGD technology to limit SO2 emissions from your steam generating unit, you must not discharge into the atmosphere any gases from a new affected source which contain Hg in excess of 42 x 10-\6\ lb/MWh or 0.042 lb/GWh on an output basis. The SI equivalent is 0.0053 ng/J.

(ii) If you utilize dry FGD technology to limit SO2 emissions from your steam generating unit, you must not discharge into the atmosphere any gases from a new affected source which contain Hg in excess of 78 x 10-\6\ lb/MWh or 0.078 lb/GWh on an output basis. The SI equivalent is 0.0098 ng/J.

(3) For each coal-fired electric utility steam generating unit that burns only lignite, you must not discharge into the atmosphere any gases from a new affected source which contain Hg in excess of 145 x 10-\6\ lb/MWh or 0.145 lb/GWh on an output basis. The SI equivalent is 0.0183 ng/J.

(4) For each coal-burning electric utility steam generating unit that burns only coal refuse, you must not discharge into the atmosphere any gases from a new affected source which contain Hg in excess of 1.4 x 10^{-6} lb/MWh or 0.0014 lb/GWh on an output basis. The SI equivalent is 0.00018 ng/J.

(5) For each coal-fired electric utility steam generating unit that burns a blend of coals from different coal ranks (i.e., bituminous coal, subbituminous coal, lignite) or a blend of coal and coal refuse, you must not discharge into the atmosphere any gases from a new affected source that contain Hg in excess of the monthly unit-specific Hg emissions limit established according to paragraph (a)(5)(i) or (ii) of this section, as applicable to the affected unit.

(i) If you operate a coal-fired electric utility steam generating unit that burns a blend of coals from different coal ranks or a blend of coal and coal refuse, you must not discharge into the atmosphere any gases from a new affected source that contain Hg in excess of the computed weighted Hg emissions limit based on the proportion of energy output (in British thermal units, Btu) contributed by each coal rank burned during the compliance period and its applicable Hg emissions limit in paragraphs (a)(1) through (4) of this section as determined using Equation 1 of this section. You must meet the weighted Hg emissions limit calculated using Equation 1 of this section by calculating the unit emission rate based on the total Hg loading of the unit and the total Btu or megawatt hours contributed by all fuels burned during the compliance period.

$$EL_b = \frac{\sum_{i=1}^{n} EL_i (HH_i)}{\sum_{i=1}^{n} HH_i} \qquad \text{(Eq. 1)}$$

Where:

EL_b = Total allowable Hg in lb/MWh that can be emitted to the atmosphere from any affected source being averaged under the blending provision.
EL_i = Hg emissions limit for the subcategory i (coal rank) that applies to affected source, lb/MWh.
HH_i = Electricity output from affected source during the production period related to use of the corresponding subcategory i (coal rank) that falls within the compliance period, gross MWh generated by the electric utility steam generating unit.
n = Number of subcategories (coal ranks) being averaged for an affected source.

(ii) If you operate a coal-fired electric utility steam generating unit that burns a blend of coals from different coal ranks or a blend of coal and coal refuse together with one or more non-regulated, supplementary fuels, you must not discharge into the atmosphere any gases from the unit that contain Hg in excess of the computed weighted Hg emission limit based on the proportion of electricity output (in MWh) contributed by each coal rank burned during the compliance period and its applicable Hg emissions limit in paragraphs (a)(1) through (4) of this section as determined using Equation 1 of this section. You must meet the weighted Hg emissions limit calculated using Equation 1 of this section by calculating the unit emission rate based on the total Hg loading of the unit and the total megawatt hours contributed by both regulated and nonregulated fuels burned during the compliance period.

(b) For each IGCC electric utility steam generating unit, on and after the date on which the initial performance test required to be conducted under Sec. 60.8 is completed, no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any affected facility for which construction or reconstruction commenced after January 30, 2004, any gases which contain Hg emissions in excess of 20×10^{-6} lb/MWh or 0.020 lb/GWh on an output basis. The SI equivalent is 0.0025 ng/J. This Hg emissions limit is based on a 12-month rolling average using the procedures in Sec. 60.50Da(g).

Sec. 60.46Da [Reserved]

Sec. 60.47Da Commercial demonstration permit.

(a) An owner or operator of an affected facility proposing to demonstrate an emerging technology may apply to the Administrator for a commercial demonstration permit. The Administrator will issue a commercial demonstration permit in accordance with paragraph (e) of this section. Commercial demonstration permits may be issued only by the Administrator, and this authority will not be delegated.

(b) An owner or operator of an affected facility that combusts solid solvent refined coal (SRC-I) and who is issued a commercial demonstration permit by the Administrator is not subject to the SO_2 emission reduction requirements under Sec. 60.43Da(c) but must, as a minimum, reduce SO_2 emissions to 20 percent of the potential combustion concentration (80 percent reduction) for each 24-hour period of steam generator operation and to less than 520 ng/J (1.20 lb/million Btu) heat input on a 30-day rolling average basis.

(c) An owner or operator of a fluidized bed combustion electric utility steam generator (atmospheric or pressurized) who is issued a commercial demonstration permit by the Administrator is not subject to the SO_2 emission reduction requirements under Sec. 60.43Da(a) but must, as a minimum, reduce SO_2 emissions to 15 percent of the potential combustion concentration (85 percent reduction) on a 30-day rolling average basis and to less than 520 ng/J (1.20 lb/million Btu) heat input on a 30-day rolling average basis.

(d) The owner or operator of an affected facility that combusts coal-derived liquid fuel and who is issued a commercial demonstration permit by the Administrator is not subject to the applicable NO_x emission limitation and percent reduction under Sec. 60.44Da(a) but must, as a minimum, reduce emissions to less than 300 ng/J (0.70 lb/million Btu) heat input on a 30-day rolling average basis.

(e) Commercial demonstration permits may not exceed the following equivalent MW electrical generation capacity for any one technology category, and the total equivalent MW electrical generation capacity for all commercial demonstration plants may not exceed 15,000 MW.

Technology	Pollutant	Equivalent electrical capacity (MW electrical output)
Solid solvent refined coal (SRC I).....	SO2	6,000-10,000
Fluidized bed combustion (atmospheric)....	SO2	400-3,000
Fluidized bed combustion (pressurized).....	SO2	400-1,200
Coal liquification.....	NOx	750-10,000
Total allowable for all technologies.....		15,000

Sec. 60.48Da Compliance provisions.

(a) Compliance with the particulate matter emission limitation under Sec. 60.42Da(a)(1) constitutes compliance with the percent reduction requirements for particulate matter under Sec. 60.42Da(a)(2) and (3).

(b) Compliance with the nitrogen oxides emission limitation under Sec. 60.44Da(a) constitutes compliance with the percent reduction requirements under Sec. 60.44Da(a)(2).

(c) The particulate matter emission standards under Sec. 60.42Da, the nitrogen oxides emission standards under Sec. 60.44Da, and the Hg emission standards under Sec. 60.45Da apply at all times except during periods of startup, shutdown, or malfunction.

(d) During emergency conditions in the principal company, an affected facility with a malfunctioning flue gas desulfurization system may be operated if sulfur dioxide emissions are minimized by:

(1) Operating all operable flue gas desulfurization system modules, and bringing back into operation any malfunctioned module as soon as repairs are completed,

(2) Bypassing flue gases around only those flue gas desulfurization system modules that have been taken out of operation because they were incapable of any sulfur dioxide emission reduction or which would have suffered significant physical damage if they had remained in operation, and

(3) Designing, constructing, and operating a spare flue gas desulfurization system module for an affected facility larger than 365 MW (1,250 million Btu/hr) heat input (approximately 125 MW electrical output capacity). The Administrator may at his discretion require the owner or operator within 60 days of notification to demonstrate spare module capability. To demonstrate this capability, the owner or operator must demonstrate compliance with the appropriate requirements under paragraph (a), (b), (d), (e), and (h) under Sec. 60.43Da for any period of operation lasting from 24 hours to 30 days when:

(i) Any one flue gas desulfurization module is not operated,

(ii) The affected facility is operating at the maximum heat input rate,

(iii) The fuel fired during the 24-hour to 30-day period is representative of the type and average sulfur content of fuel used over a typical 30-day period, and

(iv) The owner or operator has given the Administrator at least 30 days notice of the date and period of time over which the demonstration will be performed.

(e) After the initial performance test required under Sec. 60.8, compliance with the sulfur dioxide emission limitations and percentage reduction requirements under Sec. 60.43Da and the nitrogen oxides emission
limitations under Sec. 60.44Da is based on the average emission rate for 30 successive boiler operating days. A separate performance test is completed at the end of each boiler operating day after the initial performance test, and a new 30 day average emission rate for both sulfur dioxide and nitrogen oxides and a new percent reduction for sulfur dioxide are calculated to show compliance with the standards.

(f) For the initial performance test required under Sec. 60.8, compliance with the sulfur dioxide emission limitations and percent reduction requirements under Sec. 60.43Da and the nitrogen oxides emission limitation under Sec. 60.44Da is based on the average emission rates for sulfur dioxide, nitrogen oxides, and percent reduction for sulfur dioxide for the first 30 successive boiler operating days. The initial performance test is the only test in which at least 30 days prior notice is required unless otherwise specified by the Administrator. The initial performance test is to be scheduled so that the first boiler operating day of the 30 successive boiler operating days is completed within 60 days after achieving the maximum production rate at which the affected facility will be operated, but not later than 180 days after initial startup of the facility.

(g) The owner or operator of an affected facility subject to emission limitations in this subpart shall determine compliance as follows:

(1) Compliance with applicable 30-day rolling average SO2 and NOX emission limitations is determined by calculating the arithmetic average of all hourly emission rates for SO2 and NOX for the 30 successive boiler operating days, except for data obtained during startup, shutdown, malfunction (NOX only), or emergency conditions (SO2) only.

(2) Compliance with applicable SO2 percentage reduction requirements is determined based on the average inlet and outlet SO2 emission rates for the 30 successive boiler operating days.

(3) Compliance with applicable daily average particulate matter emission limitations is determined by calculating the arithmetic average of all hourly emission rates for particulate matter each boiler operating day, except for data obtained during startup, shutdown, and malfunction.

(h) If an owner or operator has not obtained the minimum quantity of emission data as required under Sec. 60.49Da of this subpart, compliance of the affected facility with the emission requirements under Secs. 60.43Da and 60.44Da of this subpart for the day on which the 30-day period ends may be determined by the Administrator by following the applicable procedures in section 7 of Method 19.
[44 FR 33613, June 11, 1979, as amended at 54 FR 6664, Feb. 14, 1989]

(i) Compliance provisions for sources subject to Sec. 60.44Da(d)(1), (e)(1), or (f). The owner or operator of an affected facility subject to Sec. 60.44Da(d)(1) or (e)(1) shall calculate NOX emissions by multiplying the average hourly NOX output concentration, measured according to the provisions of Sec. 60.49Da(c), by the average hourly flow rate, measured according to the provisions of Sec. 60.49Da(l),

and dividing by the average hourly gross energy output, measured according to the provisions of Sec. 60.49Da(k).

(j) Compliance provisions for duct burners subject to § 60.44Da(a)(1). To determine compliance with the emissions limits for NOx required by § 60.44Da(a) for duct burners used in combined cycle systems, either of the procedures described in paragraph (j)(1) or (2) of this section may be used:

(1) The owner or operator of an affected duct burner shall conduct the performance test required under § 60.8 using the appropriate methods in appendix A of this part. Compliance with the emissions limits under § 60.44Da (a)(1) is determined on the average of three (nominal 1-hour) runs for the initial and subsequent performance tests. During the performance test, one sampling site shall be located in the exhaust of the turbine prior to the duct burner. A second sampling site shall be located at the outlet from the heat recovery steam generating unit. Measurements shall be taken at both sampling sites during the performance test; or

(2) The owner or operator of an affected duct burner may elect to determine compliance by using the continuous emission monitoring system specified under Sec. 60.49Da for measuring NOX and oxygen and meet the requirements of Sec. 60.49Da. Data from a CEMS certified (or recertified) according to the provisions of 40 CFR 75.20, meeting the QA and QC requirements of 40 CFR 75.21, and validated according to 40 CFR 75.23 may be used. This includes data substituted according to 40 CFR 75.21(i) for invalid data and 40 CFR 75.30 for missing data or data adjusted for negative bias as required by 40 CFR 75.23(d). The sampling site shall be located at the outlet from the steam generating unit. The NOX emission rate at the outlet from the steam generating unit shall constitute the NOX emission rate from the duct burner of the combined cycle system.

(k) Compliance provisions for duct burners subject to Sec. 60.44Da(d)(1) or (e)(1). To determine compliance with the emission limitation for NOX required by Sec. 60.44Da(d)(1) or (e)(1) for duct burners used in combined cycle systems, either of the procedures described in paragraphs (k)(1) and (2) of this section may be used:

(1) The owner or operator of an affected duct burner used in combined cycle systems shall determine compliance with the applicable NOX emission limitation in Sec. 60.44Da(d)(1) or (e)(1) as follows:

(i) The emission rate (E) of NOX shall be computed using Equation 1 of this section:

$$E = [(Csg \times Qsg)-(Cte \times Qte)]/(Osg \times h) \quad \text{(Eq. 1)}$$

Where:
E = emission rate of NOX from the duct burner, ng/J (lb/Mwh) gross output
Csg = average hourly concentration of NOX exiting the steam generating unit, ng/dscm (lb/dscf)
Cte = average hourly concentration of NOX in the turbine exhaust upstream from duct burner, ng/dscm (lb/dscf)
Qsg = average hourly volumetric flow rate of exhaust gas from steam generating unit, dscm/hr (dscf/hr)
Qte = average hourly volumetric flow rate of exhaust gas from combustion turbine, dscm/hr (dscf/hr)
Osg = average hourly gross energy output from steam generating unit, J (Mwh)
h = average hourly fraction of the total heat input to the steam generating unit derived from the combustion of fuel in the affected duct burner

(ii) Method 7E of appendix A of this part shall be used to determine the NOX concentrations (Csg and Cte). Method 2, 2F or 2G of appendix A of this part, as appropriate, shall be used to determine the volumetric flow rates (Qsg and Qte) of the exhaust gases. The volumetric flow rate measurements shall be taken at the same time as the concentration measurements.

(iii) The owner or operator shall develop, demonstrate, and provide information satisfactory to the Administrator to determine the average hourly gross energy output from the steam generating unit, and the average hourly percentage of the total heat input to the steam generating unit derived from the combustion of fuel in the affected duct burner.

(iv) Compliance with the applicable NOX emission limitation in Sec. 60.44Da(d)(1) or (e)(1) is determined by the three-run average (nominal 1-hour runs) for the initial and subsequent performance tests.

(2) The owner or operator of an affected duct burner used in a combined cycle system may elect to determine compliance with the applicable NOX emission limitation in Sec. 60.44Da(d)(1) or (e)(1) on a 30-day rolling average basis as indicated in paragraphs (k)(2)(i) through (iv) of this section.

(i) The emission rate (E) of NOX shall be computed using Equation 2 of this section:

E = (Csg x Qsd) /Occ (Eq. 2)

Where:
E = emission rate of NOX from the duct burner, ng/J (lb/Mwh) gross output
Csg = average hourly concentration of NOX exiting the steam generating unit, ng/dscm (lb/dscf)
Qsg = average hourly volumetric flow rate of exhaust gas from steam generating unit, dscm/hr (dscf/hr)
Occ = average hourly gross energy output from entire combined cycle unit, J (Mwh)

(ii) The continuous emissions monitoring system specified under Sec. 60.49Da for measuring NOX and oxygen shall be used to determine the average hourly NOX concentrations (Csg). The continuous flow monitoring system specified in Sec. 60.49Da(l) shall be used to determine the volumetric flow rate (Qsg) of the exhaust gas. The sampling site shall be located at the outlet from the steam generating unit. Data from a continuous flow monitoring system certified (or recertified) following procedures specified in 40 CFR 75.20, meeting the quality assurance and quality control requirements of 40 CFR 75.21, and validated according to 40 CFR 75.23 may be used.

(iii) The continuous monitoring system specified under Sec. 60.49Da(k) for measuring and determining gross energy output shall be used to determine the average hourly gross energy output from the entire combined cycle unit (Occ), which is the combined output from the combustion turbine and the steam generating unit.

(iv) The owner or operator may, in lieu of installing, operating, and recording data from the continuous flow monitoring system specified in Sec. 60.49Da(l), determine the mass rate (lb/hr) of NOX emissions by installing, operating, and maintaining continuous fuel flowmeters following the appropriate measurements procedures specified in appendix D of 40 CFR part 75. If this compliance option is selected, the emission rate (E) of NOX shall be computed using Equation 3 of this section:

E = (ERsg x Hcc) /Occ (Eq. 3)

Where:
E = emission rate of NOX from the duct burner, ng/J (lb/Mwh) gross output
ERsg = average hourly emission rate of NOX exiting the steam generating unit heat input calculated using appropriate F-factor as described in Method 19, ng/J (lb/million Btu)
Hcc = average hourly heat input rate of entire combined cycle unit, J/hr (million Btu/hr)
Occ = average hourly gross energy output from entire combined cycle unit, J (Mwh)

(3) When an affected duct burner steam generating unit utilizes a common steam turbine with one or more affected duct burner steam generating units, the owner or operator shall either:

(i) Determine compliance with the applicable NOX emissions limits by measuring the emissions combined with the emissions from the other unit(s) utilizing the common steam turbine; or

(ii) Develop, demonstrate, and provide information satisfactory to the Administrator on methods for apportioning the combined gross energy output from the steam turbine for each of the affected duct burners. The Administrator may approve such demonstrated substitute methods for apportioning the combined gross energy output measured at the steam turbine whenever the demonstration ensures accurate estimation of emissions regulated under this part.

(l) Compliance provisions for sources subject to Sec. 60.45Da. The owner or operator of an affected facility subject to Sec. 60.45Da (new sources constructed or reconstructed after January 30, 2004) shall calculate the Hg emission rate (lb/MWh) for each calendar month of the year, using hourly Hg concentrations measured according to the provisions of Sec. 60.49Da(p) in conjunction with hourly stack gas volumetric flow rates measured according to the provisions of Sec. 60.49Da(l) or (m), and hourly gross electrical outputs, determined according to the provisions in Sec. 60.49Da(k). Compliance with the applicable standard under Sec. 60.45Da is determined on a 12-month rolling average basis.

(m) Compliance provisions for sources subject to Sec. 60.43Da(i)(1)(i) or (j)(1)(i). The owner or operator of an affected facility subject to Sec. 60.43Da(i)(1)(i) or (j)(1)(i) shall calculate SO2 emissions by multiplying the average hourly SO2 output concentration, measured according to the provisions of Sec. 60.49Da(b), by the average hourly flow rate, measured according to the provisions of Sec. 60.49Da(l), and divided by the average hourly gross energy output, measured according to the provisions of Sec. 60.49Da(k).

(n) Compliance provisions for sources subject to Sec. 60.42Da(c)(1). The owner or operator of an affected facility subject to Sec. 60.42Da(c)(1) shall calculate particulate matter emissions by multiplying the average hourly particulate matter output concentration, measured according to the provisions of Sec. 60.49Da(t), by the average hourly flow rate, measured according to the provisions of Sec. 60.49Da(l), and divided by the average hourly gross energy output, measured according to the provisions of Sec. 60.49Da(k). Compliance with the emission limit is determined by calculating the arithmetic average of the hourly emission rates computed for each boiler operating day.

(o) Compliance provisions for sources subject to Sec. 60.42Da(c)(2) or (d). Except as provided for in paragraph (p) of this section, the owner or operator of an affected facility for which construction, reconstruction, or modification commenced after February 28, 2005, shall demonstrate compliance with each applicable emission limit according to the requirements in paragraphs (o)(1) through (o)(5) of this section.

(1) Conduct an initial performance test according to the requirements in Sec. 60.50Da to demonstrate compliance by the applicable date specified in Sec. 60.8(a) and, thereafter, conduct the performance test annually, and

(2) An owner or operator must use opacity monitoring equipment as an indicator of continuous particulate matter control device performance and demonstrate compliance with Sec. 60.42Da(b). In addition, baseline parameters shall be established as the highest hourly opacity average measured during the performance test. If any hourly average opacity measurement is more than 110 percent of the baseline level, the owner or operator will conduct another performance test within 60 days to demonstrate compliance. A new baseline is established during each stack test. The new baseline shall not exceed the opacity limit specified in Sec. 60.42Da(b), and

(3) An owner or operator using an ESP to comply with the applicable emission limits shall use voltage and secondary current monitoring equipment to measure voltage and secondary current to the ESP. Baseline parameters shall be established as average rates measured during the performance test. If a 3-hour average voltage and secondary current average deviates more than 10 percent from the baseline level, the owner or operator will conduct another performance test within 60 days to demonstrate compliance. A new baseline is established during each stack test, and

(4) An owner or operator using a fabric filter to comply with the applicable emission limits shall install, calibrate, maintain, and continuously operate a bag leak detection system according to paragraphs (o)(4)(i) through (viii) of this section.

(i) Install and operate a bag leak detection system for each exhaust stack of the fabric filter.

(ii) Each bag leak detection system must be installed, operated, calibrated, and maintained in a manner consistent with the manufacturer's written specifications and recommendations and in accordance with the guidance provided in EPA-454/R-98-015, September 1997.

(iii) The bag leak detection system must be certified by the manufacturer to be capable of detecting particulate matter emissions at concentrations of 10 milligrams per actual cubic meter or less.

(iv) The bag leak detection system sensor must provide output of relative or absolute particulate matter loadings.

(v) The bag leak detection system must be equipped with a device to continuously record the output signal from the sensor.

(vi) The bag leak detection system must be equipped with an alarm system that will sound automatically when an increase in relative particulate matter emissions over a preset level is detected. The alarm must be located where it is easily heard by plant operating personnel. Corrective actions must be initiated within 1 hour of a bag leak detection system alarm. If the alarm is engaged for more than 5 percent of the total operating time on a 30-day rolling average, a performance test must be performed within 60 days to demonstrate compliance.

(vii) For positive pressure fabric filter systems that do not duct all compartments of cells to a common stack, a bag leak detection system must be installed in each baghouse compartment or cell.

(viii) Where multiple bag leak detectors are required, the system's instrumentation and alarm may be shared among detectors, and

(5) An owner or operator of a modified affected source electing to meet the emission limitations in Sec. 60.42Da(d) shall determine the percent reduction in particulate matter by using the emission rate for particulate matter determined by the performance test conducted according to the requirements in paragraph (o)(1) of this section and the ash content on a mass basis of the fuel burned during each performance test run as determined by analysis of the fuel as fired.

(p) As an alternative to meeting the compliance provisions specified in paragraph (o) of this section, an owner or operator may elect to install, certify, maintain, and operate a continuous emission monitoring system measuring particulate matter emissions discharged from the affected facility to the atmosphere and record the output of the system as specified in paragraphs (p)(1) through (p)(8) of this section.

(1) The owner or operator shall submit a written notification to the Administrator of intent to demonstrate compliance with this subpart by using a continuous monitoring system measuring particulate matter. This notification shall be sent at least 30 calendar days before the initial startup of the monitor for compliance determination purposes. The owner or operator may discontinue operation of the monitor and instead return to demonstration of compliance with this subpart according to the requirements in

paragraph (o) of this section by submitting written notification to the Administrator of such intent at least 30 calendar days before shutdown of the monitor for compliance determination purposes.

(2) Each continuous emission monitor shall be installed, certified, operated, and maintained according to the requirements in Sec. 60.49Da(v).

