# ADEQ
# MINOR SOURCE
# AIR PERMIT

Permit No. : 2058-AR-2

IS ISSUED TO:

Pet Solutions, LLC
RR 1, Box 306, Mt. Tabor Rd.
Danville, AR 72833
Yell County
AFIN: 75-00333

THIS PERMIT IS THE ABOVE REFERENCED PERMITTEE'S AUTHORITY TO CONSTRUCT, MODIFY, OPERATE, AND/OR MAINTAIN THE EQUIPMENT AND/OR FACILITY IN THE MANNER AS SET FORTH IN THE DEPARTMENT'S MINOR SOURCE AIR PERMIT AND THE APPLICATION. THIS PERMIT IS ISSUED PURSUANT TO THE PROVISIONS OF THE ARKANSAS WATER AND AIR POLLUTION CONTROL ACT (ARK. CODE ANN. SEC. 8-4-101 *ET SEQ.*) AND THE REGULATIONS PROMULGATED THEREUNDER, AND IS SUBJECT TO ALL LIMITS AND CONDITIONS CONTAINED HEREIN.

Signed:

| | |
|---|---|
| __________________ | __________________ |
| Mike Porta<br>Interim Chief, Air Division | Date Amended |

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List of Acronyms and Abbreviations

| | |
|---|---|
| A.C.A. | Arkansas Code Annotated |
| AFIN | ADEQ Facility Identification Number |
| CFR | Code of Federal Regulations |
| CO | Carbon Monoxide |
| HAP | Hazardous Air Pollutant |
| lb/hr | Pound Per Hour |
| No. | Number |
| $NO_x$ | Nitrogen Oxide |
| PM | Particulate Matter |
| $PM_{10}$ | Particulate Matter Smaller Than Ten Microns |
| SO2 | Sulfur Dioxide |
| Tpy | Tons Per Year |
| UTM | Universal Transverse Mercator |
| VOC | Volatile Organic Compound |

## Section I: FACILITY INFORMATION

| | |
|---|---|
| PERMITTEE: | Pet Solutions, LLC |
| AFIN: | 75-00333 |
| PERMIT NUMBER: | 2058-AR-2 |
| FACILITY ADDRESS: | RR 1, Box 306, Mt. Tabor Rd.<br>Danville, AR 72833 |
| MAILING ADDRESS: | 10511 Gauge Road<br>Danville, AR 72833 |
| COUNTY: | Yell |
| CONTACT POSITION: | Lewis Gray |
| TELEPHONE NUMBER: | 479-576-2050 |
| REVIEWING ENGINEER: | Bryan Leamons |
| UTM North South (Y): | 3899 |
| UTM East West (X): | 486 |
| Zone: | 15 |

## Section II: INTRODUCTION

Summary of Permit Activity

Pet Solutions, LLC operates a poultry by-product plant near Danville. The purpose of the rendering facility is to transform inedible meat processing by-products from poultry processors into grease/oils and protein solids (bone meal) which can be used as ingredients in the animal feed processing industry. This modification permits a 600 bhp boiler and steam turbine generator for production of electricity to be used on-site. The boiler is permitted to combust wood waste, cardboard, and off-spec poultry by-products. This modification also corrects permitted emission rates and limits in relation to the natural gas boiler (SN-01). The boiler was previously permitted at heat input of 20 MMBtu/hr. It is now permitted at 25.1 MMBtu/hr.

Process Description

The "primary" liquid feedstock is trucked to the plant in various sized tanker trucks and open top trailers. Upon arriving at the facility, the material is received in the "high building" and dumped into the receiving bin. The raw material is then transported directly to the cookers. The composition of the combined materials processed at this facility is typically 15% fat (tallow/grease), 20% protein solids, and 65% moisture by weight.

The "cooking" process is performed in five to eight horizontal, cylindrical, non-pressurized vessels equipped with a steam jacket and agitator. The steam is provided by two natural gas boilers (SN-01 and SN-05) located in the boiler building. Materials placed in the cookers are dehydrated thereby facilitating the separation of the fats and proteins. Cooking time is dependent upon various factors that include the consistency of the waste and ambient temperatures inside the plant.

Vapor emissions vented from the cookers pass through a condensate knockout (cyclone) and then enter the multistage scrubber (SN-03) that is located on the processing facility roof. Two 1,000 gallon tanks located in the boiler room provide either a sodium hypochlorite or chlorine dioxide solution to the scrubber for odor abatement. Each tank is supplied with the oxidizing solution to maintain a minimum of 200 ORP reading. Then, this solution is supplied to two of the three scrubber stages. In addition, the main processing building contains various air duct drops to the cooker and screw-press areas that route plant ventilation emissions through the scrubber system.

Upon completion of the cooking process, material from the batch cookers is dumped into a percolator drain pan. The percolator drain pan contains a screen that separates the liquid fat from the protein solids. From the drain pan, the protein solids, which still contain about 25% fat, are conveyed to a press. The press completes the separation of fat from solids, and yields protein solids that have a residual fat content of about 10%. These solids are then ground and screened to produce protein (bone) meal. The meal is stored in holding bins that are located adjacent to the ship-out area (SN-04). The fat from both the press and the drain pan is pumped to the two grease storage tanks for shipping. Both grease and bone meal are stored and shipped from the load-out area located on the southeast portion of the rendering facility.

