



## DIVISION OF ENVIRONMENTAL QUALITY

Sarah Huckabee Sanders  
GOVERNOR

Shane E. Khoury  
SECRETARY

March 26, 2024

Via email to: [jhyde@creativefoamusa.com](mailto:jhyde@creativefoamusa.com) & First Class Mail

Jeff Hyde  
General Manager  
Creative Foam Products, LLC.  
P. O. Box 489  
North Little Rock, AR 72114

Re: Notice of Final Permitting Decision; Permit No. 2448-AOP-R0

Dear Mr. Hyde,

After considering the application and other applicable materials as required by APC&EC Rule 8.211 and Ark. Code Ann. § 8-4-101 *et seq.*, this notice of final permitting decision is provided for:

Creative Foam Products, LLC.  
1301 E. Eighth Street  
North Little Rock, AR 72114

Permit Number: 2448-AOP-R0

Permitting Decision: approval with permit conditions as set forth in final Permit No. 2448-AOP-R0

Accessing the Permitting Decision:  
<https://www.adeq.state.ar.us/downloads/WebDatabases/PermitsOnline/Air/2448-AOP-R0.pdf>.

Accessing the Statement of Basis:  
<https://www.adeq.state.ar.us/downloads/WebDatabases/PermitsOnline/Air/2448-AOP-R0-SOB.pdf>.

Rule 26.903 of the Rules of the Arkansas Operating Air Permit Program do not require a public notice or public comment period for Administrative Amendments.

Sincerely,

A handwritten signature in dark ink, appearing to read "Demetria Kimbrough". The signature is fluid and cursive, with the first name being more prominent.

Demetria Kimbrough  
Associate Director, Office of Air Quality, Division of Environmental Quality  
5301 Northshore Drive, North Little Rock, AR 72118-5317

Enclosure: Certificate of Service

**CERTIFICATE OF SERVICE**

I, Natasha Oates, hereby certify that the final permit decision notice has been mailed by first class mail to Creative Foam Products, LLC., P. O. Box 489, North Little Rock, AR, 72114, on this 26th day of March, 2024.

*Natasha Oates*

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Natasha Oates, AA, Office of Air Quality



## **DIVISION OF ENVIRONMENTAL QUALITY**

# **OPERATING AIR PERMIT**

**PERMIT NUMBER:** 2448-AOP-R0

**IS ISSUED TO:**

Creative Foam Products, LLC.  
1301 E. Eighth Street  
North Little Rock, AR 72114  
Pulaski County  
**AFIN:** 60-06113

PURSUANT TO THE RULES OF THE ARKANSAS OPERATING AIR PERMIT PROGRAM, RULE 26: 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:

March 26, 2024    AND    March 25, 2029

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

**Signed:**

A handwritten signature in dark ink, appearing to read "Demetria Kimbrough", is written over a horizontal line.

Demetria Kimbrough  
Associate Director, Office of Air Quality  
Division of Environmental Quality

March 26, 2024

Date

Creative Foam Products, LLC.  
Permit #: 2448-AOP-R0  
AFIN: 60-06113

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Creative Foam Products, LLC.

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#### List of Acronyms and Abbreviations

Ark. Code Ann.	Arkansas Code Annotated
AFIN	Arkansas DEQ Facility Identification Number
C.F.R.	Code of Federal Regulations
CO	Carbon Monoxide
COMS	Continuous Opacity Monitoring System
HAP	Hazardous Air Pollutant
Hp	Horsepower
lb/hr	Pound Per Hour
NESHAP	National Emission Standards (for) Hazardous Air Pollutants
MVAC	Motor Vehicle Air Conditioner
No.	Number
NO <sub>x</sub>	Nitrogen Oxide
NSPS	New Source Performance Standards
PM	Particulate Matter
PM <sub>10</sub>	Particulate Matter Equal To Or Smaller Than Ten Microns
PM <sub>2.5</sub>	Particulate Matter Equal To Or Smaller Than 2.5 Microns
SNAP	Significant New Alternatives Program (SNAP)
SO <sub>2</sub>	Sulfur Dioxide
SSM	Startup, Shutdown, and Malfunction Plan
Tpy	Tons Per Year
UTM	Universal Transverse Mercator
VOC	Volatile Organic Compound

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## SECTION I: FACILITY INFORMATION

PERMITTEE: Creative Foam Products, LLC.

AFIN: 60-06113

PERMIT NUMBER: 2448-AOP-R0

FACILITY ADDRESS: 1301 E. Eighth Street  
North Little Rock, AR 72114

MAILING ADDRESS: P. O. Box 489  
North Little Rock, AR 72114

COUNTY: Pulaski County

CONTACT NAME: Jeff Hyde

CONTACT POSITION: General Manager

TELEPHONE NUMBER: (501) 766-2503

REVIEWING ENGINEER: Sterling Powers

UTM North South (Y): Zone 15: 3846739.1 m

UTM East West (X): Zone 15: 568684.11 m

## **SECTION II: INTRODUCTION**

### **Summary of Permit Activity**

Creative Foam Products, LLC operates an expanded polystyrene (EPS) block molding facility at 1308 West 8<sup>th</sup> Street in North Little Rock, AR. The facility submitted an application to change the facility permit from a Minor Source Permit to a Title V Permit. A dust collector was added to the Remelt phase of the bead expansion process for SN-01, Boiler #2 was added (SN-02B), the throughput for the facility was increased to 240.0 tpy VOC, and process descriptions were updated. Permitted emissions increased by 0.8 tpy PM<sub>10</sub>, 0.1 tpy SO<sub>x</sub>, 145.3 tpy VOC, 3.8 tpy CO, 4.5 tpy NO<sub>x</sub>, 0.8 tpy PM, and 0.18 tpy Total HAPs.

### **Process Description**

The foam blocks are used for a variety of purposes such as insulation, architectural shapes and packaging material. Creative Foam Products will use a maximum of 8,000 pounds of EPS beads on an hourly basis, and 240 tons per year of VOC emissions on an annual basis.

Production of EPS foam blocks consists of five steps: pre-expansion, pre-puff aging, block molding, block storage and block fabrication.

#### **Pre-Expansion (2 Units)**

Raw material consisting of EPS beads impregnated with a blowing agent (pentane) is transferred into a bead hopper which is then loaded into the pre-expander. The beads are processed in a batch expander with low pressure steam from the boiler to soften and expand the beads. Pentane released during the process is vented outside the facility. At this point, the beads are 20 to 60 times larger and very fragile.

#### **Pre-Puff Aging**

The excess moisture on the pre-expanded beads resulting from the steam expansion process is then dried with hot air as the beads pass through the bead dryer. From the dryer, the beads are pneumatically fed into large mesh holding bags or “silos” where they cool and age for a period of time. After stabilization of the beads, they are pneumatically fed into the block mold. Pentane released during this stage is vented outside the facility.

#### **Block Molding (2 Units)**

After the mold is filled with beads and locked, steam is injected. This causes the beads to soften and expand further by vaporizing more of the pentane and fusing the beads together to form a solid block. Recycled EPS may be incorporated at this stage to produce a recycled content product. The pentane released during the process is vented outside.

#### **Recycle**

In the block fabrication process the dust collector (Dust Distributor, Insignificant Activity) is used to separate foam and dust particles. Foam particles are sent to the scrap SILO, whereas the



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dust is sent to dust bags (supersack). The facility will now add a dust collector for the existing remelt process (under SN-01).

### **Block Storage**

The blocks are stored in the block storage room for the first 48 hours or until cured. Pentane released during this process is vented outside.

### **Block Fabrication (2 Units)**

In the fabrication area, blocks are cut and sliced into the desired sizes and shapes. There is no emission of pentane in this area since the blocks have been cured in the block storage area. In the block fabrication process the dust distributor is used to separate foam and dust particles. Foam particles are sent to the scrap SILO, whereas the dust is sent to the dust bags (supersack). Scrap material from the block fabrication process is recycled, mixed with the new raw material and sent back to the block molding process.

## **Rules and Regulations**

The following table contains the rules and regulations applicable to this permit.

Rules and Regulations
Arkansas Air Pollution Control Code, Rule 18, effective March 14, 2016
Rules of the Arkansas Plan of Implementation for Air Pollution Control, Rule 19, effective May 6, 2022
Rules of the Arkansas Operating Air Permit Program, Rule 26, effective March 14, 2016
40 C.F.R. Part 60, Subpart Dc - Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units

### Emission Summary

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				
Source Number	Description	Pollutant	Emission Rates	
			lb/hr	tpy
Total Allowable Emissions		PM	0.1	0.4
		PM <sub>10</sub>	0.4	0.4
		SO <sub>2</sub>	0.1	0.1
		VOC	210.4	240.0
		CO	1.1	3.8
		NO <sub>x</sub>	0.02	4.5
HAPs		Total HAPs	0.04	0.18
SN-01	Pre-Expansion	VOC	74.9	240.0*
	Pre-Puff Aging		155.6	
	Block Molding		92.2	
	Block Storage		55.9	
	Remelt	PM	0.1	0.4
SN-02A	Boiler #1 (10.46 MMBtu/hr)	PM <sub>10</sub>	0.1	0.4
		SO <sub>2</sub>	0.1	0.1
		VOC	0.1	0.3
		CO	0.9	3.8
		NO <sub>x</sub>	1.1	4.5
		Single HAP (Hexane)	0.02	0.09
		Total HAPs	0.02	0.09
		SN-02B	Boiler #2 (10.46 MMBtu/hr)	PM
PM <sub>10</sub>	0.1			0.4
SO <sub>2</sub>	0.1			0.1
VOC	0.1			0.3
CO	0.9			3.8
NO <sub>x</sub>	1.1			4.5

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EMISSION SUMMARY				
Source Number	Description	Pollutant	Emission Rates	
			lb/hr	tpy
		Single HAP (Hexane)	0.02	0.09
		Total HAPs	0.02	0.09

\*Annual VOC Limit for production of EPS Foam is 240.0 tpy.

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### **SECTION III: PERMIT HISTORY**

Permit #2448-A is the initial permit for this facility. The facility submitted an application for an initial minor source permit with permitted emissions of 0.4 tpy PM/PM<sub>10</sub>, 0.1 tpy SO<sub>2</sub>, 95.3 tpy VOC, 3.8 tpy CO, 4.5 tpy NO<sub>x</sub> and 0.09 tpy Total HAPs.

Permit #2448-AR-1 is an administrative amendment modification adding a dust distributor to the insignificant activities list, and updating process descriptions. Permitted emissions are unchanged.

## SECTION IV: SPECIFIC CONDITIONS

### SN-01

#### Five Stage EPS Foam Block Process

Production of EPS foam blocks consists of five steps: pre-expansion, pre-puff aging, block molding, block storage and block fabrication. Raw material consisting of EPS beads impregnated with a blowing agent (pentane) is transferred into a bead hopper, processed and expanded, then dried, cooled, put into a block mold, and stored in a heated room until cured.

#### Specific Conditions

1. The permittee shall not exceed the emission rates set forth in the following table. The permittee shall demonstrate compliance with this condition by Specific Condition #5. [Rule 19.501 *et seq.* and 40 C.F.R. § 52 Subpart E]

SN	Description	Pollutant	lb/hr	tpy
01	Pre Expansion	VOC	74.9	240.0
	Pre-Puff Aging	VOC	155.6	
	Block Molding	VOC	92.2	
	Block Storage	VOC	55.9	
	Remelt (Dust Collector)	PM <sub>10</sub> VOC	0.1 64.0	

2. The permittee shall not exceed the emission rates set forth in the following table. The permittee shall demonstrate compliance with this condition by Specific Condition #13. [Rule 18.801 and Ark. Code Ann. § 8-4-203 as referenced by Ark. Code Ann. §§ 8-4-304 and 8-4-311]

SN	Description	Pollutant	lb/hr	tpy
01	Remelt (Dust Collector)	PM	0.1	0.40

3. Visible emissions may not exceed the limits specified in the following table of this permit as measured by EPA Reference Method 9.