(3) The initial performance evaluation shall be completed no later than 180 days after the date of initial startup of the affected facility, as specified under Sec. 60.8 of subpart A of this part or within 180 days of the date of notification to the Administrator required under paragraph (p)(1) of this section, whichever is later.

(4) Compliance with the applicable emissions limit shall be determined based on the 24-hour daily (block) average of the hourly arithmetic average emissions concentrations using the continuous monitoring system outlet data. The 24-hour block arithmetic average emission concentration shall be calculated using EPA Reference Method 19, section 4.1.

(5) At a minimum, valid continuous monitoring system hourly averages shall be obtained for 90 percent of all operating hours on a 30-day rolling average.

(i) At least two data points per hour shall be used to calculate each 1-hour arithmetic average.

(ii) [Reserved]

(6) The 1-hour arithmetic averages required shall be expressed in ng/J, MMBtu/h, or lb/MWh and shall be used to calculate the boiler operating day daily arithmetic average emission concentrations. The 1-hour arithmetic averages shall be calculated using the data points required under Sec. 60.13(e)(2) of subpart A of this part.

(7) All valid continuous monitoring system data shall be used in calculating average emission concentrations even if the minimum continuous emission monitoring system data requirements of paragraph (j)(5) of this section are not met.

(8) When particulate matter emissions data are not obtained because of continuous emission monitoring system breakdowns, repairs, calibration checks, and zero and span adjustments, emissions data shall be obtained by using other monitoring systems as approved by the Administrator or EPA Reference Method 19 to provide, as necessary, valid emissions data for a minimum of 90 percent of all operating hours per 30-day rolling average.

Sec. 60.49Da Emission monitoring.

(a) Except as provided for in paragraphs (t) and (u) of this section, the owner or operator of an affected facility, shall install, calibrate, maintain, and operate a continuous monitoring system, and record the output of the system, for measuring the opacity of emissions discharged to the atmosphere, except where gaseous fuel is the only fuel combusted. If opacity interference due to water droplets exists in the stack (for example, from the use of an FGD system), the opacity is monitored upstream of the interference (at the inlet to the FGD system). If opacity interference is experienced at all locations (both at the inlet and outlet of the sulfur dioxide control system), alternate parameters indicative of the particulate matter control system's performance are monitored (subject to the approval of the Administrator).

(b) The owner or operator of an affected facility shall install, calibrate, maintain, and operate a continuous monitoring system, and record the output of the system, for measuring sulfur dioxide emissions, except where natural gas is the only fuel combusted, as follows:

(1) Sulfur dioxide emissions are monitored at both the inlet and outlet of the sulfur dioxide control device.

(2) For a facility that qualifies under the numerical limit provisions of Sec. 60.43Da(d), (i), (j), or (k) sulfur dioxide emissions are only monitored as discharged to the atmosphere.

(3) An ``as fired'' fuel monitoring system (upstream of coal pulverizers) meeting the requirements of Method 19 may be used to determine potential sulfur dioxide emissions in place of a continuous sulfur dioxide emission monitor at the inlet to the sulfur dioxide control device as required under paragraph (b)(1) of this section.

(c) (1) The owner or operator of an affected facility shall install, calibrate, maintain, and operate a continuous monitoring system, and record the output of the system, for measuring nitrogen oxides emissions discharged to the atmosphere; or

(2) If the owner or operator has installed a nitrogen oxides emission rate continuous emission monitoring system (CEMS) to meet the requirements of part 75 of this chapter and is continuing to meet the ongoing requirements of part 75 of this chapter, that CEMS may be used to meet the requirements of this secttion, except that the owner or operator shall also meet the requirements of Sec. 60.51Da. Data reported
to meet the requirements of Sec. 60.51Da shall not include data substituted using the missing data procedures in subpart D of part 75 of this chapter, nor shall the data have been bias adjusted according to the procedures of part 75 of this chapter.

(d) The owner or operator of an affected facility shall install, calibrate, maintain, and operate a continuous monitoring system, and record the output of the system, for measuring the oxygen or carbon dioxide content of the flue gases at each location where sulfur dioxide or nitrogen oxides emissions are monitored.

(e) The continuous monitoring systems under paragraphs (b), (c), and (d) of this section are operated and data recorded during all periods of operation of the affected facility including periods of startup, shutdown, malfunction or emergency conditions, except for continuous monitoring system breakdowns, repairs, calibration checks, and zero and span adjustments.

(f) (1) For units that began construction, reconstruction, or modification on or before February 28, 2005, the owner or operator shall obtain emission data for at least 18 hours in at least 22 out of 30 successive boiler operating days. If this minimum data requirement cannot be met with a continuous monitoring system, the owner or operator shall supplement emission data with other monitoring systems approved by the Administrator or the reference methods and procedures as described in paragraph (h) of this section.

(2) For units that began construction, reconstruction, or modification after February 28, 2005, the owner or operator shall obtain emission data for at least 90 percent of all operating hours for each 30 successive boiler operating days. If this minimum data requirement cannot be met with a continuous monitoring system, the owner or operator shall supplement emission data with other monitoring systems approved by the Administrator or the reference methods and procedures as described in paragraph (h) of this section.

(g) The 1-hour averages required under paragraph Sec. 60.13(h) are expressed in ng/J (lb/million Btu) heat input and used to calculate the average emission rates under Sec. 60.48Da. The 1-hour averages are calculated using the data points required under Sec. 60.13(b). At least two data points must be used to calculate the 1-hour averages.

(h) When it becomes necessary to supplement continuous monitoring system data to meet the minimum data requirements in paragraph (f) of this section, the owner or operator shall use the reference methods

and procedures as specified in this paragraph. Acceptable alternative methods and procedures are given in paragraph (j) of this section.

(1) Method 6 shall be used to determine the SO_2 concentration at the same location as the SO_2 monitor. Samples shall be taken at 60-minute intervals. The sampling time and sample volume for each sample shall be at least 20 minutes and 0.020 dscm (0.71 dscf). Each sample represents a 1-hour average.

(2) Method 7 shall be used to determine the NO_x concentration at the same location as the NO_x monitor. Samples shall be taken at 30-minute intervals. The arithmetic average of two consecutive samples represents a 1-hour average.

(3) The emission rate correction factor, integrated bag sampling and analysis procedure of Method 3B shall be used to determine the O_2 or CO_2 concentration at the same location as the O_2 or CO_2 monitor. Samples shall be taken for at least 30 minutes in each hour. Each sample represents a 1-hour average.

(4) The procedures in Method 19 shall be used to compute each 1-hour average concentration in ng/J (1b/million Btu) heat input.

(i) The owner or operator shall use methods and procedures in this paragraph to conduct monitoring system performance evaluations under Sec. 60.13(c) and calibration checks under Sec. 60.13(d). Acceptable alternative methods and procedures are given in paragraph (j) of this section.

(1) Methods 3B, 6, and 7, as applicable, shall be used to determine O_2, SO_2, and NO_x concentrations respectively.

(2) SO_2 or NO_x (NO), as applicable, shall be used for preparing the calibration gas mixtures (in N_2, as applicable) under Performance Specification 2 of appendix B of this part.

(3) For affected facilities burning only fossil fuel, the span value for a continuous monitoring system for measuring opacity is between 60 and 80 percent and for a continuous monitoring system measuring nitrogen oxides is determined as follows:

Fossil fuel	Span value for nitrogen oxides (ppm)
Gas.....	500
Liquid.....	500
Solid.....	1,000
Combination.....	500 (x+y)+1,000z

where:
x is the fraction of total heat input derived from gaseous fossil fuel,
y is the fraction of total heat input derived from liquid fossil fuel,and
z is the fraction of total heat input derived from solid fossil fuel.

(4) All span values computed under paragraph (b)(3) of this section for burning combinations of fossil fuels are rounded to the nearest 500 ppm.

(5) For affected facilities burning fossil fuel, alone or in combination with non-fossil fuel, the span value of the sulfur dioxide continuous monitoring system at the inlet to the sulfur dioxide control device is 125 percent of the maximum estimated hourly potential emissions of the fuel fired, and the

outlet of the sulfur dioxide control device is 50 percent of maximum estimated hourly potential emissions of the fuel fired.

(j) The owner or operator may use the following as alternatives to the reference methods and procedures specified in this section:

(1) For Method 6, Method 6A or 6B (whenever Methods 6 and 3 or 3B data are used) or 6C may be used. Each Method 6B sample obtained over 24 hours represents 24 1-hour averages. If Method 6A or 6B is used under paragraph (i) of this section, the conditions under Sec. 60.46(d)(1) apply; these conditions do not apply under paragraph (h) of this section.

(2) For Method 7, Method 7A, 7C, 7D, or 7E may be used. If Method 7C, 7D, or 7E is used, the sampling time for each run shall be 1 hour.

(3) For Method 3, Method 3A or 3B may be used if the sampling time is 1 hour.

(4) For Method 3B, Method 3A may be used.

[44 FR 33613, June 11, 1979, as amended at 54 FR 6664, Feb. 14, 1989; 55 FR 5212, Feb. 14, 1990; 55 FR 18876, May 7, 1990]

(k) The procedures specified in paragraphs (k)(1) through (3) of this section shall be used to determine gross output for sources demonstrating compliance with the output-based standard under Sec. 60.44Da(d)(1).

(1) The owner or operator of an affected facility with electricity generation shall install, calibrate, maintain, and operate a wattmeter; measure gross electrical output in megawatt-hour on a continuous basis;
and record the output of the monitor.

(2) The owner or operator of an affected facility with process steam generation shall install, calibrate, maintain, and operate meters for steam flow, temperature, and pressure; measure gross process steam output in joules per hour (or Btu per hour) on a continuous basis; and record the output of the monitor.

(3) For affected facilities generating process steam in combination with electrical generation, the gross energy output is determined from the gross electrical output measured in accordance with paragraph (k)(1) of this section plus 75 percent of the gross thermal output (measured relative to ISO conditions) of the process steam measured in accordance with paragraph (k)(2) of this section.

(l) The owner or operator of an affected facility demonstrating compliance with an output-based standard under Sec. 60.42Da, Sec. 60.43Da, Sec. 60.44Da, or Sec. 60.45Da shall install, certify, operate, and maintain a continuous flow monitoring system meeting the requirements of Performance Specification 6 of appendix B and procedure 1 of appendix F of this subpart, and record the output of the system, for measuring the flow of exhaust gases discharged to the atmosphere; or

(m) Alternatively, data from a continuous flow monitoring system certified according to the requirements of 40 CFR 75.20, meeting the applicable quality control and quality assurance requirements of 40 CFR 75.21, and validated according to 40 CFR 75.23, may be used.

(n) Gas-fired and oil-fired units. The owner or operator of an affected unit that qualifies as a gas-fired or oil-fired unit, as defined in 40 CFR 72.2, may use, as an alternative to the requirements specified in either paragraph (l) or (m) of this section, a fuel flow monitoring system certified and operated according to the requirements of appendix D of 40 CFR part 75.

(o) The owner or operator of a duct burner, as described in Sec. 60.41Da, which is subject to the NOX standards of Sec. 60.44Da(a)(1), (d)(1), or (e)(1) is not required to install or operate a continuous emissions monitoring system to measure NOX emissions; a wattmeter to measure gross electrical output; meters to measure steam flow, temperature, and pressure; and a continuous flow monitoring system tommeasure the flow of exhaust gases discharged to the atmosphere.

(p) The owner or operator of an affected facility demonstrating compliance with an Hg limit in Sec. 60.45Da shall install and operate a continuous emissions monitoring system (CEMS) to measure and record the concentration of Hg in the exhaust gases from each stack according to the requirements in paragraphs (p)(1) through (p)(3) of this section. Alternatively, for an affected facility that is also subject to the requirements of subpart I of part 75 of this chapter, the owner or operator may install, certify, maintain, operate and quality-assure the data from a Hg CEMS according to Sec. 75.10 of this chapter and appendices A and B to part 75 of this chapter, in lieu of following the procedures in paragraphs (p)(1) through (p)(3) of this section.

(1) The owner or operator must install, operate, and maintain each CEMS according to Performance Specification 12A in appendix B to this part.

(2) The owner or operator must conduct a performance evaluation of each CEMS according to the requirements of Sec. 60.13 and Performance Specification 12A in appendix B to this part.

(3) The owner or operator must operate each CEMS according to the requirements in paragraphs (p)(3)(i) through (iv) of this section.

(i) As specified in Sec. 60.13(e)(2), each CEMS must complete a minimum of one cycle of operation (sampling, analyzing, and data recording) for each successive 15-minute period.

(ii) The owner or operator must reduce CEMS data as specified in Sec. 60.13(h).

(iii) The owner or operator shall use all valid data points collected during the hour to calculate the hourly average Hg concentration.

(iv) The owner or operator must record the results of each required certification and quality assurance test of the CEMS.

(4) Mercury CEMS data collection must conform to paragraphs (p)(4)(i) through (iv) of this section.

(i) For each calendar month in which the affected unit operates, valid hourly Hg concentration data, stack gas volumetric flow rate data, moisture data (if required), and electrical output data (i.e., valid data for all of these parameters) shall be obtained for at least 75 percent of the unit operating hours in the month.

(ii) Data reported to meet the requirements of this subpart shall not include hours of unit startup, shutdown, or malfunction. In addition, for an affected facility that is also subject to subpart I of part 75 of this chapter, data reported to meet the requirements of this subpart shall not include data substituted using the missing data procedures in subpart D of part 75 of this chapter, nor shall the data have been bias adjusted according to the procedures of part 75 of this chapter.

(iii) If valid data are obtained for less than 75 percent of the unit operating hours in a month, you must discard the data collected in that month and replace the data with the mean of the individual monthly emission rate values determined in the last 12 months. In the 12-month rolling average calculation, this substitute Hg emission rate shall be weighted according to the number of unit operating hours in the month for which the data capture requirement of Sec. 60.49Da(p)(4)(i) was not met.

(iv) Notwithstanding the requirements of paragraph (p)(4)(iii) of this section, if valid data are obtained for less than 75 percent of the unit operating hours in another month in that same 12-month rolling average cycle, discard the data collected in that month and replace the data with the highest individual monthly emission rate determined in the last 12 months. In the 12-month rolling average

calculation, this substitute Hg emission rate shall be weighted according to the number of unit operating hours in the month for which the data capture requirement of Sec. 60.49Da(p)(4)(i) was not met.

(q) As an alternative to the CEMS required in paragraph (p) of this section, the owner or operator may use a sorbent trap monitoring system (as defined in Sec. 72.2 of this chapter) to monitor Hg concentration, according to the procedures described in Sec. 75.15 of this chapter and appendix K to part 75 of this chapter.

(r) For Hg CEMS that measure Hg concentration on a dry basis or for sorbent trap monitoring systems, the emissions data must be corrected for the stack gas moisture content. A certified continuous moisture monitoring system that meets the requirements of Sec. 75.11(b) of this chapter is acceptable for this purpose. Alternatively, the appropriate default moisture value, as specified in Sec. 75.11(b) or Sec. 75.12(b) of this chapter, may be used.

(s) The owner or operator shall prepare and submit to the Administrator for approval a unit-specific monitoring plan for each monitoring system, at least 45 days before commencing certification testing of the monitoring systems. The owner or operator shall comply with the requirements in your plan. The plan must address the requirements in paragraphs (s)(1) through (6) of this section.

(1) Installation of the CEMS sampling probe or other interface at a measurement location relative to each affected process unit such that the measurement is representative of the exhaust emissions (e.g., on or downstream of the last control device);

(2) Performance and equipment specifications for the sample interface, the pollutant concentration or parametric signal analyzer, and the data collection and reduction systems;

(3) Performance evaluation procedures and acceptance criteria (e.g., calibrations, relative accuracy test audits (RATA), etc.);

(4) Ongoing operation and maintenance procedures in accordance with the general requirements of Sec. 60.13(d) or part 75 of this chapter (as applicable);

(5) Ongoing data quality assurance procedures in accordance with the general requirements of Sec. 60.13 or part 75 of this chapter (as applicable); and

(6) Ongoing record keeping and reporting procedures in accordance with the requirements of this subpart.

(t) The owner or operator of an affected facility demonstrating compliance with the output-based emissions limitation under Sec. 60.42Da(c)(1) shall install, certify, operate, and maintain a continuous monitoring system for measuring particulate matter emissions according to the requirements of paragraph (v) of this section. An owner or operator of an affected source demonstrating compliance with the input-based emission limitation under Sec. 60.42Da(c)(2) may install, certify, operate, and maintain a continuous monitoring system for measuring particulate matter emissions according to the requirements of paragraph (v) of this section in lieu of the requirements in Sec. 60.48Da(o).

(u) An owner or operator of an affected source that meets the conditions in either paragraph (u)(1) or (2) of this section is exempted from the continuous opacity monitoring system requirements in paragraph (a) of this section and the monitoring requirements in Sec. 60.48Da(o).

(1) A continuous monitoring system for measuring particulate matter emissions is used to demonstrate continuous compliance on a boiler operating day average with the emissions limitations under Sec. 60.42Da(a)(1) or Sec. 60.42Da(c)(2) and is installed, certified, operated, and maintained on the affected source according to the requirements of paragraph (v) of this section.

(2) The affected source burns only oil that contains no more than 0.15 weight percent sulfur or liquid or gaseous fuels that when combusted without sulfur dioxide emission control, have a sulfur dioxide emissions rate equal to or less than or equal to 65 ng/J (0.15 lb/MMBtu) heat input.

(v) The owner or operator of an affected facility using a continuous emission monitoring system measuring particulate matter emissions to meet requirements of this subpart shall install, certify, operate, and maintain the continuous monitoring system as specified in paragraphs (v)(1) through (v)(3).

(1) The owner or operator shall conduct a performance evaluation of the continuous monitoring system according to the applicable requirements of Sec. 60.13, Performance Specification 11 in appendix B of this part, and procedure 2 in appendix F of this part.

(2) During each relative accuracy test run of the continuous emission monitoring system required by Performance Specification 11 in appendix B of this part, particulate matter and oxygen (or carbon dioxide) data shall be collected concurrently (or within a 30-to 60-minute period) by both the continuous emission monitors and conducting performance tests using the following test methods.

(i) For particulate matter, EPA Reference Method 5, 5B, or 17 shall be used.

(ii) For oxygen (or carbon dioxide), EPA Reference Method 3, 3A, or 3B, as applicable shall be used.

(3) Quarterly accuracy determinations and daily calibration drift tests shall be performed in accordance with procedure 2 in appendix F of this part. Relative Response Audit's must be performed annually and Response Correlation Audits must be performed every 3 years.

Sec. 60.50Da Compliance determination procedures and methods.

(a) In conducting the performance tests required in Sec. 60.8, the owner or operator shall use as reference methods and procedures the methods in appendix A of this part or the methods and procedures as specified in this section, except as provided in Sec. 60.8(b). Section 60.8(f) does not apply to this section for SO_2 and NO_x. Acceptable alternative methods are given in paragraph (e) of this section.

(b) The owner or operator shall determine compliance with the particulate matter standards in Sec. 60.42Da as follows:

(1) The dry basis F factor (O_2) procedures in Method 19 shall be used to compute the emission rate of particulate matter.

(2) For the particular matter concentration, Method 5 shall be used at affected facilities without wet FGD systems and Method 5B shall be used after wet FGD systems.

(i) The sampling time and sample volume for each run shall be at least 120 minutes and 1.70 dscm (60 dscf). The probe and filter holder heating system in the sampling train may be set to provide an average gas temperature of no greater than 160±14 ºC (320±25 ºF).

(ii) For each particulate run, the emission rate correction factor, integrated or grab sampling and analysis procedures of Method 3B shall be used to determine the O_2 concentration. The O_2 sample shall be obtained simultaneously with, and at the same traverse points as, the particulate run. If the particulate run has more than 12 traverse points, the O_2 traverse points may be reduced to 12 provided that Method 1 is used to locate the 12 O_2 traverse points. If the grab sampling procedure is used, the O_2 concentration for the run shall be the arithmetic mean of the sample O_2 concentrations at all traverse points.

(3) Method 9 and the procedures in Sec. 60.11 shall be used to determine opacity.

(c) The owner or operator shall determine compliance with the SO_2 standards in Sec. 60.43Da as follows:

(1) The percent of potential SO_2 emissions ($\%P_s$) to the atmosphere shall be computed using the following equation:

$$\%P_s = [(100 - \%R_f) (100 - \%R_g)]/100$$

where:
%Ps = percent of potential SO_2 emissions, percent.
%Rf = percent reduction from fuel pretreatment, percent.
%Rg = percent reduction by SO_2 control system, percent.

(2) The procedures in Method 19 may be used to determine percent reduction ($\%R_f$ of sulfur by such processes as fuel pretreatment (physical coal cleaning, hydrodesulfurization of fuel oil, etc.), coal pulverizers, and bottom and flyash interactions. This determination is optional.

(3) The procedures in Method 19 shall be used to determine the percent SO_2 reduction ($\%R_g$) of any SO_2 control system. Alternatively, a combination of an ``as fired" fuel monitor and emission rates measured after the control system, following the procedures in Method 19, may be used if the percent reduction is calculated using the average emission rate from the $SO_2$ control device and the average $SO_2$ input rate from the ``as fired" fuel analysis for 30 successive boiler operating days.

(4) The appropriate procedures in Method 19 shall be used to determine the emission rate.

(5) The continuous monitoring system in Sec. 60.49Da (b) and (d) shall be used to determine the concentrations of SO_2 and CO_2 or O_2.

(d) The owner or operator shall determine compliance with the NO_x standard in Sec. 60.44Da as follows:

(1) The appropriate procedures in Method 19 shall be used to determine the emission rate of NO_x.

(2) The continous monitoring system in Sec. 60.49Da (c) and (d) shall be used to determine the concentrations of NO_x and CO_2 or O_2.

(e) The owner or operator may use the following as alternatives to the reference methods and procedures specified in this section:

(1) For Method 5 or 5B, Method 17 may be used at facilities with or without wet FGD systems if the stack temperature at the sampling location does not exceed an average temperature of 160 ºC (320 ºF). The procedures of Secs. 2.1 and 2.3 of Method 5B may be used in Method 17 only if it is used after wet FGD systems. Method 17 shall not be used after wet FGD systems if the effluent is saturated or laden with water droplets.

(2) The F_c factor (CO_2) procedures in Method 19 may be used to compute the emission rate of particulate matter under the stipulations of Sec. 60.48(d)(1). The CO_2 shall be determined in the same manner as the O_2 concentration.

(f) Electric utility combined cycle gas turbines are performance tested for particulate matter, sulfur dioxide, and nitrogen oxides using the procedures of Method 19. The sulfur dioxide and nitrogen oxides emission rates from the gas turbine used in Method 19 calculations are determined when the gas turbine is performance tested under subpart GG. The potential uncontrolled particulate matter emission rate from a gas turbine is defined as 17 ng/J (0.04 lb/million Btu) heat input.

(g) For the purposes of determining compliance with the emission limits in Sec. Sec. 60.45Da and 60.46Da, the owner or operator of an electric utility steam generating unit which is also a cogeneration unit shall use the procedures in paragraphs (g)(1) and (2) of this section to calculate emission rates based on electrical output to the grid plus half of the equivalent electrical energy in the unit's process stream.

(1) All conversions from Btu/hr unit input to MW unit output must use equivalents found in 40 CFR 60.40(a)(1) for electric utilities (i.e., 250 million Btu/hr input to a electric utility steam generating unit is equivalent to 73 MW input to the electric utility steam generating unit); 73 MW input to the electric utility steam generating unit is equivalent to 25 MW output from the boiler electric utility steam generating unit; therefore, 250 million Btu input to the electric utility steam generating unit is equivalent to 25 MW output from the electric utility steam generating unit).