A 600 bhp boiler (SN-06) is located on-site to produce steam. The steam powers a steam turbine generator. The electricity is used on-site only. The boiler is permitted to combust wood waste including wood chips and ground pallets, cardboard, and off-spec poultry by-products including meal, fat, and sludge. Sludge is defined as secondary protein nutrients (SPN) consisting of solids, fats, and moisture. SPN is a by-product of wastewater treatment at this facility.

## Regulations

The following table contains the regulations applicable to this permit.

| Regulations |
|---|
| Arkansas Air Pollution Control Code, Regulation 18, effective February 15, 1999 |
| Regulations of the Arkansas Plan of Implementation for Air Pollution Control, Regulation 19, effective December 19, 2004 |
| New Source Performance Standards, 40 CFR, Part 60, Subpart Dc, Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units |

The New Source Performance Standards (NSPS) at 40 CFR, Part 60, Subpart Dc is applicable to boilers constructed or modified after June 9, 1989 capable of combusting greater than 10 million BTUs/hr input of heat fuel but less than 100 million BTUs/hr heat input of fuel. Since the oldest boiler (SN-01) was installed before 1989 and not modified, it is not subject to Subpart Dc.

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

## Total Allowable Emissions

| TOTAL ALLOWABLE EMISSIONS | | |
|---|---|---|
| Pollutant | Emission Rates | |
| | lb/hr | tpy |
| PM | 9.1 | 39.7 |

| TOTAL ALLOWABLE EMISSIONS | | |
|---|---|---|
| Pollutant | Emission Rates | |
| | lb/hr | tpy |
| $PM_{10}$ | 9.1 | 39.7 |
| $SO_2$ | 0.9 | 3.3 |
| VOC | 0.9 | 3.9 |
| CO | 22.0 | 96.5 |
| $NO_x$ | 12.1 | 52.8 |

## Section III: PERMIT HISTORY

Permit 2058-A was issued to Pet Solutions, LLC on March 19, 2004. This facility was previously owned and operated by J & B Farms. In early 2002, J & B Farms ceased operation and voided the existing air permit. This permit allowed the new operator to reopen the facility and begin production. The facility was to be operated in the same manner as previously permitted without any new equipment.

Permit 2058-AR-1 was issued on March 24, 2005. This modification removed one Natural Gas Boiler (SN-02) and installed a new Natural Gas Boiler (SN-05).

Section IV: EMISSION UNIT INFORMATION

Specific Conditions

1. The permittee shall not exceed the emission rates set forth in the following table. [Regulation 19, §19.501 et seq., effective December 19, 2004 and A.C.A. §8-4-203 as referenced by A.C.A. §8-4-304 and §8-4-311]

| SN | Description | Pollutant | lb/hr | tpy |
|---|---|---|---|---|
| 01 | Natural Gas Boiler (25.1 MMBTU/hr) | $PM_{10}$ | 0.2 | 0.8 |
| | | $SO_2$ | 0.1 | 0.1 |
| | | VOC | 0.1 | 0.6 |
| | | CO | 2.1 | 9.1 |
| | | $NO_x$ | 2.5 | 10.8 |
| 02 | Natural Gas Boiler (13.4 MMBTU/hr) | Removed From Service | | |
| 03 | Horizontal Counterflow Wet Scrubber | VOC | 0.1 | 0.4 |
| 04 | Load-Out Shipping | $PM_{10}$ | 0.1 | 0.1 |
| 05 | Natural Gas Boiler (33.48 MMBTU/hr) | $PM_{10}$ | 0.2 | 1.1 |
| | | $SO_2$ | 0.1 | 0.1 |
| | | VOC | 0.2 | 0.8 |
| | | CO | 2.8 | 12.1 |
| | | $NO_x$ | 3.3 | 14.4 |
| 06 | Wood Fired Boiler (28.5 MMBtu/hr) | $PM_{10}$ | 9.1 | 39.7 |
| | | $SO_2$ | 0.7 | 3.1 |
| | | VOC | 0.5 | 2.1 |
| | | CO | 17.2 | 75.4 |
| | | $NO_x$ | 6.3 | 27.6 |

2. The permittee shall not exceed the emission rates set forth in the following table. [Regulation 18, §18.801, effective February 15, 1999, and A.C.A. §8-4-203 as referenced by A.C.A. §8-4-304 and §8-4-311]

| SN | Description | Pollutant | lb/hr | tpy |
|---|---|---|---|---|
| 01 | Natural Gas Boiler (25.1 MMBTU/hr) | PM | 0.2 | 0.8 |
| 02 | Natural Gas Boiler (13.4 MMBTU/hr) | Removed From Service | | |
| 04 | Load-Out Shipping | PM | 0.1 | 0.1 |
| 05 | Natural Gas Boiler (33.48 MMBTU/hr) | PM | 0.2 | 1.1 |
| 06 | Wood Fired Boiler (28.5 MMBtu/hr) | PM | 9.1 | 39.7 |

3. Visible emissions may not exceed the limits specified in the following table of this permit as measured by EPA Reference Method 9. [A.C.A. §8-4-203 as referenced by A.C.A. §8-4-304 and §8-4-311]

| SN | Limit | Regulatory Citation |
|---|---|---|
| 01 | 5% | §18.501 of Regulation 18 |
| 04 | 5% | §18.501 of Regulation 18 |
| 05 | 5% | §18.501 of Regulation 18 |
| 06 | 20% | §19.503 of Regulation 19 |

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 Regulation 18, if the emission of the air contaminant constitutes air pollution within the meaning of A.C.A. §8-4-303. [Regulation 18, §18.801 and A.C.A. §8-4-203 as referenced by A.C.A. §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. [Regulation 18, §18.901 and A.C.A. §8-4-203 as referenced by A.C.A. §8-4-304 and §8-4-311]