SN	Limit	Regulatory Citation
01 (Remelt with Dust Collector)	5%	Rule 18.501

Weekly observations of the opacity from SN-01 (Remelt with Dust Collector) shall be conducted by a person trained but not necessarily certified in EPA Reference Method 9. If visible emissions in excess of the permitted levels are detected, the permittee shall immediately take action to identify the cause of the visible emissions in excess of the permit limit, implement corrective action, and document that visible emissions did not appear to be in excess of the permitted opacity following the corrective action/perform an EPA Reference Method 9 test to verify emissions are not in excess of the permitted level. The permittee shall maintain records which contain the following items in order to demonstrate compliance with this specific condition. These records shall be updated weekly, kept on site, and made available to Division of Environmental Quality personnel upon request.

- a. The date and time of the observation.
  - b. If visible emissions which appeared to be above the permitted limit were detected.
  - c. If visible emissions which appeared to be above the permitted limit were detected, the cause of the exceedance of the opacity limit, the corrective action taken, and if the visible emissions appeared to be below the permitted limit after the corrective action was taken.
  - d. The name of the person conducting the opacity observations.
4. The permittee shall not cause or permit the emission of air contaminants, including odors or water vapor and including an air contaminant whose emission is not otherwise prohibited by Rule 18, if the emission of the air contaminant constitutes air pollution within the meaning of Ark. Code Ann. § 8-4-303. [Rule 18.801 and Ark. Code Ann. § 8-4-203 as referenced by Ark. Code Ann. §§ 8-4-304 and 8-4-311]
5. The permittee shall not conduct operations in such a manner as to unnecessarily cause air contaminants and other pollutants to become airborne. [Rule 18.901 and Ark. Code Ann. § 8-4-203 as referenced by Ark. Code Ann. §§ 8-4-304 and 8-4-311]
6. The permittee shall not exceed a VOC (as pentane) content of 8% by weight for any expandable polystyrene resin used at the facility. The resin shall not contain any Hazardous Air Pollutant or Air Contaminant. [Rule 19.705 and Ark. Code Ann. § 8-4-203 as referenced by Ark. Code Ann. §§ 8-4-304 and 8-4-311, and 40 C.F.R. 70.6]
7. The permittee shall not exceed an emission rate of 240.0 tons of VOC per rolling twelve-month period. [Rule 19.705 and Ark. Code Ann. § 8-4-203 as referenced by Ark. Code Ann. §§ 8-4-304 and 8-4-311, and 40 C.F.R. 70.6]

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8. The permittee shall maintain monthly records to demonstrate compliance with Specific Condition #6 and 7. Records shall consist of a material balance of emissions from the facility which shall be a summation by month of the polystyrene bead usage in the process (in tons) multiplied times the weight fraction of VOC in the beads as shown on the Safety Data Sheet (SDS) and the appropriate emission factors for the process in the table below, as outlined in the 1999 BASF technical bulletin: "Environmental Pentane Emissions During Processing."

Process	Emission Rate
Pre-Expansion	13%
Pre-Puff Aging	27%
Block Molding	16%
Block Storage	9.7%
Remelt with Dust Collector	100%

The permittee shall update these records by the fifteenth day of the month following the month to which the records pertain. The twelve month rolling totals, the SDS, and each individual month's data shall be maintained on site, made available to the Division Personnel upon request, and submitted in accordance with General Provision #7. [Rule 19.705 and Ark. Code Ann. § 8-4-203 as referenced by Ark. Code Ann. §§ 8-4-304 and 8-4-311]

**SN-02A and SN-02B**  
**Boiler #1 and #2 (10.46 MMBtu/hr each)**

The Boiler #1 (SN-02A) and Boiler #2 (SN-02B) are both 250 hp Super Seminole 1250 steam boilers that produce 10.46 MMBtu/hr. The feed tanks to the boilers are 300 gal each.

**Specific Conditions**

9. The permittee shall not exceed the emission rates set forth in the following table. The permittee shall demonstrate compliance with this condition by Specific Condition #13. [Rule 19.501 *et seq.* and 40 C.F.R. § 52 Subpart E]

SN	Description	Pollutant	lb/hr	tpy
02A	Boiler #1 (10.46 MMBtu/hr)	PM <sub>10</sub>	0.1	0.4
		SO <sub>2</sub>	0.1	0.1
		VOC	0.1	0.3
		CO	0.9	3.8
		NO <sub>x</sub>	1.1	4.5
02B	Boiler #2 (10.46 MMBtu/hr)	PM <sub>10</sub>	0.1	0.4
		SO <sub>2</sub>	0.1	0.1
		VOC	0.1	0.3
		CO	0.9	3.8
		NO <sub>x</sub>	1.1	4.5

10. The permittee shall not exceed the emission rates set forth in the following table. The permittee shall demonstrate compliance with this condition by Specific Condition #13. [Rule 18.801 and Ark. Code Ann. § 8-4-203 as referenced by Ark. Code Ann. §§ 8-4-304 and 8-4-311]

SN	Description	Pollutant	lb/hr	tpy
02A	Boiler #1 (10.46 MMBtu/hr)	PM	0.1	0.4
		Single HAP (Hexane)	0.02	0.02
		Total HAPs	0.02	0.09
02B	Boiler #2 (10.46 MMBtu/hr)	PM	0.1	0.4
		Single HAP (Hexane)	0.02	0.02
		Total HAPs	0.02	0.09

11. Visible emissions may not exceed the limits specified in the following table of this permit as measured by EPA Reference Method 9. Compliance with this opacity limit shall be demonstrated by the use of natural gas as fuel.



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SN	Limit	Regulatory Citation
02	5%	Rule 18.501

12. The permittee shall use only natural gas as fuel at SN-02A and 02B. [Rule 18.1004, Rule 19.705, Ark. Code Ann. § 8-4-203 as referenced by Ark. Code Ann. §§ 8-4-304 and 8-4-311 and 40 C.F.R. Part 70.6]
13. The permittee shall submit notification of the date of construction or reconstruction and actual startup, as provided by § 60.7 of this part. This notification shall include: [Rule 19.304 and 40 C.F.R. § 60.48c(a)(1-3)]
  - a. The design heat input capacity of the affected facility and identification of fuels to be combusted in the affected facility.
  - b. If applicable, a copy of any federally enforceable requirement that limits the annual capacity factor for any fuel or mixture of fuels under §60.42c, or §60.43c.
  - c. The annual capacity factor at which the owner or operator anticipates operating the affected facility based on all fuels fired and based on each individual fuel fire.
14. Boiler #1 and #2 (SN-02A and 02B) are considered affected sources under 40 C.F.R. Part 60, Subpart Dc. The permittee shall maintain records of the amount of natural gas combusted. These records shall be maintained on a monthly basis and updated by the 15th day of the month after the month which the records represent. These records shall be kept on site and be made available to Department personnel upon request. The permittee is required to maintain these records for at least two years. [Rule 19.304 and 40 C.F.R. Part 60, Subpart Dc]

Creative Foam Products, LLC.

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## **SECTION V: COMPLIANCE PLAN AND SCHEDULE**

Creative Foam Products, LLC. will continue to operate in compliance with those identified regulatory provisions. The facility will examine and analyze future rules and 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. [Rule 19.704, 40 C.F.R. § 52 Subpart E, and Ark. Code Ann. § 8-4-203 as referenced by Ark. Code Ann. §§ 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. [Rule 19.410(B) and 40 C.F.R. § 52 Subpart E]
3. The permittee must test any equipment scheduled for testing, unless otherwise 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 Division of Environmental Quality or within 180 days of permit issuance if no date is specified. The permittee must notify the Division of Environmental Quality of the scheduled date of compliance testing at least fifteen (15) business days in advance of such test. The permittee shall submit the compliance test results to the Division of Environmental Quality within sixty (60) calendar days after completing the testing. [Rule 19.702 and/or Rule 18.1002 and Ark. Code Ann. § 8-4-203 as referenced by Ark. Code Ann. §§ 8-4-304 and 8-4-311]
4. The permittee must provide:
  - 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.

[Rule 19.702 and/or Rule 18.1002 and Ark. Code Ann. § 8-4-203 as referenced by Ark. Code Ann. §§ 8-4-304 and 8-4-311]
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. [Rule 19.303 and Ark. Code Ann. § 8-4-203 as referenced by Ark. Code Ann. §§ 8-4-304 and 8-4-311]
6. This permit subsumes and incorporates all previously issued air permits for this facility. [Rule 26 and Ark. Code Ann. § 8-4-203 as referenced by Ark. Code Ann. §§ 8-4-304 and 8-4-311]

Creative Foam Products, LLC.

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7. Unless otherwise specified in the permit, approval to construct any new major stationary source or a major modification subject to 40 C.F.R. § 52.21 shall become invalid if construction is not commenced within 18 months after receipt of such approval, if construction is discontinued for a period of 18 months or more, or if construction is not completed within a reasonable time. The Division of Environmental Quality may extend the 18-month period upon a satisfactory showing that an extension is justified. [Rule 19.901 *et seq.* and 40 C.F.R. § 52 Subpart E]

#### Permit Shield

2. Compliance with the conditions of this permit shall be deemed compliance with all applicable requirements, as of the date of permit issuance, included in and specifically identified in the following table of this condition. The permit specifically identifies the following as applicable requirements based upon the information submitted by the permittee in an application dated September 25, 2023.

#### Applicable Regulations

Source No.	Regulation	Description
N/A		

The permit specifically identifies the following as inapplicable based upon information submitted by the permittee in an application dated September 25, 2023.

#### Inapplicable Regulations

Source No.	Regulation	Description
N/A		

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## SECTION VII: INSIGNIFICANT ACTIVITIES

The Division of Environmental Quality deems the following types of activities or emissions as insignificant on the basis of size, emission rate, production rate, or activity in accordance with Group A of the Insignificant Activities list found in Rule 18 and Rule 19 Appendix A. Group B insignificant activities may be listed but are not required to be listed in permits. Insignificant activity emission determinations rely upon the information submitted by the permittee in an application dated September 25, 2023. [Rule 26.304 and Ark. Code Ann. § 8-4-203 as referenced by Ark. Code Ann. §§ 8-4-304 and 8-4-311]

Description	Category
Cooling Tower	A-13
Crusher	A-13
Dust Distributor (Block Fabrication Process)	A-13

## SECTION VIII: GENERAL PROVISIONS

1. Any terms or conditions included in this permit which specify and reference Arkansas Pollution Control & Ecology Commission Rule 18 or the Arkansas Water and Air Pollution Control Act (Ark. Code Ann. § 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 Rule 18 was adopted pursuant to the Arkansas Water and Air Pollution Control Act (Ark. Code Ann. § 8-4-101 *et seq.*). Any terms or conditions included in this permit which specify and reference Arkansas Pollution Control & Ecology Commission Rule 18 or the Arkansas Water and Air Pollution Control Act (Ark. Code Ann. § 8-4-101 *et seq.*) as the origin of and authority for the terms or conditions are enforceable under this Arkansas statute. [40 C.F.R. § 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 C.F.R. § 70.6(a)(2) and Rule 26.701(B)]
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 Division of Environmental Quality takes final action on the renewal application. The Division of Environmental Quality will not necessarily notify the permittee when the permit renewal application is due. [Rule 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 C.F.R. § 70.6(a)(1)(ii) and Rule 26.701(A)(2)]
5. The permittee must maintain the following records of monitoring information as required by this permit.
  - 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.