(2) Use the Equation 1 of this section to determine the cogeneration Hg emission rate over a specific compliance period.

$$ER_{cogen} = \frac{M}{\left(V_{grid} + 0.75 \times V_{process}\right)} \quad \text{(Eq. 1)}$$

Where:
ERcogen = Cogeneration Hg emission rate over a compliance period in lb/MWh;
E = Mass of Hg emitted from the stack over the same compliance period (lb);
Vgrid = Amount of energy sent to the grid over the same compliance period (MWh); and
Vprocess = Amount of energy converted to steam for process use over the same compliance period (MWh).

(h) The owner or operator shall determine compliance with the Hg limit in Sec. 60.45Da according to the procedures in paragraphs (h)(1) through (3) of this section.

(1) The initial performance test shall be commenced by the applicable date specified in Sec. 60.8(a). The required continuous monitoring systems must be certified prior to commencing the test. The performance test consists of collecting hourly Hg emission data (lb/MWh) with the continuous monitoring systems for 12 successive months of unit operation (excluding hours of unit startup, shutdown and
malfunction). The average Hg emission rate is calculated for each month, and then the weighted, 12-month average Hg emission rate is calculated according to paragraph (h)(2) or (h)(3) of this section, as applicable. If, for any month in the initial performance test, the minimum data capture requirement in Sec. 60.49Da(p)(4)(i) is not met, the owner or operator shall report a substitute Hg emission rate for that month, as follows. For the first such month, the substitute monthly Hg emission rate shall be the arithmetic average of all valid hourly Hg emission rates recorded to date. For any subsequent month(s) with insufficient data capture, the substitute monthly Hg emission rate shall be the highest valid hourly Hg emission rate recorded to date. When the 12-month average Hg emission rate for the initial performance test is calculated, for each month in which there was insufficient data capture, the substitute monthly Hg emission rate shall be weighted according to the number of unit operating hours in that month. Following the initial performance test, the owner or operator shall demonstrate compliance by calculating the weighted average of all monthly Hg emission rates (in lb/MWh) for each 12 successive calendar months, excluding data obtained during startup, shutdown, or malfunction.

(2) If a CEMS is used to demonstrate compliance, follow the procedures in paragraphs (h)(2)(i) through (iii) of this section to determine the 12-month rolling average.

(i) Calculate the total mass of Hg emissions over a month (M), in pounds (lb), using either Equation 2 in paragraph (h)(2)(i)(A) of this section or Equation 3 in paragraph (h)(2)(i)(B) of this section, in conjunction with Equation 4 in paragraph (h)(2)(i)(C) of this section.

(A) If the Hg CEMS measures Hg concentration on a wet basis, use Equation 2 below to calculate the Hg mass emissions for each valid hour:

$$E_h = K\,C_h Q_h t_h \qquad \text{(Eq. 2)}$$

Where:
E_h = Hg mass emissions for the hour, (lb)
K = Units conversion constant, 6.24 x 10^{-11} lb-scm/[mu]g-scf
C_h = Hourly Hg concentration, wet basis, ([mu]g/scm)
Q_h = Hourly stack gas volumetric flow rate, (scfh)
t_h = Unit operating time, i.e., the fraction of the hour for which the unit operated. For example, th = 0.50 for a half-hour of unit operation and 1.00 for a full hour of operation.

(B) If the Hg CEMS measures Hg concentration on a dry basis, use Equation 3 below to calculate the Hg mass emissions for each valid hour:

$$E_h = K\,C_h Q_h t_h \left(1 - B_{ws}\right) \qquad \text{(Eq. 3)}$$

Where:
E_h = Hg mass emissions for the hour, (lb)
K = Units conversion constant, 6.24 x 10^{-11} lb-scm/[mu]g-scf
C_h = Hourly Hg concentration, dry basis, ([mu]g/dscm)
Q_h = Hourly stack gas volumetric flow rate, (scfh)
t_h = Unit operating time, i.e., the fraction of the hour for which the unit operated
B_{ws} = Stack gas moisture content, expressed as a decimal fraction (e.g., for 8 percent H2O, Bws = 0.08)

(C) Use Equation 4, below, to calculate M, the total mass of Hg emitted for the month, by summing the hourly masses derived from Equation 2 or 3 (as applicable):

$$M = \sum_{h=1}^{n} E_h \qquad \text{(Eq. 4)}$$

Where:
M = Total Hg mass emissions for the month, (lb)
E_h = Hg mass emissions for hour ``h", from Equation 2 or 3 of this section, (lb)
n = The number of unit operating hours in the month with valid CEM and electrical output data, excluding hours of unit startup, shutdown and malfunction

(ii) Calculate the monthly Hg emission rate on an output basis (lb/MWh) using Equation 5, below. For a cogeneration unit, use Equation 1 in paragraph (g) of this section instead.

$$ER = \frac{M}{P} \qquad \text{(Eq. 5)}$$

Where:
ER = Monthly Hg emission rate, (lb/MWh)
M = Total mass of Hg emissions for the month, from Equation 4, above, (lb)
P = Total electrical output for the month, for the hours used to calculate M, (MWh)

(iii) Until 12 monthly Hg emission rates have been accumulated, calculate and report only the monthly averages. Then, for each subsequent calendar month, use Equation 6 below to calculate the 12-month rolling average as a weighted average of the Hg emission rate for the current month and the

Hg emission rates for the previous 11 months, with one exception. Calendar months in which the unit does not operate (zero unit operating hours) shall not be included in the 12-month rolling average.

$$E_{avg} = \frac{\sum_{i=i}^{12} (ER)_i n_i}{\sum_{i=i}^{12} n_i} \qquad \text{(Eq. 6)}$$

Where:
E_{avg} = Weighted 12-month rolling average Hg emission rate, lb/MWh)
$(ER)_i$ = Monthly Hg emission rate, for month ``i'', (lb/MWh)
n = The number of unit operating hours in month ``i'' with valid CEM and electrical output data, excluding hours of unit startup, shutdown, and malfunction

(3) If a sorbent trap monitoring system is used in lieu of a Hg CEMS, as described in Sec. 75.15 of this chapter and in appendix K to part 75 of this chapter, calculate the monthly Hg emission rates using Equations 3 through 5 of this section, except that for a particular pair of sorbent traps, Ch in Equation 3 shall be the flow-proportional average Hg concentration measured over the data collection period.

(i) Daily calibration drift (CD) tests and quarterly accuracy determinations shall be performed for Hg CEMS in accordance with Procedure 1 of appendix F to this part. For the CD assessments, you may use either elemental mercury or mercuric chloride (Hg[deg] or HgCl2) standards. The four quarterly accuracy determinations shall consist of one RATA and three measurement error (ME) tests using HgCl2 standards, as described in section 8.3 of Performance Specification 12-A in appendix B to this part (note: Hg[deg] standards may be used if the Hg monitor does not have a converter). Alternatively, the owner or operator may implement the applicable daily, weekly, quarterly, and annual quality assurance (QA) requirements for Hg CEMS in appendix B to part 75 of this chapter, in lieu of the QA procedures in appendices B and F to this part. Annual RATA of sorbent trap monitoring systems shall be performed in accordance with appendices A and B to part 75 of this chapter, and all other quality assurance requirements specified in appendix K to part 75 of this chapter shall be met for sorbent trap monitoring systems.

Sec. 60.51Da Reporting requirements.

(a) For sulfur dioxide, nitrogen oxides, particulate matter, and Hg emissions, the performance test data from the initial and subsequent performance test and from the performance evaluation of the continuous monitors (including the transmissometer) are submitted to the Administrator.

(b) For sulfur dioxide and nitrogen oxides the following information is reported to the Administrator for each 24-hour period.

(1) Calendar date.

(2) The average sulfur dioxide and nitrogen oxide emission rates (ng/J or lb/million Btu) for each 30 successive boiler operating days, ending with the last 30-day period in the quarter; reasons for non-compliance with the emission standards; and, description of corrective actions taken.

(3) Percent reduction of the potential combustion concentration of sulfur dioxide for each 30 successive boiler operating days, ending with the last 30-day period in the quarter; reasons for non-compliance with the standard; and, description of corrective actions taken.

(4) Identification of the boiler operating days for which pollutant or dilutent data have not been obtained by an approved method for at least 18 hours of operation of the facility; justification for not obtaining sufficient data; and description of corrective actions taken.

(5) Identification of the times when emissions data have been excluded from the calculation of average emission rates because of startup, shutdown, malfunction (NO_2 only), emergency conditions (SO_2 only), or other reasons, and justification for excluding data for reasons other than startup, shutdown, malfunction, or emergency conditions.

(6) Identification of ``F'' factor used for calculations, method of determination, and type of fuel combusted.

(7) Identification of times when hourly averages have been obtained based on manual sampling methods.

(8) Identification of the times when the pollutant concentration exceeded full span of the continuous monitoring system.

(9) Description of any modifications to the continuous monitoring system which could affect the ability of the continuous monitoring system to comply with Performance Specifications 2 or 3.

(c) If the minimum quantity of emission data as required by Sec. 60.49Da is not obtained for any 30 successive boiler operating days, the following information obtained under the requirements of Sec. 60.48Da(h) is reported to the Administrator for that 30-day period:

(1) The number of hourly averages available for outlet emission rates (n_o) and inlet emission rates (n_i) as applicable.

(2) The standard deviation of hourly averages for outlet emission rates (s_o) and inlet emission rates (s_i) as applicable.

(3) The lower confidence limit for the mean outlet emission rate E_o*) and the upper confidence limit for the mean inlet mission rate (E_i*) as applicable.

(4) The applicable potential combustion concentration.

(5) The ratio of the upper confidence limit for the mean outlet emission rate (E_o*) and the allowable emission rate (E_{std}) as applicable.

(d) If any standards under Sec. 60.43Da are exceeded during emergency conditions because of control system malfunction, the owner or operator of the affected facility shall submit a signed statement:

(1) Indicating if emergency conditions existed and requirements under Sec. 60.48Da(d) were met during each period, and

(2) Listing the following information:

(i) Time periods the emergency condition existed;

(ii) Electrical output and demand on the owner or operator's electric utility system and the affected facility;

(iii) Amount of power purchased from interconnected neighboring utility companies during the emergency period;

(iv) Percent reduction in emissions achieved;

(v) Atmospheric emission rate (ng/J) of the pollutant discharged; and

(vi) Actions taken to correct control system malfunction.

(e) If fuel pretreatment credit toward the sulfur dioxide emission standard under Sec. 60.43Da is claimed, the owner or operator of the affected facility shall submit a signed statement:

(1) Indicating what percentage cleaning credit was taken for the calendar quarter, and whether the credit was determined in accordance with the provisions of Sec. 60.50Da and Method 19 (appendix A); and

(2) Listing the quantity, heat content, and date each pretreated fuel shipment was received during the previous quarter; the name and location of the fuel pretreatment facility; and the total quantity and total heat content of all fuels received at the affected facility during the previous quarter.

(f) For any periods for which opacity, sulfur dioxide or nitrogen oxides emissions data are not available, the owner or operator of the affected facility shall submit a signed statement indicating if any changes were made in operation of the emission control system during the period of data unavailability. Operations of the control system and affected facility during periods of data unavailability are to be compared with operation of the control system and affected facility before and following the period of data unavailability.

(g) For Hg, the following information shall be reported to the Administrator:

(1) Company name and address;

(2) Date of report and beginning and ending dates of the reporting period;

(3) The applicable Hg emission limit (lb/MWh); and

(4) For each month in the reporting period:

(i) The number of unit operating hours;

(ii) The number of unit operating hours with valid data for Hg concentration, stack gas flow rate, moisture (if required), and electrical output;

(iii) The monthly Hg emission rate (lb/MWh);

(iv) The number of hours of valid data excluded from the calculation of the monthly Hg emission rate, due to unit startup, shutdown and malfunction; and

(v) The 12-month rolling average Hg emission rate (lb/MWh); and

(5) The data assessment report (DAR) required by appendix F to this part, or an equivalent summary of QA test results if the QA of part 75 of this chapter are implemented.

(h) The owner or operator of the affected facility shall submit a signed statement indicating whether:

(1) The required continuous monitoring system calibration, span, and drift checks or other periodic audits have or have not been performed as specified.

(2) The data used to show compliance was or was not obtained in accordance with approved methods and procedures of this part and is representative of plant performance.

(3) The minimum data requirements have or have not been met; or, the minimum data requirements have not been met for errors that were unavoidable.

(4) Compliance with the standards has or has not been achieved during the reporting period.

(i) For the purposes of the reports required under Sec. 60.7, periods of excess emissions are defined as all 6-minute periods during which the average opacity exceeds the applicable opacity standards under Sec. 60.42Da(b). Opacity levels in excess of the applicable opacity standard and the date of such excesses are to be submitted to the Administrator each calendar quarter.

(j) The owner or operator of an affected facility shall submit the written reports required under this section and subpart A of this part to the Administrator semiannually for each six-month period. All semiannual reports shall be postmarked by the 30th day following the end of each six-month period.

(k) The owner or operator of an affected facility may submit electronic quarterly reports for SO2 and/or NOX and/or opacity and/or Hg in lieu of submitting the written reports required under paragraphs (b), (g), and (i) of this section. The format of each quarterly electronic report shall be coordinated with the permitting authority. The electronic report(s) shall be submitted no later than 30 days after the end of the calendar quarter and shall be accompanied by a certification statement from the owner or operator, indicating whether compliance with the applicable emission standards and minimum data requirements of this subpart was achieved during the reporting period. before submitting reports in the electronic format, the owner or operator shall coordinate with the permitting authority to obtain their agreement to submit reports in this alternative format.

Sec. 60.52Da Recordkeeping requirements.

The owner or operator of an affected facility subject to the emissions limitations in Sec. 60.45Da or Sec. 60.46Da shall provide notifications in accordance with Sec. 60.7(a) and shall maintain records of all information needed to demonstrate compliance including performance tests, monitoring data, fuel analyses, and calculations, consistent with the requirements of Sec. 60.7(f).

APPENDIX D

40 CFR Part 60, Subpart Db

[Last updated 2/27/06]

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Subpart Db--Standards of Performance for Industrial-Commercial-Institutional Steam Generating Units

Sec.

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Subpart Db--Standards of Performance for Industrial-Commercial-Institutional Steam Generating Units

§ 60.40b Applicability and delegation of authority.

(a) The affected facility to which this subpart applies is each steam generating unit that commences construction, modification, or reconstruction after June 19, 1984, and that has a heat input capacity from fuels combusted in the steam generating unit of greater than 29 MW (100 million Btu/hour).

(b) Any affected facility meeting the applicability requirements under paragraph (a) of this section and commencing construction, modification, or reconstruction after June 19, 1984, but on or before June 19, 1986, is subject to the following standards:

(1) Coal-fired affected facilities having a heat input capacity between 29 and 73 MW (100 and 250 million Btu/hour), inclusive, are subject to the particulate matter and nitrogen oxides standards under this subpart.

(2) Coal-fired affected facilities having a heat input capacity greater than 73 MW (250 million Btu/hour) and meeting the applicability requirements under subpart D (Standards of performance for fossil-fuel-fired steam generators; § 60.40) are subject to the particulate matter and nitrogen oxides standards under this subpart and to the sulfur dioxide standards under subpart D (§ 60.43).

(3) Oil-fired affected facilities having a heat input capacity between 29 and 73 MW (100 and 250 million Btu/hour), inclusive, are subject to the nitrogen oxides standards under this subpart.

(4) Oil-fired affected facilities having a heat input capacity greater than 73 MW (250 million Btu/hour) and meeting the applicability requirements under subpart D (Standards of performance for fossil-fuel-fired steam generators; § 60.40) are also subject to the nitrogen oxides standards under this subpart and the particulate matter and sulfur dioxide standards under subpart D (§ 60.42 and § 60.43).

(c) Affected facilities which also meet the applicability requirements under subpart J (Standards of performance for petroleum refineries; § 60.104) are subject to the particulate matter and nitrogen oxides standards under this subpart and the sulfur dioxide standards under subpart J (§ 60.104).

(d) Affected facilities which also meet the applicability requirements under subpart E (Standards of performance for incinerators; § 60.50) are subject to the nitrogen oxides and particulate matter standards under this subpart.

(e) Steam generating units meeting the applicability requirements under subpart Da (Standards of performance for electric utility steam generating units; § 60.40a) are not subject to this subpart.

(f) Any change to an existing steam generating unit for the sole purpose of combusting gases containing TRS as defined under § 60.281 is not considered a modification under § 60.14 and the steam generating unit is not subject to this subpart.

(g) In delegating implementation and enforcement authority to a State under section 111(c) of the Act, the following authorities shall be retained by the Administrator and not transferred to a State.

(1) Section 60.44b(f).
(2) Section 60.44b(g).
(3) Section 60.49b(a)(4).

(h) Affected facilities which meet the applicability requirements under subpart Eb (Standards of performance for municipal waste combustors; § 60.50b) are not subject to this subpart.

(i) Heat recovery steam generators that are associated with combined cycle gas turbines and that meet the applicability requirements of subpart KKKK of this part are not subject to this subpart. This subpart will continue to apply to all other heat recovery steam generators that are capable of combusting more than 29 MW (100 MMBtu/h) heat input of fossil fuel. If the heat recovery steam generator is subject to this subpart, only emissions resulting from combustion of fuels in the steam generating unit are subject to this subpart. (The gas turbine emissions are subject to subpart GG or KKKK, as applicable, of this part.)

(j) Any affected facility meeting the applicability requirements under paragraph (a) of this section and commencing construction, modification, or reconstruction after June 19, 1986 is not subject to Subpart D (Standards of Performance for Fossil-Fuel-Fired Steam Generators, Sec. 60.40).

(k) Any facility covered by subpart Eb or subpart AAAA of this part is not covered by this subpart.

(l) Any facility covered by an EPA approved State or Federal section 111(d)/129 plan implementing subpart Cb or subpart BBBB of this part is not covered by this subpart.

§ 60.41b Definitions.

As used in this subpart, all terms not defined herein shall have the meaning given them in the Act and in subpart A of this part.

Annual capacity factor means the ratio between the actual heat input to a steam generating unit from the fuels listed in § 60.42b(a), § 60.43b(a), or § 60.44b(a), as applicable, during a calendar year and the potential heat input to the steam generating unit had it been operated for 8,760 hours during a calendar year at the maximum steady state design heat input capacity. In the case of steam generating units that are

rented or leased, the actual heat input shall be determined based on the combined heat input from all operations of the affected facility in a calendar year.

Byproduct/waste means any liquid or gaseous substance produced at chemical manufacturing plants, petroleum refineries, or pulp and paper mills (except natural gas, distillate oil, or residual oil) and combusted in a steam generating unit for heat recovery or for disposal. Gaseous substances with carbon dioxide levels greater than 50 percent or carbon monoxide levels greater than 10 percent are not byproduct/waste for the purposes of this subpart.

Chemical manufacturing plants means industrial plants which are classified by the Department of Commerce under Standard Industrial Classification (SIC) Code 28.

Coal means all solid fuels classified as anthracite, bituminous, subbituminous, or lignite by the American Society of Testing and Materials in ASTM D388-77, 90, 91, 95, or 98a. Standard Specification for Classification of Coals by Rank (IBR--see § 60.17), coal refuse, and petroleum coke. Coal-derived synthetic fuels, including but not limited to solvent refined coal, gasified coal, coal-oil mixtures, and coal-water mixtures,
are also included in this definition for the purposes of this subpart.

Coal refuse means any byproduct of coal mining or coal cleaning operations with an ash content greater than 50 percent, by weight, and a heating value less than 13,900 kJ/kg (6,000 Btu/lb) on a dry basis.

Cogeneration, also known as combined heat and power, means a facility that simultaneously produces both electric (or mechanical) and useful thermal energy from the same primary energy source.

Combined cycle system means a system in which a separate source, such as a gas turbine, internal combustion engine, kiln, etc., provides exhaust gas to a heat recovery steam generating unit.

Conventional technology means wet flue gas desulfurization (FGD) technology, dry FGD technology, atmospheric fluidized bed combustion technology, and oil hydrodesulfurization technology.

Distillate oil means fuel oils that contain 0.05 weight percent nitrogen or less and comply with the specifications for fuel oil numbers 1 and 2, as defined by the American Society of Testing and Materials in
ASTM D396-78, 89, 90, 92, 96, 98. Standard Specifications for Fuel Oils (incorporated by reference--see § 60.17).

Dry flue gas desulfurization technology means a sulfur dioxide control system that is located downstream of the steam generating unit and removes sulfur oxides from the combustion gases of the steam generating unit by contacting the combustion gases with an alkaline slurry or solution and forming a dry powder material. This definition includes devices where the dry powder material is subsequently converted
to another form. Alkaline slurries or solutions used in dry flue gas desulfurization technology include but are not limited to lime and sodium.

Duct burner means a device that combusts fuel and that is placed in the exhaust duct from another source, such as a stationary gas turbine, internal combustion engine, kiln, etc., to allow the firing of additional fuel to heat the exhaust gases before the exhaust gases enter a heat recovery steam generating unit.

Emerging technology means any sulfur dioxide control system that is not defined as a conventional technology under this section, and for which the owner or operator of the facility has applied to the Administrator and received approval to operate as an emerging technology under § 60.49b(a)(4).

Federally enforceable means all limitations and conditions that are enforceable by the Administrator, including the requirements of 40 CFR parts 60 and 61, requirements within any applicable State Implementation Plan, and any permit requirements established under 40 CFR 52.21 or under 40 CFR 51.18 and 40 CFR 51.24.

Fluidized bed combustion technology means combustion of fuel in a bed or series of beds (including but not limited to bubbling bed units and circulating bed units) of limestone aggregate (or other sorbent
materials) in which these materials are forced upward by the flow of combustion air and the gaseous products of combustion.

Fuel pretreatment means a process that removes a portion of the sulfur in a fuel before combustion of the fuel in a steam generating unit.

Full capacity means operation of the steam generating unit at 90 percent or more of the maximum steady-state design heat input capacity.

Heat input means heat derived from combustion of fuel in a steam generating unit and does not include the heat input from preheated combustion air, recirculated flue gases, or exhaust gases from other sources, such as gas turbines, internal combustion engines, kilns, etc.

Heat release rate means the steam generating unit design heat input capacity (in MW or Btu/hour) divided by the furnace volume (in cubic meters or cubic feet); the furnace volume is that volume bounded by the front furnace wall where the burner is located, the furnace side waterwall, and extending to the level just below or in front of the first row of convection pass tubes.

Heat transfer medium means any material that is used to transfer heat from one point to another point.

High heat release rate means a heat release rate greater than 730,000 J/sec-m^3 (70,000 Btu/hour-ft^3).

Lignite means a type of coal classified as lignite A or lignite B by the American Society of Testing and Materials in ASTM D388-77, 90, 91, 95, or 98a. Standard Specification for Classification of Coals by Rank (IBR--see § 60.17).

Low heat release rate means a heat release rate of 730,000 J/sec-m^3 (70,000 Btu/hour-ft^3) or less.

Mass-feed stoker steam generating unit means a steam generating unit where solid fuel is introduced directly into a retort or is fed directly onto a grate where it is combusted.

Maximum heat input capacity means the ability of a steam generating unit to combust a stated maximum amount of fuel on a steady state basis, as determined by the physical design and characteristics of the steam generating unit.

Municipal-type solid waste means refuse, more than 50 percent of which is waste consisting of a mixture of paper, wood, yard wastes, food wastes, plastics, leather, rubber, and other combustible materials, and noncombustible materials such as glass and rock.