6. The permittee shall immediately clean any spills to insure that nuisance odors do not leave the property boundary. [§18.901 and A.C.A. §8-4-203 as referenced by A.C.A. §8-4-304 and §8-4-311]

7. The permittee shall process only poultry by-products. The permittee may also process whole hogs which must be processed immediately upon arrival at the facility. [A.C.A. §8-4-203 as referenced by A.C.A. §8-4-304 and §8-4-311]

8. All rendering raw material received at the plant site shall be placed in the rendering process building immediately or shall not be stored outside for a period longer than 18 hours, unless this material is stored under refrigerated conditions. [A.C.A. §8-4-203 as referenced by A.C.A. §8-4-304 and §8-4-311]

9. All rendering raw material received at the plant site shall be placed in the rendering process building immediately or shall not be stored outside for a period longer than 18 hours, unless this material is stored under refrigerated conditions. [A.C.A. §8-4-203 as referenced by A.C.A. §8-4-304 and §8-4-311]

10. The permittee shall use only natural gas to fuel SN-01 and SN-05. [§19.705 and A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311]

11. The Oxidation Reduction Potential (ORP) of the scrubber shall be maintained at a minimum of 200. [§19.705 and A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311]

12. To demonstrate compliance with Specific Condition 11, the permittee shall monitor and record the ORP once every 8 hours during operation. These records shall be maintained on-site and shall be provided to Department personnel upon request. [§19.705 of Regulation 18 and A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311]

13. The permittee shall maintain a negative pressure inside the building. [§19.705 and A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311]

14. To demonstrate compliance with Specific Condition 13, the permittee shall test the building pressure once a month. This test shall consist of a smoke test, anemometer, or other test to demonstrate that the airflow is into the building at all openings except the scrubber discharge. These records shall be maintained on-site and shall be provided to Department personnel upon request. [§19.705 and A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311]

15. All doors, windows, and other openings to the facility shall be kept closed when not in use. [§19.705 and A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311]

16. The permittee shall submit notification of the date of construction, anticipated startup, and actual startup of the Wood Fired Boiler (SN-06). [§19.304 and 60.48c(a) of 40 CFR Part 60, Subpart Dc]

17. The permittee shall maintain records of the amount of natural gas burned in SN-05 on a monthly basis. This shall be done by a separate flow meter or as a percentage of the total

gas used at the facility based on a BTU rating.  These records shall be kept on-site for a period of 2 years following the date of each record.  [§19.304 and 60.48c(g) and (i) of 40 CFR Part 60, Subpart Dc]

18. The permittee shall record and maintain records of the amounts of each fuel combusted during each day at SN-06.  These records shall be kept on-site for a period of 2 years following the date of each record.  [§19.304, and 60.48c(g) and (i) of 40 CFR Part 60, Subpart Dc]

19. The permittee shall not exceed the following on a daily basis.  Records required by Specific Condition 18 shall be used to demonstrate compliance.  [§19.705 and A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311]

| Fuel Type | Daily Limit (tons) |
|---|---|
| Wood waste including wood chips, sawdust, or ground pallets | unlimited |
| Cardboard | 15.8 |
| Poultry Fat | 1.9 |
| Poultry Meal | 4.8 |
| Sludge | 11.3 |

20. Sludge is defined in the permit application as secondary protein nutrients (SPN) consisting of solids, fats, and moisture.  SPN is a by-product of wastewater treatment at this facility.  Only sludge that meets this definition may be combusted as “sludge” by this facility.  [§19.705 and A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311]

21. At SN-06 the permittee shall perform a one-time initial stack test for the following pollutants to demonstrate compliance with the corresponding emission limits listed in Specific Condition 1.  Testing shall be performed while operating at or above 90% total capacity and while combusting poultry fat at a rate between 142.5 pounds per hour and 158.3 pounds per hour.  Testing shall otherwise be performed in accordance with General Condition 7.  [§19.702 and A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311]

| Pollutant | Test Method |
|---|---|
| VOC | 25A |
| CO | 10 |
| $NO_x$ | 7E |

22. At SN-06 the permittee shall not combust trash, garbage, refuse or other materials from off-site that could be considered relevant in defining the facility as a municipal or hazardous waste combustor. The cardboard and pallets listed in Specific Condition 19 may only originate from poultry/ swine process shipments. No plastics or foams of any kind shall be combusted in the boiler whether it is intentional or incidental leftovers from within the cardboard shipping materials. Although ground pallets are permitted as wood fuel, no pallet grinding process has been permitted by this permit. [§19.705 and A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311]

## Section V: INSIGNIFICANT ACTIVITIES

The Department 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 Regulation 18 and 19 Appendix A. Insignificant activity emission determinations rely upon the information submitted by the permittee in an application received April 12, 2005.

| Description | Category |
|---|---|
| 1 - 1,200 gallon diesel tank | A-3 |
| 1 - 640 gallon diesel tank | A-3 |
| 1 - 290 gallon gasoline tank | A-13 |

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## Section VI: GENERAL CONDITIONS

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

2. This permit does not relieve the owner or operator of the equipment and/or the facility from compliance with all applicable provisions of the Arkansas Water and Air Pollution Control Act and the regulations promulgated under the Act. [A.C.A. §8-4-203 as referenced by A.C.A. §8-4-304 and §8-4-311]