[40 C.F.R. § 70.6(a)(3)(ii)(A) and Rule 26.701(C)(2)]

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 C.F.R. § 70.6(a)(3)(ii)(B) and Rule 26.701(C)(2)(b)]
7. The permittee must submit reports of all required monitoring every six (6) months. If the permit establishes no other reporting period, the reporting period shall end on the last day of the month six months after the issuance of the initial Title V permit and every six months thereafter. The report is due on the first day of the second month after the end of the reporting period. The first report due after issuance of the initial Title V permit shall contain six months of data and each report thereafter shall contain 12 months of data. The report shall contain data for all monitoring requirements in effect during the reporting period. If a monitoring requirement is not in effect for the entire reporting period, only those months of data in which the monitoring requirement was in effect are required to be reported. The report must clearly identify all instances of deviations from permit requirements. A responsible official as defined in Rule 26.2 must certify all required reports. The permittee will send the reports electronically using <https://portal.adeq.state.ar.us> or mail them to the address below:

Division of Environmental Quality  
Office of Air Quality  
ATTN: Compliance Inspector Supervisor  
5301 Northshore Drive  
North Little Rock, AR 72118-5317

[40 C.F.R. § 70.6(a)(3)(iii)(A) and Rule 26.701(C)(3)(a)]

8. The permittee shall report to the Division of Environmental Quality all deviations from permit requirements, including those attributable to upset conditions as defined in the permit.
  - a. For all upset conditions (as defined in Rule 19.601), the permittee will make an initial report to the Division of Environmental Quality by the next business day after the discovery of the occurrence. The initial report may 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 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 Division of Environmental Quality 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.

[Rule 19.601, Rule 19.602, Rule 26.701(C)(3)(b), and 40 C.F.R. § 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 Rule are declared to be separable and severable. [40 C.F.R. § 70.6(a)(5), Rule 26.701(E), and Ark. Code Ann. § 8-4-203 as referenced by Ark. Code Ann. §§ 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 Rule 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 C.F.R. § 70.6(a)(6)(i) and Rule 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 C.F.R. § 70.6(a)(6)(ii) and Rule 26.701(F)(2)]
- 12. The Division of Environmental Quality 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 C.F.R. § 70.6(a)(6)(iii) and Rule 26.701(F)(3)]
13. This permit does not convey any property rights of any sort, or any exclusive privilege. [40 C.F.R. § 70.6(a)(6)(iv) and Rule 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 Division of Environmental Quality may require the permittee to furnish such records directly to the Director along with a claim of confidentiality. [40 C.F.R. § 70.6(a)(6)(v) and Rule 26.701(F)(5)]
  15. The permittee must pay all permit fees in accordance with the procedures established in Rule 9. [40 C.F.R. § 70.6(a)(7) and Rule 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 C.F.R. § 70.6(a)(8) and Rule 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 C.F.R. § 70.6(a)(9)(i) and Rule 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 Division of Environmental Quality specifically designates terms and conditions of the permit as being federally unenforceable under the Act or under any of its applicable requirements. [40 C.F.R. § 70.6(b) and Rule 26.702(A) and (B)]
  19. Any document (including reports) required by this permit pursuant to 40 C.F.R. § 70 must contain a certification by a responsible official as defined in Rule 26.2. [40 C.F.R. § 70.6(c)(1) and Rule 26.703(A)]
  20. The permittee must allow an authorized representative of the Division of Environmental Quality, upon presentation of credentials, to perform the following: [40 C.F.R. § 70.6(c)(2) and Rule 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. If the 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 on the first day of the second month after the end of the reporting period. The permittee must also submit the compliance certification to the Administrator as well as to the Division of Environmental Quality. All compliance certifications required by this permit must include the following: [40 C.F.R. § 70.6(c)(5) and Rule 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; and
  - e. Such other facts as the Division of Environmental Quality 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: [Rule 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. [Ark. Code Ann. § 8-4-203 as referenced by Ark. Code Ann. §§ 8-4-304 and 8-4-311]
- 24. The permittee may request in writing and at least 15 days in advance of the deadline, an extension to any testing, compliance or other dates in this permit. No such extensions are authorized until the permittee receives written Division of Environmental Quality

approval. The Division of Environmental Quality may grant such a request, at its discretion in the following circumstances:

- a. Such an extension does not violate a federal requirement;
- b. The permittee demonstrates the need for the extension; and
- c. The permittee documents that all reasonable measures have been taken to meet the current deadline and documents reasons it cannot be met.

[Rule 18.314(A), Rule 19.416(A), Rule 26.1013(A), Ark. Code Ann. § 8-4-203 as referenced by Ark. Code Ann. §§ 8-4-304 and 8-4-311, and 40 C.F.R. § 52 Subpart E]

25. The permittee may request in writing and at least 30 days in advance, temporary emissions and/or testing that would otherwise exceed an emission rate, throughput requirement, or other limit in this permit. No such activities are authorized until the permittee receives written Division of Environmental Quality approval. Any such emissions shall be included in the facility's total emissions and reported as such. The Division of Environmental Quality may grant such a request, at its discretion under the following conditions:

- a. Such a request does not violate a federal requirement;
- b. Such a request is temporary in nature;
- c. Such a request will not result in a condition of air pollution;
- d. The request contains such information necessary for the Division of Environmental Quality to evaluate the request, including but not limited to, quantification of such emissions and the date/time such emission will occur;
- e. Such a request will result in increased emissions less than five tons of any individual criteria pollutant, one ton of any single HAP and 2.5 tons of total HAPs; and
- f. The permittee maintains records of the dates and results of such temporary emissions/testing.

[Rule 18.314(B), Rule 19.416(B), Rule 26.1013(B), Ark. Code Ann. § 8-4-203 as referenced by Ark. Code Ann. §§ 8-4-304 and 8-4-311, and 40 C.F.R. § 52 Subpart E]

26. The permittee may request in writing and at least 30 days in advance, an alternative to the specified monitoring in this permit. No such alternatives are authorized until the permittee receives written Division of Environmental Quality approval. The Division of Environmental Quality may grant such a request, at its discretion under the following conditions:

- a. The request does not violate a federal requirement;
- b. The request provides an equivalent or greater degree of actual monitoring to the current requirements; and
- c. Any such request, if approved, is incorporated in the next permit modification application by the permittee.

Creative Foam Products, LLC.

Permit #: 2448-AOP-R0

AFIN: 60-06113

[Rule 18.314(C), Rule 19.416(C), Rule 26.1013(C), Ark. Code Ann. § 8-4-203 as referenced by Ark. Code Ann. §§ 8-4-304 and 8-4-311, and 40 C.F.R. § 52 Subpart E]

27. Any credible evidence based on sampling, monitoring, and reporting may be used to determine violations of applicable emission limitations. [Rule 18.1001, Rule 19.701, Ark. Code Ann. § 8-4-203 as referenced by Ark. Code Ann. §§ 8-4-304 and 8-4-311, and 40 C.F.R. § 52 Subpart E]

# **Appendix A**

## **Subpart Dc**

*Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units*

## Subpart Dc—Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units

Source: [72 FR 32759](#), June 13, 2007, unless otherwise noted.

### § 60.40c Applicability and delegation of authority.

- (a) Except as provided in [paragraphs \(d\), \(e\), \(f\), and \(g\)](#) of this section, the affected facility to which this subpart applies is each steam generating unit for which construction, modification, or reconstruction is commenced after June 9, 1989 and that has a maximum design heat input capacity of 29 megawatts (MW) (100 million British thermal units per hour (MMBtu/h)) or less, but greater than or equal to 2.9 MW (10 MMBtu/h).
- (b) In delegating implementation and enforcement authority to a State under section 111(c) of the Clean Air Act, [§ 60.48c\(a\)\(4\)](#) shall be retained by the Administrator and not transferred to a State.
- (c) Steam generating units that meet the applicability requirements in [paragraph \(a\)](#) of this section are not subject to the sulfur dioxide (SO<sub>2</sub>) or particulate matter (PM) emission limits, performance testing requirements, or monitoring requirements under this subpart ([§ 60.42c](#), [§ 60.43c](#), [§ 60.44c](#), [§ 60.45c](#), [§ 60.46c](#), or [§ 60.47c](#)) during periods of combustion research, as defined in [§ 60.41c](#).
- (d) Any temporary change to an existing steam generating unit for the purpose of conducting combustion research is not considered a modification under [§ 60.14](#).
- (e) Affected facilities (*i.e.* heat recovery steam generators and fuel heaters) that are associated with stationary combustion turbines and 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, fuel heaters, and other affected facilities that are capable of combusting more than or equal to 2.9 MW (10 MMBtu/h) heat input of fossil fuel but less than or equal to 29 MW (100 MMBtu/h) heat input of fossil fuel. If the heat recovery steam generator, fuel heater, or other affected facility is subject to this subpart, only emissions resulting from combustion of fuels in the steam generating unit are subject to this subpart. (The stationary combustion turbine emissions are subject to subpart GG or KKKK, as applicable, of this part.)
- (f) Any affected facility that meets the applicability requirements of and is subject to subpart AAAA or [subpart CCCC of this part](#) is not subject to this subpart.
- (g) Any facility that meets the applicability requirements and is subject to an EPA approved State or Federal section 111(d)/129 plan implementing [subpart BBBB of this part](#) is not subject to this subpart.

(h) Affected facilities that also meet the applicability requirements under subpart J or [subpart Ja of this part](#) are subject to the PM and NO<sub>x</sub> standards under this subpart and the SO<sub>2</sub> standards under subpart J or [subpart Ja of this part](#), as applicable.

(i) Temporary boilers are not subject to this subpart.

[[72 FR 32759](#), June 13, 2007, as amended at [74 FR 5090](#), Jan. 28, 2009; [77 FR 9461](#), Feb. 16, 2012]

## § 60.41c Definitions.

As used in this subpart, all terms not defined herein shall have the meaning given them in the Clean Air 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 an individual fuel or combination of fuels during a period of 12 consecutive calendar months and the potential heat input to the steam generating unit from all fuels had the steam generating unit been operated for 8,760 hours during that 12-month period at the maximum 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 during a period of 12 consecutive calendar months.

*Coal* means all solid fuels classified as anthracite, bituminous, subbituminous, or lignite by the American Society of Testing and Materials in ASTM D388 (incorporated by reference, see [§ 60.17](#)), coal refuse, and petroleum coke. Coal-derived synthetic fuels derived from coal for the purposes of creating useful heat, including but not limited to solvent refined coal, gasified coal not meeting the definition of natural gas, coal-oil mixtures, and coal-water mixtures, are also included in this definition for the purposes of this subpart.

*Coal refuse* means any by-product 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 kilojoules per kilogram (kJ/kg) (6,000 Btu per pound (Btu/lb) on a dry basis.

*Combined cycle system* means a system in which a separate source (such as a stationary gas turbine, internal combustion engine, or kiln) provides exhaust gas to a steam generating unit.

*Combustion research* means the experimental firing of any fuel or combination of fuels in a steam generating unit for the purpose of conducting research and development of more efficient combustion or more effective prevention or control of air pollutant emissions from combustion, provided that, during these periods of research and development, the heat generated is not used for any purpose other than preheating combustion air for use by that steam generating unit (*i.e.*, the heat generated is released to the atmosphere without being used for space heating, process heating, driving pumps, preheating combustion air for other units, generating electricity, or any other purpose).