Natural gas means (1) a naturally occurring mixture of hydrocarbon and nonhydrocarbon gases found in geologic formations beneath the earth's surface, of which the principal constituent is methane; or (2)
liquid petroleum gas, as defined by the American Society for Testing and Materials in ASTM D1835-82, 86, 87, 91, or 97 ``Standard Specification for Liquid Petroleum Gases'' (IBR--see § 60.17).

Noncontinental area means the State of Hawaii, the Virgin Islands, Guam, American Samoa, the Commonwealth of Puerto Rico, or the Northern Mariana Islands.

Oil means crude oil or petroleum or a liquid fuel derived from crude oil or petroleum, including distillate and residual oil.

Petroleum refinery means industrial plants as classified by the Department of Commerce under Standard Industrial Classification (SIC) Code 29.

Potential sulfur dioxide emission rate means the theoretical sulfur dioxide emissions (ng/J, lb/million Btu heat input) that would result from combusting fuel in an uncleaned state and without using emission
control systems.

Process heater means a device that is primarily used to heat a material to initiate or promote a chemical reaction in which the material participates as a reactant or catalyst.

Pulp and paper mills means industrial plants which are classified by the Department of Commerce under North American Industry Classification System (NAICS) Code 322 or Standard Industrial Classification (SIC) Code 26.

Pulverized coal-fired steam generating unit means a steam generating unit in which pulverized coal is introduced into an air stream that carries the coal to the combustion chamber of the steam generating unit where it is fired in suspension. This includes both conventional pulverized coal-fired and micropulverized coal-fired steam generating units.

Residual oil means crude oil, fuel oil numbers 1 and 2 that have a nitrogen content greater than 0.05 weight percent, and all fuel oil numbers 4, 5 and 6, as defined by the American Society of Testing and Materials in ASTM D396-78, Standard Specifications for Fuel Oils (IBR--see § 60.17).

Spreader stoker steam generating unit means a steam generating unit in which solid fuel is introduced to the combustion zone by a mechanism that throws the fuel onto a grate from above. Combustion takes place
both in suspension and on the grate.

Steam generating unit means a device that combusts any fuel or byproduct/waste to produce steam or to heat water or any other heat transfer medium. This term includes any municipal-type solid waste incinerator with a heat recovery steam generating unit or any steam generating unit that combusts fuel and is part of a cogeneration system or a combined cycle system. This term does not include process heaters as they are defined in this subpart.

Steam generating unit operating day means a 24-hour period between 12:00 midnight and the following midnight during which any fuel is combusted at any time in the steam generating unit. It is not necessary for fuel to be combusted continuously for the entire 24-hour period.

Very low sulfur oil for units constructed, reconstructed, or modified on or before February 28, 2005, means an oil that contains no more than 0.5 weight percent sulfur or that, when combusted without sulfur dioxide emission control, has a sulfur dioxide emission rate equal to or less than 215 ng/J (0.5 lb/MMBtu) heat input. For units constructed, reconstructed, or modified after February 28, 2005, very low sulfur oil means an oil that contains no more than 0.3 weight percent sulfur or that, when combusted without sulfur dioxide emission control, has a sulfur dioxide emission rate equal to or less than 140 ng/J (0.32 lb/MMBtu) heat input.

Wet flue gas desulfurization technology means a sulfur dioxide control system that is located downstream of the steam generating unit and removes sulfur oxides from the combustion gases of the steam
generating unit by contacting the combustion gas with an alkaline slurry or solution and forming a liquid material. This definition applies to devices where the aqueous liquid material product of this contact is subsequently converted to other forms. Alkaline reagents used in wet flue gas desulfurization technology include, but are not limited to, lime, limestone, and sodium.

Wet scrubber system means any emission control device that mixes an aqueous stream or slurry with the exhaust gases from a steam generating unit to control emissions of particulate matter or sulfur dioxide.

Wood means wood, wood residue, bark, or any derivative fuel or residue thereof, in any form, including, but not limited to, sawdust, sanderdust, wood chips, scraps, slabs, millings, shavings, and processed pellets made from wood or other forest residues.

[52 FR 47842, Dec. 16, 1987, as amended at 54 FR 51819, Dec. 18, 1989]

§ 60.42b Standard for sulfur dioxide.

(a) Except as provided in paragraphs (b), (c), (d), (j), or (k) of this section, on and after the date on which the performance test is completed or required to be completed under Sec. 60.8 of this part, whichever date comes first, no owner or operator of an affected facility that commenced construction, reconstruction, or modification on or before February 28, 2005, that combusts coal or oil shall cause to be discharged into the atmosphere any gases that contain sulfur dioxide in excess of 87 ng/J (0.20 lb/MMBtu) or 10 percent (0.10) of the potential sulfur dioxide emission rate (90 percent reduction) and the emission limit determined according to the following formula:

$E_s = (K_aH_a+K_bH_b)/(H_a+H_b)$

where:
E_s is the sulfur dioxide emission limit, in ng/J or lb/million Btu heat input,
K_a is 520 ng/J (or 1.2 lb/million Btu),
K_b is 340 ng/J (or 0.80 lb/million Btu),
H_a is the heat input from the combustion of coal, in J (million Btu),
H_b is the heat input from the combustion of oil, in J (million Btu).

Only the heat input supplied to the affected facility from the combustion of coal and oil is counted under this section. No credit is provided for the heat input to the affected facility from the combustion of natural gas, wood, municipal-type solid waste, or other fuels or heat input to the affected facility from exhaust gases from another source, such as gas turbines, internal combustion engines, kilns, etc.

(b) On and after the date on which the performance test is completed or required to be completed under Sec. 60.8 of this part, whichever date comes first, no owner or operator of an affected facility that commenced construction, reconstruction, or modification on or before February 28, 2005, that combusts coal refuse alone in a fluidized bed combustion steam generating unit shall cause to be discharged into the atmosphere any gases that contain sulfur dioxide in excess of 87 ng/J (0.20 lb/MMBtu) or 20 percent (0.20) of the potential sulfur dioxide emission rate (80 percent reduction) and 520 ng/J (1.2 lb/MMBtu) heat input. If coal or oil is fired with coal refuse, the affected facility is subject to paragraph (a) or (d) of this section, as applicable.

(c) On and after the date on which the performance test is completed or is required to be completed under § 60.8 of this part, whichever comes first, no owner or operator of an affected facility that combusts coal or oil, either alone or in combination with any other fuel, and that uses an emerging technology for the control of sulfur dioxide emissions, shall cause to be discharged into the atmosphere any gases that contain sulfur dioxide in excess of 50 percent of the potential sulfur dioxide emission rate (50 percent reduction) and that contain sulfur dioxide in excess of the emission limit determined according to the following formula:

$Es=(K_cH_c+K_d\ H_d)/(H_c+H_d)$

where:
E_s is the sulfur dioxide emission limit, expressed in ng/J (lb/million Btu) heat input,
K_c is 260 ng/J (0.60 lb/million Btu),
K_d is 170 ng/J (0.40 lb/million Btu),
H_c is the heat input from the combustion of coal, J (million Btu),
H_d is the heat input from the combustion of oil, J (million Btu).

Only the heat input supplied to the affected facility from the combustion of coal and oil is counted under this section. No credit is provided for the heat input to the affected facility from the combustion of natural gas, wood, municipal-type solid waste, or other fuels, or from the heat input to the affected facility from exhaust gases from another source, such as gas turbines, internal combustion engines, kilns, etc.

(d) On and after the date on which the performance test is completed or required to be completed under Sec. 60.8 of this part, whichever comes first, no owner or operator of an affected facility listed in paragraphs (d)(1), (2), (3), or (4) of this section shall cause to be discharged into the atmosphere any gases that contain sulfur dioxide in excess of 520 ng/J (1.2 lb/million Btu) heat input if the affected facility combusts coal, or 215 ng/J (0.5 lb/million Btu) heat input if the affected facility combusts oil other than very low sulfur oil. Percent reduction requirements are not applicable to affected facilities under paragraphs (d)(1), (2), (3) or (4).
Percent reduction requirements are not applicable to affected facilities under paragraphs (d)(1), (2), or (3).

(1) Affected facilities that have an annual capacity factor for coal and oil of 30 percent (0.30) or less and are subject to a Federally enforceable permit limiting the operation of the affected facility to an annual capacity factor for coal and oil of 30 percent (0.30) or less;

(2) Affected facilities located in a noncontinental area; or

(3) Affected facilities combusting coal or oil, alone or in combination with any fuel, in a duct burner as part of a combined cycle system where 30 percent (0.30) or less of the heat input to the steam generating unit is from combustion of coal and oil in the duct burner and 70 percent (0.70) or more of the heat input to the steam generating unit is from the exhaust gases entering the duct burner; or

(4) The affected facility burns coke oven gas alone or in combination with any other gaseous fuels.

(e) Except as provided in paragraph (f) of this section, compliance with the emission limits, fuel oil sulfur limits, and/or percent reduction requirements under this section are determined on a 30-day rolling average basis.

(f) Except as provided in paragraph (j)(2) of this section, compliance with the emission limits or fuel oil sulfur limits under this section is determined on a 24-hour average basis for affected facilities that (1) have a Federally enforceable permit limiting the annual capacity factor for oil to 10 percent or less, (2) combust only very low sulfur oil, and (3) do not combust any other fuel.

(g) Except as provided in paragraph (i) of this section, the sulfur dioxide emission limits and percent reduction requirements under this section apply at all times, including periods of startup, shutdown, and malfunction.

(h) Reductions in the potential sulfur dioxide emission rate through fuel pretreatment are not credited toward the percent reduction requirement under paragraph (c) of this section unless:

(1) Fuel pretreatment results in a 50 percent or greater reduction in potential sulfur dioxide emissions and

(2) Emissions from the pretreated fuel (without combustion or post combustion sulfur dioxide control) are equal to or less than the emission limits specified in paragraph (c) of this section.

(i) An affected facility subject to paragraph (a), (b), or (c) of this section may combust very low sulfur oil or natural gas when the sulfur dioxide control system is not being operated because of malfunction or maintenance of the sulfur dioxide control system.

(j) Percent reduction requirements are not applicable to affected facilities combusting only very low sulfur oil. The owner or operator of an affected facility combusting very low sulfur oil shall demonstrate that the oil meets the definition of very low sulfur oil by:

(1)Following the performance testing procedures as described in § 60.45b(c) or § 60.45b(d), and following the monitoring procedures as described in § 60.47b(a) or § 60.47b(b) to determine sulfur dioxide emission rate or fuel oil sulfur content; or

(2)maintaining fuel receipts as described in § 60.49b(r).

(k) On or after the date on which the initial performance test is completed or is required to be completed under Sec. 60.8, whichever date comes first, no owner or operator of an affected facility that commences construction or reconstruction after February 28, 2005, and that combusts coal, oil, gas, a mixture of these fuels, or a mixture of these fuels with any other fuels shall cause to be discharged into the atmosphere any gases that contain sulfur dioxide in excess of 87 ng/J (0.20 lb/MMBtu) heat input or 8 percent (0.08) of the potential sulfur dioxide emission rate (92 percent reduction) and 520 ng/J (1.2 lb/MMBtu) heat input, except as provided in paragraphs (k)(1) or (k)(2). Affected facilities subject to this paragraph are also subject to paragraphs (e) through (g) of this section.

(1) Units firing only oil that contains no more than 0.3 weight percent sulfur or any individual fuel with a potential sulfur dioxide emission rates of 140 ng/J (0.32 lb/MMBtu) heat input or less are exempt from all other sulfur dioxide emission limits in this paragraph.

(2) Units that are located in a noncontinental area and that combust coal or oil shall not discharge any gases that contain sulfur dioxide in excess of 520 ng/J (1.2 lb/MMBtu) heat input if the affected facility combusts coal, or 230 ng/J (0.54 lb/MMBtu) heat input if the affected facility combusts oil.

§ 60.43b Standard for particulate matter.

(a) On and after the date on which the initial performance test is completed or is required to be completed under § 60.8 of this part, whichever comes first, no owner or operator of an affected facility which combusts coal or combusts mixtures of coal with other fuels, shall cause to be discharged into the atmosphere from that affected facility any gases that contain particulate matter in excess of the following emission limits:

(1) 22 ng/J (0.051 lb/million Btu) heat input,

(i) If the affected facility combusts only coal, or

(ii) If the affected facility combusts coal and other fuels and has an annual capacity factor for the other fuels of 10 percent (0.10) or less.

(2) 43 ng/J (0.10 lb/million Btu) heat input if the affected facility combusts coal and other fuels and has an annual capacity factor for the other fuels greater than 10 percent (0.10) and is subject to a federally enforceable requirement limiting operation of the affected facility to an annual capacity factor greater than 10 percent (0.10) for fuels other than coal.

(3) 86 ng/J (0.20 lb/million Btu) heat input if the affected facility combusts coal or coal and other fuels and

(i) Has an annual capacity factor for coal or coal and other fuels of 30 percent (0.30) or less,

(ii) Has a maximum heat input capacity of 73 MW (250 million Btu/ hour) or less,

(iii) Has a federally enforceable requirement limiting operation of the affected facility to an annual capacity factor of 30 percent (0.30) or less for coal or coal and other solid fuels, and

(iv) Construction of the affected facility commenced after June 19, 1984, and before November 25, 1986.

(b) On and after the date on which the performance test is completed or required to be completed under 60.8 of this part, whichever date comes first, no owner or operator of an affected facility that combusts oil (or mixtures of oil with other fuels) and uses a conventional or emerging technology to reduce sulfur dioxide emissions shall cause to be discharged into the atmosphere from that affected facility any gases that contain particulate matter in excess of 43 ng/J (0.10 lb/million Btu) heat input.

(c) On and after the date on which the initial performance test is completed or is required to be completed under § 60.8 of this part, whichever date comes first, no owner or operator of an affected facility that combusts wood, or wood with other fuels, except coal, shall cause to be discharged from that affected facility any gases that contain particulate matter in excess of the following emission limits:

(1) 43 ng/J (0.10 lb/million Btu) heat input if the affected facility has an annual capacity factor greater than 30 percent (0.30) for wood.

(2) 86 ng/J (0.20 lb/million Btu) heat input if

(i) The affected facility has an annual capacity factor of 30 percent (0.30) or less for wood,

(ii) Is subject to a federally enforceable requirement limiting operation of the affected facility to an annual capacity factor of 30 percent (0.30) or less for wood, and

(iii) Has a maximum heat input capacity of 73 MW (250 million Btu/hour) or less.

(d) On and after the date on which the initial performance test is completed or is required to be completed under § 60.8 of this part, whichever date comes first, no owner or operator of an affected facility that combusts municipal-type solid waste or mixtures of municipal-type solid waste with other fuels, shall cause to be discharged into the atmosphere from that affected facility any gases that contain particulate matter in excess of the following emission limits:

(1) 43 ng/J (0.10 lb/million Btu) heat input,

(i) If the affected facility combusts only municipal-type solid waste, or

(ii) If the affected facility combusts municipal-type solid waste and other fuels and has an annual capacity factor for the other fuels of 10 percent (0.10) or less.

(2) 86 ng/J (0.20 lb/million Btu) heat input if the affected facility combusts municipal-type solid waste or municipal-type solid waste and other fuels; and

(i) Has an annual capacity factor for municipal-type solid waste and other fuels of 30 percent (0.30) or less,

(ii) Has a maximum heat input capacity of 73 MW (250 million Btu/hour) or less,

(iii) Has a federally enforceable requirement limiting operation of the affected facility to an annual capacity factor of 30 percent (0.30) for municipal-type solid waste, or municipal-type solid waste and other fuels, and

(iv) Construction of the affected facility commenced after June 19, 1984, but before November 25, 1986.

(e) For the purposes of this section, the annual capacity factor is determined by dividing the actual heat input to the steam generating unit during the calendar year from the combustion of coal, wood, or municipal-type solid waste, and other fuels, as applicable, by the potential heat input to the steam generating unit if the steam generating unit had been operated for 8,760 hours at the maximum design heat input capacity.

(f) On and after the date on which the initial performance test is completed or is required to be completed under 60.8 of this part, whichever date comes first, no owner or operator of an affected facility that combusts coal, oil, wood, or mixtures of these fuels with any other fuels shall cause to be discharged into

the atmosphere any gases that exhibit greater than 20 percent opacity (6-minute average), except for one 6-minute period per hour of not more than 27 percent opacity.

(g) The particulate matter and opacity standards apply at all times, except during periods of startup, shutdown or malfunction.

(h) (1) On or after the date on which the initial performance test is completed or is required to be completed under Sec. 60.8, whichever date comes first, no owner or operator of an affected facility that commences construction, reconstruction, or modification after February 28, 2005, and that combusts coal, oil, gas, wood, a mixture of these fuels, or a mixture of these fuels with any other fuels shall cause to be discharged into the atmosphere from that affected facility any gases that contain particulate matter emissions in excess of 13 ng/J (0.030 lb/MMBtu) heat input, except as provided in paragraphs (h)(2), (h)(3), (h)(4), and (h)(5).

(2) As an alternative to meeting the requirements of paragraph (h)(1) of this section, the owner or operator of an affected facility for which modification commenced after February 28, 2005, may elect to meet the requirements of this paragraph. On and after the date on which the performance test required to be conducted under Sec. 60.8 is completed, the owner or operator subject to the provisions of this subpart shall not cause to be discharged into the atmosphere from any affected facility for which modification commenced after February 28, 2005, any gases that contain particulate matter in excess of:

(i) 22 ng/J (0.051 lb/MMBtu) heat input derived from the combustion of coal, oil, gas, wood, a mixture of these fuels, or a mixture of these fuels with any other fuels, and

(ii) 0.2 percent of the combustion concentration (99.8 percent reduction) when combusting coal, oil, gas, wood, a mixture of these fuels, or a mixture of these fuels with any other fuels.

(3) On or after the date on which the initial performance test is completed or is required to be completed under Sec. 60.8, whichever date comes first, no owner or operator of an affected facility that commences modification after February 28, 2005, and that combusts over 30 percent wood (by heat input) on an annual basis and has a maximum heat input capacity of 73 MW (250 MMBtu/h) or less shall cause to be discharged into the atmosphere from that affected facility any gases that contain particulate matter emissions in excess of 43 ng/J (0.10 lb/MMBtu) heat input.

(4) On or after the date on which the initial performance test is completed or is required to be completed under Sec. 60.8, whichever date comes first, no owner or operator of an affected facility that commences modification after February 28, 2005, and that combusts over 30 percent wood (by heat input) on an annual basis and has a maximum heat input capacity greater than 73 MW (250 MMBtu/h) shall cause to be discharged into the atmosphere from that affected facility any gases that contain particulate matter emissions in excess of 37 ng/J (0.085 lb/MMBtu) heat input.

(5) On or after the date on which the initial performance test is completed or is required to be completed under Sec. 60.8, whichever date comes first, no owner or operator of an affected facility that commences construction, reconstruction, or modification after February 28, 2005, and that combusts only oil that contains no more than 0.3 weight percent sulfur or other liquid or gaseous fuels with potential sulfur dioxide emission rates of 140 ng/J (0.32 lb/MMBtu) heat input or less is not subject to the PM or opacity limits in this section.

§ 60.44b Standard for nitrogen oxides.

(a) Except as provided under paragraphs (k) and (l) of this section, on and after the date on which the initial performance test is completed or is required to be completed under § 60.8 of this part, whichever date comes first, no owner or operator of an affected facility that is subject to the provisions of this section and that

combusts only coal, oil, or natural gas shall cause to be discharged into the atmosphere from that affected facility any gases that contain nitrogen oxides (expressed as NO_2 in excess of the following emission limits:

Fuel/Steam generating unit type	Nitrogen oxide emission limits ng/J (lb/million Btu) (expressed as NO_2) heat input
(1) Natural gas and distillate oil, except (4):	
(i) Low heat release rate	43 (0.10)
(ii) High heat release rate	86 (0.20)
(2) Residual oil:	
(i) Low heat release rate	130 (0.30)
(ii) High heat release rate	170 (0.40)
(3) Coal:	
(i) Mass-feed stoker	210 (0.50)
(ii) Spreader stoker and fluidized bed combustion	260 (0.60)
(iii) Pulverized coal	300 (0.70)
(iv) Lignite, except (v)	260 (0.60)
(v) Lignite mined in North Dakota, South Dakota, or Montana and combusted in a slag tap furnace	340 (0.80)
(vi) Coal-derived synthetic fuels	210 (0.50)
(4) Duct burner used in a combined cycle system:	
(i) Natural gas and distillate oil	86 (0.20)
(ii) Residual oil	170 (0.40)

(b) Except as provided under paragraphs (k) and (l) of this section, on and after the date on which the initial performance test is completed or is required to be completed under § 60.8 of this part, whichever date comes first, no owner or operator of an affected facility that simultaneously combusts mixtures of coal, oil, or natural gas shall cause to be discharged into the atmosphere from that affected facility any gases that contain nitrogen oxides in excess of a limit determined by the use of the following formula:

$$E_n=[(EL_{go}\ H_{go})+(EL_{ro}H_{ro})+(EL_c\ H_c)]/\ (H_{go}+H_{ro}+H_c)$$

where:

E_n is the nitrogen oxides emission limit (expressed as NO_2), ng/J (lb/million Btu)
EL_{go} is the appropriate emission limit from paragraph (a)(1) for combustion of natural gas or distillate oil, ng/J (lb/million Btu)
H_{go} is the heat input from combustion of natural gas or distillate oil,
EL_{ro} is the appropriate emission limit from paragraph (a)(2) for combustion of residual oil,
H_{ro} is the heat input from combustion of residual oil,
EL_c is the appropriate emission limit from paragraph (a)(3) for combustion of coal, and
H_c is the heat input from combustion of coal.

(c) Except as provided under paragraph (l) of this section, on and after the date on which the initial performance test is completed or is required to be completed under § 60.8 of this part, whichever date comes first, no owner or operator of an affected facility that simultaneously combusts coal or oil, or a mixture of these fuels with natural gas, and wood, municipal-type solid waste, or any other fuel shall cause to be discharged into the atmosphere any gases that contain nitrogen oxides in excess of the emission limit for the coal or oil, or mixtures of these fuels with natural gas combusted in the affected facility, as determined pursuant to paragraph (a) or (b) of this section, unless the affected facility has an annual capacity factor for coal or oil, or mixture of these fuels with natural gas of 10 percent (0.10) or less and is subject to a federally enforceable requirement that limits operation of the affected facility to an annual capacity factor of 10 percent (0.10) or less for coal, oil, or a mixture of these fuels with natural gas.

(d) On and after the date on which the initial performance test is completed or is required to be completed under § 60.8 of this part, whichever date comes first, no owner or operator of an affected facility that simultaneously combusts natural gas with wood, municipal-type solid waste, or other solid fuel, except coal, shall cause to be discharged into the atmosphere from that affected facility any gases that contain nitrogen oxides in excess of 130 ng/J (0.30 lb/million Btu) heat input unless the affected facility has an annual capacity factor for natural gas of 10 percent (0.10) or less and is subject to a federally enforceable requirement that limits operation of the affected facility to an annual capacity factor of 10 percent (0.10) or less for natural
gas.