3. The permittee will notify the Department in writing within thirty (30) days after commencement of construction, completion of construction, first operation of equipment and/or facility, and first attainment of the equipment and/or facility target production rate. [Regulation 19, §19.704 and/or A.C.A. §8-4-203 as referenced by A.C.A. §8-4-304 and §8-4-311]

4. Construction or modification must commence within eighteen (18) months from the date of permit issuance. [Regulation 19, §19.410(B) and/or Regulation 18, §18.309(B) and A.C.A. §8-4-203 as referenced by A.C.A. §8-4-304 and §8-4-311]

5. The permittee must keep records for five years to enable the Department to determine compliance with the terms of this permit such as hours of operation, throughput, upset conditions, and continuous monitoring data. The Department may use the records, at the discretion of the Department, to determine compliance with the conditions of the permit. [Regulation 19, §19.705 and/or Regulation 18, §18.1004 and A.C.A. §8-4-203 as referenced by A.C.A. §8-4-304 and §8-4-311]

6. A responsible official must certify any reports required by any condition contained in this permit and submit any reports to the Department at the address below. [Regulation 19, §19.705 and/or Regulation 18, §18.1004 and A.C.A. §8-4-203 as referenced by A.C.A. §8-4-304 and §8-4-311]

    Arkansas Department of Environmental Quality
    Air Division
    ATTN: Compliance Inspector Supervisor
    Post Office Box 8913

Little Rock, AR 72219

7. The permittee will test any equipment scheduled for testing, unless stated in the Specific Conditions of this permit or by any federally regulated requirements, within the following time frames: (1) newly constructed or 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) existing equipment already operating according to the time frames set forth by the Department. The permittee must notify the Department of the scheduled date of compliance testing at least fifteen (15) days in advance of such test. The permittee must submit compliance test results to the Department within thirty (30) days after the completion of testing. [Regulation 19, §19.702 and/or Regulation 18, §18.1002 and A.C.A. §8-4-203 as referenced by A.C.A. §8-4-304 and §8-4-311]

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

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

9. The permittee will operate equipment, control apparatus and emission monitoring equipment within their design limitations. The permittee will maintain in good condition at all times equipment, control apparatus and emission monitoring equipment. [Regulation 19, §19.303 and/or Regulation 18, §18.1104 and A.C.A. §8-4-203 as referenced by A.C.A. §8-4-304 and §8-4-311]

10. If the permittee exceeds an emission limit established by this permit, the permittee will be deemed in violation of said permit and will be subject to enforcement action. The Department may forego enforcement action for emissions exceeding any limits established by this permit provided the following requirements are met: [Regulation 19, §19.601 and/or Regulation 18, §18.1101 and A.C.A. §8-4-203 as referenced by A.C.A. §8-4-304 and §8-4-311]

   a. The permittee demonstrates to the satisfaction of the Department that the emissions resulted from an equipment malfunction or upset and are not the result of negligence or improper maintenance, and the permittee took all reasonable measures to immediately minimize or eliminate the excess emissions.
   b. The permittee reports the occurrence or upset or breakdown of equipment (by telephone, facsimile, or overnight delivery) to the Department by the end of the next business day after the occurrence or the discovery of the occurrence.
   c. The permittee must submit to the Department, within five business days after the occurrence or the discovery of the occurrence, a full, written report of such occurrence, including a statement of all known causes and of the scheduling and nature of the actions to be taken to minimize or eliminate future occurrences,

including, but not limited to, action to reduce the frequency of occurrence of such conditions, to minimize the amount by which said limits are exceeded, and to reduce the length of time for which said limits are exceeded. If the information is included in the initial report, the information need not be submitted again.

11. The permittee shall allow representatives of the Department upon the presentation of credentials: [A.C.A. §8-4-203 as referenced by A.C.A. §8-4-304 and §8-4-311]

    a. To enter upon the permittee's premises, or other premises under the control of the permittee, where an air pollutant source is located or in which any records are required to be kept under the terms and conditions of this permit;
    b. To have access to and copy any records required to be kept under the terms and conditions of this permit, or the Act;
    c. To inspect any monitoring equipment or monitoring method required in this permit;
    d. To sample any emission of pollutants; and
    e. To perform an operation and maintenance inspection of the permitted source.

12. The Department issued this permit in reliance upon the statements and presentations made in the permit application. The Department has no responsibility for the adequacy or proper functioning of the equipment or control apparatus. [A.C.A. §8-4-203 as referenced by A.C.A. §8-4-304 and §8-4-311]

13. The Department may revoke or modify this permit when, in the judgment of the Department, such revocation or modification is necessary to comply with the applicable provisions of the Arkansas Water and Air Pollution Control Act and the regulations promulgated the Arkansas Water and Air Pollution Control Act. [Regulation 19, §19.410(A) and/or Regulation 18, §18.309(A) and A.C.A. §8-4-203 as referenced by A.C.A. §8-4-304 and §8-4-311]

14. This permit may be transferred. An applicant for a transfer must submit a written request for transfer of the permit on a form provided by the Department and submit the disclosure statement required by Arkansas Code Annotated '8 1 106 at least thirty (30) days in advance of the proposed transfer date. The permit will be automatically transferred to the new permittee unless the Department denies the request to transfer within thirty (30) days of the receipt of the disclosure statement. The Department may deny a transfer on the basis of the information revealed in the disclosure statement or other investigation or, deliberate falsification or omission of relevant information. [Regulation 19, §19.407(B) and/or Regulation 18, §18.307(B) and A.C.A. §8-4-203 as referenced by A.C.A. §8-4-304 and §8-4-311]

