



# INDIANA DEPARTMENT OF ENVIRONMENTAL MANAGEMENT

*We Protect Hoosiers and Our Environment.*

100 N. Senate Avenue • Indianapolis, IN 46204  
(800) 451-6027 • (317) 232-8603 • [www.idem.IN.gov](http://www.idem.IN.gov)

**Michael R. Pence**  
Governor

**Thomas W. Easterly**  
Commissioner

To: Interested Parties

Date: September 4, 2014

From: Matthew Stuckey, Chief  
Permits Branch  
Office of Air Quality

Source Name: Griffin Industries LLC

Permit Level: Title V - Significant Permit Modification

Permit Number: 055 - 34320 - 00008

Source Location: 7358 South Griffin Road, Newberry, Indiana

Type of Action Taken: Modification at an existing source  
Revisions to permit requirements

## Notice of Decision: Approval - Effective Immediately

Please be advised that on behalf of the Commissioner of the Department of Environmental Management, I have issued a decision regarding the matter referenced above.

The final decision is available on the IDEM website at: <http://www.in.gov/apps/idem/caats/>  
To view the document, select Search option 3, then enter permit 34320.

If you would like to request a paper copy of the permit document, please contact IDEM's central file room:

Indiana Government Center North, Room 1201  
100 North Senate Avenue, MC 50-07  
Indianapolis, IN 46204  
Phone: 1-800-451-6027 (ext. 4-0965)  
Fax (317) 232-8659

Pursuant to IC 13-17-3-4 and 326 IAC 2, this permit modification is effective immediately, unless a petition for stay of effectiveness is filed and granted, and may be revoked or modified in accordance with the provisions of IC 13-15-7-1.

*(continues on next page)*

If you wish to challenge this decision, IC 4-21.5-3-7 and IC 13-15-7-3 require that you file a petition for administrative review. This petition may include a request for stay of effectiveness and must be submitted to the Office Environmental Adjudication, 100 North Senate Avenue, Government Center North, Suite N 501E, Indianapolis, IN 46204, **within eighteen (18) days of the mailing of this notice**. The filing of a petition for administrative review is complete on the earliest of the following dates that apply to the filing:

- (1) the date the document is delivered to the Office of Environmental Adjudication (OEA);
- (2) the date of the postmark on the envelope containing the document, if the document is mailed to OEA by U.S. mail; or
- (3) The date on which the document is deposited with a private carrier, as shown by receipt issued by the carrier, if the document is sent to the OEA by private carrier.

The petition must include facts demonstrating that you are either the applicant, a person aggrieved or adversely affected by the decision or otherwise entitled to review by law. Please identify the permit, decision, or other order for which you seek review by permit number, name of the applicant, location, date of this notice and all of the following:

- (1) the name and address of the person making the request;
- (2) the interest of the person making the request;
- (3) identification of any persons represented by the person making the request;
- (4) the reasons, with particularity, for the request;
- (5) the issues, with particularity, proposed for considerations at any hearing; and
- (6) identification of the terms and conditions which, in the judgment of the person making the request, would be appropriate in the case in question to satisfy the requirements of the law governing documents of the type issued by the Commissioner.

Pursuant to 326 IAC 2-7-18(d), any person may petition the U.S. EPA to object to the issuance of a Title V operating permit or modification within sixty (60) days of the end of the forty-five (45) day EPA review period. Such an objection must be based only on issues that were raised with reasonable specificity during the public comment period, unless the petitioner demonstrates that it was impracticable to raise such issues, or if the grounds for such objection arose after the comment period.

To petition the U.S. EPA to object to the issuance of a Title V operating permit, contact:

U.S. Environmental Protection Agency  
401 M Street  
Washington, D.C. 20406

If you have technical questions regarding the enclosed documents, please contact the Office of Air Quality, Permits Branch at (317) 233-0178. Callers from within Indiana may call toll-free at 1-800-451-6027, ext. 3-0178.



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Michael R. Pence  
Governor

Thomas W. Easterly  
Commissioner

Michael Schmidt  
Griffin Industries LLC  
4221 Alexandria Pike  
Cold Spring, KY 41076-1897

September 4, 2014

Re: 055-34320-00008  
Significant Permit Modification to  
Part 70 Renewal No.: T055-32418-00008

Dear Michael Schmidt:

Griffin Industries LLC was issued a Part 70 Operating Permit Renewal No. T055-32418-00008 on October 16, 2013 for a stationary animal and agricultural byproducts rendering operation located at 7358 South Griffin Road, Newberry, IN 47449. An application requesting changes to this permit was received on March 03, 2014. Pursuant to the provisions of 326 IAC 2-7-12, a significant permit modification to this permit is hereby approved as described in the attached Technical Support Document.

For your convenience, the entire Part 70 Operating Permit Renewal as modified is attached.

A copy of the permit is available on the Internet at: <http://www.in.gov/ai/appfiles/idem-caats/>. For additional information about air permits and how the public and interested parties can participate, refer to the IDEM's Guide for Citizen Participation and Permit Guide on the Internet at: [www.idem.in.gov](http://www.idem.in.gov)

This decision is subject to the Indiana Administrative Orders and Procedures Act - IC 4-21.5-3-5. If you have any questions on this matter, please contact Nida Habeeb, of my staff, at 317-234-8531 or 1-800-451-6027, and ask for extension 4-8531.

Sincerely,

Jason R. Krawczyk  
Section Chief  
Permits Branch  
Office of Air Quality

Attachment(s): Updated Permit, Technical Support Document, and Appendix A

JK/NH

cc: File - Greene County  
Greene County Health Department  
U.S. EPA, Region V  
Compliance and Enforcement Branch  
Billing, Licensing and Training Section



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## Part 70 Operating Permit Renewal OFFICE OF AIR QUALITY

**Griffin Industries LLC  
7358 South Griffin Road  
Newberry, Indiana, 47449**

(herein known as the Permittee) is hereby authorized to operate subject to the conditions contained herein, the source described in Section A (Source Summary) of this permit.

**The Permittee must comply with all conditions of this permit. Noncompliance with any provisions of this permit is grounds for enforcement action; permit termination, revocation and reissuance, or modification; or denial of a permit renewal application. Noncompliance with any provision of this permit, except any provision specifically designated as not federally enforceable, constitutes a violation of the Clean Air Act. It shall not be a defense for the Permittee in an enforcement action that it would have been necessary to halt or reduce the permitted activity in order to maintain compliance with the conditions of this permit. An emergency does constitute an affirmative defense in an enforcement action provided the Permittee complies with the applicable requirements set forth in Section B, Emergency Provisions.**

This permit is issued in accordance with 326 IAC 2 and 40 CFR Part 70 Appendix A and contains the conditions and provisions specified in 326 IAC 2-7 as required by 42 U.S.C. 7401, et. seq. (Clean Air Act as amended by the 1990 Clean Air Act Amendments), 40 CFR Part 70.6, IC 13-15 and IC 13-17.

Operation Permit No.: T055-32418-00008	
Issued by: / Original Signed by: Iryn Calilung, Section Chief Permits Branch Office of Air Quality	Issuance Date: October 16, 2013  Expiration Date: October 16, 2018

Significant Permit Modification No.: T055-34320-00008	
Issued by:  Jason R. Krawczyk, Section Chief Permits Branch Office of Air Quality	Issuance Date: September 4, 2014 Expiration Date: September 4, 2019

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## SECTION A SOURCE SUMMARY

This permit is based on information requested by the Indiana Department of Environmental Management (IDEM), Office of Air Quality (OAQ). The information describing the source contained in conditions A.1 through A.3 is descriptive information and does not constitute enforceable conditions. However, the Permittee should be aware that a physical change or a change in the method of operation that may render this descriptive information obsolete or inaccurate may trigger requirements for the Permittee to obtain additional permits or seek modification of this permit pursuant to 326 IAC 2, or change other applicable requirements presented in the permit application.