(e) Except as provided under paragraph (l) of this section, on and after the date on which the initial performance test is completed or is required to be completed under § 60.8 of this part, whichever date comes first, no owner or operator of an affected facility that simultaneously combusts coal, oil, or natural gas with byproduct/waste shall cause to be discharged into the atmosphere any gases that contain nitrogen oxides in excess of the emission limit determined by the following formula unless the affected facility has an annual capacity factor for coal, oil, and natural gas of 10 percent (0.10) or less and is subject to a federally enforceable requirement that limits operation of the affected facility to an annual capacity factor of 10 percent
(0.10) or less:

$$E_n=[(EL_{go}\ H_{go})+(EL_{ro}H_{ro})+(EL_c\ H_c)]/\ (H_{go}+H_{ro}+H_c)$$

where:

E_n is the nitrogen oxides emission limit (expressed as NO_2), ng/J (lb/million Btu)
EL_{go} is the appropriate emission limit from paragraph (a)(1) for combustion of natural gas or distillate oil, ng/J (lb/million Btu).
H_{go} is the heat input from combustion of natural gas or distillate oil and gaseous byproduct/waste, ng/J (lb/million Btu.).
EL_{ro} is the appropriate emission limit from paragraph (a)(2) for combustion of residual oil, ng/J (lb/million Btu).
H_{ro} is the heat input from combustion of residual oil and/or liquid byproduct/waste.
EL_c is the appropriate emission limit from paragraph (a)(3) for combustion of coal, and
H_c is the heat input from combustion of coal.

(f) Any owner or operator of an affected facility that combusts byproduct/waste with either natural gas or oil may petition the Administrator within 180 days of the initial startup of the affected facility to establish a nitrogen oxides emission limit which shall apply specifically to that affected facility when the byproduct/waste is combusted. The petition shall include sufficient and appropriate data, as determined by the Administrator, such as nitrogen oxides emissions from the affected facility, waste composition (including nitrogen content), and combustion conditions to allow the Administrator to confirm that the affected facility is unable to comply with the emission limits in paragraph (e) of this section and to determine the appropriate
emission limit for the affected facility.

(1) Any owner or operator of an affected facility petitioning for a facility-specific nitrogen oxides emission limit under this section shall:

(i) Demonstrate compliance with the emission limits for natural gas and distillate oil in paragraph (a)(1) of this section or for residual oil in paragraph (a)(2) of this section, as appropriate, by conducting a 30-day performance test as provided in § 60.46b(e). During the performance test only natural gas, distillate oil, or residual oil shall be combusted in the affected facility; and

(ii) Demonstrate that the affected facility is unable to comply with the emission limits for natural gas and distillate oil in paragraph (a)(1) of this section or for residual oil in paragraph (a)(2) of this section, as appropriate, when gaseous or liquid byproduct/waste is combusted in the affected facility under the same conditions and using the same technological system of emission reduction applied when demonstrating compliance under paragraph (f)(1)(i) of this section.

(2) The nitrogen oxides emission limits for natural gas or distillate oil in paragraph (a)(1) of this section or for residual oil in paragraph (a)(2) of this section, as appropriate, shall be applicable to the affected facility until and unless the petition is approved by the Administrator. If the petition is approved by the Administrator, a facility-specific nitrogen oxides emission limit will be established at the nitrogen oxides emission level achievable when the affected facility is combusting oil or natural gas and byproduct/waste in a manner that the Administrator determines to be consistent with minimizing nitrogen oxides emissions.

(g) Any owner or operator of an affected facility that combusts hazardous waste (as defined by 40 CFR part 261 or 40 CFR part 761) with natural gas or oil may petition the Administrator within 180 days of the initial startup of the affected facility for a waiver from compliance with the nitrogen oxides emission limit which applies specifically to that affected facility. The petition must include sufficient and appropriate data, as determined by the Administrator, on nitrogen oxides emissions from the affected facility, waste destruction efficiencies, waste composition (including nitrogen content), the quantity of specific wastes to be combusted and combustion conditions to allow the Administrator to determine if the affected facility is able to comply
with the nitrogen oxides emission limits required by this section. The owner or operator of the affected facility shall demonstrate that when hazardous waste is combusted in the affected facility, thermal destruction efficiency requirements for hazardous waste specified in an applicable federally enforceable requirement preclude compliance with the nitrogen oxides emission limits of this section. The nitrogen oxides emission limits for natural gas or distillate oil in paragraph (a)(1) of this section or for residual oil in paragraph (a)(2) of this section, as appropriate, are applicable to the affected facility until and unless the petition is approved by the Administrator. (See 40 CFR 761.70 for regulations applicable to the incineration of materials containing
polychlorinated biphenyls (PCB's).)

(h) For purposes of paragraph (i) of this section, the nitrogen oxide standards under this section apply at all times including periods of startup, shutdown, or malfunction.

(i) Except as provided under paragraph (j) of this section, compliance with the emission limits under this section is determined on a 30-day rolling average basis.

(j) Compliance with the emission limits under this section is determined on a 24-hour average basis for the initial performance test and on a 3-hour average basis for subsequent performance tests for any affected facilities that:

(1) Combust, alone or in combination, only natural gas, distillate oil, or residual oil with a nitrogen content of 0.30 weight percent or less;

(2) Have a combined annual capacity factor of 10 percent or less for natural gas, distillate oil, and residual oil with a nitrogen content of 0.30 weight percent or less; and

(3) Are subject to a Federally enforceable requirement limiting operation of the affected facility to the firing of natural gas, distillate oil, and/or residual oil with a nitrogen content of 0.30 weight percent or less and limiting operation of the affected facility to a combined annual capacity factor of 10 percent or less for natural gas, distillate oil, and residual oil and a nitrogen content of 0.30 weight percent or less.

(k) Affected facilities that meet the criteria described in paragraphs (j) (1), (2), and (3) of this section, and that have a heat input capacity of 73 MW (250 million Btu/hour) or less, are not subject to the nitrogen oxides emission limits under this section.

(l) On and after the date on which the initial performance test is completed or is required to be completed under § 60.8 of this part, whichever date comes first, no owner or operator of an affected facility which commenced construction, modification, or reconstruction after July 9, 1997 shall cause to be discharged into the atmosphere from that affected facility any gases that contain nitrogen oxides (expressed as NO_2) in excess of the following limits:

(1) If the affected facility combusts coal, oil, or natural gas, or a mixture of these fuels, or with any other fuels: A limit of 86 ng/J (0.20 lb/million Btu) heat input unless the affected facility has an annual capacity factor for coal, oil, and natural gas of 10 percent (0.10) or less and is subject to a federally enforceable requirement that limits operation of the facility to an annual capacity factor of 10 percent (0.10) or less for coal, oil, and natural gas; or

(2) If the affected facility has a low heat release rate and combusts natural gas or distillate oil in excess of 30 percent of the heat input from the combustion of all fuels, a limit determined by use of the following formula:

$$E_n = [(0.10 * H_{go})+(0.20 * H_r)]/(H_{go}+H_r)$$

Where:

E_n is the NO_X emission limit, (lb/million Btu),
H_{go} is the heat input from combustion of natural gas or distillate oil, and
H_r is the heat input from combustion of any other fuel.

(3) After February 27, 2006, units may comply with an optional limit of 270 ng/J (2.1 lb/MWh) gross energy output, based on a 30-day rolling average. Units complying with this output-based limit must demonstrate compliance according to the procedures of Sec. 60.46a (i)(1), and must monitor emissions according to Sec. 60.47a(c)(1), (c)(2), (k), and (l).

§ 60.45b Compliance and performance test methods and procedures for sulfur dioxide.

(a) The sulfur dioxide emission standards under § 60.42b apply at all times.

(b) In conducting the performance tests required under § 60.8, the owner or operator shall use the methods and procedures in appendix A of this part or the methods and procedures as specified in this section, except as provided in § 60.8(b). Section 60.8(f) does not apply to this section. The 30-day notice required in § 60.8(d) applies only to the initial performance test unless otherwise specified by the Administrator.

(c) The owner or operator of an affected facility shall conduct performance tests to determine compliance with the percent of potential sulfur dioxide emission rate (% Ps) and the sulfur dioxide emission rate (Es) pursuant to Sec. 60.42b following the procedures listed below, except as provided under paragraph (d) and (k) of this section.

(1) The initial performance test shall be conducted over the first 30 consecutive operating days of the steam generating unit. Compliance with the sulfur dioxide standards shall be determined using a 30-day
average. The first operating day included in the initial performance test shall be scheduled within 30 days after achieving the maximum production rate at which the affected facility will be operated, but not later than 180 days after initial startup of the facility.

(2) If only coal or only oil is combusted, the following procedures are used:

(i) The procedures in Method 19 are used to determine the hourly sulfur dioxide emission rate (E_{ho}) and the 30-day average emission rate (E_{ao}). The hourly averages used to compute the 30-day averages are obtained from the continuous emission monitoring system of § 60.47b (a) or (b).

(ii) The percent of potential sulfur dioxide emission rate ($\%P_s$) emitted to the atmosphere is computed using the following formula:

$$\% P_s = 100\ (1-\% R_g/100)(1-\% R_f/100)$$

where:

$\% R_g$ is the sulfur dioxide removal efficiency of the control device as determined by Method 19, in percent.
$\% R_f$ is the sulfur dioxide removal efficiency of fuel pretreatment as determined by Method 19, in percent.

(3) If coal or oil is combusted with other fuels, the same procedures required in paragraph (c)(2) of this section are used, except as provided in the following:

(i) An adjusted hourly sulfur dioxide emission rate (E_{ho}^{o}) is used in Equation 19-19 of Method 19 to compute an adjusted 30-day average emission rate
(E_{ao}^{o}). The E_{ho} is computed using the following formula:

$$E_{ho}^{o} = [E_{ho}-E_w(1-X_k)]/X_k$$

where:

E_{ho}^{o} is the adjusted hourly sulfur dioxide emission rate, ng/J (lb/million Btu).
E_{ho} is the hourly sulfur dioxide emission rate, ng/J (lb/million Btu).
E_w is the sulfur dioxide concentration in fuels other than coal and oil combusted in the affected facility, as determined by the fuel sampling and analysis procedures in Method 19, ng/J (lb/million Btu). The

value E_w for each fuel lot is used for each hourly average during the time that the lot is being combusted.

X_k is the fraction of total heat input from fuel combustion derived from coal, oil, or coal and oil, as determined by applicable procedures in Method 19.

(ii) To compute the percent of potential sulfur dioxide emission rate (% P_s), an adjusted % R_g (% R_g) is computed from the adjusted $E_{ao}{}^o$ from paragraph (b)(3)(i) of this section and an adjusted average sulfur dioxide inlet rate (Eai^o) using the following formula:

$$\% Rg^o = 100 (1.0 - E_{ao}{}^o) / E_{ai}{}^o)$$

To compute $E_{ai}{}^o$, an adjusted hourly sulfur dioxide inlet rate ($E_{hi}{}^o$) is used. The $E_{hi}{}^o$ is computed using the following formula:

$$E_{hi}{}^o = [E_{hi} - E_w(1-X_k)]/X_k$$

where:

$E_{hi}{}^o$ is the adjusted hourly sulfur dioxide inlet rate, ng/J (lb/million Btu).
E_{hi} is the hourly sulfur dioxide inlet rate, ng/J (lb/million Btu).

(4) The owner or operator of an affected facility subject to paragraph (b)(3) of this section does not have to measure parameters E_w or X_k if the owner or operator elects to assume that $X_k = 1.0$. Owners or operators of affected facilities who assume $X_k = 1.0$ shall

(i) Determine % P_s following the procedures in paragraph (c)(2) of this section, and

(ii) Sulfur dioxide emissions (E_s) are considered to be in compliance with sulfur dioxide emission limits under § 60.42b.

(5) The owner or operator of an affected facility that qualifies under the provisions of § 60.42b(d) does not have to measure parameters E_w or X_k under paragraph (b)(3) of this section if the owner or operator of the affected facility elects to measure sulfur dioxide emission rates of the coal or oil following the
fuel sampling and analysis procedures under Method 19.

(d) Except as provided in paragraph (j), the owner or operator of an affected facility that combusts only very low sulfur oil, has an annual capacity factor for oil of 10 percent (0.10) or less, and is subject to a Federally enforceable requirement limiting operation of the affected facility to an annual capacity factor for oil of 10 percent (0.10) or less shall:

(1) Conduct the initial performance test over 24 consecutive steam generating unit operating hours at full load;

(2) Determine compliance with the standards after the initial performance test based on the arithmetic average of the hourly emissions data during each steam generating unit operating day if a continuous emission measurement system (CEMS) is used, or based on a daily average if Method 6B or fuel sampling and analysis procedures under Method 19 are used.

(e) The owner or operator of an affected facility subject to § 60.42b(d)(1) shall demonstrate the maximum design capacity of the steam generating unit by operating the facility at maximum capacity for 24 hours. This demonstration will be made during the initial performance test and a subsequent demonstration may be requested at any other time. If the 24-hour average firing rate for the affected facility is less than the

maximum design capacity provided by the manufacturer of the affected facility, the 24-hour average firing rate shall be used to determine the capacity utilization rate for the affected facility, otherwise the maximum design capacity provided by the manufacturer is used.

(f) For the initial performance test required under § 60.8, compliance with the sulfur dioxide emission limits and percent reduction requirements under § 60.42b is based on the average emission rates and the average percent reduction for sulfur dioxide for the first 30 consecutive steam generating unit operating days, except as provided under paragraph (d) of this section. The initial performance test is the only test for which at least 30 days prior notice is required unless otherwise specified by the Administrator. The initial performance test is to be scheduled so that the first steam generating unit operating day of the 30 successive steam generating unit operating days is completed within 30 days after achieving the maximum production rate at which the affected facility will be operated, but not later than 180 days after initial startup of the facility. The boiler load during the 30-day period does not have to be the maximum design load, but must be
representative of future operating conditions and include at least one 24-hour period at full load.

(g) After the initial performance test required under § 60.8, compliance with the sulfur dioxide emission limits and percent reduction requirements under § 60.42b is based on the average emission rates and the average percent reduction for sulfur dioxide for 30 successive steam generating unit operating days, except as provided under paragraph (d). A separate performance test is completed at the end of each steam generating unit operating day after the initial performance test, and a new 30-day average emission rate and percent reduction for sulfur dioxide are calculated to show compliance with the standard.

(h) Except as provided under paragraph (i) of this section, the owner or operator of an affected facility shall use all valid sulfur dioxide emissions data in calculating % P_s and E_{ho} under paragraph (c), of this section whether or not the minimum emissions data requirements under § 60.46b are achieved. All valid emissions data, including valid sulfur dioxides emission data collected during periods of startup, shutdown and malfunction, shall be used in calculating % P_s and E_{ho} pursuant to paragraph (c)of this section.

(i) During periods of malfunction or maintenance of the sulfur dioxide control systems when oil is combusted as provided under § 60.42b(i), emission data are not used to calculate % P_s or E_s under § 60.42b (a), (b) or (c), however, the emissions data are used to determine compliance with the emission limit under § 60.42b(i).

(j) The owner or operator of an affected facility that combusts very low sulfur oil is not subject to the compliance and performance testing requirements of this section if the owner or operator obtains fuel receipts as described in § 60.49b(r).

(k) Units that burn only oil that contains no more than 0.3 weight percent sulfur or fuels with potential sulfur dioxide emission rates of 140 ng/J (0.32 lb/MMBtu) heat input or less may demonstrate compliance by maintaining records of fuel supplier certifications of sulfur content of the fuels burned.

§ 60.46b Compliance and performance test methods and procedures for particulate matter and nitrogen oxides.

(a) The particulate matter emission standards and opacity limits under Sec. 60.43b apply at all times except during periods of startup, shutdown, or malfunction, and as specified in paragraphs (i) and (j) of this section. The nitrogen oxides emission standards under Sec. 60.44b apply at all times.

(b) Compliance with the particulate matter emission standards under Sec. 60.43b shall be determined through performance testing as described in paragraph (d) of this section, except as provided in paragraph (i) and (j).

(c) Compliance with the nitrogen oxides emission standards under § 60.44b shall be determined through performance testing under paragraph (e) or (f), or under paragraphs (g) and (h) of this section, as applicable.

(d) To determine compliance with the particulate matter emission limits and opacity limits under § 60.43b, the owner or operator of any affected facility shall conduct an initial performance test as required under § 60.8 using the following procedures and reference methods

(1) Method 3B is used for gas analysis when applying Method 5 or Method 17.

(2) Method 5, Method 5B, or Method 17 shall be used to measure the concentration of particulate matter as follows:

(i) Method 5 shall be used at affected facilities without wet flue gas desulfurization (FGD) systems; and

(ii) Method 17 may be used at facilities with or without wet scrubber systems provided the stack gas temperature does not exceed a temperature of 160 ºC (320 ºF). The procedures of sections 2.1 and 2.3 of Method 5B may be used in Method 17 only if it is used after a wet FGD system. Do not use Method 17 after wet FGD systems if the effluent is saturated or laden with water droplets.

(iii) Method 5B is to be used only after wet FGD systems.

(3) Method 1 is used to select the sampling site and the number of traverse sampling points. The sampling time for each run is at least 120 minutes and the minimum sampling volume is 1.7 dscm (60 dscf) except that smaller sampling times or volumes may be approved by the Administrator when necessitated by process variables or other factors.

(4) For Method 5, the temperature of the sample gas in the probe and filter holder is monitored and is maintained at 160±14 °C (320±25 °F).

(5) For determination of particulate matter emissions, the oxygen or carbon dioxide sample is obtained simultaneously with each run of Method 5, Method 5B or Method 17 by traversing the duct at the same sampling location.

(6) For each run using Method 5, Method 5B or Method 17, the emission rate expressed in nanograms per joule heat input is determined using:

(i) The oxygen or carbon dioxide measurements and particulate matter measurements obtained under this section,

(ii) The dry basis F factor, and

(iii) The dry basis emission rate calculation procedure contained in Method 19.

(7) Method 9 is used for determining the opacity of stack emissions.

(e) To determine compliance with the emission limits for nitrogen oxides required under § 60.44b, the owner or operator of an affected facility shall conduct the performance test as required under § 60.8 using the continuous system for monitoring nitrogen oxides under § 60.48(b).

(1) For the initial compliance test, nitrogen oxides from the steam generating unit are monitored for 30 successive steam generating unit operating days and the 30-day average emission rate is used to determine

compliance with the nitrogen oxides emission standards under § 60.44b. The 30-day average emission rate is calculated as the average of all hourly emissions data recorded by the monitoring system during the 30-day test period.

(2) Following the date on which the initial performance test is completed or is required to be completed under § 60.8 of this part, whichever date comes first, the owner or operator of an affected facility which combusts coal or which combusts residual oil having a nitrogen content greater than 0.30 weight percent shall determine compliance with the nitrogen oxides emission standards under § 60.44b on a continuous basis through the use of a 30-day rolling average emission rate. A new 30-day rolling average emission rate is calculated each steam generating unit operating day as the average of all of the hourly nitrogen oxides emission data for the preceding 30 steam generating unit operating days.

(3) Following the date on which the initial performance test is completed or is required to be completed under § 60.8 of this part, whichever date comes first, the owner or operator of an affected facility which has a heat input capacity greater than 73 MW (250 million Btu/hour) and which combusts natural gas, distillate oil, or residual oil having a nitrogen content of 0.30 weight percent or less shall determine compliance with the nitrogen oxides standards under § 60.44b on a continuous basis through the use of a 30-day rolling average emission rate. A new 30-day rolling average emission rate is calculated each steam generating unit operating day as the average of all of the hourly nitrogen oxides emission data for the preceding 30 steam generating unit operating days.

(4) Following the date on which the initial performance test is completed or required to be completed under § 60.8 of this part, whichever date comes first, the owner or operator of an affected facility which has a heat input capacity of 73 MW (250 million Btu/hour) or less and which combusts natural gas, distillate oil, or residual oil having a nitrogen content of 0.30 weight percent or less shall upon request determine compliance with the nitrogen oxides standards under § 60.44b through the use of a 30-day performance test. During periods when performance tests are not requested, nitrogen oxides emissions data collected pursuant to § 60.48b(g)(1) or § 60.48b(g)(2) are used to calculate a 30-day rolling average emission rate on a daily basis and used to prepare excess emission reports, but will not be used to determine compliance with the nitrogen oxides emission standards. A new 30-day rolling average emission rate is calculated each steam generating unit operating day as the average of all of the hourly nitrogen oxides emission data for the preceding 30 steam generating unit operating days.

(5) If the owner or operator of an affected facility which combusts residual oil does not sample and analyze the residual oil for nitrogen content, as specified in § 60.49b(e), the requirements of paragraph
(iii) of this section apply and the provisions of paragraph (iv) of this section are inapplicable.

(f) To determine compliance with the emission limit for NO_x required by § 60.44b(a)(4) or § 60.44b(l) for duct burners used in combined cycle systems, either of the procedures described in paragraph (f)(1) or (2) of this section may be used:

(1) The owner or operator of an affected facility shall conduct the performance test required under § 60.8 as follows:

(i) The emissions rate (E) of NOX shall be computed using Equation of 1 this section:

$$E = Esg + (Hg / Hb)(Esg - Eg) \qquad \text{(Eq. 1)}$$

Where:

E = emissions rate of NOX from the duct burner, ng/J (lb/million Btu) heat input

Esg = combined effluent emissions rate, in ng/J (lb/million Btu) heat input using appropriate F-Factor as described in Method 19

Hg = heat input rate to the combustion turbine, in Joules/hour (million Btu/hour)

Hb = heat input rate to the duct burner, in Joules/hour (million Btu/hour)
Eg = emissions rate from the combustion turbine, in ng/J (lb/million Btu) heat input calculated using appropriate F-Factor as described in Method 19

(ii) Method 7E of appendix A of this part shall be used to determine the NOX concentrations. Method 3A or 3B of appendix A of this part shall be used to determine oxygen concentration.

(iii) The owner or operator shall identify and demonstrate to the Administrator's satisfaction suitable methods to determine the average hourly heat input rate to the combustion turbine and the average hourly heat input rate to the affected duct burner.

(iv) Compliance with the emissions limits under Sec. 60.44b (a)(4) or Sec. 60.44b(l) is determined by the three-run average (nominal 1-hour runs) for the initial and subsequent performance tests; or

(2) The owner or operator of an affected facility may elect to determine compliance on a 30-day rolling average basis by using the continuous emission monitoring system specified under Sec. 60.48b for measuring NO_X and oxygen and meet the requirements of Sec. 60.48b. The sampling site shall be located at the outlet from the steam generating unit. The NO_X emissions rate at the outlet from the steam generating unit shall constitute the NO_X emissions rate from the duct burner of the combined cycle system.

(g) The owner or operator of an affected facility described in § 60.44b(j) or § 60.44b(k) shall demonstrate the maximum heat input capacity of the steam generating unit by operating the facility at maximum capacity for 24 hours. The owner or operator of an affected facility shall determine the maximum heat input capacity using the heat loss method described in sections 5 and 7.3 of the ASME Power Test Codes 4.1 (see IBR § 60.17(h)). This demonstration of maximum heat input capacity shall be made during the initial performance test for affected facilities that meet the criteria of § 60.44b(j). It shall be made within 60 days after achieving the maximum production rate at which the affected facility will be operated, but not later than 180 days after initial start-up of each facility, for affected facilities meeting the criteria of § 60.44b(k). Subsequent demonstrations may be required by the Administrator at any other time. If this demonstration indicates that the maximum heat input capacity of the affected facility is less than that stated by the manufacturer of the affected facility, the maximum heat input capacity determined during this demonstration shall be used to determine the capacity utilization rate for the affected facility. Otherwise, the maximum heat input capacity provided by the manufacturer is used.

(h) The owner or operator of an affected facility described in § 60.44b(j) that has a heat input capacity greater than 73 MW (250 million Btu/hour) shall:

(1) Conduct an initial performance test as required under § 60.8 over a minimum of 24 consecutive steam generating unit operating hours at maximum heat input capacity to demonstrate compliance with the nitrogen oxides emission standards under § 60.44b using Method 7, 7A, 7E, or other approved reference methods; and

(2) Conduct subsequent performance tests once per calendar year or every 400 hours of operation (whichever comes first) to demonstrate compliance with the nitrogen oxides emission standards under § 60.44b over a minimum of 3 consecutive steam generating unit operating hours at maximum heat input capacity using Method 7, 7A, 7E, or other approved reference methods.