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

*Distillate oil* means fuel oil that complies with the specifications for fuel oil numbers 1 or 2, as defined by the American Society for Testing and Materials in ASTM D396 (incorporated by reference, see [§ 60.17](#)), diesel fuel oil numbers 1 or 2, as defined by the American Society for Testing and Materials in ASTM D975 (incorporated by reference, see [§ 60.17](#)), kerosine, as defined by the American Society of Testing and Materials in ASTM D3699 (incorporated by reference, see [§ 60.17](#)), biodiesel as defined by the American Society of Testing and Materials in ASTM D6751 (incorporated by reference, see [§ 60.17](#)), or biodiesel blends as defined by the American Society of Testing and Materials in ASTM D7467 (incorporated by reference, see [§ 60.17](#)).

*Dry flue gas desulfurization technology* means a SO<sub>2</sub> control system that is located between the steam generating unit and the exhaust vent or stack, and that removes sulfur oxides from the combustion gases of the steam generating unit by contacting the combustion gases with an alkaline reagent and water, whether introduced separately or as a premixed 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 reagents used in dry flue gas desulfurization systems include, but are not limited to, lime and sodium compounds.

*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 steam generating unit.

*Emerging technology* means any SO<sub>2</sub> control system that is not defined as a conventional technology under this section, and for which the owner or operator of the affected facility has received approval from the Administrator to operate as an emerging technology under [§ 60.48c\(a\)\(4\)](#).

*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 [51.24](#).

*Fluidized bed combustion technology* means a device wherein fuel is distributed onto a bed (or series of beds) of limestone aggregate (or other sorbent materials) for combustion; and these materials are forced upward in the device by the flow of combustion air and the gaseous products of combustion. Fluidized bed combustion technology includes, but is not limited to, bubbling bed units and circulating bed units.

*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.



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

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

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

*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) Liquefied petroleum (LP) gas, as defined by the American Society for Testing and Materials in ASTM D1835 (incorporated by reference, see [§ 60.17](#)); or
- (3) A mixture of hydrocarbons that maintains a gaseous state at ISO conditions. Additionally, natural gas must either be composed of at least 70 percent methane by volume or have a gross calorific value between 34 and 43 megajoules (MJ) per dry standard cubic meter (910 and 1,150 Btu per dry standard cubic foot).

*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 oil and residual oil.

*Potential sulfur dioxide emission rate* means the theoretical SO<sub>2</sub> emissions (nanograms per joule (ng/J) or lb/MMBtu 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.

*Residual oil* means crude oil, fuel oil that does not comply with the specifications under the definition of distillate oil, and all fuel oil numbers 4, 5, and 6, as defined by the American Society for Testing and Materials in ASTM D396 (incorporated by reference, see [§ 60.17](#)).

*Steam generating unit* means a device that combusts any fuel and produces steam or heats water or heats any heat transfer medium. This term includes any duct burner that combusts fuel

and is part of a combined cycle system. This term does not include process heaters as 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.

*Temporary boiler* means a steam generating unit that combusts natural gas or distillate oil with a potential SO<sub>2</sub> emissions rate no greater than 26 ng/J (0.060 lb/MMBtu), and the unit is designed to, and is capable of, being carried or moved from one location to another by means of, for example, wheels, skids, carrying handles, dollies, trailers, or platforms. A steam generating unit is not a temporary boiler if any one of the following conditions exists:

- (1) The equipment is attached to a foundation.
- (2) The steam generating unit or a replacement remains at a location for more than 180 consecutive days. Any temporary boiler that replaces a temporary boiler at a location and performs the same or similar function will be included in calculating the consecutive time period.
- (3) The equipment is located at a seasonal facility and operates during the full annual operating period of the seasonal facility, remains at the facility for at least 2 years, and operates at that facility for at least 3 months each year.
- (4) The equipment is moved from one location to another in an attempt to circumvent the residence time requirements of this definition.

*Wet flue gas desulfurization technology* means an SO<sub>2</sub> control system that is located between the steam generating unit and the exhaust vent or stack, and that 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 includes devices where the liquid material is subsequently converted to another form. Alkaline reagents used in wet flue gas desulfurization systems include, but are not limited to, lime, limestone, and sodium compounds.

*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 PM or SO<sub>2</sub>.

*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.

[[72 FR 32759](#), June 13, 2007, as amended at [74 FR 5090](#), Jan. 28, 2009; [77 FR 9461](#), Feb. 16, 2012]

## **§ 60.42c Standard for sulfur dioxide (SO<sub>2</sub>).**

(a) Except as provided in [paragraphs \(b\), \(c\), and \(e\)](#) of this section, on and after the date on which the performance test is completed or required to be completed under [§ 60.8](#), whichever date comes first, the owner or operator of an affected facility that combusts only coal shall neither: cause to be discharged into the atmosphere from the affected facility any gases that contain SO<sub>2</sub> in excess of 87 ng/J (0.20 lb/MMBtu) heat input or 10 percent (0.10) of the potential SO<sub>2</sub> emission rate (90 percent reduction), nor cause to be discharged into the atmosphere from the affected facility any gases that contain SO<sub>2</sub> in excess of 520 ng/J (1.2 lb/MMBtu) heat input. If coal is combusted with other fuels, the affected facility shall neither: cause to be discharged into the atmosphere from the affected facility any gases that contain SO<sub>2</sub> in excess of 87 ng/J (0.20 lb/MMBtu) heat input or 10 percent (0.10) of the potential SO<sub>2</sub> emission rate (90 percent reduction), nor cause to be discharged into the atmosphere from the affected facility any gases that contain SO<sub>2</sub> in excess of the emission limit is determined pursuant to [paragraph \(e\)\(2\)](#) of this section.

(b) Except as provided in [paragraphs \(c\) and \(e\)](#) of this section, on and after the date on which the performance test is completed or required to be completed under [§ 60.8](#), whichever date comes first, the owner or operator of an affected facility that:

(1) Combusts only coal refuse alone in a fluidized bed combustion steam generating unit shall neither:

(i) Cause to be discharged into the atmosphere from that affected facility any gases that contain SO<sub>2</sub> in excess of 87 ng/J (0.20 lb/MMBtu) heat input or 20 percent (0.20) of the potential SO<sub>2</sub> emission rate (80 percent reduction); nor

(ii) Cause to be discharged into the atmosphere from that affected facility any gases that contain SO<sub>2</sub> in excess of SO<sub>2</sub> in excess of 520 ng/J (1.2 lb/MMBtu) heat input. If coal is fired with coal refuse, the affected facility subject to [paragraph \(a\)](#) of this section. If oil or any other fuel (except coal) is fired with coal refuse, the affected facility is subject to the 87 ng/J (0.20 lb/MMBtu) heat input SO<sub>2</sub> emissions limit or the 90 percent SO<sub>2</sub> reduction requirement specified in [paragraph \(a\)](#) of this section and the emission limit is determined pursuant to [paragraph \(e\)\(2\)](#) of this section.

(2) Combusts only coal and that uses an emerging technology for the control of SO<sub>2</sub> emissions shall neither:

(i) Cause to be discharged into the atmosphere from that affected facility any gases that contain SO<sub>2</sub> in excess of 50 percent (0.50) of the potential SO<sub>2</sub> emission rate (50 percent reduction); nor

(ii) Cause to be discharged into the atmosphere from that affected facility any gases that contain SO<sub>2</sub> in excess of 260 ng/J (0.60 lb/MMBtu) heat input. If coal is combusted with other fuels, the affected facility is subject to the 50 percent SO<sub>2</sub> reduction requirement specified in this paragraph and the emission limit determined pursuant to [paragraph \(e\)\(2\)](#) of this section.

(c) On and after the date on which the initial performance test is completed or required to be completed under [§ 60.8](#), whichever date comes first, no owner or operator of an affected facility that combusts coal, alone or in combination with any other fuel, and is listed in [paragraphs \(c\)\(1\), \(2\), \(3\), or \(4\)](#) of this section shall cause to be discharged into the atmosphere from that affected facility any gases that contain SO<sub>2</sub> in excess of the emission limit determined pursuant to [paragraph \(e\)\(2\)](#) of this section. Percent reduction requirements are not applicable to affected facilities under paragraphs (c)(1), (2), (3), or (4).

(1) Affected facilities that have a heat input capacity of 22 MW (75 MMBtu/h) or less;

(2) Affected facilities that have an annual capacity for coal of 55 percent (0.55) or less and are subject to a federally enforceable requirement limiting operation of the affected facility to an annual capacity factor for coal of 55 percent (0.55) or less.

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

(4) Affected facilities that combust coal in a duct burner as part of a combined cycle system where 30 percent (0.30) or less of the heat entering the steam generating unit is from combustion of coal in the duct burner and 70 percent (0.70) or more of the heat entering the steam generating unit is from exhaust gases entering the duct burner.

(d) On and after the date on which the initial performance test is completed or required to be completed under [§ 60.8](#), whichever date comes first, no owner or operator of an affected facility that combusts oil shall cause to be discharged into the atmosphere from that affected facility any gases that contain SO<sub>2</sub> in excess of 215 ng/J (0.50 lb/MMBtu) heat input from oil; or, as an alternative, no owner or operator of an affected facility that combusts oil shall combust oil in the affected facility that contains greater than 0.5 weight percent sulfur. The percent reduction requirements are not applicable to affected facilities under this paragraph.

(e) On and after the date on which the initial performance test is completed or required to be completed under [§ 60.8](#), whichever date comes first, no owner or operator of an affected facility that combusts coal, oil, or coal and oil with any other fuel shall cause to be discharged into the atmosphere from that affected facility any gases that contain SO<sub>2</sub> in excess of the following:

(1) The percent of potential SO<sub>2</sub> emission rate or numerical SO<sub>2</sub> emission rate required under [paragraph \(a\)](#) or [\(b\)\(2\)](#) of this section, as applicable, for any affected facility that

(i) Combusts coal in combination with any other fuel;

(ii) Has a heat input capacity greater than 22 MW (75 MMBtu/h); and

(iii) Has an annual capacity factor for coal greater than 55 percent (0.55); and

(2) The emission limit determined according to the following formula for any affected facility that combusts coal, oil, or coal and oil with any other fuel:

$$E_s = \frac{(K_a H_a + K_b H_b + K_c H_c)}{(H_a + H_b + H_c)}$$

Where:

$E_s$  = SO<sub>2</sub> emission limit, expressed in ng/J or lb/MMBtu heat input;

$K_a$  = 520 ng/J (1.2 lb/MMBtu);

$K_b$  = 260 ng/J (0.60 lb/MMBtu);

$K_c$  = 215 ng/J (0.50 lb/MMBtu);

$H_a$  = Heat input from the combustion of coal, except coal combusted in an affected facility subject to [paragraph \(b\)\(2\)](#) of this section, in Joules (J) [MMBtu];

$H_b$  = Heat input from the combustion of coal in an affected facility subject to [paragraph \(b\)\(2\)](#) of this section, in J (MMBtu); and

$H_c$  = Heat input from the combustion of oil, in J (MMBtu).

(f) Reduction in the potential SO<sub>2</sub> emission rate through fuel pretreatment is not credited toward the percent reduction requirement under [paragraph \(b\)\(2\)](#) of this section unless:

(1) Fuel pretreatment results in a 50 percent (0.50) or greater reduction in the potential SO<sub>2</sub> emission rate; and

(2) Emissions from the pretreated fuel (without either combustion or post-combustion SO<sub>2</sub> control) are equal to or less than the emission limits specified under [paragraph \(b\)\(2\)](#) of this section.