### A.1 General Information [326 IAC 2-7-4(c)][326 IAC 2-7-5(14)][326 IAC 2-7-1(22)]

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The Permittee owns and operates a stationary animal and agricultural byproducts rendering operation.

Source Address:	7358 South Griffin Road, Newberry, Indiana, 47449
General Source Phone Number:	812-659-3390
SIC Code:	2077 (Animal and Marine Fats and Oils)
County Location:	Greene
Source Location Status:	Attainment for all criteria pollutants
Source Status:	Part 70 Operating Permit Program Minor Source, under PSD and Emission Offset Rules Minor Source for Greenhouse Gases Minor Source, Section 112 of the Clean Air Act Not 1 of 28 Source Categories

### A.2 Emission Units and Pollution Control Equipment Summary [326 IAC 2-7-4(c)(3)][326 IAC 2-7-5(14)]

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This stationary source consists of the following emission units and pollution control devices:

- (a) Blood meal making process, constructed in 1968 (except Dupps dryer, approved in 2014 for construction), with a maximum production rate of 1.0 ton of blood meal per hour, controlled by a series of 3 scrubbers with sequence as Blood Centrifuge Venturi Scrubber (Venturi1C), Packed Bed Scrubber (Packed 1C) and In-Room Air Scrubber (Room 32B), exhausting to Stack RAS-2 and consisting of the following:
- (I) Blood receiving
  - (II) Coagulator
  - (III) Centrifuge
  - (IV) One (1) steam heated dryer, identified as Dupps dryer, approved in 2014 for construction, with a maximum production rate of 1.0 ton of blood meal per hour and exhausting to Stack RAS-2.
  - (V) Screen
  - (VI) Storage
- (b) Feather meal making process, constructed in 1968, with a maximum production rate of 2.88 tons of feather meal per hour, controlled by a series of 3 scrubbers with sequence as Feather Plant Venturi Scrubber (Venturi10B), Feather Plant Packed Bed Scrubber (Packed 10B) and In-Room Air Scrubber (Room 32B), exhausting to Stack RAS-2, and consisting of the following:
- (I) Feather receiving and spreader
  - (II) Hydrolizer
  - (III) Feather Press
  - (IV) Feather Dryer, identified as Feather Dryer
  - (V) Shell and tube Condensers and cooling tower

- (VI) Underground storage tank
  - (VII) Hammermill
- (c) Poultry meal making process, constructed in 1968, with a maximum production rate of 10.15 tons of Poultry meal per hour, controlled by series of 3 scrubbers with sequence as Meat Plant Venturi Scrubber (Venturi 3A), Meat Plant Packed Bed Scrubber (Packed 3A) and Meat Plant In-Room Air Scrubber (Room 32A), exhausting to Stack RAS-1, and consisting of the following:
- (I) Two (2) Grinders
  - (II) Two (2) Cookers (Cooker A and Cooker B)
  - (III) Drainers
  - (IV) Presses
  - (V) Screens
  - (VI) Centrifuges
  - (VII) Shell and tube Condensers and cooling tower
- (d) Four (4) boilers, identified as 05, 06, 07, and 08, constructed in 2008, used for supplying heat in Feather meal, Poultry meal and Blood Meal making processes, each is capable of burning natural gas, processed grease, fuel oil no. 2, and waste/spec used oil. Each boiler 05, 06, and 07 has a heat input capacity of 50.2 million British thermal units per hour (MMBtu/hr), exhausting to stacks H, I, and J respectively, and boiler 08 has a heat input capacity of 33.746 MMBtu/hr, exhausting to stack K.
- (e) Material storage and handling facilities including:
- (1) Ten (10) enclosed tanks totaling 559 tons of capacity, used for storing tallow/grease, with enclosed piping for material handling,
  - (2) Three (3) 250 ton capacity enclosed silos, used for storing meat meal, feather meal, and poultry meal, with five (5) screw conveyors for material handling, and
  - (3) One (1) 30 ton capacity enclosed silo, used for storing blood meal, with three (3) screw conveyor for material handling.

A.3 Insignificant Activities [326 IAC 2-7-1(21)]

This stationary source does not have insignificant activities as defined in 326 IAC 2-7-1(21).

A.4 Part 70 Permit Applicability [326 IAC 2-7-2]

This stationary source is required to have a Part 70 permit by 326 IAC 2-7-2 (Applicability) because:

- (a) It is a major source, as defined in 326 IAC 2-7-1(22);
- (b) It is a source in a source category designated by the United States Environmental Protection Agency (U.S. EPA) under 40 CFR 70.3 (Part 70 - Applicability).

## SECTION B GENERAL CONDITIONS

### B.1 Definitions [326 IAC 2-7-1]

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Terms in this permit shall have the definition assigned to such terms in the referenced regulation. In the absence of definitions in the referenced regulation, the applicable definitions found in the statutes or regulations (IC 13-11, 326 IAC 1-2 and 326 IAC 2-7) shall prevail.

### B.2 Permit Term [326 IAC 2-7-5(2)][326 IAC 2-1.1-9.5][326 IAC 2-7-4(a)(1)(D)][IC 13-15-3-6(a)]

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- (a) This permit, T055-32418-00008, is issued for a fixed term of five (5) years from the issuance date of this permit, as determined in accordance with IC 4-21.5-3-5(f) and IC 13-15-5-3. Subsequent revisions, modifications, or amendments of this permit do not affect the expiration date of this permit.
- (b) If IDEM, OAQ, upon receiving a timely and complete renewal permit application, fails to issue or deny the permit renewal prior to the expiration date of this permit, this existing permit shall not expire and all terms and conditions shall continue in effect, including any permit shield provided in 326 IAC 2-7-15, until the renewal permit has been issued or denied.

### B.3 Term of Conditions [326 IAC 2-1.1-9.5]

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Notwithstanding the permit term of a permit to construct, a permit to operate, or a permit modification, any condition established in a permit issued pursuant to a permitting program approved in the state implementation plan shall remain in effect until:

- (a) the condition is modified in a subsequent permit action pursuant to Title I of the Clean Air Act; or
- (b) the emission unit to which the condition pertains permanently ceases operation.

### B.4 Enforceability [326 IAC 2-7-7] [IC 13-17-12]

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Unless otherwise stated, all terms and conditions in this permit, including any provisions designed to limit the source's potential to emit, are enforceable by IDEM, the United States Environmental Protection Agency (U.S. EPA) and by citizens in accordance with the Clean Air Act.

### B.5 Severability [326 IAC 2-7-5(5)]

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The provisions of this permit are severable; a determination that any portion of this permit is invalid shall not affect the validity of the remainder of the permit.

### B.6 Property Rights or Exclusive Privilege [326 IAC 2-7-5(6)(D)]

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This permit does not convey any property rights of any sort or any exclusive privilege.

### B.7 Duty to Provide Information [326 IAC 2-7-5(6)(E)]

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- (a) The Permittee shall furnish to IDEM, OAQ, within a reasonable time, any information that IDEM, OAQ may request in writing to determine whether cause exists for modifying, revoking and reissuing, or terminating this permit, or to determine compliance with this permit. Upon request, the Permittee shall also furnish to IDEM, OAQ copies of records required to be kept by this permit.
- (b) For information furnished by the Permittee to IDEM, OAQ, the Permittee may include a claim of confidentiality in accordance with 326 IAC 17.1. When furnishing copies of requested records directly to U. S. EPA, the Permittee may assert a claim of confidentiality in accordance with 40 CFR 2, Subpart B.