(i) Units burning only oil that contains no more than 0.3 weight percent sulfur or liquid or gaseous fuels with a potential sulfur dioxide emission rates of 140 ng/J (0.32 lb/MMBtu) heat input or less may

demonstrate compliance by maintaining fuel supplier certifications of the sulfur content of the fuels burned.

(j) In place of particulate matter testing with EPA Reference Method 5, 5B, or 17, an owner or operator may elect to install, calibrate, maintain, and operate a continuous emission monitoring system for monitoring particulate matter emissions discharged to the atmosphere and record the output of the system. The owner or operator of an affected facility who elects to continuously monitor particulate matter emissions instead of conducting performance testing using EPA Method 5, 5B, or 17 shall comply with the requirements specified in paragraphs (j)(1) through (j)(13) of this section.

(1) Notify the Administrator one month before starting use of the system.

(2) Notify the Administrator one month before stopping use of the system.

(3) The monitor shall be installed, evaluated, and operated in accordance with Sec. 60.13 of subpart A of this part.

(4) The initial performance evaluation shall be completed no later than 180 days after the date of initial startup of the affected facility, as specified under Sec. 60.8 of subpart A of this part or within 180 days of notification to the Administrator of use of the continuous monitoring system if the owner or operator was previously determining compliance by Method 5, 5B, or 17 performance tests, whichever is later.

(5) The owner or operator of an affected facility shall conduct an initial performance test for particulate matter emissions as required under Sec. 60.8 of subpart A of this part. Compliance with the particulate matter emission limit shall be determined by using the continuous emission monitoring system specified in paragraph (j) of this section to measure particulate matter and calculating a 24-hour block arithmetic average emission concentration using EPA Reference Method 19, section 4.1.

(6) Compliance with the particulate matter emission limit shall be determined based on the 24-hour daily (block) average of the hourly arithmetic average emission concentrations using continuous emission monitoring system outlet data.

(7) At a minimum, valid continuous monitoring system hourly averages shall be obtained as specified in paragraphs (j)(7)(i) of this section for 75 percent of the total operating hours per 30-day rolling average.

(i) At least two data points per hour shall be used to calculate each 1-hour arithmetic average.

(8) The 1-hour arithmetic averages required under paragraph (j)(7) of this section shall be expressed in ng/J or lb/MMBtu heat input and shall be used to calculate the boiler operating day daily arithmetic average emission concentrations. The 1-hour arithmetic averages shall be calculated using the data points required under Sec. 60.13(e)(2) of subpart A of this part.

(9) All valid continuous emission monitoring system data shall be used in calculating average emission concentrations even if the minimum continuous emission monitoring system data requirements of paragraph (j)(7) of this section are not met.

(10) The continuous emission monitoring system shall be operated according to Performance Specification 11 in appendix B of this part.

(11) During the correlation testing runs of the continuous emission monitoring system required by Performance Specification 11 in appendix B of this part, particulate matter and oxygen (or carbon dioxide) data shall be collected concurrently (or within a 30- to 60-minute period) by both the continuous emission monitors and the test methods specified in paragraphs (j)(7)(i) of this section.

(i) For particulate matter, EPA Reference Method 5, 5B, or 17 shall be used.

(ii) For oxygen (or carbon dioxide), EPA reference Method 3, 3A, or 3B, as applicable shall be used.

(12) Quarterly accuracy determinations and daily calibration drift tests shall be performed in accordance with procedure 2 in appendix F of this part. Relative Response Audit's must be performed annually and Response Correlation Audits must be performed every 3 years.

(13) When particulate matter emissions data are not obtained because of continuous emission monitoring system breakdowns, repairs, calibration checks, and zero and span adjustments, emissions data shall be obtained by using other monitoring systems as approved by the Administrator or EPA Reference Method 19 to provide, as necessary, valid emissions data for a minimum of 75 percent of total operating hours per 30-day rolling average.

§ 60.47b Emission monitoring for sulfur dioxide.

(a) Except as provided in paragraphs (b),(f), and (g) of this section, the owner or operator of an affected facility subject to the sulfur dioxide standards under Sec. 60.42b shall install, calibrate, maintain, and operate continuous emission monitoring systems (CEMS) for measuring sulfur dioxide concentrations and either oxygen (O2) or carbon dioxide (CO2) concentrations and shall record the output of the systems. The sulfur dioxide and either oxygen or carbon dioxide concentrations shall both be monitored at the inlet and outlet of the sulfur dioxide control device.

(b) As an alternative to operating CEMS as required under paragraph (a) of this section, an owner or operator may elect to determine the average sulfur dioxide emissions and percent reduction by:

(1) Collecting coal or oil samples in an as-fired condition at the inlet to the steam generating unit and analyzing them for sulfur and heat content according to Method 19. Method 19 provides procedures for converting these measurements into the format to be used in calculating the average sulfur dioxide input rate, or

(2) Measuring sulfur dioxide according to Method 6B at the inlet or outlet to the sulfur dioxide control system. An initial stratification test is required to verify the adequacy of the Method 6B sampling location. The stratification test shall consist of three paired runs of a suitable sulfur dioxide and carbon dioxide measurement train operated at the candidate location and a second similar train operated according
to the procedures in section 3.2 and the applicable procedures in section 7 of Performance Specification 2. Method 6B, Method 6A, or a combination of Methods 6 and 3 or 3B or Methods 6C and 3A are suitable measurement techniques. If Method 6B is used for the second train, sampling time and timer operation may be adjusted for the stratification test as long as an adequate sample volume is collected; however, both
sampling trains are to be operated similarly. For the location to be adequate for Method 6B 24-hour tests, the mean of the absolute difference between the three paired runs must be less than 10 percent.

(3) A daily sulfur dioxide emission rate, E_D, shall be determined using the procedure described in Method 6A, section 7.6.2 (Equation 6A-8) and stated in ng/J (lb/million Btu) heat input.

(4) The mean 30-day emission rate is calculated using the daily measured values in ng/J (lb/million Btu) for 30 successive steam generating unit operating days using equation 19-20 of Method 19.

(c) The owner or operator of an affected facility shall obtain emission data for at least 75 percent of the operating hours in at least 22 out of 30 successive boiler operating days. If this minimum data requirement is not met with a single monitoring system, the owner or operator of the affected facility shall supplement the emission data with data collected with other monitoring systems as approved by the Administrator or the reference methods and procedures as described in paragraph (b) of this section.

(d) The 1-hour average sulfur dioxide emission rates measured by the CEMS required by paragraph (a) of this section and required under Sec. 60.13(h) is expressed in ng/J or lb/MMBtu heat input and is used to calculate the average emission rates under Sec. 60.42(b). Each 1-hour average sulfur dioxide emission rate must be based on 30 or more minutes of steam generating unit operation. The hourly averages shall be calculated according to Sec. 60.13(h)(2). Hourly sulfur dioxide emission rates are not calculated if the affected facility is operated less than 30 minutes in a given clock hour and are not counted toward determination of a steam generating unit operating day.

(e) The procedures under § 60.13 shall be followed for installation, evaluation, and operation of the CEMS.

(1) All CEMS shall be operated in accordance with the applicable procedures under Performance Specifications 1, 2, and 3 (appendix B).

(2) Quarterly accuracy determinations and daily calibration drift tests shall be performed in accordance with Procedure 1 (appendix F).

(3) For affected facilities combusting coal or oil, alone or in combination with other fuels, the span value of the sulfur dioxide CEMS at the inlet to the sulfur dioxide control device is 125 percent of the maximum estimated hourly potential sulfur dioxide emissions of the fuel combusted, and the span value of the CEMS at the outlet to the sulfur dioxide control device is 50 percent of the maximum estimated hourly potential sulfur dioxide emissions of the fuel combusted.

(f) The owner or operator of an affected facility that combusts very low sulfur oil is not subject to the emission monitoring requirements of this section if the owner or operator obtains fuel receipts as described
in § 60.49b(r).

(g) Units burning any fuel with a potential sulfur dioxide emission rate of 140 ng/J (0.32 lb/MMBtu) heat input or less are not required to conduct emissions monitoring if they maintain fuel supplier certifications of the sulfur content of the fuels burned.

§ 60.48b Emission monitoring for particulate matter and nitrogen oxides.

(a) The owner or operator of an affected facility subject to the opacity standard under Sec. 60.43b shall install, calibrate, maintain, and operate a continuous monitoring system for measuring the opacity of emissions discharged to the atmosphere and record the output of the system, except as provided in paragraphs (j) and (k) of this section.

(b) Except as provided under paragraphs (g), (h), and (i) of this section, the owner or operator of an affected facility subject to a nitrogen oxides standard under Sec. 60.44b shall comply with either paragraphs (b)(1) or (b)(2) of this section.

(1) Install, calibrate, maintain, and operate a continuous monitoring system, and record the output of the system, for measuring nitrogen oxides emissions discharged to the atmosphere; or

(2) If the owner or operator has installed a nitrogen oxides emission rate continuous emission monitoring system (CEMS) to meet the requirements of part 75 of this chapter and is continuing to meet the ongoing requirements of part 75 of this chapter, that CEMS may be used to meet the requirements of this section, except that the owner or operator shall also meet the requirements of § 60.49b. Data reported to meet the requirements of § 60.49b shall not include data substituted using the missing data procedures

in subpart D of part 75 of this chapter, nor shall the data have been bias adjusted according to the procedures of part 75 of this chapter.

(c) The continuous monitoring systems required under paragraph (b) of this section shall be operated and data recorded during all periods of operation of the affected facility except for continuous monitoring system breakdowns and repairs. Data is recorded during calibration checks, and zero and span adjustments.

(d) The 1-hour average nitrogen oxides emission rates measured by the continuous nitrogen oxides monitor required by paragraph (b) of this section and required under Sec. 60.13(h) shall be expressed in ng/J or lb/MMBtu heat input and shall be used to calculate the average emission rates under Sec. 60.44b. The 1-hour averages shall be calculated using the data points required under Sec. 60.13(h)(2).

(e) The procedures under § 60.13 shall be followed for installation, evaluation, and operation of the continuous monitoring systems.

(1) For affected facilities combusting coal, wood or municipal-type solid waste, the span value for a continuous monitoring system for measuring opacity shall be between 60 and 80 percent.

(2) For affected facilities combusting coal, oil, or natural gas, the span value for nitrogen oxides is determined as follows:

Fuel	Span values for nitrogen oxides (PPM)
Natural gas.....	500
Oil.....	500
Coal.....	1,000
Mixtures.....	500(x+y)+1,000z

where:
x is the fraction of total heat input derived from natural gas,
y is the fraction of total heat input derived from oil, and
z is the fraction of total heat input derived from coal.

(3) All span values computed under paragraph (e)(2) of this section for combusting mixtures of regulated fuels are rounded to the nearest 500 ppm.

(f) When nitrogen oxides emission data are not obtained because of continuous monitoring system breakdowns, repairs, calibration checks and zero and span adjustments, emission data will be obtained by using standby monitoring systems, Method 7, Method 7A, or other approved reference methods to provide emission data for a minimum of 75 percent of the operating hours in each steam generating unit operating day, in at least 22 out of 30 successive steam generating unit operating days.

(g) The owner or operator of an affected facility that has a heat input capacity of 73 MW (250 million Btu/hour) or less, and which has an annual capacity factor for residual oil having a nitrogen content of

0.30 weight percent or less, natural gas, distillate oil, or any mixture of these fuels, greater than 10 percent (0.10) shall:

(1) Comply with the provisions of paragraphs (b), (c), (d), (e)(2), (e)(3), and (f) of this section, or

(2) Monitor steam generating unit operating conditions and predict nitrogen oxides emission rates as specified in a plan submitted pursuant to § 60.49b(c).

(h) The owner or operator of a duct burner, as described in § 60.41b, which is subject to the NO_x standards of § 60.44b(a)(4) or § 60.44b(l) is not required to install or operate a continuous emissions monitoring system to measure NO_x emissions.

(i) The owner or operator of an affected facility described in § 60.44b(j) or § 60.44b(k) is not required to install or operate a continuous monitoring system for measuring nitrogen oxides emissions.

(j) Units that burn only oil that contains no more than 0.3 weight percent sulfur or liquid or gaseous fuels with potential sulfur dioxide emission rates of 140 ng/J (0.32 lb/MMBtu) heat input or less are not required to conduct PM emissions monitoring if they maintain fuel supplier certifications of the sulfur content of the fuels burned.

(k) Owners or operators complying with the PM emission limit by using a PM CEMs monitor instead of monitoring opacity must calibrate, maintain, and operate a continuous monitoring system, and record the output of the system, for PM emissions discharged to the atmosphere as specified in Sec. 60.46b(j). The continuous monitoring systems specified in paragraph Sec. 60.46b(j) shall be operated and data recorded during all periods of operation of the affected facility except for continuous monitoring system breakdowns and repairs. Data is recorded during calibration checks, and zero and span adjustments.

§ 60.49b Reporting and recordkeeping requirements.

(a) The owner or operator of each affected facility shall submit notification of the date of initial startup, as provided by § 60.7. This notification shall include:

(1) The design heat input capacity of the affected facility and identification of the fuels to be combusted in the affected facility,

(2) If applicable, a copy of any Federally enforceable requirement that limits the annual capacity factor for any fuel or mixture of fuels under §§ 60.42b(d)(1), 60.43b(a)(2), (a)(3)(iii), (c)(2)(ii), (d)(2)(iii), 60.44b(c), (d), (e), (i), (j), (k), 60.45b(d), (g), 60.46b(h), or 60.48b(i),

(3) The annual capacity factor at which the owner or operator anticipates operating the facility based on all fuels fired and based on each individual fuel fired, and,

(4) Notification that an emerging technology will be used for controlling emissions of sulfur dioxide. The Administrator will examine the description of the emerging technology and will determine whether the technology qualifies as an emerging technology. In making this determination, the Administrator may require the owner or operator of the affected facility to submit additional information concerning the control device. The affected facility is subject to the provisions of § 60.42b(a) unless and until this determination is made by the Administrator.

(b) The owner or operator of each affected facility subject to the sulfur dioxide, particulate matter, and/or nitrogen oxides emission limits under §§ 60.42b, 60.43b, and 60.44b shall submit to the Administrator the performance test data from the initial performance test and the performance evaluation of the CEMS using the applicable performance specifications in appendix B. The owner or operator of each affected

facility described in § 60.44b(j) or § 60.44b(k) shall submit to the Administrator the maximum heat input capacity data from the demonstration of the maximum heat input capacity of the affected facility.

(c) The owner or operator of each affected facility subject to the nitrogen oxides standard of § 60.44b who seeks to demonstrate compliance with those standards through the monitoring of steam generating unit operating conditions under the provisions of § 60.48b(g)(2) shall submit to the Administrator for approval a plan that identifies the operating conditions to be monitored under § 60.48b(g)(2) and the records to be maintained under § 60.49b(j). This plan shall be submitted to the Administrator for approval within 360 days of the initial startup of the affected facility. The plan shall:

(1) Identify the specific operating conditions to be monitored and the relationship between these operating conditions and nitrogen oxides emission rates (i.e., ng/J or lbs/million Btu heat input). Steam generating unit operating conditions include, but are not limited to, the degree of staged combustion (i.e., the ratio of primary air to secondary and/or tertiary air) and the level of excess air (i.e., flue gas oxygen level);

(2) Include the data and information that the owner or operator used to identify the relationship between nitrogen oxides emission rates and these operating conditions;

(3) Identify how these operating conditions, including steam generating unit load, will be monitored under § 60.48b(g) on an hourly basis by the owner or operator during the period of operation of the affected facility; the quality assurance procedures or practices that will be employed to ensure that the data generated by monitoring these operating conditions will be representative and accurate; and the type and format of the records of these operating conditions, including steam generating unit load, that will be maintained by the owner or operator under § 60.49b(j). If the plan is approved, the owner or operator shall maintain records of predicted nitrogen oxide emission rates and the monitored operating conditions, including steam generating unit load, identified in the plan.

(d) The owner or operator of an affected facility shall record and maintain records of the amounts of each fuel combusted during each day and calculate the annual capacity factor individually for coal, distillate oil, residual oil, natural gas, wood, and municipal-type solid waste for the recording period. The annual capacity factor is determined on a 12-month rolling average basis with a new annual capacity factor calculated at the end of each calendar month.

(e) For an affected facility that combusts residual oil and meets the criteria under §§ 60.46b(e)(4), 60.44b(j), or (k), the owner or operator shall maintain records of the nitrogen content of the residual oil combusted in the affected facility and calculate the average fuel nitrogen content for the reporting period. The nitrogen content shall be determined using ASTM Method D3431-80, Test Method for Trace Nitrogen in Liquid Petroleum Hydrocarbons (IBR-see § 60.17), or fuel suppliers. If residual oil blends are being combusted, fuel nitrogen specifications may be prorated based on the ratio of residual oils of different nitrogen content in the fuel blend.

(f) For facilities subject to the opacity standard under § 60.43b, the owner or operator shall maintain records of opacity.

(g) Except as provided under paragraph (p) of this section, the owner or operator of an affected facility subject to the nitrogen oxides standards under § 60.44b shall maintain records of the following information for each steam generating unit operating day:

(1) Calendar date.

(2) The average hourly nitrogen oxides emission rates (expressed as NO<INF>2</INF>) (ng/J or lb/million Btu heat input) measured or predicted.

(3) The 30-day average nitrogen oxides emission rates (ng/J or lb/million Btu heat input) calculated at the end of each steam generating unit operating day from the measured or predicted hourly nitrogen oxide
emission rates for the preceding 30 steam generating unit operating days.

(4) Identification of the steam generating unit operating days when the calculated 30-day average nitrogen oxides emission rates are in excess of the nitrogen oxides emissions standards under § 60.44b, with the reasons for such excess emissions as well as a description of corrective actions taken.

(5) Identification of the steam generating unit operating days for which pollutant data have not been obtained, including reasons for not obtaining sufficient data and a description of corrective actions taken.

(6) Identification of the times when emission data have been excluded from the calculation of average emission rates and the reasons for excluding data.

(7) Identification of ``F'' factor used for calculations, method of determination, and type of fuel combusted.

(8) Identification of the times when the pollutant concentration exceeded full span of the continuous monitoring system.

(9) Description of any modifications to the continuous monitoring system that could affect the ability of the continuous monitoring system to comply with Performance Specification 2 or 3.

(10) Results of daily CEMS drift tests and quarterly accuracy assessments as required under appendix F, Procedure 1.

(h) The owner or operator of any affected facility in any category listed in paragraphs (h)(1) or (2) of this section is required to submit excess emission reports for any excess emissions which occurred during the reporting period.

(1) Any affected facility subject to the opacity standards under § 60.43b(e) or to the operating parameter monitoring requirements under § 60.13(i)(1).

(2) Any affected facility that is subject to the nitrogen oxides standard of § 60.44b, and that

(i) Combusts natural gas, distillate oil, or residual oil with a nitrogen content of 0.3 weight percent or less, or

(ii) Has a heat input capacity of 73 MW (250 million Btu/hour) or less and is required to monitor nitrogen oxides emissions on a continuous basis under § 60.48b(g)(1) or steam generating unit operating conditions under § 60.48b(g)(2).

(3) For the purpose of § 60.43b, excess emissions are defined as all 6-minute periods during which the average opacity exceeds the opacity standards under § 60.43b(f).

(4) For purposes of § 60.48b(g)(1), excess emissions are defined as any calculated 30-day rolling average nitrogen oxides emission rate, as determined under § 60.46b(e), which exceeds the applicable emission limits in § 60.44b.

(i) The owner or operator of any affected facility subject to the continuous monitoring requirements for nitrogen oxides under § 60.48(b) shall submit reports containing the information recorded under paragraph (g) of this section.

(j) The owner or operator of any affected facility subject to the sulfur dioxide standards under § 60.42b shall submit reports.

(k) For each affected facility subject to the compliance and performance testing requirements of § 60.45b and the reporting requirement in paragraph (j) of this section, the following information shall be reported to the Administrator:

(1) Calendar dates covered in the reporting period.

(2) Each 30-day average sulfur dioxide emission rate (ng/J or lb/million Btu heat input) measured during the reporting period, ending with the last 30-day period; reasons for noncompliance with the emission standards; and a description of corrective actions taken.

(3) Each 30-day average percent reduction in sulfur dioxide emissions calculated during the reporting period, ending with the last 30-day period; reasons for noncompliance with the emission standards; and a description of corrective actions taken.

(4) Identification of the steam generating unit operating days that coal or oil was combusted and for which sulfur dioxide or diluent (oxygen or carbon dioxide) data have not been obtained by an approved method for at least 75 percent of the operating hours in the steam generating unit operating day; justification for not obtaining sufficient data; and description of corrective action taken.

(5) Identification of the times when emissions data have been excluded from the calculation of average emission rates; justification for excluding data; and description of corrective action taken if data have been excluded for periods other than those during which coal or oil were not combusted in the steam generating unit.

(6) Identification of ``F'' factor used for calculations, method of determination, and type of fuel combusted.

(7) Identification of times when hourly averages have been obtained based on manual sampling methods.

(8) Identification of the times when the pollutant concentration exceeded full span of the CEMS.

(9) Description of any modifications to the CEMS that could affect the ability of the CEMS to comply with Performance Specification 2 or 3.

(10) Results of daily CEMS drift tests and quarterly accuracy assessments as required under appendix F, Procedure 1.

(11) The annual capacity factor of each fired as provided under paragraph (d) of this section.

(l) For each affected facility subject to the compliance and performance testing requirements of § 60.45b(d) and the reporting requirements of paragraph (j) of this section, the following information shall be reported to the Administrator:

(1) Calendar dates when the facility was in operation during the reporting period;

(2) The 24-hour average sulfur dioxide emission rate measured for each steam generating unit operating day during the reporting period that coal or oil was combusted, ending in the last 24-hour period in the quarter; reasons for noncompliance with the emission standards; and a description of corrective actions taken;

(3) Identification of the steam generating unit operating days that coal or oil was combusted for which sulfur dioxide or diluent (oxygen or carbon dioxide) data have not been obtained by an approved method for at least 75 percent of the operating hours; justification for not obtaining sufficient data; and description of corrective action taken.

(4) Identification of the times when emissions data have been excluded from the calculation of average emission rates; justification for excluding data; and description of corrective action taken if data have been excluded for periods other than those during which coal or oil were not combusted in the steam generating unit.

(5) Identification of ``F'' factor used for calculations, method of determination, and type of fuel combusted.

(6) Identification of times when hourly averages have been obtained based on manual sampling methods.

(7) Identification of the times when the pollutant concentration exceeded full span of the CEMS.

(8) Description of any modifications to the CEMS which could affect the ability of the CEMS to comply with Performance Specification 2 or 3.

(9) Results of daily CEMS drift tests and quarterly accuracy assessments as required under appendix F, Procedure 1.

(m) For each affected facility subject to the sulfur dioxide standards under § 60.42b for which the minimum amount of data required under § 60.47b(f) were not obtained during the reporting period, the following information is reported to the Administrator in addition to that required under paragraph (k) of this section:

(1) The number of hourly averages available for outlet emission rates and inlet emission rates.

(2) The standard deviation of hourly averages for outlet emission rates and inlet emission rates, as determined in Method 19, section 7.

(3) The lower confidence limit for the mean outlet emission rate and the upper confidence limit for the mean inlet emission rate, as calculated in Method 19, section 7.