(g) Except as provided in [paragraph \(h\)](#) of this section, compliance with the percent reduction requirements, fuel oil sulfur limits, and emission limits of this section shall be determined on a 30-day rolling average basis.

(h) For affected facilities listed under [paragraphs \(h\)\(1\), \(2\), \(3\), or \(4\)](#) of this section, compliance with the emission limits or fuel oil sulfur limits under this section may be determined based on a certification from the fuel supplier, as described under [§ 60.48c\(f\)](#), as applicable.

(1) Distillate oil-fired affected facilities with heat input capacities between 2.9 and 29 MW (10 and 100 MMBtu/hr).

(2) Residual oil-fired affected facilities with heat input capacities between 2.9 and 8.7 MW (10 and 30 MMBtu/hr).

(3) Coal-fired affected facilities with heat input capacities between 2.9 and 8.7 MW (10 and 30 MMBtu/h).

(4) Other fuels-fired affected facilities with heat input capacities between 2.9 and 8.7 MW (10 and 30 MMBtu/h).

(i) The SO<sub>2</sub> emission limits, fuel oil sulfur limits, and percent reduction requirements under this section apply at all times, including periods of startup, shutdown, and malfunction.

(j) For affected facilities located in noncontinental areas and affected facilities complying with the percent reduction standard, 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 wood or other fuels or for heat derived from exhaust gases from other sources, such as stationary gas turbines, internal combustion engines, and kilns.

[[72 FR 32759](#), June 13, 2007, as amended at [74 FR 5090](#), Jan. 28, 2009; [77 FR 9462](#), Feb. 16, 2012]

## **§ 60.43c Standard for particulate matter (PM).**

(a) On and after the date on which the initial performance test is completed or required to be completed under [§ 60.8](#), 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 combusts mixtures of coal with other fuels and has a heat input capacity of 8.7 MW (30 MMBtu/h) or greater, shall cause to be discharged into the atmosphere from that affected facility any gases that contain PM in excess of the following emission limits:

(1) 22 ng/J (0.051 lb/MMBtu) heat input if the affected facility combusts only coal, or combusts coal with 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/MMBtu) heat input if the affected facility combusts coal with other fuels, 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.

(b) On and after the date on which the initial performance test is completed or required to be completed under [§ 60.8](#), 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 wood or combusts mixtures of wood with other fuels (except coal) and has a heat input capacity of 8.7 MW (30 MMBtu/h) or greater, shall cause to be discharged into the atmosphere from that affected facility any gases that contain PM in excess of the following emissions limits:



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

(2) 130 ng/J (0.30 lb/MMBtu) heat input if the affected facility has an annual capacity factor for wood of 30 percent (0.30) or less and is subject to a federally enforceable requirement limiting operation of the affected facility to an annual capacity factor for wood of 30 percent (0.30) or less.

(c) On and after the date on which the initial performance test is completed or required to be completed under [§ 60.8](#), whichever date comes first, no owner or operator of an affected facility that combusts coal, wood, or oil and has a heat input capacity of 8.7 MW (30 MMBtu/h) or greater shall cause to be discharged into the atmosphere from that affected facility 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. Owners and operators of an affected facility that elect to install, calibrate, maintain, and operate a continuous emissions monitoring system (CEMS) for measuring PM emissions according to the requirements of this subpart and are subject to a federally enforceable PM limit of 0.030 lb/MMBtu or less are exempt from the opacity standard specified in this [paragraph \(c\)](#).

(d) The PM and opacity standards under this section apply at all times, except during periods of startup, shutdown, or malfunction.

(e)

(1) On and after the date on which the initial performance test is completed or is required to be completed under [§ 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, wood, a mixture of these fuels, or a mixture of these fuels with any other fuels and has a heat input capacity of 8.7 MW (30 MMBtu/h) or greater shall cause to be discharged into the atmosphere from that affected facility any gases that contain PM in excess of 13 ng/J (0.030 lb/MMBtu) heat input, except as provided in [paragraphs \(e\)\(2\)](#), [\(e\)\(3\)](#), and [\(e\)\(4\)](#) of this section.

(2) As an alternative to meeting the requirements of [paragraph \(e\)\(1\)](#) 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 initial performance test is completed or required to be completed under [§ 60.8](#), whichever date comes first, no owner or operator of an affected facility that commences modification after February 28, 2005 shall cause to be discharged into the atmosphere from that affected facility any gases that contain PM in excess of both:

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

(3) On and after the date on which the initial performance test is completed or is required to be completed under [§ 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 heat input capacity of 8.7 MW (30 MMBtu/h) or greater shall cause to be discharged into the atmosphere from that affected facility any gases that contain PM in excess of 43 ng/J (0.10 lb/MMBtu) heat input.

(4) An 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 0.50 weight percent sulfur or a mixture of 0.50 weight percent sulfur oil with other fuels not subject to a PM standard under [§ 60.43c](#) and not using a post-combustion technology (except a wet scrubber) to reduce PM or SO<sub>2</sub> emissions is not subject to the PM limit in this section.

[[72 FR 32759](#), June 13, 2007, as amended at [74 FR 5091](#), Jan. 28, 2009; [77 FR 9462](#), Feb. 16, 2012]

## **§ 60.44c Compliance and performance test methods and procedures for sulfur dioxide.**

(a) Except as provided in [paragraphs \(g\) and \(h\)](#) of this section and [§ 60.8\(b\)](#), performance tests required under [§ 60.8](#) shall be conducted following the procedures specified in [paragraphs \(b\), \(c\), \(d\), \(e\), and \(f\)](#) of this section, as applicable. [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.

(b) The initial performance test required under [§ 60.8](#) shall be conducted over 30 consecutive operating days of the steam generating unit. Compliance with the percent reduction requirements and SO<sub>2</sub> emission limits under [§ 60.42c](#) 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 the initial startup of the facility. The steam generating unit load during the 30-day period does not have to be the maximum design heat input capacity, but must be representative of future operating conditions.

(c) After the initial performance test required under [paragraph \(b\)](#) of this section and [§ 60.8](#), compliance with the percent reduction requirements and SO<sub>2</sub> emission limits under [§ 60.42c](#) is based on the average percent reduction and the average SO<sub>2</sub> emission rates for 30 consecutive steam generating unit operating days. A separate performance test is completed at the end of each steam generating unit operating day, and a new 30-day average percent reduction and SO<sub>2</sub> emission rate are calculated to show compliance with the standard.

(d) If only coal, only oil, or a mixture of coal and oil is combusted in an affected facility, the procedures in Method 19 of [appendix A of this part](#) are used to determine the hourly SO<sub>2</sub> emission rate (E<sub>ho</sub>) and the 30-day average SO<sub>2</sub> emission rate (E<sub>ao</sub>). The hourly averages used



to compute the 30-day averages are obtained from the CEMS. Method 19 of [appendix A of this part](#) shall be used to calculate  $E_{ao}$  when using daily fuel sampling or Method 6B of [appendix A of this part](#).

(e) If coal, oil, or coal and oil are combusted with other fuels:

(1) An adjusted  $E_{ho}$  ( $E_{hoO}$ ) is used in Equation 19–19 of Method 19 of [appendix A of this part](#) to compute the adjusted  $E_{ao}$  ( $E_{aoO}$ ). The  $E_{hoO}$  is computed using the following formula:

$$E_{hoO} = \frac{E_{ho} - E_w(1 - X_k)}{X_k}$$

Where:

$E_{hoO}$  = Adjusted  $E_{ho}$ , ng/J (lb/MMBtu);

$E_{ho}$  = Hourly  $SO_2$  emission rate, ng/J (lb/MMBtu);

$E_w$  =  $SO_2$  concentration in fuels other than coal and oil combusted in the affected facility, as determined by fuel sampling and analysis procedures in Method 9 of [appendix A of this part](#), ng/J (lb/MMBtu). The value  $E_w$  for each fuel lot is used for each hourly average during the time that the lot is being combusted. The owner or operator does not have to measure  $E_w$  if the owner or operator elects to assume  $E_w = 0$ .

$X_k$  = Fraction of the total heat input from fuel combustion derived from coal and oil, as determined by applicable procedures in Method 19 of [appendix A of this part](#).

(2) The owner or operator of an affected facility that qualifies under the provisions of [§ 60.42c\(c\)](#) or [\(d\)](#) (where percent reduction is not required) does not have to measure the parameters  $E_w$  or  $X_k$  if the owner or operator of the affected facility elects to measure emission rates of the coal or oil using the fuel sampling and analysis procedures under Method 19 of [appendix A of this part](#).

(f) Affected facilities subject to the percent reduction requirements under [§ 60.42c\(a\)](#) or [\(b\)](#) shall determine compliance with the  $SO_2$  emission limits under [§ 60.42c](#) pursuant to [paragraphs \(d\)](#) or [\(e\)](#) of this section, and shall determine compliance with the percent reduction requirements using the following procedures:

(1) If only coal is combusted, the percent of potential  $SO_2$  emission rate is computed using the following formula:

$$\%P_s = 100 \left( 1 - \frac{\%R_g}{100} \right) \left( 1 - \frac{\%R_f}{100} \right)$$

Where:

$\%P_s$  = Potential SO<sub>2</sub> emission rate, in percent;

$\%R_g$  = SO<sub>2</sub> removal efficiency of the control device as determined by Method 19 of [appendix A of this part](#), in percent; and

$\%R_f$  = SO<sub>2</sub> removal efficiency of fuel pretreatment as determined by Method 19 of [appendix A of this part](#), in percent.

(2) If coal, oil, or coal and oil are combusted with other fuels, the same procedures required in [paragraph \(f\)\(1\)](#) of this section are used, except as provided for in the following:

(i) To compute the  $\%P_s$ , an adjusted  $\%R_g$  ( $\%R_{go}$ ) is computed from  $E_{ao}$  from [paragraph \(e\)\(1\)](#) of this section and an adjusted average SO<sub>2</sub> inlet rate ( $E_{ai,o}$ ) using the following formula:

$$\%R_{go} = 100 \left( 1 - \frac{E_{ao}}{E_{ai,o}} \right)$$

Where:

$\%R_{go}$  = Adjusted  $\%R_g$ , in percent;

$E_{ao}$  = Adjusted  $E_{ao}$ , ng/J (lb/MMBtu); and

$E_{ai,o}$  = Adjusted average SO<sub>2</sub> inlet rate, ng/J (lb/MMBtu).

(ii) To compute  $E_{ai,o}$ , an adjusted hourly SO<sub>2</sub> inlet rate ( $E_{hi,o}$ ) is used. The  $E_{hi,o}$  is computed using the following formula:

$$E_{hi,o} = \frac{E_h - E_o (1 - X_v)}{X_v}$$

Where:

$E_{hi,o}$  = Adjusted  $E_{hi}$ , ng/J (lb/MMBtu);

$E_{hi}$  = Hourly SO<sub>2</sub> inlet rate, ng/J (lb/MMBtu);

$E_w$  = SO<sub>2</sub> concentration in fuels other than coal and oil combusted in the affected facility, as determined by fuel sampling and analysis procedures in Method 19 of [appendix A of this part](#), ng/J (lb/MMBtu). The value  $E_w$  for each fuel lot is used for each hourly average during the time that the lot is being combusted. The owner or operator does not have to measure  $E_w$  if the owner or operator elects to assume  $E_w = 0$ ; and

$X_k$  = Fraction of the total heat input from fuel combustion derived from coal and oil, as determined by applicable procedures in Method 19 of [appendix A of this part](#).