15. This permit shall be available for inspection on the premises where the control apparatus is located. [A.C.A. §8-4-203 as referenced by A.C.A. §8-4-304 and §8-4-311]

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

17. This permit supersedes and voids all previously issued air permits for this facility. [Regulation 18 and 19 and A.C.A. §8-4-203 as referenced by A.C.A. §8-4-304 and §8-4-311]

18. The permittee must pay all permit fees in accordance with the procedures established in Regulation No. 9. [A.C.A §8-1-105(c)]

# APPENDIX

40 CFR Part 60, Subpart Dc

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

**Source:** 55 FR 37683, Sept. 12, 1990, unless otherwise noted.

## § 60.40c Applicability and delegation of authority.

(a) Except as provided in paragraph (d) 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 Btu per hour (Btu/hr)) or less, but greater than or equal to 2.9 MW (10 million Btu/hr).
(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 which meet the applicability requirements in paragraph (a) of this section are not subject to the sulfur dioxide ($SO_2$) 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.
[55 FR 37683, Sept. 12, 1990, as amended at 61 FR 20736, May 8, 1996]

## § 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 ch a separate source (such as a stationary gas turbine, internal combustion engine, or kiln) provides exhaust gas to a steam generating unit.
*Coal* means all solid fuels classified as anthracite, bituminous, subbituminous, or lignite by the American Society for Testing and Materials in ASTM D388–77, "Standard Specification for Classification of Coals by Rank" (incorporated by reference—see §60.17); coal refuse; and petroleum coke. Synthetic fuels derived from coal for the purpose of creating useful heat, including but not limited to solvent-refined coal, gasified coal, coal-oil mixtures, and coal-water mixtures, are included in this definition for the purposes of this subpart.
*Coal 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.
*Cogeneration steam generating unit* means a steam generating unit that simultaneously produces both electrical (or mechanical) and thermal energy from the same primary energy source.
*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 D396–78, 89, 90, 92, 96, or 98, "Standard Specification for Fuel Oils" (incorporated by reference—see §60.17).
*Dry flue gas desulfurization technology* means a sulfur dioxide ($SO_2$) 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 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 $SO_2$ 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 40 CFR 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 D1835–86, 87, 91, or 97, "Standard Specification for Liquefied Petroleum Gases" (incorporated by reference—see §60.17).
*Noncontinental area* means the State of Hawaii, the Virgin Islands, Guam, American Samoa, the Commonwealth of Puerto Rico, or the Northern Mariana Islands.
*Oil* means crude oil or petroleum, or a liquid fuel derived from crude oil or petroleum, including distillate oil and residual oil.
*Potential sulfur dioxide emission rate* means the theoretical $SO_2$ emissions (nanograms per joule [ng/J], or pounds per million Btu [lb/million Btu] heat input) that would result from combusting fuel in an uncleaned state and without using emission control systems.
*Process heater* means a device that is primarily used to heat a material to initiate or promote a chemical reaction in which the material participates as a reactant or catalyst.
*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 D396–78, 89, 90, 92, 96, or 98, "Standard Specification for Fuel Oils" (incorporated by reference—see §60.17).
*Steam generating unit* means a device that combusts any fuel and produces steam or heats water or any other 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.
*Wet flue gas desulfurization technology* means an $SO_2$ 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 particulate matter (PM) or $SO_2$.
*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.
[55 FR 37683, Sept. 12, 1990, as amended at 61 FR 20736, May 8, 1996; 65 FR 61752, Oct. 17, 2000]

## § 60.42c Standard for sulfur dioxide.

(a) Except as provided in paragraphs (b), (c), and (e) of this section, on and after the date on which the initial performance test is completed or required to be completed under §60.8 of this part, whichever date comes first, the owner or operator of an affected facility that combusts only coal shall neither: (1) cause to be discharged into the atmosphere from that affected facility any gases that contain $SO_2$ in excess of 10 percent (0.10) of the potential $SO_2$ emission rate (90 percent

reduction); nor (2) cause to be discharged into the atmosphere from that affected facility any gases that contain $SO_2$ in excess of 520 ng/J (1.2 lb/million Btu) heat input. If coal is combusted with other fuels, the affected facility is subject to the 90 percent $SO_2$ reduction requirement specified in this paragraph and 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 initial performance test is completed or required to be completed under §60.8 of this part, whichever date comes first, the owner or operator of an affected facility that:
(1) Combusts 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 $SO_2$ in excess of 20 percent (0.20) of the potential $SO_2$ emission rate (80 percent reduction); nor
(ii) Cause to be discharged into the atmosphere from that affected facility any gases that contain $SO_2$ in excess of 520 ng/J (1.2 lb/million Btu) heat input. If coal is fired with coal refuse, the affected facility is 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 90 percent $SO_2$ reduction requirement specified in paragraph (a) of this section and the emission limit determined pursuant to paragraph (e)(2) of this section.
(2) Combusts only coal and that uses an emerging technology for the control of $SO_2$ emissions shall neither:
(i) Cause to be discharged into the atmosphere from that affected facility any gases that contain $SO_2$ in excess of 50 percent (0.50) of the potential $SO_2$ emission rate (50 percent reduction); nor
(ii) Cause to be discharged into the atmosphere from that affected facility any gases that contain $SO_2$ in excess of 260 ng/J (0.60 lb/million Btu) heat input. If coal is combusted with other fuels, the affected facility is subject to the 50 percent $SO_2$ 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 of this part, 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 $SO_2$ 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 million Btu/hr) 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.
(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 of this part, 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 $SO_2$ in excess of 215 ng/J (0.50 lb/million Btu) heat input; 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 of this part, 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 $SO_2$ in excess of the following:
(1) The percent of potential $SO_2$ 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 million Btu/hr), 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:
$E_s=(K_a H_a+K_b H_b+K_c H_c)/H_a+H_b+H_c)$

where:

$E_s$ is the $SO_2$ emission limit, expressed in ng/J or lb/million Btu heat input,

$K_a$ is 520 ng/J (1.2 lb/million Btu),

$K_b$ is 260 ng/J (0.60 lb/million Btu),

$K_c$ is 215 ng/J (0.50 lb/million Btu),

$H_a$ is the 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) [million Btu]

$H_b$ is the heat input from the combustion of coal in an affected facility subject to paragraph (b)(2) of this section, in J (million Btu)

$H_c$ is the heat input from the combustion of oil, in J (million Btu).

(f) Reduction in the potential $SO_2$ 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 $SO_2$ emission rate; and
(2) Emissions from the pretreated fuel (without either combustion or post-combustion $SO_2$ 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), or (3) 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)(1), (2), or (3), as applicable.
(1) Distillate oil-fired affected facilities with heat input capacities between 2.9 and 29 MW (10 and 100 million Btu/hr).
(2) Residual oil-fired affected facilities with heat input capacities between 2.9 and 8.7 MW (10 and 30 million Btu/hr).
(3) Coal-fired facilities with heat input capacities between 2.9 and 8.7 MW (10 and 30 million Btu/hr).
(i) The $SO_2$ 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) 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.
[55 FR 37683, Sept. 12, 1990, as amended at 65 FR 61753, Oct. 17, 2000]

## § 60.43c Standard for particulate matter.

(a) On and after the date on which the initial performance test is completed or required to be completed under §60.8 of this part, whichever date comes first, no owner or operator of an affected facility that combusts coal or combusts mixtures of coal with other fuels and has a heat input capacity of 8.7 MW (30 million Btu/hr) 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/million Btu) 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/million Btu) heat imput 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 of this part, whichever date comes first, no owner or operator of an affected facility that combusts wood or combusts mixtures of wood with other fuels (except coal) and has a heat input capacity of 8.7 MW (30 million Btu/hr) 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/million Btu) 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/million Btu) 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 of this part, 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 million Btu/hr) 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.
(d) The PM and opacity standards under this section apply at all times, except during periods of startup, shutdown, or malfunction.
[55 FR 37683, Sept. 12, 1990, as amended at 65 FR 61753, Oct. 17, 2000]

# § 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 in §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 $SO_2$ 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 affect 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) and §60.8, compliance with the percent reduction requirements and $SO_2$ emission limits under §60.42c is based on the average percent reduction and the average $S0_2$ 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 $SO_2$ 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 are used to determine the hourly $SO_2$ emission rate ($E_{ho}$) and the 30-day average $SO_2$ emission rate ($E_{ao}$). The hourly averages used to compute the 30-day averages are obtained from the continuous emission monitoring system (CEMS). Method 19 shall be used to calculate $E_{ao}$ when using daily fuel sampling or Method 6B.
(e) If coal, oil, or coal and oil are combusted with other fuels:
(1) An adjusted $E_{ho}$ ($E_{ho}$o) is used in Equation 19–19 of Method 19 to compute the adjusted $E_{ao}$ ($E_{ao}$o). The $E_{ho}$o is computed using the following formula:
$E_{ho}o=[E_{ho}-E_w(1-X_k)]/X_k$

where:

$E_{ho}o$ is the adjusted $E_{ho}$, ng/J (lb/million Btu)

$E_{ho}$ is the hourly $SO_2$ emission rate, ng/J (lb/million Btu)

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

$X_k$ is the fraction of the total heat input from fuel combustion derived from coal and oil, as determined by applicable procedures in Method 19.

(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.
(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:
$\%P_s=100(1-\%R_g/100)(1-\%R_f/100)$

where

$\%P_s$ is the percent of potential $SO_2$ emission rate, in percent

$\%R_g$ is the $SO_2$ removal efficiency of the control device as determined by Method 19, in percent

$\%R_f$ is the $SO_2$ removal efficiency of fuel pretreatment as determined by Method 19, 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 $\%R_g$ ($\%R_g$o) is computed from $E_{ao}$o from paragraph (e)(1) of this section and an adjusted average $SO_2$ inlet rate ($E_{ai}$o) using the following formula:
$\%R_go=100\ [1.0- E_{ao}o/E_{ai}o)]$

where:

$\%R_go$ is the adjusted $\%R_g$, in percent

$E_{ao}o$ is the adjusted $E_{ao}$, ng/J (lb/million Btu)

$E_{ai}o$ is the adjusted average $SO_2$ inlet rate, ng/J (lb/million Btu)

(ii) To compute $E_{ai}$o, an adjusted hourly $SO_2$ inlet rate ($E_{hi}$o) is used. The $E_{hi}$o is computed using the following formula:
$E_{hi}o=[E_{hi}- E_w\ (1-X_k)]/X_k$

where:

$E_{hi}o$ is the adjusted $E_{hi}$, ng/J (lb/million Btu)

$E_{hi}$ is the hourly $SO_2$ inlet rate, ng/J (lb/million Btu)

$E_w$ is the $SO_2$ concentration in fuels other than coal and oil combusted in the affected facility, as determined by fuel sampling and analysis procedures in Method 19, ng/J (lb/million Btu). The value $E_w$ for each fuel lot is used for each hourly average during the time that the lot is being combusted. The owner or operator does not have to measure $E_w$ if the owner or operator elects to assume $E_w$ = O.