(4) The ratio of the lower confidence limit for the mean outlet emission rate and the allowable emission rate, as determined in Method 19, section 7.

(n) If a percent removal efficiency by fuel pretreatment (i.e., $\%R_f$) is used to determine the overall percent reduction (i.e., $\% R_o$) under § 60.45b, the owner or operator of the affected facility shall submit a signed statement with the report:

(1) Indicating what removal efficiency by fuel pretreatment (i.e., $\% R_f$) was credited during the reporting period;

(2) Listing the quantity, heat content, and date each pretreated fuel shipment was received during the previous calendar quarter; the name and location of the fuel pretreatment facility; and the total quantity and total heat content of all fuels received at the affected facility during the reporting period;

(3) Documenting the transport of the fuel from the fuel pretreatment facility to the steam generating unit.

(4) Including a signed statement from the owner or operator of the fuel pretreatment facility certifying that the percent removal efficiency achieved by fuel pretreatment was determined in accordance with the provisions of Method 19 (appendix A) and listing the heat content and sulfur content of each fuel before and after fuel pretreatment.

(o) All records required under this section shall be maintained by the owner or operator of the affected facility for a period of 2 years following the date of such record.

(p) The owner or operator of an affected facility described in § 60.44b(j) or (k) shall maintain records of the following information for each steam generating unit operating day:

(1) Calendar date,

(2) The number of hours of operation, and

(3) A record of the hourly steam load.

(q) The owner or operator of an affected facility described in § 60.44b(j) or § 60.44b(k) shall submit to the Administrator a report containing:

(1) The annual capacity factor over the previous 12 months;

(2) The average fuel nitrogen content during the reporting period, if residual oil was fired; and

(3) If the affected facility meets the criteria described in § 60.44b(j), the results of any nitrogen oxides emission tests required during the reporting period, the hours of operation during the reporting period, and the hours of operation since the last nitrogen oxides emission test.

(r) The owner or operator of an affected facility who elects to demonstrate that the affected facility combusts only very low sulfur oil under § 60.42b(j)(2) shall obtain and maintain at the affected facility fuel receipts from the fuel supplier which certify that the oil meets the definition of distillate oil as defined in § 60.41b. For the purposes of this section, the oil need not meet the fuel nitrogen content specification in the definition of distillate oil. Reports shall be submitted to the Administrator certifying that only very low sulfur oil meeting this definition was combusted in the affected facility during the reporting period.

(s) Facility specific nitrogen oxides standard for Cytec Industries Fortier Plant's C.AOG incinerator located in Westwego, Louisiana:

(1) Definitions.

Oxidation zone is defined as the portion of the C.AOG incinerator that extends from the inlet of the oxidizing zone combustion air to the outlet gas stack.

Reducing zone is defined as the portion of the C.AOG incinerator that extends from the burner section to the inlet of the oxidizing zone combustion air.

Total inlet air is defined as the total amount of air introduced into the C.AOG incinerator for combustion of natural gas and chemical by-product waste and is equal to the sum of the air flow into the reducing zone and the air flow into the oxidation zone.

(2) Standard for nitrogen oxides.

(i) When fossil fuel alone is combusted, the nitrogen oxides emission limit for fossil fuel in Sec. 60.44b(a) applies.

(ii) When natural gas and chemical by-product waste are simultaneously combusted, the nitrogen oxides emission limit is 289 ng/J (0.67 lb/million Btu) and a maximum of 81 percent of the total inlet air provided for combustion shall be provided to the reducing zone of the C.AOG incinerator.

(3) Emission monitoring.

(i) The percent of total inlet air provided to the reducing zone shall be determined at least every 15 minutes by measuring the air flow of all the air entering the reducing zone and the air flow of all the air entering the oxidation zone, and compliance with the percentage of total inlet air that is provided to the reducing zone shall be determined on a 3-hour average basis.

(ii) The nitrogen oxides emission limit shall be determined by the compliance and performance test methods and procedures for nitrogen oxides in Sec. 60.46b(i).

(iii) The monitoring of the nitrogen oxides emission limit shall be performed in accordance with Sec. 60.48b.

(4) Reporting and recordkeeping requirements.

(i) The owner or operator of the C.AOG incinerator shall submit a report on any excursions from the limits required by paragraph (a)(2) of this section to the Administrator with the quarterly report required by paragraph (i) of this section.

(ii) The owner or operator of the C.AOG incinerator shall keep records of the monitoring required by paragraph (a)(3) of this section for a period of 2 years following the date of such record.

(iii) The owner of operator of the C.AOG incinerator shall perform all the applicable reporting and recordkeeping requirements of this section.

(t) Facility-specific nitrogen oxides standard for Rohm and Haas Kentucky Incorporated's Boiler No. 100 located in Louisville, Kentucky:

(1) Definitions.

Air ratio control damper is defined as the part of the low nitrogen oxides burner that is adjusted to control the split of total combustion air delivered to the reducing and oxidation portions of the combustion flame.

Flue gas recirculation line is defined as the part of Boiler No. 100 that recirculates a portion of the boiler flue gas back into the combustion air.

(2) Standard for nitrogen oxides.

(i) When fossil fuel alone is combusted, the nitrogen oxides emission limit for fossil fuel in § 60.44b(a) applies.

(ii) When fossil fuel and chemical by-product waste are simultaneously combusted, the nitrogen oxides emission limit is 473 ng/J (1.1 lb/million Btu), and the air ratio control damper tee handle shall be at a minimum of 5 inches (12.7 centimeters) out of the boiler, and the flue gas recirculation line shall be operated at a minimum of 10 percent open as indicated by its valve opening position indicator.

(3) Emission monitoring for nitrogen oxides.

(i) The air ratio control damper tee handle setting and the flue gas recirculation line valve opening position indicator setting shall be recorded during each 8-hour operating shift.

(ii) The nitrogen oxides emission limit shall be determined by the compliance and performance test methods and procedures for nitrogen oxides in § 60.46b.

(iii) The monitoring of the nitrogen oxides emission limit shall be performed in accordance with § 60.48b.

(4) Reporting and recordkeeping requirements.

(i) The owner or operator of Boiler No. 100 shall submit a report on any excursions from the limits required by paragraph (b)(2) of this section to the Administrator with the quarterly report required by § 60.49b(i).

(ii) The owner or operator of Boiler No. 100 shall keep records of the monitoring required by paragraph (b)(3) of this section for a period of 2 years following the date of such record.

(iii) The owner of operator of Boiler No. 100 shall perform all the applicable reporting and recordkeeping requirements of § 60.49b.

(u) Site-specific standard for Merck & Co., Inc.'s Stonewall Plant in Elkton, Virginia.

(1) This paragraph applies only to the pharmaceutical manufacturing facility, commonly referred to as the Stonewall Plant, located at Route 340 South, in Elkton, Virginia (``site'') and only to the natural gas-fired boilers installed as part of the powerhouse conversion required pursuant to 40 CFR 52.2454(g). The requirements of this paragraph shall apply, and the requirements of §§ 60.40b through 60.49b(t) shall not apply, to the natural gas-fired boilers installed pursuant to 40 CFR 52.2454(g).

(i) The site shall equip the natural gas-fired boilers with low nitrogen oxide (NO_x) technology.

(ii) The site shall install, calibrate, maintain, and operate a continuous monitoring and recording system for measuring NO_x emissions discharged to the atmosphere and opacity using a continuous
emissions monitoring system or a predictive emissions monitoring system.

(iii) Within 180 days of the completion of the powerhouse conversion, as required by 40 CFR 52.2454, the site shall perform a stack test to quantify criteria pollutant emissions.

(2) [Reserved]

(v) The owner or operator of an affected facility may submit electronic quarterly reports for SO_2 and/or NO_X and/or opacity in lieu of submitting the written reports required under paragraphs (h), (i), (j), (k) or (l) of this section. The format of each quarterly electronic report shall be coordinated with the permitting authority. The electronic reeport(s) shall be submitted no later than 30 days after the end of the calendar quarter and shall be accompanied by a certification statement from the owner or operator, indicating whether compliance with the applicable emission standards and minimum data requirements of this subpart was achieved during the reporting period. Before submitting reports in the electronic format, the owner or operator shall coordinate with the permitting authority to obtain their agreement to submit reports in this alternative format.
[52 FR 47842, Dec. 16, 1987, as amended at 54 FR 51820, 51825, Dec. 18, 1989; 60 FR 28062, May 30, 1995; 61 FR 14031, Mar. 29, 1996; 62 FR 52641, Oct. 8, 1997]

(w) The reporting period for the reports required under this subpart is each six-month period. All reports shall be submitted to the Administrator and shall be postmarked by the 30th day following the end of the reporting period.

(x) Facility-specific nitrogen oxides standard for Weyerhaeuser Company's No. 2 Power Boiler located in New Bern, North Carolina:

(1) Standard for nitrogen oxides.

(i) When fossil fuel alone is combusted, the nitrogen oxides emission limit for fossil fuel in Sec. 60.44b(a) applies.

(ii) When fossil fuel and chemical by-product waste are simultaneously combusted, the nitrogen oxides emission limit is 215 ng/J (0.5 lb/million Btu).

(2) Emission monitoring for nitrogen oxides.

(i) The nitrogen oxides emissions shall be determined by the compliance and performance test methods and procedures for nitrogen oxides in Sec. 60.46b.

(ii) The monitoring of the nitrogen oxides emissions shall be performed in accordance with Sec. 60.48b.

(3) Reporting and recordkeeping requirements.

(i) The owner or operator of the No. 2 Power Boiler shall submit a report on any excursions from the limits required by paragraph (x)(2) of this section to the Administrator with the quarterly report required by Sec. 60.49b(i).

(ii) The owner or operator of the No. 2 Power Boiler shall keep records of the monitoring required by paragraph (x)(3) of this section for a period of 2 years following the date of such record.

(iii) The owner or operator of the No. 2 Power Boiler shall perform all the applicable reporting and recordkeeping requirements of Sec. 60.49b.

APPENDIX E

40 CFR Part 60, Subpart Kb

[Last Updated 10/15/03]
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Subpart Kb — Standards of Performance for Volatile Organic Liquid Storage Vessels (Including Petroleum Liquid Storage Vessels) for Which Construction, Reconstruction, or Modification Commenced After July 23, 1984

§ 60.110b Applicability and designation of affected facility.

(a) Except as provided in paragraph (b) of this section, the affected facility to which this subpart applies is each storage vessel with a capacity greater than or equal to 75 cubic meters (m^3) that is used to store volatile organic liquids (VOL) for which construction, reconstruction, or modification is commenced after July 23, 1984.

(b) This subpart does not apply to storage vessels with a capacity greater than or equal to 151m3 storing a liquid with a maximum true vapor pressure less than 3.5 kilopascals (kPa) or with a capacity greater than or equal to 75 m^3 but less than 151 m^3 storing a liquid with a maximum true vapor pressure less than 15.0 kPa.

(c) [Reserved]

(d) This subpart does not apply to the following:

(1) Vessels at coke oven by-product plants.

(2) Pressure vessels designed to operate in excess of 204.9 kPa and without emissions to the atmosphere.

(3) Vessels permanently attached to mobile vehicles such as trucks, rail-cars, barges, or ships.

(4) Vessels with a design capacity less than or equal to 1,589.874 m^3 used for petroleum or condensate stored, processed, or treated prior to custody transfer.

(5) Vessels located at bulk gasoline plants.

(6) Storage vessels located at gasoline service stations.

(7) Vessels used to store beverage alcohol.

(8) Vessels subject to subpart GGGG of 40 CFR part 63.

(e) *Alternative means of compliance* -- (1) *Option to comply with part 65.* Owners or operators may choose to comply with 40 CFR part 65, subpart C, to satisfy the requirements of §§ 60.112b through 60.117b for storage vessels that are subject to this subpart that meet the specifications in paragraphs (e)(1)(i) and (ii) of this section. When choosing to comply with 40 CFR part 65, subpart C, the monitoring requirements of § 60.116b(c), (e), (f)(1), and (g) still apply. Other provisions applying to owners or operators who choose to comply with 40 CFR part 65 are provided in 40 CFR 65.1.

(i) A storage vessel with a design capacity greater than or equal to 151 m3 containing a VOL that, as stored, has a maximum true vapor pressure equal to or greater than 5.2 kPa; or

(ii) A storage vessel with a design capacity greater than 75 m3 but less than 151 m3 containing a VOL that, as stored, has a maximum true vapor pressure equal to or greater than 27.6 kPa.

(2) *Part 60, subpart A.* Owners or operators who choose to comply with 40 CFR part 65, subpart C, must also comply with §§ 60.1, 60.2, 60.5, 60.6, 60.7(a)(1) and (4), 60.14, 60.15, and 60.16 for those storage vessels. All sections and paragraphs of subpart A of this part that are not mentioned in this

paragraph (e)(2) do not apply to owners or operators of storage vessels complying with 40 CFR part 65, subpart C, except that provisions required to be met prior to implementing 40 CFR part 65 still apply. Owners and operators who choose to comply with 40 CFR part 65, subpart C, must comply with 40 CFR part 65, subpart A.

(3) *Internal floating roof report.* If an owner or operator installs an internal floating roof and, at initial startup, chooses to comply with 40 CFR part 65, subpart C, a report shall be furnished to the Administrator stating that the control equipment meets the specifications of 40 CFR 65.43. This report shall be an attachment to the notification required by 40 CFR 65.5(b).

(4) *External floating roof report.* If an owner or operator installs an external floating roof and, at initial startup, chooses to comply with 40 CFR part 65, subpart C, a report shall be furnished to the Administrator stating that the control equipment meets the specifications of 40 CFR 65.44. This report shall be an attachment to the notification required by 40 CFR 65.5(b).

§ 60.111b Definitions.

Terms used in this subpart are defined in the Act, in subpart A of this part, or in this subpart as follows:

Bulk gasoline plant means any gasoline distribution facility that has a gasoline throughput less than or equal to 75,700 liters per day. Gasoline throughput shall be the maximum calculated design throughput as may be limited by compliance with an enforceable condition under Federal requirement or Federal, State or local law, and discoverable by the Administrator and any other person.

Condensate means hydrocarbon liquid separated from natural gas that condenses due to changes in the temperature or pressure, or both, and remains liquid at standard conditions.

Custody transfer means the transfer of produced petroleum and/or condensate, after processing and/or treatment in the producing operations, from storage vessels or automatic transfer facilities to pipelines or any other forms of transportation.

Fill means the introduction of VOL into a storage vessel but not necessarily to complete capacity.

Gasoline service station means any site where gasoline is dispensed to motor vehicle fuel tanks from stationary storage tanks.

Maximum true vapor pressure means the equilibrium partial pressure exerted by the volatile organic compounds (as defined in 40 CFR 51.100) in the stored VOL at the temperature equal to the highest calendar-month average of the VOL storage temperature for VOL's stored above or below the ambient temperature or at the local maximum monthly average temperature as reported by the National Weather Service for VOL's stored at the ambient temperature, as determined:

(1) In accordance with methods de-scribed in American Petroleum institute Bulletin 2517, Evaporation Loss From External Floating Roof Tanks, (incorporated by reference—see § 60.17); or

(2) As obtained from standard reference texts; or

(3) As determined by ASTM Method D2879–83, 96, or 97 (incorporated by reference— see § 60.17);

(4) Any other method approved by the Administrator.

Reid vapor pressure means the absolute vapor pressure of volatile crude oil and volatile nonviscous petroleum liquids except liquified petroleum gases, as determined by ASTM D323–82 or 94 (incorporated by reference—see § 60.17).

Petroleum means the crude oil removed from the earth and the oils derived from tar sands, shale, and coal.

Petroleum liquids means petroleum, condensate, and any finished or intermediate products manufactured in a petroleum refinery.

Process tank means a tank that is used within a process (including a solvent or raw material recovery process) to collect material discharged from a feedstock storage vessel or equipment within the process before the material is transferred to other equipment within the process, to a product or by-product storage vessel, or to a vessel used to store recovered solvent or raw material. In many process tanks, unit operations such as reactions and blending are conducted. Other process tanks, such as surge control vessels and bottoms receivers, however, may not involve unit operations.

Storage vessel means each tank, reservoir, or container used for the storage of volatile organic liquids but does not include:

(1) Frames, housing, auxiliary supports, or other components that are not directly involved in the containment of liquids or vapors;

(2) Subsurface caverns or porous rock reservoirs; or

(3) Process tanks.

Volatile organic liquid (VOL) means any organic liquid which can emit volatile organic compounds (as defined in 40 CFR 51.100) into the atmosphere.

Waste means any liquid resulting from industrial, commercial, mining or agricultural operations, or from community activities that is discarded or is being accumulated, stored, or physically, chemically, or biologically treated prior to being discarded or recycled.
[52 FR 11429, Apr. 8, 1987, as amended at 54 FR 32973, Aug. 11, 1989]

§ 60.112b Standard for volatile organic compounds (VOC).

(a) The owner or operator of each storage vessel either with a design capacity greater than or equal to 151 m^3
containing a VOL that, as stored, has a maximum true vapor pressure equal to or greater than 5.2 kPa but less than 76.6 kPa or with a design capacity greater than or equal to 75 m^3 but less than 151 m^3 containing a VOL that, as stored, has a maximum true vapor pressure equal to or greater than 27.6 kPa but less than 76.6 kPa, shall equip each storage vessel with one of the following:

(1) A fixed roof in combination with an internal floating roof meeting the following specifications:

(i) The internal floating roof shall rest or float on the liquid surface (but not necessarily in complete contact with it) inside a storage vessel that has a fixed roof. The internal floating roof shall be floating on the liquid surface at all times, except during initial fill and during those intervals when the storage vessel is completely emptied or subsequently emptied and refilled. When the roof is resting on the leg supports, the process of filling, emptying, or refilling shall be continuous and shall be accomplished as rapidly as possible.

(ii) Each internal floating roof shall be equipped with one of the following closure devices between the wall of the storage vessel and the edge of the internal floating roof:

(A) A foam- or liquid-filled seal mounted in contact with the liquid (liquid-mounted seal). A liquid-mounted seal means a foam- or liquid-filled seal mounted in contact with the liquid between the wall of the storage vessel and the floating roof continuously around the circumference of the tank.

(B) Two seals mounted one above the other so that each forms a continuous closure that completely covers the space between the wall of the storage vessel and the edge of the internal floating roof. The lower seal may be vapor-mounted, but both must be continuous.

(C) A mechanical shoe seal. A mechanical shoe seal is a metal sheet held vertically against the wall of the storage vessel by springs or weighted levers and is connected by braces to the floating roof. A flexible coated fabric (envelope) spans the annular space between the metal sheet and the floating roof.

(iii) Each opening in a noncontact internal floating roof except for automatic bleeder vents (vacuum breaker vents) and the rim space vents is to provide a projection below the liquid surface.

(iv) Each opening in the internal floating roof except for leg sleeves, automatic bleeder vents, rim space vents, column wells, ladder wells, sample wells, and stub drains is to be equipped with a cover or lid which is to be maintained in a closed position at all times (i.e., no visible gap) except when the device is in actual use. The cover or lid shall be equipped with a gasket. Covers on each access hatch and automatic gauge float well shall be bolted except when they are in use.

(v) Automatic bleeder vents shall be equipped with a gasket and are to be closed at all times when the roof is floating except when the roof is being floated off or is being landed on the roof leg supports.

(vi) Rim space vents shall be equipped with a gasket and are to be set to open only when the internal floating roof is not floating or at the manufacturer's recommended setting.

(vii) Each penetration of the internal floating roof for the purpose of sampling shall be a sample well. The sample well shall have a slit fabric cover that covers at least 90 percent of the opening.

(viii) Each penetration of the internal floating roof that allows for passage of a column supporting the fixed roof shall have a flexible fabric sleeve seal or a gasketed sliding cover.

(ix) Each penetration of the internal floating roof that allows for passage of a ladder shall have a gasketed sliding cover.

(2) An external floating roof. An external floating roof means a pontoon-type or double-deck type cover that rests on the liquid surface in a vessel with no fixed roof. Each external floating roof must meet the following specifications:

(i) Each external floating roof shall be equipped with a closure device between the wall of the storage vessel and the roof edge. The closure device is to consist of two seals, one above the other. The lower seal is referred to as the primary seal, and the upper seal is referred to as the secondary seal.

(A) The primary seal shall be either a mechanical shoe seal or a liquid-mounted seal. Except as provided in § 60.113b(b)(4), the seal shall completely cover the annular space between the edge of the floating roof and tank wall.

(B) The secondary seal shall completely cover the annular space between the external floating roof and the wall of the storage vessel in a continuous fashion except as allowed in § 60.113b(b)(4).

(ii) Except for automatic bleeder vents and rim space vents, each opening in a noncontact external floating roof shall provide a projection below the liquid surface. Except for automatic bleeder vents, rim space vents, roof drains, and leg sleeves, each opening in the roof is to be equipped with a gasketed cover, seal, or lid that is to be maintained in a closed position at all times (i.e., no visible gap) except when the device is in actual use. Automatic bleeder vents are to be closed at all times when the roof is floating except when the roof is being floated off or is being landed on the roof leg supports. Rim vents are to be set to open when the roof is being floated off the roof legs supports or at the manufacturer's recommended setting. Automatic bleeder vents and rim space vents are to be gasketed. Each emergency roof drain is to be provided with a slotted membrane fabric cover that covers at least 90 percent of the area of the opening.

(iii) The roof shall be floating on the liquid at all times (i.e., off the roof leg supports) except during initial fill until the roof is lifted off leg supports and when the tank is completely emptied and subsequently refilled. The process of filling, emptying, or refilling when the roof is resting on the leg supports
shall be continuous and shall be accomplished as rapidly as possible.

(3) A closed vent system and control device meeting the following specifications:

(i) The closed vent system shall be designed to collect all VOC vapors and gases discharged from the storage vessel and operated with no detectable emissions as indicated by an instrument reading of less than 500 ppm above background and visual inspections, as determined in part 60, subpart
VV, § 60.485(b).

(ii) The control device shall be designed and operated to reduce inlet VOC emissions by 95 percent or greater. If a flare is used as the control device, it shall meet the specifications described in the general control device requirements (§ 60.18) of the General Provisions.

(4) A system equivalent to those described in paragraphs (a)(1), (a)(2), or (a)(3) of this section as provided in § 60.114b of this subpart.

(b) The owner or operator of each storage vessel with a design capacity greater than or equal to 75 m^3 which contains a VOL that, as stored, has a maximum true vapor pressure greater than or equal to 76.6 kPa shall equip each storage vessel with one of the following:

(1) A closed vent system and control device as specified in § 60.112b(a)(3).

(2) A system equivalent to that described in paragraph (b)(1) as provided in § 60.114b of this subpart.

(c) *Site-specific standard for Merck & Co., Inc.'s Stonewall Plant in Elkton, Virginia.* This paragraph applies only to the pharmaceutical manufacturing facility, commonly referred to as the Stonewall Plant, located at Route 340 South, in Elkton, Virginia (''site'').

(1) For any storage vessel that otherwise would be subject to the control technology requirements of paragraphs (a) or (b) of this section, the site shall have the option of either complying directly with the requirements of this subpart, or reducing the site-wide total criteria pollutant emissions cap (total emissions cap) in accordance with the procedures set forth in a permit issued pursuant to 40 CFR 52.2454. If the site
chooses the option of reducing the total emissions cap in accordance with the procedures set forth in such permit, the requirements of such permit shall apply in lieu of the otherwise applicable requirements of this subpart for such storage vessel.

(2) For any storage vessel at the site not subject to the requirements of 40 CFR 60.112b (a) or (b), the requirements of 40 CFR 60.116b (b) and (c) and the General Provisions (subpart A of this part) shall not apply.