(g) For oil-fired affected facilities where the owner or operator seeks to demonstrate compliance with the fuel oil sulfur limits under [§ 60.42c](#) based on shipment fuel sampling, the initial performance test shall consist of sampling and analyzing the oil in the initial tank of oil to be fired in the steam generating unit to demonstrate that the oil contains 0.5 weight percent sulfur or less. Thereafter, the owner or operator of the affected facility shall sample the oil in the fuel tank after each new shipment of oil is received, as described under [§ 60.46c\(d\)\(2\)](#).

(h) For affected facilities subject to [§ 60.42c\(h\)\(1\)](#), [\(2\)](#), or [\(3\)](#) where the owner or operator seeks to demonstrate compliance with the SO<sub>2</sub> standards based on fuel supplier certification, the performance test shall consist of the certification from the fuel supplier, as described in [§ 60.48c\(f\)](#), as applicable.

(i) The owner or operator of an affected facility seeking to demonstrate compliance with the SO<sub>2</sub> standards under [§ 60.42c\(c\)\(2\)](#) shall demonstrate the maximum design heat input capacity of the steam generating unit by operating the steam generating unit at this capacity for 24 hours. This demonstration shall be made during the initial performance test, and a subsequent demonstration may be requested at any other time. If the demonstrated 24-hour average firing rate for the affected facility is less than the maximum design heat input capacity stated by the manufacturer of the affected facility, the demonstrated 24-hour average firing rate shall be used to determine the annual capacity factor for the affected facility; otherwise, the maximum design heat input capacity provided by the manufacturer shall be used.

(j) The owner or operator of an affected facility shall use all valid SO<sub>2</sub> emissions data in calculating %P<sub>s</sub> and  $E_{ho}$  under [paragraphs \(d\)](#), [\(e\)](#), or [\(f\)](#) of this section, as applicable, whether or not the minimum emissions data requirements under [§ 60.46c\(f\)](#) are achieved. All valid emissions data, including valid data collected during periods of startup, shutdown, and malfunction, shall be used in calculating %P<sub>s</sub> or  $E_{ho}$  pursuant to [paragraphs \(d\)](#), [\(e\)](#), or [\(f\)](#) of this section, as applicable.

[[72 FR 32759](#), June 13, 2007, as amended at [74 FR 5091](#), Jan. 28, 2009]

## **§ 60.45c Compliance and performance test methods and procedures for particulate matter.**

(a) The owner or operator of an affected facility subject to the PM and/or opacity standards under [§ 60.43c](#) shall conduct an initial performance test as required under [§ 60.8](#), and shall conduct subsequent performance tests as requested by the Administrator, to determine compliance with the standards using the following procedures and reference methods, except as specified in [paragraph \(c\)](#) of this section.

(1) Method 1 of [appendix A of this part](#) shall be used to select the sampling site and the number of traverse sampling points.

(2) Method 3A or 3B of appendix A–2 of this part shall be used for gas analysis when applying Method 5 or 5B of appendix A–3 of this part or 17 of appendix A–6 of this part.

(3) Method 5, 5B, or 17 of [appendix A of this part](#) shall be used to measure the concentration of PM as follows:

(i) Method 5 of [appendix A of this part](#) may be used only at affected facilities without wet scrubber systems.

(ii) Method 17 of [appendix A of this part](#) may be used at affected facilities with or without wet scrubber systems provided the stack gas temperature does not exceed a temperature of 160 °C (320 °F). The procedures of Sections 8.1 and 11.1 of Method 5B of [appendix A of this part](#) may be used in Method 17 of [appendix A of this part](#) only if Method 17 of [appendix A of this part](#) is used in conjunction with a wet scrubber system. Method 17 of [appendix A of this part](#) shall not be used in conjunction with a wet scrubber system if the effluent is saturated or laden with water droplets.

(iii) Method 5B of [appendix A of this part](#) may be used in conjunction with a wet scrubber system.

(4) The sampling time for each run shall be at least 120 minutes and the minimum sampling volume shall be 1.7 dry standard cubic meters (dscm) [60 dry standard cubic feet (dscf)] except that smaller sampling times or volumes may be approved by the Administrator when necessitated by process variables or other factors.

(5) For Method 5 or 5B of [appendix A of this part](#), the temperature of the sample gas in the probe and filter holder shall be monitored and maintained at  $160 \pm 14$  °C ( $320 \pm 25$  °F).

(6) For determination of PM emissions, an oxygen (O<sub>2</sub>) or carbon dioxide (CO<sub>2</sub>) measurement shall be obtained simultaneously with each run of Method 5, 5B, or 17 of [appendix A of this part](#) by traversing the duct at the same sampling location.

(7) For each run using Method 5, 5B, or 17 of [appendix A of this part](#), the emission rates expressed in ng/J (lb/MMBtu) heat input shall be determined using:

(i) The O<sub>2</sub> or CO<sub>2</sub> measurements and PM measurements obtained under this section,

(ii) The dry basis F factor, and

(iii) The dry basis emission rate calculation procedure contained in Method 19 of [appendix A of this part](#).

(8) Method 9 of appendix A–4 of this part shall be used for determining the opacity of stack emissions.

(b) The owner or operator of an affected facility seeking to demonstrate compliance with the PM standards under [§ 60.43c\(b\)\(2\)](#) shall demonstrate the maximum design heat input capacity of the steam generating unit by operating the steam generating unit at this capacity for 24 hours. This demonstration shall be made during the initial performance test, and a subsequent demonstration may be requested at any other time. If the demonstrated 24-hour average firing rate for the affected facility is less than the maximum design heat input capacity stated by the manufacturer of the affected facility, the demonstrated 24-hour average firing rate shall be used to determine the annual capacity factor for the affected facility; otherwise, the maximum design heat input capacity provided by the manufacturer shall be used.

(c) In place of PM testing with Method 5 or 5B of appendix A–3 of this part or Method 17 of appendix A–6 of this part, an owner or operator may elect to install, calibrate, maintain, and operate a CEMS for monitoring PM 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 PM emissions instead of conducting performance testing using Method 5 or 5B of appendix A–3 of this part or Method 17 of appendix A–6 of this part shall install, calibrate, maintain, and operate a CEMS and shall comply with the requirements specified in [paragraphs \(c\)\(1\) through \(c\)\(14\)](#) of this section.

(1) Notify the Administrator 1 month before starting use of the system.

(2) Notify the Administrator 1 month before stopping use of the system.

(3) The monitor shall be installed, evaluated, and operated in accordance with [§ 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 [§ 60.8](#) of [subpart A of this part](#) or within 180 days of notification to the Administrator of use of CEMS if the owner or operator was previously determining compliance by Method 5, 5B, or 17 of [appendix A of this part](#) performance tests, whichever is later.

(5) The owner or operator of an affected facility shall conduct an initial performance test for PM emissions as required under [§ 60.8](#) of [subpart A of this part](#). Compliance with the PM emission limit shall be determined by using the CEMS specified in [paragraph \(d\)](#) of this section to measure PM and calculating a 24-hour block arithmetic average emission concentration using EPA Reference Method 19 of [appendix A of this part, section 4.1](#).

(6) Compliance with the PM emission limit shall be determined based on the 24-hour daily (block) average of the hourly arithmetic average emission concentrations using CEMS outlet data.

(7) At a minimum, valid CEMS hourly averages shall be obtained as specified in [paragraph \(c\)\(7\)\(i\)](#) 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.

(ii) [Reserved]

(8) The 1-hour arithmetic averages required under [paragraph \(c\)\(7\)](#) 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 [§ 60.13\(e\)\(2\)](#) of [subpart A of this part](#).

(9) All valid CEMS data shall be used in calculating average emission concentrations even if the minimum CEMS data requirements of [paragraph \(c\)\(7\)](#) of this section are not met.

(10) The CEMS shall be operated according to Performance Specification 11 in [appendix B of this part](#).

(11) During the correlation testing runs of the CEMS required by Performance Specification 11 in [appendix B of this part](#), PM and O<sub>2</sub> (or CO<sub>2</sub>) data shall be collected concurrently (or within a 30- to 60-minute period) by both the continuous emission monitors and performance tests conducted using the following test methods.

(i) For PM, Method 5 or 5B of appendix A–3 of this part or Method 17 of appendix A–6 of this part shall be used; and

(ii) For O<sub>2</sub> (or CO<sub>2</sub>), Method 3A or 3B of appendix A–2 of this part, 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 PM emissions data are not obtained because of CEMS 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 of [appendix A of this part](#) to provide, as necessary, valid emissions data for a minimum of 75 percent of total operating hours on a 30-day rolling average.

(14) As of January 1, 2012, and within 90 days after the date of completing each performance test, as defined in [§ 60.8](#), conducted to demonstrate compliance with this subpart, you must

submit relative accuracy test audit (*i.e.*, reference method) data and performance test (*i.e.*, compliance test) data, except opacity data, electronically to EPA's Central Data Exchange (CDX) by using the Electronic Reporting Tool (ERT) (see [http://www.epa.gov/ttn/chief/ert/ert\\_tool.html/](http://www.epa.gov/ttn/chief/ert/ert_tool.html/)) or other compatible electronic spreadsheet. Only data collected using test methods compatible with ERT are subject to this requirement to be submitted electronically into EPA's WebFIRE database.

(d) The owner or operator of an affected facility seeking to demonstrate compliance under [§ 60.43c\(e\)\(4\)](#) shall follow the applicable procedures under [§ 60.48c\(f\)](#). For residual oil-fired affected facilities, fuel supplier certifications are only allowed for facilities with heat input capacities between 2.9 and 8.7 MW (10 to 30 MMBtu/h).

[[72 FR 32759](#), June 13, 2007, as amended at [74 FR 5091](#), Jan. 28, 2009; [76 FR 3523](#), Jan. 20, 2011; [77 FR 9463](#), Feb. 16, 2012]

## **§ 60.46c Emission monitoring for sulfur dioxide.**

(a) Except as provided in [paragraphs \(d\) and \(e\)](#) of this section, the owner or operator of an affected facility subject to the SO<sub>2</sub> emission limits under [§ 60.42c](#) shall install, calibrate, maintain, and operate a CEMS for measuring SO<sub>2</sub> concentrations and either O<sub>2</sub> or CO<sub>2</sub> concentrations at the outlet of the SO<sub>2</sub> control device (or the outlet of the steam generating unit if no SO<sub>2</sub> control device is used), and shall record the output of the system. The owner or operator of an affected facility subject to the percent reduction requirements under [§ 60.42c](#) shall measure SO<sub>2</sub> concentrations and either O<sub>2</sub> or CO<sub>2</sub> concentrations at both the inlet and outlet of the SO<sub>2</sub> control device.

(b) The 1-hour average SO<sub>2</sub> emission rates measured by a CEMS shall be expressed in ng/J or lb/MMBtu heat input and shall be used to calculate the average emission rates under [§ 60.42c](#). Each 1-hour average SO<sub>2</sub> emission rate must be based on at least 30 minutes of operation, and shall be calculated using the data points required under [§ 60.13\(h\)\(2\)](#). Hourly SO<sub>2</sub> emission rates are not calculated if the affected facility is operated less than 30 minutes in a 1-hour period and are not counted toward determination of a steam generating unit operating day.

(c) 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 of [appendix B of this part](#).

(2) Quarterly accuracy determinations and daily calibration drift tests shall be performed in accordance with Procedure 1 of [appendix F of this part](#).

(3) For affected facilities subject to the percent reduction requirements under [§ 60.42c](#), the span value of the SO<sub>2</sub> CEMS at the inlet to the SO<sub>2</sub> control device shall be 125 percent of the maximum estimated hourly potential SO<sub>2</sub> emission rate of the fuel combusted, and the span



value of the SO<sub>2</sub> CEMS at the outlet from the SO<sub>2</sub> control device shall be 50 percent of the maximum estimated hourly potential SO<sub>2</sub> emission rate of the fuel combusted.