$X_k$ is the fraction of the total heat input from fuel combustion derived from coal and oil, as determined by applicable procedures in Method 19.

(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 $SO_2$ standards based on fuel supplier certification, the performance test shall consist of the certification, the certification from the fuel supplier, as described under §60.48c(f)(1), (2), or (3), as applicable.
(i) The owner or operator of an affected facility seeking to demonstrate compliance with the $SO_2$ 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 $SO_2$ emissions data in calculating $\%P_s$ 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 $\%P_s$ or $E_{ho}$ pursuant to paragraphs (d), (e), or (f) of this section, as applicable.
[55 FR 37683, Sept. 12, 1990, as amended at 65 FR 61753, Oct. 17, 2000]

## § 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.
(1) Method 1 shall be used to select the sampling site and the number of traverse sampling points.
(2) Method 3 shall be used for gas analysis when applying Method 5, Method 5B, or Method 17.
(3) Method 5, Method 5B, or Method 17 shall be used to measure the concentration of PM as follows:
(i) Method 5 may be used only at affected facilities without wet scrubber systems.
(ii) Method 17 may be used at affected facilities with or without wet scrubber systems provided the stack gas temperature does not exceed a temperature of 160 ℃ (320 ℉). The procedures of Sections 8.1 and 11.1 of Method 5B may be used in Method 17 only if Method 17 is used in conjunction with a wet scrubber system. Method 17 shall not be used in conjunction with a wet scrubber system if the effluent is saturated or laden with water droplets.
(iii) Method 5B 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 Method 5B, the temperature of the sample gas in the probe and filter holder shall be monitored and maintained at 160±14 ℃ (320±25 ℉).
(6) For determination of PM emissions, an oxygen or carbon dioxide measurement shall be obtained simultaneously with each run of Method 5, Method 5B, or Method 17 by traversing the duct at the same sampling location.
(7) For each run using Method 5, Method 5B, or Method 17, the emission rates expressed in ng/J (lb/million Btu) heat input shall be determined using:
(i) The oxygen or carbon dioxide 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 (appendix A).
(8) Method 9 (6-minute average of 24 observations) 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.
[55 FR 37683, Sept. 12, 1990, as amended at 65 FR 61753, Oct. 17, 2000]

## § 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 $SO_2$ emission limits under §60.42c shall install, calibrate, maintain, and operate a CEMS for measuring $SO_2$ concentrations and either oxygen or carbon dioxide concentrations at the outlet of the $SO_2$ control device (or the outlet of the steam generating unit if no $SO_2$ 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 $SO_2$ concentrations and either oxygen or carbon dioxide concentrations at both the inlet and outlet of the $SO_2$ control device.
(b) The 1-hour average $SO_2$ emission rates measured by a CEMS shall be expressed in ng/J or lb/million Btu heat input and shall be used to calculate the average emission rates under §60.42c. Each 1-hour average $SO_2$ emission rate must be based on at least 30 minutes of operation and include at least 2 data points representing two 15-minute periods. Hourly $SO_2$ 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 (appendix B).
(2) Quarterly accuracy determinations and daily calibration drift tests shall be performed in accordance with Procedure 1 (appendix F).
(3) For affected facilities subject to the percent reduction requirements under §60.42c, the span value of the $SO_2$ CEMS at the inlet to the $SO_2$ control device shall be 125 percent of the maximum estimated hourly potential $SO_2$ emission rate of the fuel combusted, and the span value of the $SO_2$ CEMS at the outlet from the $SO_2$ control device shall be 50 percent of the maximum estimated hourly potential $SO_2$ 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 $SO_2$ CEMS at the outlet from the $SO_2$ control device (or outlet of the steam generating unit if no $SO_2$ control device is used) shall be 125 percent of the maximum estimated hourly potential $SO_2$ emission rate of the fuel combusted.
(d) As an alternative to operating a CEMS at the inlet to the $SO_2$ control device (or outlet of the steam generating unit if no $SO_2$ control device is used) as required under paragraph (a) of this section, an owner or operator may elect to determine the average $SO_2$ emission rate by sampling the fuel prior to combustion. As an alternative to operating a CEMS at the outlet from the $SO_2$ control device (or outlet of the steam generating unit if no $SO_2$ control device is used) as required under paragraph (a) of this section, an owner or operator may elect to determine the average $SO_2$ emission rate by using Method 6B. Fuel sampling shall be conducted pursuant to either paragraph (d)(1) or (d)(2) of this section. Method 6B 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 the Method 19. Method 19 provides procedures for converting these measurements into the format to be used in calculating the average $SO_2$ 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 fule 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 may be used in lieu of CEMS to measure $SO_2$ at the inlet or outlet of the $SO_2$ control system. An initial stratification test is required to verify the adequacy of the Method 6B sampling location. The stratification test shall consist of three paired runs of a suitable $SO_2$ and carbon dioxide 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 (appendix B). Method 6B, Method 6A, or a combination of Methods 6 and 3 or Methods 6C and 3A are suitable measurement techniques. If Method 6B is used for the second train, sampling time and timer operation may be adjusted for the stratification test as long as an adequate sample volume is collected; however, both sampling trains are to be operated similarly. For the location to be adequate for Method 6B 24-hour tests, the mean of the absolute difference between the three paired runs must be less than 10 percent (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 $SO_2$ standards based on fuel supplier certification, as described under §60.48c(f) (1), (2), or (3), 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.
[55 FR 37683, Sept. 12, 1990, as amended at 65 FR 61753, Oct. 17, 2000]