[52 FR 11429, Apr. 8, 1987, as amended at 62 FR 52641, Oct. 8, 1997]

§ 60.113b Testing and procedures.

The owner or operator of each storage vessel as specified in § 60.112b(a) shall meet the requirements of paragraph (a), (b), or (c) of this section. The applicable paragraph for a particular storage vessel depends on the control equipment installed to meet the requirements of § 60.112b.

(a) After installing the control equipment required to meet § 60.112b(a)(1) (permanently affixed roof and internal floating roof), each owner or operator shall:

(1) Visually inspect the internal floating roof, the primary seal, and the secondary seal (if one is in service), prior to filling the storage vessel with VOL. If there are holes, tears, or other openings in the primary seal, the secondary seal, or the seal fabric or defects in the internal floating roof, or both, the owner or operator shall repair the items before filling the storage vessel.

(2) For Vessels equipped with a liquid-mounted or mechanical shoe primary seal, visually inspect the internal floating roof and the primary seal or the secondary seal (if one is in service) through manholes and roof hatches on the fixed roof at least once every 12 months after initial fill. If the internal floating roof is not resting on the surface of the VOL inside the storage vessel, or there is liquid accumulated on the roof, or the seal is detached, or there are holes or tears in the seal fabric, the owner or operator shall repair the items or empty and remove the storage vessel from service within 45 days. If a failure that is detected during inspections required in this paragraph cannot be repaired within 45 days and if the vessel cannot be emptied within 45 days, a 30-day extension may be requested from the Administrator in the inspection report required in § 60.115b(a)(3). Such a request for an extension must document that alternate storage capacity is unavailable and specify a schedule of actions the company will take that will assure that the control equipment will be repaired or the vessel will be emptied as soon as possible.

(3) For vessels equipped with a double-seal system as specified in § 60.112b(a)(1)(ii)(B):

(i) Visually inspect the vessel as specified in paragraph (a)(4) of this section at least every 5 years; or

(ii) Visually inspect the vessel as specified in paragraph (a)(2) of this section.

(4) Visually inspect the internal floating roof, the primary seal, the secondary seal (if one is in service), gaskets, slotted membranes and sleeve seals (if any) each time the storage vessel is emptied and degassed. If the internal floating roof has defects, the primary seal has holes, tears, or other openings in the seal or the seal fabric, or the secondary seal has holes, tears, or other openings in the seal or the seal fabric, or the gaskets no longer close off the liquid surfaces from the atmosphere, or the slotted membrane has more than 10 percent open area, the owner or operator shall repair the items as necessary so that none of the
conditions specified in this paragraph exist before refilling the storage vessel with VOL. In no event shall inspections conducted in accordance with this provision occur at intervals greater than 10 years in the case of vessels conducting the annual visual inspection as specified in paragraphs (a)(2) and (a)(3)(ii) of this section and at intervals no greater than 5 years in the case of vessels specified in paragraph (a)(3)(i) of this section.

(5) Notify the Administrator in writing at least 30 days prior to the filling or refilling of each storage vessel for which an inspection is required by paragraphs (a)(1) and (a)(4) of this section to afford the Administrator the opportunity to have an observer present. If the inspection required by paragraph (a)(4) of this section is not planned and the owner or operator could not have known about the inspection 30 days in advance or refilling the tank, the owner or operator shall notify the Administrator at least 7 days prior to the refilling of the storage vessel. Notification shall be made by telephone immediately followed by written documentation demonstrating why the inspection was unplanned. Alternatively, this

notification including the written documentation may be made in writing and sent by express mail so that it is received by the Administrator at least 7 days prior to the refilling.

(b) After installing the control equipment required to meet § 60.112b(a)(2) (external floating roof), the owner or operator shall:

(1) Determine the gap areas and maximum gap widths, between the primary seal and the wall of the storage vessel and between the secondary seal and the wall of the storage vessel according to the following frequency.

(i) Measurements of gaps between the tank wall and the primary seal (seal gaps) shall be performed during the hydrostatic testing of the vessel or within 60 days of the initial fill with VOL and at least once every 5 years thereafter.

(ii) Measurements of gaps between the tank wall and the secondary seal shall be performed within 60 days of the initial fill with VOL and at least once per year thereafter.

(iii) If any source ceases to store VOL for a period of 1 year or more, subsequent introduction of VOL into the vessel shall be considered an initial fill for the purposes of paragraphs (b)(1)(i) and (b)(1)(ii) of this section.

(2) Determine gap widths and areas in the primary and secondary seals individually by the following procedures:

(i) Measure seal gaps, if any, at one or more floating roof levels when the roof is floating off the roof leg supports.

(ii) Measure seal gaps around the entire circumference of the tank in each place where a 0.32-cm diameter uniform probe passes freely (without forcing or binding against seal) between the seal and the wall of the storage vessel and measure the circumferential distance of each such location.

(iii) The total surface area of each gap described in paragraph (b)(2)(ii) of this section shall be determined by using probes of various widths to measure accurately the actual distance from the tank wall to the seal and multiplying each such width by its respective circumferential distance.

(3) Add the gap surface area of each gap location for the primary seal and the secondary seal individually and divide the sum for each seal by the nominal diameter of the tank and compare each ratio to the respective standards in paragraph (b)(4) of this section.

(4) Make necessary repairs or empty the storage vessel within 45 days of identification in any inspection for seals not meeting the requirements listed in (b)(4) (i) and (ii) of this section:

(i) The accumulated area of gaps between the tank wall and the mechanical shoe or liquid-mounted primary seal shall not exceed 212 Cm^2 per meter of tank diameter, and the width of any portion of any gap shall not exceed 3.81 cm.

(A) One end of the mechanical shoe is to extend into the stored liquid, and the other end is to extend a minimum vertical distance of 61 cm above the stored liquid surface.

(B) There are to be no holes, tears, or other openings in the shoe, seal fabric, or seal envelope.

(ii) The secondary seal is to meet the following requirements:

(A) The secondary seal is to be installed above the primary seal so that it completely covers the space between the roof edge and the tank wall except as provided in paragraph (b)(2)(iii) of this section.

(B) The accumulated area of gaps between the tank wall and the secondary seal shall not exceed 21.2 cm 2 per meter of tank diameter, and the width of any portion of any gap shall not exceed 1.27 cm.

(C) There are to be no holes, tears, or other openings in the seal or seal fabric.

(iii) If a failure that is detected during inspections required in paragraph (b)(1) of § 60.113b(b) cannot be repaired within 45 days and if the vessel cannot be emptied within 45 days, a 30-day extension may be requested from the Administrator in the inspection report required in § 60.115b(b)(4). Such extension request must include a demonstration of unavailability of alternate storage capacity and a specification of a schedule that will assure that the control equipment will be repaired or the vessel will be emptied as soon as possible.

(5) Notify the Administrator 30 days in advance of any gap measurements required by paragraph (b)(1) of this section to afford the Administrator the opportunity to have an observer present.

(6) Visually inspect the external floating roof, the primary seal, secondary seal, and fittings each time the vessel is emptied and degassed.

(i) If the external floating roof has defects, the primary seal has holes, tears, or other openings in the seal or the seal fabric, or the secondary seal has holes, tears, or other openings in the seal or the seal fabric, the owner or operator shall repair the items as necessary so that none of the conditions specified in this paragraph exist before filling or refilling the storage vessel with VOL.

(ii) For all the inspections required by paragraph (b)(6) of this section, the owner or operator shall notify the Administrator in writing at least 30 days prior to the filling or refilling of each storage vessel to afford the Administrator the opportunity to inspect the storage vessel prior to refilling. If the inspection required by paragraph (b)(6) of this section is not planned and the owner or operator could not have known about the inspection 30 days in advance of refilling the tank, the owner or operator shall notify the Administrator at least 7 days prior to the refilling of the storage vessel. Notification shall be made by telephone immediately followed by written documentation demonstrating why the inspection was unplanned. Alternatively, this notification including the written documentation may be made in writing and sent by express mail so that it is received by the Administrator at least 7 days prior to the refilling.

(c) The owner or operator of each source that is equipped with a closed vent system and control device as required in § 60.112b (a)(3) or (b)(2) (other than a flare) is exempt from § 60.8 of the General Provisions and shall meet the following requirements.

(1) Submit for approval by the Administrator as an attachment to the notification required by § 60.7(a)(1) or, if the facility is exempt from § 60.7(a)(1), as an attachment to the notification required by § 60.7(a)(2), an operating plan containing the information listed below.

(i) Documentation demonstrating that the control device will achieve the required control efficiency during maximum loading conditions. This documentation is to include a description of the gas stream which enters the control device, including flow and VOC content under varying liquid level conditions (dynamic and static) and manufacturer’s design specifications for the control device. If the control device or the closed vent capture system receives vapors, gases, or liquids other than fuels from sources that are not designated sources under this subpart, the efficiency demonstration is to include consideration of all vapors, gases, and liquids received by the closed vent capture system and control device. If an enclosed combustion device with a minimum residence time of 0.75 seconds and a minimum temperature of 816 °C is used to meet the 95 percent requirement, documentation that those conditions will exist is sufficient to meet the requirements of this paragraph.

(ii) A description of the parameter or parameters to be monitored to ensure that the control device will be operated in conformance with its design and an explanation of the criteria used for selection of that parameter (or parameters).

(2) Operate the closed vent system and control device and monitor the parameters of the closed vent system and control device in accordance with the operating plan submitted to the Administrator in accordance with paragraph (c)(1) of this section, unless the plan was modified by the Administrator during the review process. In this case, the modified plan applies.

(d) The owner or operator of each source that is equipped with a closed vent system and a flare to meet the requirements in § 60.112b (a)(3) or (b)(2) shall meet the requirements as specified in the general control device requirements, § 60.18 (e) and (f).
[52 FR 11429, Apr. 8, 1987, as amended at 54 FR 32973, Aug. 11, 1989]

§ 60.114b Alternative means of emission limitation.

(a) If, in the Administrator's judgment, an alternative means of emission limitation will achieve a reduction in
emissions at least equivalent to the reduction in emissions achieved by any requirement in § 60.112b, the Administrator will publish in the FEDERAL REGISTER a notice permitting the use of the alternative means for purposes of compliance with that requirement.

(b) Any notice under paragraph (a) of this section will be published only after notice and an opportunity for a hearing.

(c) Any person seeking permission under this section shall submit to the Administrator a written application including:

(1) An actual emissions test that uses a full-sized or scale-model storage vessel that accurately collects and measures all VOC emissions from a given control device and that accurately simulates wind and accounts for other emission variables such as temperature and barometric pressure.

(2) An engineering evaluation that the Administrator determines is an accurate method of determining equivalence.

(d) The Administrator may condition the permission on requirements that may be necessary to ensure operation and maintenance to achieve the same emissions reduction as specified in § 60.112b.

§ 60.115b Reporting and recordkeeping requirements.

The owner or operator of each storage vessel as specified in § 60.112b(a) shall keep records and furnish reports as required by paragraphs (a), (b), or (c) of this section depending upon the control equipment installed to meet the requirements of § 60.112b. The owner or operator shall keep copies of all reports and records required by this section, except for the record required by (c)(1), for at least 2 years. The record required by (c)(1) will be kept for the life of the control equipment.

(a) After installing control equipment in accordance with § 60.112b(a)(1) (fixed roof and internal floating roof), the owner or operator shall meet the following requirements.

(1) Furnish the Administrator with a report that describes the control equipment and certifies that the control equipment meets the specifications of § 60.112b(a)(1) and § 60.113b(a)(1). This report shall be an attachment to the notification required by § 60.7(a)(3).

(2) Keep a record of each inspection performed as required by § 60.113b (a)(1), (a)(2), (a)(3), and (a)(4). Each record shall identify the storage vessel on which the inspection was performed and shall contain the date the vessel was inspected and the observed condition of each component of the control equipment (seals, internal floating roof, and fittings).

(3) If any of the conditions described in § 60.113b(a)(2) are detected during the annual visual inspection required by § 60.113b(a)(2), a report shall be furnished to the Administrator within 30

days of the inspection. Each report shall identify the storage vessel, the nature of the defects, and the date the
storage vessel was emptied or the nature of and date the repair was made.

(4) After each inspection required by § 60.113b(a)(3) that finds holes or tears in the seal or seal fabric, or defects in the internal floating roof, or other control equipment defects listed in § 60.113b(a)(3)(ii), a report shall be furnished to the Administrator within 30 days of the inspection. The report shall identify the storage vessel and the reason it did not meet the specifications of § 61.112b(a)(1) or § 60.113b(a)(3) and list
each repair made.

(b) After installing control equipment in accordance with § 61.112b(a)(2) (external floating roof), the owner or operator shall meet the following requirements.

(1) Furnish the Administrator with a report that describes the control equipment and certifies that the control equipment meets the specifications of § 60.112b(a)(2) and § 60.113b(b)(2), (b)(3), and (b)(4). This report shall be an attachment to the notification required by § 60.7(a)(3).

(2) Within 60 days of performing the seal gap measurements required by § 60.113b(b)(1), furnish the Administrator with a report that contains:

(i) The date of measurement.

(ii) The raw data obtained in the measurement.

(iii) The calculations described in § 60.113b (b)(2) and (b)(3).

(3) Keep a record of each gap measurement performed as required by § 60.113b(b). Each record shall identify the storage vessel in which the measurement was performed and shall contain:

(i) The date of measurement.

(ii) The raw data obtained in the measurement.

(iii) The calculations described in § 60.113b (b)(2) and (b)(3).

(4) After each seal gap measurement that detects gaps exceeding the limitations specified by § 60.113b(b)(4), submit a report to the Administrator within 30 days of the inspection. The report will identify the vessel and contain the information specified in paragraph (b)(2) of this section and the date the vessel
was emptied or the repairs made and date of repair.

(c) After installing control equipment in accordance with § 60.112b (a)(3) or (b)(1) (closed vent system and control device other than a flare), the owner or operator shall keep the following records.

(1) A copy of the operating plan.

(2) A record of the measured values of the parameters monitored in accordance with § 60.113b(c)(2).

(d) After installing a closed vent system and flare to comply with § 60.112b, the owner or operator shall meet the following requirements.

(1) A report containing the measurements required by § 60.18(f) (1), (2), (3), (4), (5), and (6) shall be furnished to the Administrator as required by § 60.8 of the General Provisions. This report shall be submitted within 6 months of the initial start-up date.

(2) Records shall be kept of all periods of operation during which the flare pilot flame is absent.

(3) Semiannual reports of all periods recorded under § 60.115b(d)(2) in which the pilot flame was absent shall be furnished to the Administrator.

§ 60.116b Monitoring of operations.

(a) The owner or operator shall keep copies of all records required by this section, except for the record required by paragraph (b) of this section, for at least 2 years. The record required by paragraph (b) of this section will be kept for the life of the source.

(b) The owner or operator of each storage vessel as specified in § 60.110b(a) shall keep readily accessible records showing the dimension of the storage vessel and an analysis showing the capacity of the storage vessel.

(c) Except as provided in paragraphs (f) and (g) of this section, the owner or operator of each storage vessel either with a design capacity greater than or equal to 151 m^3 storing a liquid with a maximum true vapor pressure greater than or equal to 3.5 kPa or with a design capacity greater than or equal to 75 m^3 but less than 151 m^3 storing a liquid with a maximum true vapor pressure greater than or equal to 15.0 kPa shall maintain a record of the VOL stored, the period of storage, and the maximum true vapor pressure of that VOL during the respective storage period.

(d) Except as provided in paragraph (g) of this section, the owner or operator of each storage vessel either with a design capacity greater than or equal to 151 m^3 storing a liquid with a maximum true vapor pressure that is normally less than 5.2 kPa or with a design capacity greater than or equal to 75 m^3 but less than 151 m^3 storing a liquid with a maximum true vapor pressure that is normally less than 27.6 kPa shall notify the Administrator within 30 days when the maximum true vapor pressure of the liquid exceeds the respective
maximum true vapor vapor pressure values for each volume range.

(e) Available data on the storage temperature may be used to determine the maximum true vapor pressure as
determined below.

(1) For vessels operated above or below ambient temperatures, the maximum true vapor pressure is calculated based upon the highest expected calendar-month average of the storage temperature. For vessels operated at ambient temperatures, the maximum true vapor pressure is calculated based upon the maximum local monthly average ambient temperature as reported by the National Weather Service.

(2) For crude oil or refined petroleum products the vapor pressure may be obtained by the following:

(i) Available data on the Reid vapor pressure and the maximum expected storage temperature based on the highest expected calendar-month average temperature of the stored product may be used to determine the maximum true vapor pressure from nomographs contained in API Bulletin 2517 (incorporated by reference—see § 60.17), unless the Administrator specifically requests that the liquid be sampled, the
actual storage temperature determined, and the Reid vapor pressure determined from the sample(s).

(ii) The true vapor pressure of each type of crude oil with a Reid vapor pressure less than 13.8 kPa or with physical properties that preclude determination by the recommended method is to be determined from available data and recorded if the estimated maximum true vapor pressure is greater than 3.5 kPa.

(3) For other liquids, the vapor pressure:

(i) May be obtained from standard reference texts, or

(ii) Determined by ASTM Method D2879–83, 96, or 97 (incorporated by reference— see § 60.17); or

(iii) Measured by an appropriate method approved by the Administrator; or

(iv) Calculated by an appropriate method approved by the Administrator.

(f) The owner or operator of each vessel storing a waste mixture of indeterminate or variable composition shall be subject to the following requirements.

(1) Prior to the initial filling of the vessel, the highest maximum true vapor pressure for the range of anticipated liquid compositions to be stored will be determined using the methods described in paragraph (e) of this section.

(2) For vessels in which the vapor pressure of the anticipated liquid composition is above the cutoff for monitoring but below the cutoff for controls as defined in §60.112b(a), an initial physical test of the vapor pressure is required; and a physical test at least once every 6 months thereafter is required as determined by the following methods:

(i) ASTM Method D2879–83, 96, or 97 (incorporated by reference—see § 60.17); or

(ii) ASTM Method D323–82 or 94 (incorporated by reference—see §60.17); or

(iii) As measured by an appropriate method as approved by the Administrator.

(g) The owner or operator of each vessel equipped with a closed vent system and control device meeting the specifications of § 60.112b or with emissions reduction equipment as specified in 40 CFR 65.5(b)(4), (b)(5), (b)(6), or (c) is exempt from the requirements of paragraphs (c) and (d) of this section.

§ 60.117b Delegation of authority.

(a) In delegating implementation and enforcement authority to a State under section 111(c) of the Act, the authorities contained in paragraph (b) of this section shall be retained by the Administrator and not transferred to a State.

(b) Authorities which will not be delegated to States: §§ 60.111b(f)(4), 60.114b, 60.116b(e)(3)(iii), 60.116b(e)(3)(iv), and 60.116b(f)(2)(iii).

[52 FR 11429, Apr. 8, 1987, as amended at 52 FR 22780, June 16, 1987]

APPENDIX F

40 CFR Part 60, Subpart Y

Updated 9/15/03

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Subpart Y- Standards of Performance for Coal Preparation Plants

§ 60.250 Applicability and designation of affected facility.

(a) The provisions of this subpart are applicable to any of the following affected facilities in coal preparation plants which process more than 181 Mg (200 tons) per day: Thermal dryers, pneumatic coal-cleaning equipment (air tables), coal processing and conveying equipment (including breakers and crushers), coal storage systems, and coal transfer and loading systems.

(b) Any facility under paragraph (a) of this section that commences construction or modification after October 24, 1974, is subject to the requirements of this subpart.

§ 60.251 Definitions.

As used in this subpart, all terms not defined herein have the meaning given them in the Act and in subpart A of this part.

(a) *Coal preparation plant* means any facility (excluding underground mining operations) which prepares coal by one or more of the following processes: breaking, crushing, screening, wet or dry cleaning, and thermal drying.

(b) *Bituminous coal* means solid fossil fuel classified as bituminous coal by ASTM Designation D388-77, 90, 91, 95, or 98a (incorporated by reference -- see § 60.17).

(c) *Coal* means all solid fossil fuels classified as anthracite, bituminous, subbituminous, or lignite by ASTM Designation D388-77, 90, 91, 95, or 98a (incorporated by reference -- see § 60.17).

(d) *Cyclonic flow* means a spiraling movement of exhaust gases within a duct or stack.

(e) *Thermal dryer* means any facility in which the moisture content of bituminous coal is reduced by contact with a heated gas stream which is exhausted to the atmosphere.

(f) *Pneumatic coal-cleaning equipment* means any facility which classifies bituminous coal by size or separates bituminous coal from refuse by application of air stream(s).

(g) *Coal processing and conveying equipment* means any machinery used to reduce the size of coal or to separate coal from refuse, and the equipment used to convey coal to or remove coal and refuse from the machinery. This includes, but is not limited to, breakers, crushers, screens, and conveyor belts.

(h) *Coal storage system* means any facility used to store coal except for open storage piles.

(i) *Transfer and loading system* means any facility used to transfer and load coal for shipment.

§ 60.252 Standards for particulate matter.

(a) On and after the date on which the performance test required to be conducted by § 60.8 is completed, an owner or operator subject to the provisions of this subpart shall not cause to be discharged into the atmosphere from any thermal dryer gases which:

(1) Contain particulate matter in excess of 0.070 g/dscm (0.031 gr/dscf).

(2) Exhibit 20 percent opacity or greater.

(b) On and after the date on which the performance test required to be conducted by § 60.8 is completed, an owner or operator subject to the provisions of this subpart shall not cause to be discharged into the atmosphere from any pneumatic coal cleaning equipment, gases which:

(1) Contain particulate matter in excess of 0.040 g/dscm (0.017 gr/dscf).

(2) Exhibit 10 percent opacity or greater.

(c) On and after the date on which the performance test required to be conducted by § 60.8 is completed, an owner or operator subject to the provisions of this subpart shall not cause to be discharged into the atmosphere from any coal processing and conveying equipment, coal storage system, or coal transfer and loading system processing coal, gases which exhibit 20 percent opacity or greater.

§ 60.253 Monitoring of operations.

(a) The owner or operator of any thermal dryer shall install, calibrate, maintain, and continuously operate monitoring devices as follows:

(1) A monitoring device for the measurement of the temperature of the gas stream at the exit of the thermal dryer on a continuous basis. The monitoring device is to be certified by the manufacturer to be accurate within ±1.7 °C (±3 °F).

(2) For affected facilities that use venturi scrubber emission control equipment:

(i) A monitoring device for the continuous measurement of the pressure loss through the venturi constriction of the control equipment. The monitoring device is to be certified by the manufacturer to be accurate within ±1 inch water gauge.

(ii) A monitoring device for the continuous measurement of the water supply pressure to the control equipment. The monitoring device is to be certified by the manufacturer to be accurate within ±5 percent of design water supply pressure. The pressure sensor or tap must be located close to the water discharge point. The Administrator may be consulted for approval of alternative locations.

(b) All monitoring devices under paragraph (a) of this section are to be recalibrated annually in accordance with procedures under § 60.13(b).

§ 60.254 Test methods and procedures.

(a) In conducting the performance tests required in § 60.8, the owner or operator shall use as reference methods and procedures the test methods in appendix A of this part or other methods and procedures as specified in this section, except as provided in § 60.8(b).

(b) The owner or operator shall determine compliance with the particular matter standards in § 60.252 as follows:

(1) Method 5 shall be used to determine the particulate matter concentration. The sampling time and sample volume for each run shall be at least 60 minutes and 0.85 dscm (30 dscf). Sampling shall begin no less than 30 minutes after startup and shall terminate before shutdown procedures begin.

(2) Method 9 and the procedures in § 60.11 shall be used to determine opacity.