(4) For affected facilities that are not subject to the percent reduction requirements of [§ 60.42c](#), the span value of the SO<sub>2</sub> CEMS at the outlet from the SO<sub>2</sub> control device (or outlet of the steam generating unit if no SO<sub>2</sub> control device is used) shall be 125 percent of the maximum estimated hourly potential SO<sub>2</sub> emission rate of the fuel combusted.

(d) As an alternative to operating a CEMS at the inlet to the SO<sub>2</sub> control device (or outlet of the steam generating unit if no SO<sub>2</sub> control device is used) as required under [paragraph \(a\)](#) of this section, an owner or operator may elect to determine the average SO<sub>2</sub> emission rate by sampling the fuel prior to combustion. As an alternative to operating a CEMS at the outlet from the SO<sub>2</sub> control device (or outlet of the steam generating unit if no SO<sub>2</sub> control device is used) as required under [paragraph \(a\)](#) of this section, an owner or operator may elect to determine the average SO<sub>2</sub> emission rate by using Method 6B of [appendix A of this part](#). Fuel sampling shall be conducted pursuant to either [paragraph \(d\)\(1\)](#) or [\(d\)\(2\)](#) of this section. Method 6B of [appendix A of this part](#) shall be conducted pursuant to [paragraph \(d\)\(3\)](#) of this section.

(1) For affected facilities combusting coal or oil, coal or oil samples shall be collected daily in an as-fired condition at the inlet to the steam generating unit and analyzed for sulfur content and heat content according to the Method 19 of [appendix A of this part](#). Method 19 of [appendix A of this part](#) provides procedures for converting these measurements into the format to be used in calculating the average SO<sub>2</sub> input rate.

(2) As an alternative fuel sampling procedure for affected facilities combusting oil, oil samples may be collected from the fuel tank for each steam generating unit immediately after the fuel tank is filled and before any oil is combusted. The owner or operator of the affected facility shall analyze the oil sample to determine the sulfur content of the oil. If a partially empty fuel tank is refilled, a new sample and analysis of the fuel in the tank would be required upon filling. Results of the fuel analysis taken after each new shipment of oil is received shall be used as the daily value when calculating the 30-day rolling average until the next shipment is received. If the fuel analysis shows that the sulfur content in the fuel tank is greater than 0.5 weight percent sulfur, the owner or operator shall ensure that the sulfur content of subsequent oil shipments is low enough to cause the 30-day rolling average sulfur content to be 0.5 weight percent sulfur or less.

(3) Method 6B of [appendix A of this part](#) may be used in lieu of CEMS to measure SO<sub>2</sub> at the inlet or outlet of the SO<sub>2</sub> control system. An initial stratification test is required to verify the adequacy of the Method 6B of [appendix A of this part](#) sampling location. The stratification test shall consist of three paired runs of a suitable SO<sub>2</sub> and CO<sub>2</sub> measurement train operated at the candidate location and a second similar train operated according to the procedures in [§ 3.2](#) and the applicable procedures in section 7 of Performance Specification 2 of [appendix B of this part](#). Method 6B of [appendix A of this part](#), Method 6A of [appendix A of this part](#), or a combination of Methods 6 and 3 of [appendix A of this part](#) or Methods 6C and 3A of [appendix A of this part](#) are suitable measurement techniques. If Method 6B of [appendix A of this part](#) 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 of [appendix A of this part](#) 24-hour tests, the mean of the absolute difference between the three paired runs must be less than 10 percent (0.10).

(e) The monitoring requirements of [paragraphs \(a\)](#) and [\(d\)](#) of this section shall not apply to affected facilities subject to [§ 60.42c\(h\) \(1\), \(2\), or \(3\)](#) where the owner or operator of the affected facility seeks to demonstrate compliance with the SO<sub>2</sub> standards based on fuel supplier certification, as described under [§ 60.48c\(f\)](#), as applicable.

(f) The owner or operator of an affected facility operating a CEMS pursuant to [paragraph \(a\)](#) of this section, or conducting as-fired fuel sampling pursuant to [paragraph \(d\)\(1\)](#) of this section, shall obtain emission data for at least 75 percent of the operating hours in at least 22 out of 30 successive steam generating unit 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.

## **§ 60.47c Emission monitoring for particulate matter.**

(a) Except as provided in [paragraphs \(c\), \(d\), \(e\), and \(f\)](#) of this section, the owner or operator of an affected facility combusting coal, oil, or wood that is subject to the opacity standards under [§ 60.43c](#) shall install, calibrate, maintain, and operate a continuous opacity monitoring system (COMS) for measuring the opacity of the emissions discharged to the atmosphere and record the output of the system. The owner or operator of an affected facility subject to an opacity standard in [§ 60.43c\(c\)](#) that is not required to use a COMS due to [paragraphs \(c\), \(d\), \(e\), or \(f\)](#) of this section that elects not to use a COMS shall conduct a performance test using Method 9 of appendix A–4 of this part and the procedures in [§ 60.11](#) to demonstrate compliance with the applicable limit in [§ 60.43c](#) by April 29, 2011, within 45 days of stopping use of an existing COMS, or within 180 days after initial startup of the facility, whichever is later, and shall comply with either [paragraphs \(a\)\(1\), \(a\)\(2\), or \(a\)\(3\)](#) of this section. The observation period for Method 9 of appendix A–4 of this part performance tests may be reduced from 3 hours to 60 minutes if all 6-minute averages are less than 10 percent and all individual 15-second observations are less than or equal to 20 percent during the initial 60 minutes of observation.

(1) Except as provided in [paragraph \(a\)\(2\)](#) and [\(a\)\(3\)](#) of this section, the owner or operator shall conduct subsequent Method 9 of appendix A–4 of this part performance tests using the procedures in [paragraph \(a\)](#) of this section according to the applicable schedule in [paragraphs \(a\)\(1\)\(i\) through \(a\)\(1\)\(iv\)](#) of this section, as determined by the most recent Method 9 of appendix A–4 of this part performance test results.

(i) If no visible emissions are observed, a subsequent Method 9 of appendix A–4 of this part performance test must be completed within 12 calendar months from the date that the most recent performance test was conducted or within 45 days of the next day that fuel with an opacity standard is combusted, whichever is later;

(ii) If visible emissions are observed but the maximum 6-minute average opacity is less than or equal to 5 percent, a subsequent Method 9 of appendix A–4 of this part performance test must be completed within 6 calendar months from the date that the most recent performance test was conducted or within 45 days of the next day that fuel with an opacity standard is combusted, whichever is later;

(iii) If the maximum 6-minute average opacity is greater than 5 percent but less than or equal to 10 percent, a subsequent Method 9 of appendix A–4 of this part performance test must be completed within 3 calendar months from the date that the most recent performance test was conducted or within 45 days of the next day that fuel with an opacity standard is combusted, whichever is later; or

(iv) If the maximum 6-minute average opacity is greater than 10 percent, a subsequent Method 9 of appendix A–4 of this part performance test must be completed within 45 calendar days from the date that the most recent performance test was conducted.

(2) If the maximum 6-minute opacity is less than 10 percent during the most recent Method 9 of appendix A–4 of this part performance test, the owner or operator may, as an alternative to performing subsequent Method 9 of appendix A–4 of this part performance tests, elect to perform subsequent monitoring using Method 22 of appendix A–7 of this part according to the procedures specified in [paragraphs \(a\)\(2\)\(i\) and \(ii\)](#) of this section.

(i) The owner or operator shall conduct 10 minute observations (during normal operation) each operating day the affected facility fires fuel for which an opacity standard is applicable using Method 22 of appendix A–7 of this part and demonstrate that the sum of the occurrences of any visible emissions is not in excess of 5 percent of the observation period (*i.e.*, 30 seconds per 10 minute period). If the sum of the occurrence of any visible emissions is greater than 30 seconds during the initial 10 minute observation, immediately conduct a 30 minute observation. If the sum of the occurrence of visible emissions is greater than 5 percent of the observation period (*i.e.*, 90 seconds per 30 minute period), the owner or operator shall either document and adjust the operation of the facility and demonstrate within 24 hours that the sum of the occurrence of visible emissions is equal to or less than 5 percent during a 30 minute observation (*i.e.*, 90 seconds) or conduct a new Method 9 of appendix A–4 of this part performance test using the procedures in [paragraph \(a\)](#) of this section within 45 calendar days according to the requirements in [§ 60.45c\(a\)\(8\)](#).

(ii) If no visible emissions are observed for 10 operating days during which an opacity standard is applicable, observations can be reduced to once every 7 operating days during which an opacity standard is applicable. If any visible emissions are observed, daily observations shall be resumed.

(3) If the maximum 6-minute opacity is less than 10 percent during the most recent Method 9 of appendix A–4 of this part performance test, the owner or operator may, as an alternative to performing subsequent Method 9 of appendix A–4 performance tests, elect to perform subsequent monitoring using a digital opacity compliance system according to a site-specific monitoring plan approved by the Administrator. The observations shall be similar, but not

necessarily identical, to the requirements in [paragraph \(a\)\(2\)](#) of this section. For reference purposes in preparing the monitoring plan, see OAQPS “Determination of Visible Emission Opacity from Stationary Sources Using Computer-Based Photographic Analysis Systems.” This document is available from the U.S. Environmental Protection Agency (U.S. EPA); Office of Air Quality and Planning Standards; Sector Policies and Programs Division; Measurement Policy Group (D243–02), Research Triangle Park, NC 27711. This document is also available on the Technology Transfer Network (TTN) under Emission Measurement Center Preliminary Methods.

(b) All COMS shall be operated in accordance with the applicable procedures under Performance Specification 1 of [appendix B of this part](#). The span value of the opacity COMS shall be between 60 and 80 percent.

(c) Owners and operators of an affected facilities that burn only distillate oil that contains no more than 0.5 weight percent sulfur and/or liquid or gaseous fuels with potential sulfur dioxide emission rates of 26 ng/J (0.060 lb/MMBtu) heat input or less and that do not use a post-combustion technology to reduce SO<sub>2</sub> or PM emissions and that are subject to an opacity standard in [§ 60.43c\(c\)](#) are not required to operate a COMS if they follow the applicable procedures in [§ 60.48c\(f\)](#).

(d) Owners or operators complying with the PM emission limit by using a PM CEMS must calibrate, maintain, operate, and record the output of the system for PM emissions discharged to the atmosphere as specified in [§ 60.45c\(c\)](#). The CEMS specified in paragraph [§ 60.45c\(c\)](#) shall be operated and data recorded during all periods of operation of the affected facility except for CEMS breakdowns and repairs. Data is recorded during calibration checks, and zero and span adjustments.

(e) Owners and operators of an affected facility that is subject to an opacity standard in [§ 60.43c\(c\)](#) and that does not use post-combustion technology (except a wet scrubber) for reducing PM, SO<sub>2</sub>, or carbon monoxide (CO) emissions, burns only gaseous fuels or fuel oils that contain less than or equal to 0.5 weight percent sulfur, and is operated such that emissions of CO discharged to the atmosphere from the affected facility are maintained at levels less than or equal to 0.15 lb/MMBtu on a boiler operating day average basis is not required to operate a COMS. Owners and operators of affected facilities electing to comply with this paragraph must demonstrate compliance according to the procedures specified in [paragraphs \(e\)\(1\) through \(4\)](#) of this section; or

(1) You must monitor CO emissions using a CEMS according to the procedures specified in [paragraphs \(e\)\(1\)\(i\) through \(iv\)](#) of this section.