### B.8 Certification [326 IAC 2-7-4(f)][326 IAC 2-7-6(1)][326 IAC 2-7-5(3)(C)]

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- (a) A certification required by this permit meets the requirements of 326 IAC 2-7-6(1) if:

- (1) it contains a certification by a "responsible official" as defined by 326 IAC 2-7-1(35), and
  - (2) the certification states that, based on information and belief formed after reasonable inquiry, the statements and information in the document are true, accurate, and complete.
- (b) The Permittee may use the attached Certification Form, or its equivalent with each submittal requiring certification. One (1) certification may cover multiple forms in one (1) submittal.
  - (c) A "responsible official" is defined at 326 IAC 2-7-1(35).

**B.9 Annual Compliance Certification [326 IAC 2-7-6(5)]**

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- (a) The Permittee shall annually submit a compliance certification report which addresses the status of the source's compliance with the terms and conditions contained in this permit, including emission limitations, standards, or work practices. All certifications shall cover the time period from January 1 to December 31 of the previous year, and shall be submitted no later than July 1 of each year to:

Indiana Department of Environmental Management  
Compliance and Enforcement Branch, Office of Air Quality  
100 North Senate Avenue  
MC 61-53 IGCN 1003  
Indianapolis, Indiana 46204-2251

and

United States Environmental Protection Agency, Region V  
Air and Radiation Division, Air Enforcement Branch - Indiana (AE-17J)  
77 West Jackson Boulevard  
Chicago, Illinois 60604-3590

- (b) The annual compliance certification report required by this permit shall be considered timely if the date postmarked on the envelope or certified mail receipt, or affixed by the shipper on the private shipping receipt, is on or before the date it is due. If the document is submitted by any other means, it shall be considered timely if received by IDEM, OAQ on or before the date it is due.
- (c) The annual compliance certification report shall include the following:
  - (1) The appropriate identification of each term or condition of this permit that is the basis of the certification;
  - (2) The compliance status;
  - (3) Whether compliance was continuous or intermittent;
  - (4) The methods used for determining the compliance status of the source, currently and over the reporting period consistent with 326 IAC 2-7-5(3); and
  - (5) Such other facts, as specified in Sections D of this permit, as IDEM, OAQ may require to determine the compliance status of the source.

The submittal by the Permittee does require a certification that meets the requirements of 326 IAC 2-7-6(1) by a "responsible official" as defined by 326 IAC 2-7-1(35).

B.10 Preventive Maintenance Plan [326 IAC 2-7-5(12)][326 IAC 1-6-3]

- (a) A Preventive Maintenance Plan meets the requirements of 326 IAC 1-6-3 if it includes, at a minimum:
- (1) Identification of the individual(s) responsible for inspecting, maintaining, and repairing emission control devices;
  - (2) A description of the items or conditions that will be inspected and the inspection schedule for said items or conditions; and
  - (3) Identification and quantification of the replacement parts that will be maintained in inventory for quick replacement.

The Permittee shall implement the PMPs.

- (b) If required by specific condition(s) in Section D of this permit where no PMP was previously required, the Permittee shall prepare and maintain Preventive Maintenance Plans (PMPs) no later than ninety (90) days after issuance of this permit or ninety (90) days after initial start-up, whichever is later, including the following information on each facility:
- (1) Identification of the individual(s) responsible for inspecting, maintaining, and repairing emission control devices;
  - (2) A description of the items or conditions that will be inspected and the inspection schedule for said items or conditions; and
  - (3) Identification and quantification of the replacement parts that will be maintained in inventory for quick replacement.

If, due to circumstances beyond the Permittee's control, the PMPs cannot be prepared and maintained within the above time frame, the Permittee may extend the date an additional ninety (90) days provided the Permittee notifies:

Indiana Department of Environmental Management  
Compliance and Enforcement Branch, Office of Air Quality  
100 North Senate Avenue  
MC 61-53 IGCN 1003  
Indianapolis, Indiana 46204-2251

The PMP extension notification does not require a certification that meets the requirements of 326 IAC 2-7-6(1) by a "responsible official" as defined by 326 IAC 2-7-1(35).

The Permittee shall implement the PMPs.

- (c) A copy of the PMPs shall be submitted to IDEM, OAQ upon request and within a reasonable time, and shall be subject to review and approval by IDEM, OAQ. IDEM, OAQ may require the Permittee to revise its PMPs whenever lack of proper maintenance causes or is the primary contributor to an exceedance of any limitation on emissions. The PMPs and their submittal do not require a certification that meets the requirements of 326 IAC 2-7-6(1) by a "responsible official" as defined by 326 IAC 2-7-1(35).

- (d) To the extent the Permittee is required by 40 CFR Part 60/63 to have an Operation Maintenance, and Monitoring (OMM) Plan for a unit, such Plan is deemed to satisfy the PMP requirements of 326 IAC 1-6-3 for that unit.

**B.11 Emergency Provisions [326 IAC 2-7-16]**

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- (a) An emergency, as defined in 326 IAC 2-7-1(12), is not an affirmative defense for an action brought for noncompliance with a federal or state health-based emission limitation.
- (b) An emergency, as defined in 326 IAC 2-7-1(12), constitutes an affirmative defense to an action brought for noncompliance with a technology-based emission limitation if the affirmative defense of an emergency is demonstrated through properly signed, contemporaneous operating logs or other relevant evidence that describe the following:
- (1) An emergency occurred and the Permittee can, to the extent possible, identify the causes of the emergency;
  - (2) The permitted facility was at the time being properly operated;
  - (3) During the period of an emergency, the Permittee took all reasonable steps to minimize levels of emissions that exceeded the emission standards or other requirements in this permit;
  - (4) For each emergency lasting one (1) hour or more, the Permittee notified IDEM, OAQ, within four (4) daytime business hours after the beginning of the emergency, or after the emergency was discovered or reasonably should have been discovered;

Telephone Number: 1-800-451-6027 (ask for Office of Air Quality, Compliance and Enforcement Branch), or  
Telephone Number: 317-233-0178 (ask for Office of Air Quality, Compliance and Enforcement Branch)  
Facsimile Number: 317-233-6865

- (5) For each emergency lasting one (1) hour or more, the Permittee submitted the attached Emergency Occurrence Report Form or its equivalent, either by mail or facsimile to:

Indiana Department of Environmental Management  
Compliance and Enforcement Branch, Office of Air Quality  
100 North Senate Avenue  
MC 61-53 IGCN 1003  
Indianapolis, Indiana 46204-2251

within two (2) working days of the time when emission limitations were exceeded due to the emergency.

The notice fulfills the requirement of 326 IAC 2-7-5(3)(C)(ii) and must contain the following:

- (A) A description of the emergency;
- (B) Any steps taken to mitigate the emissions; and
- (C) Corrective actions taken.

The notification which shall be submitted by the Permittee does not require a certification that meets the requirements of 326 IAC 2-7-6(1) by a "responsible official" as defined by 326 IAC 2-7-1(35).

- (6) The Permittee immediately took all reasonable steps to correct the emergency.
- (c) In any enforcement proceeding, the Permittee seeking to establish the occurrence of an emergency has the burden of proof.
- (d) This emergency provision supersedes 326 IAC 1-6 (Malfunctions). This permit condition is in addition to any emergency or upset provision contained in any applicable requirement.
- (e) The Permittee seeking to establish the occurrence of an emergency shall make records available upon request to ensure that failure to implement a PMP did not cause or contribute to an exceedance of any limitations on emissions. However, IDEM, OAQ may require that the Preventive Maintenance Plans required under 326 IAC 2-7-4(c)(8) be revised in response to an emergency.
- (f) Failure to notify IDEM, OAQ by telephone or facsimile of an emergency lasting more than one (1) hour in accordance with (b)(4) and (5) of this condition shall constitute a violation of 326 IAC 2-7 and any other applicable rules.
- (g) If the emergency situation causes a deviation from a technology-based limit, the Permittee may continue to operate the affected emitting facilities during the emergency provided the Permittee immediately takes all reasonable steps to correct the emergency and minimize emissions.