## § 60.47c Emission monitoring for particulate matter.

(a) The owner or operator of an affected facility combusting coal, residual oil, or wood that is subject to the opacity standards under §60.43c shall install, calibrate, maintain, and operate a COMS for measuring the opacity of the emissions discharged to the atmosphere and record the output of the system.
(b) All COMS for measuring opacity shall be operated in accordance with the applicable procedures under Performance Specification 1 (appendix B). The span value of the opacity COMS shall be between 60 and 80 percent.
[55 FR 37683, Sept. 12, 1990, as amended at 65 FR 61753, Oct. 17, 2000]

## § 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, anticipated startup, 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 $SO_2$ 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 $SO_2$ 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.
(c) The owner or operator of each coal-fired, residual oil-fired, or wood-fired affected facility subject to the opacity limits under §60.43c(c) shall submit excess emission reports for any excess emissions from the affected facility which occur during the reporting period.
(d) The owner or operator of each affected facility subject to the $SO_2$ 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 $SO_2$ emission limits, fuel oil sulfur limits, or percent reduction requirements under §60.43c 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 $SO_2$ emission rate (nj/J or lb/million Btu), 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 $SO_2$ 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 $SO_2$ or diluent (oxygen or carbon dioxide) data have not been obtained by an approved method for at least 75 percent of the operating hours; justification for not obtaining sufficient data; and 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 (appendix B).
(10) If a CEMS is used, results of daily CEMS drift tests and quarterly accuracy assessments as required under appendix F, Procedure 1.
(11) If fuel supplier certification is used to demonstrate compliance, records of fuel supplier certification is used to demonstrate compliance, records of fuel supplier certification as described under paragraph (f)(1), (2), or (3) 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; and
(ii) A statement from the oil supplier that the oil complies with the specifications under the definition of distillate oil in §60.41c.
(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.
(g) The owner or operator of each affected facility shall record and maintain records of the amounts of each fuel combusted during each day.
(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.
[55 FR 37683, Sept. 12, 1990, as amended at 64 FR 7465, Feb. 12, 1999; 65 FR 61753, Oct. 17, 2000]

| Request for PDS Invoice | |
|---|---|
| Invoice Number *(assigned when invoice printed)* | PDS- |

| | | | | |
|---|---|---|---|---|
| AFIN ✱ | 75-00333 | | | |
| Name *(for confirmation only)* | Pet Solutions, LLC | | | |
| Invoice Type (pick one) ✱ | Initial | Mod ✓ | Variance | |
| | Annual | Renewal | Interim Authority | |
| Permit Number ✱ | 2058-AR-2 | | | |
| Media Code ✱ | A | | | |
| Fee Code or Pmt Type✱ | MS | | | |
| Fee Description *(for confirmation only)* | Minor Source | | | |
| Amount Due ✱ *(whole dollar amount only)* | $625 | | | |
| Printed Comment *(600 characters maximum)* | NOx: 52.8 - 23 = 29.8* 20.96 = $624.60 | | | |

| *Note: The information below is for use by the requesting division if desired; it will not print on the invoice.* | |
|---|---|
| Engineer | Bryan Leamons |
| Paid? (yes/no) | |
| Check number | |
| Comments | |

✱ **Required data** *(See "g:\Misc\PDS_FeeCodes.wpd" for descriptions and discussions of fee codes)*

| | | | |
|---|---|---|---|
| Request submitted by: | | Date: | |

Public Notice

Pursuant to A.C.A. §8-4-203, and the regulations promulgated thereunder, the Air Division of the Arkansas Department of Environmental Quality gives the following notice:

Pet Solutions, LLC, located at Route 1, Box 306, Mt. Tabor Road, Danville, AR 72833, has applied for modification to their existing minor source air permit (AFIN: 75-00333). Upon final approval and issuance by the Department, the permittee will be permitted to install and operate muti-fuel boiler to produce steam for electricity production. Emission increases result from typical products of combustion, predominantly oxides of nitrogen, which increases by 77.2 tons per year.

The application has been reviewed by the staff of the Department and has received the Department's tentative approval subject to the terms of this notice.

Citizens wishing to examine the permit application and staff findings and recommendations may do so by contacting Doug Szenher, Public Affairs Supervisor. Citizens desiring technical information concerning the application or permit should contact, Bryan Leamons, Engineer. Both Doug Szenher and Bryan Leamons can be reached at the Department's central office, 8001 National Drive, Little Rock, Arkansas 72209, telephone: (501) 682-0744.

The draft permit and permit application are available for copying at the above address. A copy of the draft permit has also been placed at the Pope County Library located at 116 East Third Street, Russellville, AR 72801. This information may be reviewed during normal business hours.

Interested or affected persons may also submit written comments or request a hearing on the proposal, or the proposed modification, to the Department at the above address Attention: Doug Szenher. In order to be considered, the comments must be submitted within thirty (30) days of publication of this notice. Although the Department is not proposing to conduct a public hearing, one will be scheduled if significant comments on the permit provisions are received. If a hearing is scheduled, adequate public notice will be given in the newspaper of largest circulation in the county in which the facility in question is, or will be, located.

The Director shall make a final decision to issue or deny this application or to impose special conditions in accordance with Section 2.1 of the Arkansas Pollution Control and Ecology Commission's Administrative Procedures (Regulation #8).

Dated this

Marcus C. Devine
Director