(i) The CO CEMS must be installed, certified, maintained, and operated according to the provisions in [§ 60.58b\(i\)\(3\)](#) of [subpart Eb of this part](#).

(ii) Each 1-hour CO emissions average is calculated using the data points generated by the CO CEMS expressed in parts per million by volume corrected to 3 percent oxygen (dry basis).

(iii) At a minimum, valid 1-hour CO emissions averages must be obtained for at least 90 percent of the operating hours on a 30-day rolling average basis. The 1-hour averages are calculated using the data points required in [§ 60.13\(h\)\(2\)](#).

(iv) Quarterly accuracy determinations and daily calibration drift tests for the CO CEMS must be performed in accordance with procedure 1 in [appendix F of this part](#).

(2) You must calculate the 1-hour average CO emissions levels for each steam generating unit operating day by multiplying the average hourly CO output concentration measured by the CO CEMS times the corresponding average hourly flue gas flow rate and divided by the corresponding average hourly heat input to the affected source. The 24-hour average CO emission level is determined by calculating the arithmetic average of the hourly CO emission levels computed for each steam generating unit operating day.

(3) You must evaluate the preceding 24-hour average CO emission level each steam generating unit operating day excluding periods of affected source startup, shutdown, or malfunction. If the 24-hour average CO emission level is greater than 0.15 lb/MMBtu, you must initiate investigation of the relevant equipment and control systems within 24 hours of the first discovery of the high emission incident and, take the appropriate corrective action as soon as practicable to adjust control settings or repair equipment to reduce the 24-hour average CO emission level to 0.15 lb/MMBtu or less.

(4) You must record the CO measurements and calculations performed according to [paragraph \(e\)](#) of this section and any corrective actions taken. The record of corrective action taken must include the date and time during which the 24-hour average CO emission level was greater than 0.15 lb/MMBtu, and the date, time, and description of the corrective action.

(f) An owner or operator of an affected facility that is subject to an opacity standard in [§ 60.43c\(c\)](#) is not required to operate a COMS provided that the affected facility meets the conditions in either [paragraphs \(f\)\(1\), \(2\), or \(3\)](#) of this section.

(1) The affected facility uses a fabric filter (baghouse) as the primary PM control device and, the owner or operator operates a bag leak detection system to monitor the performance of the fabric filter according to the requirements in section [§ 60.48Da of this part](#).

(2) The affected facility uses an ESP as the primary PM control device, and the owner or operator uses an ESP predictive model to monitor the performance of the ESP developed in accordance and operated according to the requirements in section [§ 60.48Da of this part](#).

(3) The affected facility burns only gaseous fuels and/or fuel oils that contain no greater than 0.5 weight percent sulfur, and the owner or operator operates the unit according to a written site-specific monitoring plan approved by the permitting authority. This monitoring plan must include procedures and criteria for establishing and monitoring specific parameters for the affected facility indicative of compliance with the opacity standard. For testing performed as part of this site-specific monitoring plan, the permitting authority may require as an alternative to the notification and reporting requirements specified in [§§ 60.8 and 60.11](#) that

the owner or operator submit any deviations with the excess emissions report required under [§ 60.48c\(c\)](#).

[[72 FR 32759](#), June 13, 2007, as amended at [74 FR 5091](#), Jan. 28, 2009; [76 FR 3523](#), Jan. 20, 2011; [77 FR 9463](#), Feb. 16, 2012]

## **§ 60.48c Reporting and recordkeeping requirements.**

(a) The owner or operator of each affected facility shall submit notification of the date of construction or reconstruction and actual startup, as provided by [§ 60.7 of this part](#). This notification shall include:

(1) The design heat input capacity of the affected facility and identification of 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 [§ 60.42c](#), or [§ 60.43c](#).

(3) The annual capacity factor at which the owner or operator anticipates operating the affected facility based on all fuels fired and based on each individual fuel fired.

(4) Notification if an emerging technology will be used for controlling SO<sub>2</sub> emissions. The Administrator will examine the description of the control device 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 [§ 60.42c\(a\)](#) or [\(b\)\(1\)](#), unless and until this determination is made by the Administrator.

(b) The owner or operator of each affected facility subject to the SO<sub>2</sub> emission limits of [§ 60.42c](#), or the PM or opacity limits of [§ 60.43c](#), shall submit to the Administrator the performance test data from the initial and any subsequent performance tests and, if applicable, the performance evaluation of the CEMS and/or COMS using the applicable performance specifications in [appendix B of this part](#).

(c) In addition to the applicable requirements in [§ 60.7](#), the owner or operator of an affected facility subject to the opacity limits in [§ 60.43c\(c\)](#) shall submit excess emission reports for any excess emissions from the affected facility that occur during the reporting period and maintain records according to the requirements specified in [paragraphs \(c\)\(1\) through \(3\)](#) of this section, as applicable to the visible emissions monitoring method used.

(1) For each performance test conducted using Method 9 of appendix A–4 of this part, the owner or operator shall keep the records including the information specified in [paragraphs \(c\)\(1\)\(i\) through \(iii\)](#) of this section.

(i) Dates and time intervals of all opacity observation periods;

(ii) Name, affiliation, and copy of current visible emission reading certification for each visible emission observer participating in the performance test; and

(iii) Copies of all visible emission observer opacity field data sheets;

(2) For each performance test conducted using Method 22 of appendix A-4 of this part, the owner or operator shall keep the records including the information specified in [paragraphs \(c\)\(2\)\(i\) through \(iv\)](#) of this section.

(i) Dates and time intervals of all visible emissions observation periods;

(ii) Name and affiliation for each visible emission observer participating in the performance test;

(iii) Copies of all visible emission observer opacity field data sheets; and

(iv) Documentation of any adjustments made and the time the adjustments were completed to the affected facility operation by the owner or operator to demonstrate compliance with the applicable monitoring requirements.

(3) For each digital opacity compliance system, the owner or operator shall maintain records and submit reports according to the requirements specified in the site-specific monitoring plan approved by the Administrator

(d) The owner or operator of each affected facility subject to the SO<sub>2</sub> emission limits, fuel oil sulfur limits, or percent reduction requirements under [§ 60.42c](#) shall submit reports to the Administrator.

(e) The owner or operator of each affected facility subject to the SO<sub>2</sub> emission limits, fuel oil sulfur limits, or percent reduction requirements under [§ 60.42c](#) shall keep records and submit reports as required under [paragraph \(d\)](#) of this section, including the following information, as applicable.

(1) Calendar dates covered in the reporting period.

(2) Each 30-day average SO<sub>2</sub> emission rate (ng/J or lb/MMBtu), or 30-day average sulfur content (weight percent), calculated during the reporting period, ending with the last 30-day period; reasons for any noncompliance with the emission standards; and a description of corrective actions taken.

(3) Each 30-day average percent of potential SO<sub>2</sub> emission rate calculated during the reporting period, ending with the last 30-day period; reasons for any noncompliance with the emission standards; and a description of the corrective actions taken.

(4) Identification of any steam generating unit operating days for which SO<sub>2</sub> or diluent (O<sub>2</sub> or CO<sub>2</sub>) 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 a description of corrective actions taken.

(5) Identification of any times when emissions data have been excluded from the calculation of average emission rates; justification for excluding data; and a description of corrective actions 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 the F factor used in calculations, method of determination, and type of fuel combusted.

(7) Identification of whether averages have been obtained based on CEMS rather than manual sampling methods.

(8) If a CEMS is used, identification of any times when the pollutant concentration exceeded the full span of the CEMS.

(9) If a CEMS is used, description of any modifications to the CEMS that could affect the ability of the CEMS to comply with Performance Specifications 2 or 3 of [appendix B of this part](#).

(10) If a CEMS is used, results of daily CEMS drift tests and quarterly accuracy assessments as required under appendix F, Procedure 1 of this part.

(11) If fuel supplier certification is used to demonstrate compliance, records of fuel supplier certification as described under [paragraph \(f\)\(1\), \(2\), \(3\), or \(4\)](#) of this section, as applicable. In addition to records of fuel supplier certifications, the report shall include a certified statement signed by the owner or operator of the affected facility that the records of fuel supplier certifications submitted represent all of the fuel combusted during the reporting period.

(f) Fuel supplier certification shall include the following information:

(1) For distillate oil:

(i) The name of the oil supplier;

(ii) A statement from the oil supplier that the oil complies with the specifications under the definition of distillate oil in [§ 60.41c](#); and

(iii) The sulfur content or maximum sulfur content of the oil.

(2) For residual oil:

(i) The name of the oil supplier;

(ii) The location of the oil when the sample was drawn for analysis to determine the sulfur content of the oil, specifically including whether the oil was sampled as delivered to the affected facility, or whether the sample was drawn from oil in storage at the oil supplier's or oil refiner's facility, or other location;

(iii) The sulfur content of the oil from which the shipment came (or of the shipment itself); and

(iv) The method used to determine the sulfur content of the oil.

(3) For coal:

(i) The name of the coal supplier;

(ii) The location of the coal when the sample was collected for analysis to determine the properties of the coal, specifically including whether the coal was sampled as delivered to the affected facility or whether the sample was collected from coal in storage at the mine, at a coal preparation plant, at a coal supplier's facility, or at another location. The certification shall include the name of the coal mine (and coal seam), coal storage facility, or coal preparation plant (where the sample was collected);

(iii) The results of the analysis of the coal from which the shipment came (or of the shipment itself) including the sulfur content, moisture content, ash content, and heat content; and

(iv) The methods used to determine the properties of the coal.

(4) For other fuels:

(i) The name of the supplier of the fuel;

(ii) The potential sulfur emissions rate or maximum potential sulfur emissions rate of the fuel in ng/J heat input; and

(iii) The method used to determine the potential sulfur emissions rate of the fuel.

(g)

(1) Except as provided under [paragraphs \(g\)\(2\) and \(g\)\(3\)](#) of this section, the owner or operator of each affected facility shall record and maintain records of the amount of each fuel combusted during each operating day.

(2) As an alternative to meeting the requirements of [paragraph \(g\)\(1\)](#) of this section, the owner or operator of an affected facility that combusts only natural gas, wood, fuels using fuel certification in [§ 60.48c\(f\)](#) to demonstrate compliance with the SO<sub>2</sub> standard, fuels not subject to an emissions standard (excluding opacity), or a mixture of these fuels may elect to



record and maintain records of the amount of each fuel combusted during each calendar month.

(3) As an alternative to meeting the requirements of [paragraph \(g\)\(1\)](#) of this section, the owner or operator of an affected facility or multiple affected facilities located on a contiguous property unit where the only fuels combusted in any steam generating unit (including steam generating units not subject to this subpart) at that property are natural gas, wood, distillate oil meeting the most current requirements in [§ 60.42C](#) to use fuel certification to demonstrate compliance with the SO<sub>2</sub> standard, and/or fuels, excluding coal and residual oil, not subject to an emissions standard (excluding opacity) may elect to record and maintain records of the total amount of each steam generating unit fuel delivered to that property during each calendar month.

(h) The owner or operator of each affected facility subject to a federally enforceable requirement limiting the annual capacity factor for any fuel or mixture of fuels under [§ 60.42c](#) or [§ 60.43c](#) shall calculate the annual capacity factor individually for each fuel combusted. The annual capacity factor is determined on a 12-month rolling average basis with a new annual capacity factor calculated at the end of the calendar month.

(i) All records required under this section shall be maintained by the owner or operator of the affected facility for a period of two years following the date of such record.

(j) 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.

[[72 FR 32759](#), June 13, 2007, as amended at [74 FR 5091](#), Jan. 28, 2009]