B.12 Permit Shield [326 IAC 2-7-15][326 IAC 2-7-20][326 IAC 2-7-12]

- (a) Pursuant to 326 IAC 2-7-15, the Permittee has been granted a permit shield. The permit shield provides that compliance with the conditions of this permit shall be deemed compliance with any applicable requirements as of the date of permit issuance, provided that either the applicable requirements are included and specifically identified in this permit or the permit contains an explicit determination or concise summary of a determination that other specifically identified requirements are not applicable. The Indiana statutes from IC 13 and rules from 326 IAC, referenced in conditions in this permit, are those applicable at the time the permit was issued. The issuance or possession of this permit shall not alone constitute a defense against an alleged violation of any law, regulation or standard, except for the requirement to obtain a Part 70 permit under 326 IAC 2-7 or for applicable requirements for which a permit shield has been granted.

This permit shield does not extend to applicable requirements which are promulgated after the date of issuance of this permit unless this permit has been modified to reflect such new requirements.

- (b) If, after issuance of this permit, it is determined that the permit is in nonconformance with an applicable requirement that applied to the source on the date of permit issuance, IDEM, OAQ, shall immediately take steps to reopen and revise this permit and issue a compliance order to the Permittee to ensure expeditious compliance with the applicable requirement until the permit is reissued. The permit shield shall continue in effect so long as the Permittee is in compliance with the compliance order.

- (c) No permit shield shall apply to any permit term or condition that is determined after issuance of this permit to have been based on erroneous information supplied in the permit application. Erroneous information means information that the Permittee knew to be false, or in the exercise of reasonable care should have been known to be false, at the time the information was submitted.
- (d) Nothing in 326 IAC 2-7-15 or in this permit shall alter or affect the following:
  - (1) The provisions of Section 303 of the Clean Air Act (emergency orders), including the authority of the U.S. EPA under Section 303 of the Clean Air Act;
  - (2) The liability of the Permittee for any violation of applicable requirements prior to or at the time of this permit's issuance;
  - (3) The applicable requirements of the acid rain program, consistent with Section 408(a) of the Clean Air Act; and
  - (4) The ability of U.S. EPA to obtain information from the Permittee under Section 114 of the Clean Air Act.
- (e) This permit shield is not applicable to any change made under 326 IAC 2-7-20(b)(2) (Sections 502(b)(10) of the Clean Air Act changes) and 326 IAC 2-7-20(c)(2) (trading based on State Implementation Plan (SIP) provisions).
- (f) This permit shield is not applicable to modifications eligible for group processing until after IDEM, OAQ, has issued the modifications. [326 IAC 2-7-12(c)(7)]
- (g) This permit shield is not applicable to minor Part 70 permit modifications until after IDEM, OAQ, has issued the modification. [326 IAC 2-7-12(b)(8)]

B.13 Prior Permits Superseded [326 IAC 2-1.1-9.5][326 IAC 2-7-10.5]

- (a) All terms and conditions of permits established prior to T055-32418-00008 and issued pursuant to permitting programs approved into the state implementation plan have been either:
  - (1) incorporated as originally stated,
  - (2) revised under 326 IAC 2-7-10.5, or
  - (3) deleted under 326 IAC 2-7-10.5.
- (b) Provided that all terms and conditions are accurately reflected in this permit, all previous registrations and permits are superseded by this Part 70 operating permit.

B.14 Termination of Right to Operate [326 IAC 2-7-10][326 IAC 2-7-4(a)]

The Permittee's right to operate this source terminates with the expiration of this permit unless a timely and complete renewal application is submitted at least nine (9) months prior to the date of expiration of the source's existing permit, consistent with 326 IAC 2-7-3 and 326 IAC 2-7-4(a).

B.15 Permit Modification, Reopening, Revocation and Reissuance, or Termination [326 IAC 2-7-5(6)(C)][326 IAC 2-7-8(a)][326 IAC 2-7-9]

- (a) This permit may be modified, reopened, revoked and reissued, or terminated for cause. The filing of a request by the Permittee for a Part 70 Operating Permit modification, revocation and reissuance, or termination, or of a notification of planned changes or anticipated noncompliance does not stay any condition of this permit.

[326 IAC 2-7-5(6)(C)] The notification by the Permittee does require a certification that meets the requirements of 326 IAC 2-7-6(1) by a "responsible official" as defined by 326 IAC 2-7-1(35).

- (b) This permit shall be reopened and revised under any of the circumstances listed in IC 13-15-7-2 or if IDEM, OAQ determines any of the following:
  - (1) That this permit contains a material mistake.
  - (2) That inaccurate statements were made in establishing the emissions standards or other terms or conditions.
  - (3) That this permit must be revised or revoked to assure compliance with an applicable requirement. [326 IAC 2-7-9(a)(3)]
- (c) Proceedings by IDEM, OAQ to reopen and revise this permit shall follow the same procedures as apply to initial permit issuance and shall affect only those parts of this permit for which cause to reopen exists. Such reopening and revision shall be made as expeditiously as practicable. [326 IAC 2-7-9(b)]
- (d) The reopening and revision of this permit, under 326 IAC 2-7-9(a), shall not be initiated before notice of such intent is provided to the Permittee by IDEM, OAQ at least thirty (30) days in advance of the date this permit is to be reopened, except that IDEM, OAQ may provide a shorter time period in the case of an emergency. [326 IAC 2-7-9(c)]

B.16 Permit Renewal [326 IAC 2-7-3][326 IAC 2-7-4][326 IAC 2-7-8(e)]

- (a) The application for renewal shall be submitted using the application form or forms prescribed by IDEM, OAQ and shall include the information specified in 326 IAC 2-7-4. Such information shall be included in the application for each emission unit at this source, except those emission units included on the trivial or insignificant activities list contained in 326 IAC 2-7-1(21) and 326 IAC 2-7-1(40). The renewal application does require a certification that meets the requirements of 326 IAC 2-7-6(1) by a "responsible official" as defined by 326 IAC 2-7-1(35).

Request for renewal shall be submitted to:

Indiana Department of Environmental Management  
Permit Administration and Support Section, Office of Air Quality  
100 North Senate Avenue  
MC 61-53 IGCN 1003  
Indianapolis, Indiana 46204-2251

- (b) A timely renewal application is one that is:
  - (1) Submitted at least nine (9) months prior to the date of the expiration of this permit; and
  - (2) If the date postmarked on the envelope or certified mail receipt, or affixed by the shipper on the private shipping receipt, is on or before the date it is due. If the document is submitted by any other means, it shall be considered timely if received by IDEM, OAQ on or before the date it is due.
- (c) If the Permittee submits a timely and complete application for renewal of this permit, the source's failure to have a permit is not a violation of 326 IAC 2-7 until IDEM, OAQ takes final action on the renewal application, except that this protection shall cease to apply if,

subsequent to the completeness determination, the Permittee fails to submit by the deadline specified, pursuant to 326 IAC 2-7-4(a)(2)(D), in writing by IDEM, OAQ any additional information identified as being needed to process the application.

**B.17 Permit Amendment or Modification [326 IAC 2-7-11][326 IAC 2-7-12]**

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(a) Permit amendments and modifications are governed by the requirements of 326 IAC 2-7-11 or 326 IAC 2-7-12 whenever the Permittee seeks to amend or modify this permit.

(b) Any application requesting an amendment or modification of this permit shall be submitted to:

Indiana Department of Environmental Management  
Permit Administration and Support Section, Office of Air Quality  
100 North Senate Avenue  
MC 61-53 IGCN 1003  
Indianapolis, Indiana 46204-2251

Any such application does require a certification that meets the requirements of 326 IAC 2-7-6(1) by a "responsible official" as defined by 326 IAC 2-7-1(35).

(c) The Permittee may implement administrative amendment changes addressed in the request for an administrative amendment immediately upon submittal of the request. [326 IAC 2-7-11(c)(3)]

**B.18 Permit Revision Under Economic Incentives and Other Programs [326 IAC 2-7-5(8)][326 IAC 2-7-12(b)(2)]**

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(a) No Part 70 permit revision or notice shall be required under any approved economic incentives, marketable Part 70 permits, emissions trading, and other similar programs or processes for changes that are provided for in a Part 70 permit.

(b) Notwithstanding 326 IAC 2-7-12(b)(1) and 326 IAC 2-7-12(c)(1), minor Part 70 permit modification procedures may be used for Part 70 modifications involving the use of economic incentives, marketable Part 70 permits, emissions trading, and other similar approaches to the extent that such minor Part 70 permit modification procedures are explicitly provided for in the applicable State Implementation Plan (SIP) or in applicable requirements promulgated or approved by the U.S. EPA.

**B.19 Operational Flexibility [326 IAC 2-7-20][326 IAC 2-7-10.5]**

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(a) The Permittee may make any change or changes at the source that are described in 326 IAC 2-7-20(b) or (c) without a prior permit revision, if each of the following conditions is met:

- (1) The changes are not modifications under any provision of Title I of the Clean Air Act;
- (2) Any preconstruction approval required by 326 IAC 2-7-10.5 has been obtained;
- (3) The changes do not result in emissions which exceed the limitations provided in this permit (whether expressed herein as a rate of emissions or in terms of total emissions);
- (4) The Permittee notifies the:

Indiana Department of Environmental Management

Permit Administration and Support Section, Office of Air Quality  
100 North Senate Avenue  
MC 61-53 IGCN 1003  
Indianapolis, Indiana 46204-2251

and

United States Environmental Protection Agency, Region V  
Air and Radiation Division, Regulation Development Branch - Indiana (AR-18J)  
77 West Jackson Boulevard  
Chicago, Illinois 60604-3590

in advance of the change by written notification at least ten (10) days in advance of the proposed change. The Permittee shall attach every such notice to the Permittee's copy of this permit; and

- (5) The Permittee maintains records on-site, on a rolling five (5) year basis, which document all such changes and emission trades that are subject to 326 IAC 2-7-20(b)(1) and (c)(1). The Permittee shall make such records available, upon reasonable request, for public review.

Such records shall consist of all information required to be submitted to IDEM, OAQ in the notices specified in 326 IAC 2-7-20(b)(1) and (c)(1).

- (b) The Permittee may make Section 502(b)(10) of the Clean Air Act changes (this term is defined at 326 IAC 2-7-1(36)) without a permit revision, subject to the constraint of 326 IAC 2-7-20(a). For each such Section 502(b)(10) of the Clean Air Act change, the required written notification shall include the following:
  - (1) A brief description of the change within the source;
  - (2) The date on which the change will occur;
  - (3) Any change in emissions; and
  - (4) Any permit term or condition that is no longer applicable as a result of the change.

The notification which shall be submitted is not considered an application form, report or compliance certification. Therefore, the notification by the Permittee does not require a certification that meets the requirements of 326 IAC 2-7-6(1) by a "responsible official" as defined by 326 IAC 2-7-1(35).

- (c) Emission Trades [326 IAC 2-7-20(c)]  
The Permittee may trade emissions increases and decreases at the source, where the applicable SIP provides for such emission trades without requiring a permit revision, subject to the constraints of Section (a) of this condition and those in 326 IAC 2-7-20(c).
- (d) Alternative Operating Scenarios [326 IAC 2-7-20(d)]  
The Permittee may make changes at the source within the range of alternative operating scenarios that are described in the terms and conditions of this permit in accordance with 326 IAC 2-7-5(9). No prior notification of IDEM, OAQ, or U.S. EPA is required.
- (e) Backup fuel switches specifically addressed in, and limited under, Section D of this permit shall not be considered alternative operating scenarios. Therefore, the notification requirements of part (a) of this condition do not apply.

**B.20 Source Modification Requirement [326 IAC 2-7-10.5]**

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A modification, construction, or reconstruction is governed by the requirements of 326 IAC 2.

**B.21 Inspection and Entry [326 IAC 2-7-6][IC 13-14-2-2][IC 13-30-3-1][IC 13-17-3-2]**

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Upon presentation of proper identification cards, credentials, and other documents as may be required by law, and subject to the Permittee's right under all applicable laws and regulations to assert that the information collected by the agency is confidential and entitled to be treated as such, the Permittee shall allow IDEM, OAQ, U.S. EPA, or an authorized representative to perform the following:

- (a) Enter upon the Permittee's premises where a Part 70 source is located, or emissions related activity is conducted, or where records must be kept under the conditions of this permit;
- (b) As authorized by the Clean Air Act, IC 13-14-2-2, IC 13-17-3-2, and IC 13-30-3-1, have access to and copy any records that must be kept under the conditions of this permit;
- (c) As authorized by the Clean Air Act, IC 13-14-2-2, IC 13-17-3-2, and IC 13-30-3-1, inspect any facilities, equipment (including monitoring and air pollution control equipment), practices, or operations regulated or required under this permit;
- (d) As authorized by the Clean Air Act, IC 13-14-2-2, IC 13-17-3-2, and IC 13-30-3-1, sample or monitor substances or parameters for the purpose of assuring compliance with this permit or applicable requirements; and
- (e) As authorized by the Clean Air Act, IC 13-14-2-2, IC 13-17-3-2, and IC 13-30-3-1, utilize any photographic, recording, testing, monitoring, or other equipment for the purpose of assuring compliance with this permit or applicable requirements.

**B.22 Transfer of Ownership or Operational Control [326 IAC 2-7-11]**

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- (a) The Permittee must comply with the requirements of 326 IAC 2-7-11 whenever the Permittee seeks to change the ownership or operational control of the source and no other change in the permit is necessary.
- (b) Any application requesting a change in the ownership or operational control of the source shall contain a written agreement containing a specific date for transfer of permit responsibility, coverage and liability between the current and new Permittee. The application shall be submitted to:

Indiana Department of Environmental Management  
Permit Administration and Support Section, Office of Air Quality  
100 North Senate Avenue  
MC 61-53 IGCN 1003  
Indianapolis, Indiana 46204-2251

Any such application does require a certification that meets the requirements of 326 IAC 2-7-6(1) by a "responsible official" as defined by 326 IAC 2-7-1(35).

- (c) The Permittee may implement administrative amendment changes addressed in the request for an administrative amendment immediately upon submittal of the request. [326 IAC 2-7-11(c)(3)]

B.23 Annual Fee Payment [326 IAC 2-7-19] [326 IAC 2-7-5(7)][326 IAC 2-1.1-7]

- (a) The Permittee shall pay annual fees to IDEM, OAQ within thirty (30) calendar days of receipt of a billing. Pursuant to 326 IAC 2-7-19(b), if the Permittee does not receive a bill from IDEM, OAQ the applicable fee is due April 1 of each year.
- (b) Except as provided in 326 IAC 2-7-19(e), failure to pay may result in administrative enforcement action or revocation of this permit.
- (c) The Permittee may call the following telephone numbers: 1-800-451-6027 or 317-233-4230 (ask for OAQ, Billing, Licensing, and Training Section), to determine the appropriate permit fee.

B.24 Credible Evidence [326 IAC 2-7-5(3)][326 IAC 2-7-6][62 FR 8314] [326 IAC 1-1-6]

For the purpose of submitting compliance certifications or establishing whether or not the Permittee has violated or is in violation of any condition of this permit, nothing in this permit shall preclude the use, including the exclusive use, of any credible evidence or information relevant to whether the Permittee would have been in compliance with the condition of this permit if the appropriate performance or compliance test or procedure had been performed.

## SECTION C SOURCE OPERATION CONDITIONS

### Entire Source

#### Emission Limitations and Standards [326 IAC 2-7-5(1)]

**C.1 Particulate Emission Limitations For Processes with Process Weight Rates Less Than One Hundred (100) Pounds per Hour [326 IAC 6-3-2]**

Pursuant to 326 IAC 6-3-2(e)(2), particulate emissions from any process not exempt under 326 IAC 6-3-1(b) or (c) which has a maximum process weight rate less than 100 pounds per hour and the methods in 326 IAC 6-3-2(b) through (d) do not apply shall not exceed 0.551 pounds per hour.

**C.2 Opacity [326 IAC 5-1]**

Pursuant to 326 IAC 5-1-2 (Opacity Limitations), except as provided in 326 IAC 5-1-1 (Applicability) and 326 IAC 5-1-3 (Temporary Alternative Opacity Limitations), opacity shall meet the following, unless otherwise stated in this permit:

- (a) Opacity shall not exceed an average of forty percent (40%) in any one (1) six (6) minute averaging period as determined in 326 IAC 5-1-4.
- (b) Opacity shall not exceed sixty percent (60%) for more than a cumulative total of fifteen (15) minutes (sixty (60) readings as measured according to 40 CFR 60, Appendix A, Method 9 or fifteen (15) one (1) minute nonoverlapping integrated averages for a continuous opacity monitor) in a six (6) hour period.

**C.3 Open Burning [326 IAC 4-1] [IC 13-17-9]**

The Permittee shall not open burn any material except as provided in 326 IAC 4-1-3, 326 IAC 4-1-4 or 326 IAC 4-1-6. The previous sentence notwithstanding, the Permittee may open burn in accordance with an open burning approval issued by the Commissioner under 326 IAC 4-1-4.1.

**C.4 Incineration [326 IAC 4-2] [326 IAC 9-1-2]**

The Permittee shall not operate an incinerator except as provided in 326 IAC 4-2 or in this permit. The Permittee shall not operate a refuse incinerator or refuse burning equipment except as provided in 326 IAC 9-1-2 or in this permit.

**C.5 Fugitive Dust Emissions [326 IAC 6-4]**

The Permittee shall not allow fugitive dust to escape beyond the property line or boundaries of the property, right-of-way, or easement on which the source is located, in a manner that would violate 326 IAC 6-4 (Fugitive Dust Emissions). 326 IAC 6-4-2(4) is not federally enforceable.

**C.6 Stack Height [326 IAC 1-7]**

The Permittee shall comply with the applicable provisions of 326 IAC 1-7 (Stack Height Provisions), for all exhaust stacks through which a potential (before controls) of twenty-five (25) tons per year or more of particulate matter or sulfur dioxide is emitted. The provisions of 326 IAC 1-7-1(3), 326 IAC 1-7-2, 326 IAC 1-7-3(c) and (d), 326 IAC 1-7-4, and 326 IAC 1-7-5(a), (b), and (d) are not federally enforceable.

**C.7 Asbestos Abatement Projects [326 IAC 14-10] [326 IAC 18] [40 CFR 61, Subpart M]**

- (a) Notification requirements apply to each owner or operator. If the combined amount of regulated asbestos containing material (RACM) to be stripped, removed or disturbed is at least 260 linear feet on pipes or 160 square feet on other facility components, or at least thirty-five (35) cubic feet on all facility components, then the notification requirements of

326 IAC 14-10-3 are mandatory. All demolition projects require notification whether or not asbestos is present.

- (b) The Permittee shall ensure that a written notification is sent on a form provided by the Commissioner at least ten (10) working days before asbestos stripping or removal work or before demolition begins, per 326 IAC 14-10-3, and shall update such notice as necessary, including, but not limited to the following:
  - (1) When the amount of affected asbestos containing material increases or decreases by at least twenty percent (20%); or
  - (2) If there is a change in the following:
    - (A) Asbestos removal or demolition start date;
    - (B) Removal or demolition contractor; or
    - (C) Waste disposal site.
- (c) The Permittee shall ensure that the notice is postmarked or delivered according to the guidelines set forth in 326 IAC 14-10-3(2).
- (d) The notice to be submitted shall include the information enumerated in 326 IAC 14-10-3(3).

All required notifications shall be submitted to:

Indiana Department of Environmental Management  
Compliance and Enforcement Branch, Office of Air Quality  
100 North Senate Avenue  
MC 61-53 IGCN 1003  
Indianapolis, Indiana 46204-2251

The notice shall include a signed certification from the owner or operator that the information provided in this notification is correct and that only Indiana licensed workers and project supervisors will be used to implement the asbestos removal project. The notifications do not require a certification that meets the requirements of 326 IAC 2-7-6(1) by a "responsible official" as defined by 326 IAC 2-7-1(35).

- (e) **Procedures for Asbestos Emission Control**  
The Permittee shall comply with the applicable emission control procedures in 326 IAC 14-10-4 and 40 CFR 61.145(c). Per 326 IAC 14-10-1, emission control requirements are applicable for any removal or disturbance of RACM greater than three (3) linear feet on pipes or three (3) square feet on any other facility components or a total of at least 0.75 cubic feet on all facility components.
- (f) **Demolition and Renovation**  
The Permittee shall thoroughly inspect the affected facility or part of the facility where the demolition or renovation will occur for the presence of asbestos pursuant to 40 CFR 61.145(a).
- (g) **Indiana Licensed Asbestos Inspector**  
The Permittee shall comply with 326 IAC 14-10-1(a) that requires the owner or operator, prior to a renovation/demolition, to use an Indiana Licensed Asbestos Inspector to thoroughly inspect the affected portion of the facility for the presence of asbestos. The requirement to use an Indiana Licensed Asbestos inspector is not federally enforceable.

## Testing Requirements [326 IAC 2-7-6(1)]

### C.8 Performance Testing [326 IAC 3-6]

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- (a) For performance testing required by this permit, a test protocol, except as provided elsewhere in this permit, shall be submitted to:

Indiana Department of Environmental Management  
Compliance and Enforcement Branch, Office of Air Quality  
100 North Senate Avenue  
MC 61-53 IGCN 1003  
Indianapolis, Indiana 46204-2251

no later than thirty-five (35) days prior to the intended test date. The protocol submitted by the Permittee does not require a certification that meets the requirements of 326 IAC 2-7-6(1) by a "responsible official" as defined by 326 IAC 2-7-1(35).

- (b) The Permittee shall notify IDEM, OAQ of the actual test date at least fourteen (14) days prior to the actual test date. The notification submitted by the Permittee does not require a certification that meets the requirements of 326 IAC 2-7-6(1) by a "responsible official" as defined by 326 IAC 2-7-1(35).
- (c) Pursuant to 326 IAC 3-6-4(b), all test reports must be received by IDEM, OAQ not later than forty-five (45) days after the completion of the testing. An extension may be granted by IDEM, OAQ if the Permittee submits to IDEM, OAQ a reasonable written explanation not later than five (5) days prior to the end of the initial forty-five (45) day period.

## Compliance Requirements [326 IAC 2-1.1-11]

### C.9 Compliance Requirements [326 IAC 2-1.1-11]

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The commissioner may require stack testing, monitoring, or reporting at any time to assure compliance with all applicable requirements by issuing an order under 326 IAC 2-1.1-11. Any monitoring or testing shall be performed in accordance with 326 IAC 3 or other methods approved by the commissioner or the U. S. EPA.

## Compliance Monitoring Requirements [326 IAC 2-7-5(1)][326 IAC 2-7-6(1)]

### C.10 Compliance Monitoring [326 IAC 2-7-5(3)][326 IAC 2-7-6(1)]

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Unless otherwise specified in this permit, for all monitoring requirements not already legally required, the Permittee shall be allowed up to ninety (90) days from the date of permit issuance or of initial start-up, whichever is later, to begin such monitoring. If due to circumstances beyond the Permittee's control, any monitoring equipment required by this permit cannot be installed and operated no later than ninety (90) days after permit issuance or the date of initial startup, whichever is later, the Permittee may extend the compliance schedule related to the equipment for an additional ninety (90) days provided the Permittee notifies:

Indiana Department of Environmental Management  
Compliance and Enforcement Branch, Office of Air Quality  
100 North Senate Avenue  
MC 61-53 IGCN 1003  
Indianapolis, Indiana 46204-2251

in writing, prior to the end of the initial ninety (90) day compliance schedule, with full justification of the reasons for the inability to meet this date.

The notification which shall be submitted by the Permittee does require a certification that meets the requirements of 326 IAC 2-7-6(1) by a "responsible official" as defined by 326 IAC 2-7-1(35).

Unless otherwise specified in the approval for the new emission unit(s), compliance monitoring for new emission units or emission units added through a source modification shall be implemented when operation begins.

**C.11 Instrument Specifications [326 IAC 2-1.1-11] [326 IAC 2-7-5(3)] [326 IAC 2-7-6(1)]**

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- (a) When required by any condition of this permit, an analog instrument used to measure a parameter related to the operation of an air pollution control device shall have a scale such that the expected maximum reading for the normal range shall be no less than twenty percent (20%) of full scale. The analog instrument shall be capable of measuring values outside of the normal range.
- (b) The Permittee may request that the IDEM, OAQ approve the use of an instrument that does not meet the above specifications provided the Permittee can demonstrate that an alternative instrument specification will adequately ensure compliance with permit conditions requiring the measurement of the parameters.

**Corrective Actions and Response Steps [326 IAC 2-7-5][326 IAC 2-7-6]**

**C.12 Emergency Reduction Plans [326 IAC 1-5-2] [326 IAC 1-5-3]**

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Pursuant to 326 IAC 1-5-2 (Emergency Reduction Plans; Submission):

- (a) The Permittee shall maintain the most recently submitted written emergency reduction plans (ERPs) consistent with safe operating procedures.
- (b) Upon direct notification by IDEM, OAQ that a specific air pollution episode level is in effect, the Permittee shall immediately put into effect the actions stipulated in the approved ERP for the appropriate episode level. [326 IAC 1-5-3]

**C.13 Risk Management Plan [326 IAC 2-7-5(12)] [40 CFR 68]**

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If a regulated substance, as defined in 40 CFR 68, is present at a source in more than a threshold quantity, the Permittee must comply with the applicable requirements of 40 CFR 68.

**C.14 Response to Excursions or Exceedances [326 IAC 2-7-5] [326 IAC 2-7-6]**

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Upon detecting an excursion where a response step is required by the D Section or an exceedance of a limitation in this permit:

- (a) The Permittee shall take reasonable response steps to restore operation of the emissions unit (including any control device and associated capture system) to its normal or usual manner of operation as expeditiously as practicable in accordance with good air pollution control practices for minimizing excess emissions.
- (b) The response shall include minimizing the period of any startup, shutdown or malfunction. The response may include, but is not limited to, the following:
  - (1) initial inspection and evaluation;
  - (2) recording that operations returned or are returning to normal without operator action (such as through response by a computerized distribution control system); or
  - (3) any necessary follow-up actions to return operation to normal or usual manner of operation.

- (c) A determination of whether the Permittee has used acceptable procedures in response to an excursion or exceedance will be based on information available, which may include, but is not limited to, the following:
  - (1) monitoring results;
  - (2) review of operation and maintenance procedures and records; and/or
  - (3) inspection of the control device, associated capture system, and the process.
- (d) Failure to take reasonable response steps shall be considered a deviation from the permit.
- (e) The Permittee shall record the reasonable response steps taken.

**C.15 Actions Related to Noncompliance Demonstrated by a Stack Test [326 IAC 2-7-5][326 IAC 2-7-6]**

- (a) When the results of a stack test performed in conformance with Section C - Performance Testing, of this permit exceed the level specified in any condition of this permit, the Permittee shall submit a description of its response actions to IDEM, OAQ, no later than seventy-five (75) days after the date of the test.
- (b) A retest to demonstrate compliance shall be performed no later than one hundred eighty (180) days after the date of the test. Should the Permittee demonstrate to IDEM, OAQ that retesting in one hundred eighty (180) days is not practicable, IDEM, OAQ may extend the retesting deadline
- (c) IDEM, OAQ reserves the authority to take any actions allowed under law in response to noncompliant stack tests.

The response action documents submitted pursuant to this condition do require a certification that meets the requirements of 326 IAC 2-7-6(1) by a "responsible official" as defined by 326 IAC 2-7-1(35).

**Record Keeping and Reporting Requirements [326 IAC 2-7-5(3)] [326 IAC 2-7-19]**

**C.16 Emission Statement [326 IAC 2-7-5(3)(C)(iii)][326 IAC 2-7-5(7)][326 IAC 2-7-19(c)][326 IAC 2-6]**

Pursuant to 326 IAC 2-6-3(b)(3), starting in 2006 and every three (3) years thereafter, the Permittee shall submit by July 1 an emission statement covering the previous calendar year. The emission statement shall contain, at a minimum, the information specified in 326 IAC 2-6-4(c) and shall meet the following requirements:

- (1) Indicate estimated actual emissions of all pollutants listed in 326 IAC 2-6-4(a);
- (2) Indicate estimated actual emissions of regulated pollutants as defined by 326 IAC 2-7-1(32) ("Regulated pollutant, which is used only for purposes of Section 19 of this rule") from the source, for purpose of fee assessment.

The statement must be submitted to:

Indiana Department of Environmental Management  
Technical Support and Modeling Section, Office of Air Quality  
100 North Senate Avenue

MC 61-50 IGCN 1003  
Indianapolis, Indiana 46204-2251

The emission statement does require a certification that meets the requirements of 326 IAC 2-7-6(1) by a "responsible official" as defined by 326 IAC 2-7-1(35).

C.17 General Record Keeping Requirements [326 IAC 2-7-5(3)] [326 IAC 2-7-6]

(a) Records of all required monitoring data, reports and support information required by this permit shall be retained for a period of at least five (5) years from the date of monitoring sample, measurement, report, or application. Support information includes the following, where applicable:

- (AA) All calibration and maintenance records.
- (BB) All original strip chart recordings for continuous monitoring instrumentation.
- (CC) Copies of all reports required by the Part 70 permit.

Records of required monitoring information include the following, where applicable:

- (AA) The date, place, as defined in this permit, and time of sampling or measurements.
- (BB) The dates analyses were performed.
- (CC) The company or entity that performed the analyses.
- (DD) The analytical techniques or methods used.
- (EE) The results of such analyses.
- (FF) The operating conditions as existing at the time of sampling or measurement.

These records shall be physically present or electronically accessible at the source location for a minimum of three (3) years. The records may be stored elsewhere for the remaining two (2) years as long as they are available upon request. If the Commissioner makes a request for records to the Permittee, the Permittee shall furnish the records to the Commissioner within a reasonable time.

(b) Unless otherwise specified in this permit, for all record keeping requirements not already legally required, the Permittee shall be allowed up to ninety (90) days from the date of permit issuance or the date of initial start-up, whichever is later, to begin such record keeping.

C.18 General Reporting Requirements [326 IAC 2-7-5(3)(C)] [326 IAC 2-1.1-11]

(a) The Permittee shall submit the attached Quarterly Deviation and Compliance Monitoring Report or its equivalent. Proper notice submittal under Section B –Emergency Provisions satisfies the reporting requirements of this paragraph. Any deviation from permit requirements, the date(s) of each deviation, the cause of the deviation, and the response steps taken must be reported except that a deviation required to be reported pursuant to an applicable requirement that exists independent of this permit, shall be reported according to the schedule stated in the applicable requirement and does not need to be included in this report. This report shall be submitted not later than thirty (30) days after the end of the reporting period. The Quarterly Deviation and Compliance Monitoring Report shall include a certification that meets the requirements of 326 IAC 2-7-6(1) by a "responsible official" as defined by 326 IAC 2-7-1(35). A deviation is an exceedance of a permit limitation or a failure to comply with a requirement of the permit.

(b) The address for report submittal is:

Indiana Department of Environmental Management  
Compliance and Enforcement Branch, Office of Air Quality  
100 North Senate Avenue

MC 61-53 IGCN 1003  
Indianapolis, Indiana 46204-2251

- (c) Unless otherwise specified in this permit, any notice, report, or other submission required by this permit shall be considered timely if the date postmarked on the envelope or certified mail receipt, or affixed by the shipper on the private shipping receipt, is on or before the date it is due. If the document is submitted by any other means, it shall be considered timely if received by IDEM, OAQ on or before the date it is due.
- (d) Reporting periods are based on calendar years, unless otherwise specified in this permit. For the purpose of this permit "calendar year" means the twelve (12) month period from January 1 to December 31 inclusive.

### **Stratospheric Ozone Protection**

#### **C.19 Compliance with 40 CFR 82 and 326 IAC 22-1**

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Pursuant to 40 CFR 82 (Protection of Stratospheric Ozone), Subpart F, except as provided for motor vehicle air conditioners in Subpart B, the Permittee shall comply with applicable standards for recycling and emissions reduction.

## SECTION D.1

## EMISSION UNIT OPERATION CONDITIONS

### Facility Description [326 IAC 2-7-5(15)]

- (a) Blood meal making process, constructed in 1968 (except Dupps dryer, approved in 2014 for construction), with a maximum production rate of 1.0 ton of blood meal per hour, controlled by a series of 3 scrubbers with sequence as Blood Centrifuge Venturi Scrubber (Venturi1C), Packed Bed Scrubber (Packed 1C) and In-Room Air Scrubber (Room 32B), exhausting to Stack RAS-2 and consisting of the following:
- (I) Blood receiving
  - (II) Coagulator
  - (III) Centrifuge
  - (IV) One (1) steam heated dryer, identified as Dupps dryer, approved in 2014 for construction, with a maximum production rate of 1.0 ton of blood meal per hour and exhausting to Stack RAS-2.
  - (V) Screen
  - (VI) Storage
- (b) Feather meal making process, constructed in 1968, with a maximum production rate of 2.88 tons of feather meal per hour, controlled by a series of 3 scrubbers with sequence as Feather Plant Venturi Scrubber (Venturi10B), Feather Plant Packed Bed Scrubber (Packed 10B) and In-Room Air Scrubber (Room 32B), exhausting to Stack RAS-2, and consisting of the following:
- (I) Feather receiving and spreader
  - (II) Hydrolizer
  - (III) Feather Press
  - (IV) Feather Dryer, identified as Feather Dryer
  - (V) Shell and tube Condensers and cooling tower
  - (VI) Underground storage tank
  - (VII) Hammermill
- (c) Poultry meal making process, constructed in 1968, with a maximum production rate of 10.15 tons of Poultry meal per hour, controlled by series of 3 scrubbers with sequence as Meat Plant Venturi Scrubber (Venturi 3A), Meat Plant Packed Bed Scrubber (Packed 3A) and Meat Plant In-Room Air Scrubber (Room 32A), exhausting to Stack RAS-1, and consisting of the following:
- (I) Two (2) Grinders
  - (II) Two (2) Cookers (Cooker A and Cooker B)
  - (III) Drainers
  - (IV) Presses
  - (V) Screens
  - (VI) Centrifuges
  - (VII) Shell and tube Condensers and cooling tower
- (d) Four (4) boilers, identified as 05, 06, 07, and 08, constructed in 2008, used for supplying heat in Feather meal, Poultry meal and Blood Meal making processes, each is capable of burning natural gas, processed grease, fuel oil no. 2, and waste/spec used oil. Each boiler 05, 06, and 07 has a heat input capacity of 50.2 million British thermal units per hour (MMBtu/hr), exhausting to stacks H, I, and J respectively, and boiler 08 has a heat input capacity of 33.746 MMBtu/hr, exhausting to stack K.

(The information describing the process contained in this facility description box is descriptive information and does not constitute enforceable conditions.)

**Emission Limitations and Standards [326 IAC 2-7-5(1)]**

**D.1.1 Sulfur Dioxide (SO<sub>2</sub>) [326 IAC 7-1.1-2]**

Pursuant to 326 IAC 7-1.2 (SO<sub>2</sub> Emissions Limitations), the SO<sub>2</sub> emissions from boiler 05, boiler 06, boiler 07 and boiler 08 shall each not exceed five-tenths (0.5) pounds per MMBtu heat input when combusting No. 2 fuel oil.

Pursuant to 326 IAC 7-2-1, compliance shall be demonstrated on a calendar month average.

**D.1.2 PSD Minor Limit - SO<sub>2</sub> [326 IAC 2-2]**

(a) The combined SO<sub>2</sub> emissions from combusting natural gas, No. 2 fuel oil, waste oil and processed grease in boilers 05, 06, 07 and 08, shall not exceed 249 tons per twelve (12) consecutive month period, with compliance determined at the end of each month.

(b) The sulfur content of the no. 2 fuel oil usage at the boilers shall not exceed 0.5% based on a calendar month average.

Compliance with these limits shall limit the source-wide SO<sub>2</sub> emissions to less than 250 tons per 12 consecutive month period and renders 326 IAC 2-2, not applicable.

**D.1.3 PSD Minor Limit - Particulate [326 IAC 2-2]**

In order to render 326 IAC 2-2 not applicable, the Permittee shall comply with the after control limitations specified in the following table:

Emission Units	PSD Minor limit (lb/hr)		
	PM	PM10	PM2.5
Blood Meal making process	1.34	1.22	0.51
Feather meal making process	3.51	3.51	1.32
Poultry meal making process	1.0	0.63	0.38

Compliance with these limits in conjunction with the PM, PM10 and PM2.5 PTE of other emission units at this source will limit source-wide total PM, PM10 and PM2.5 PTE, each, to less than 250 tons per 12 consecutive month period and renders 326 IAC 2-2 (PSD) not applicable.

**D.1.4 PSD Minor Limit - CO<sub>2</sub>e [326 IAC 2-2]**

The combined CO<sub>2</sub>e emissions from combusting natural gas, No. 2 fuel oil, waste oil and processed grease in boilers 05, 06, 07 and 08, shall not exceed 99,999 tons per twelve (12) consecutive month period, with compliance determined at the end of each month.

Compliance with this limit will render this source minor under 326 IAC 2-2 (Prevention of Significant Deterioration (PSD)).

**D.1.5 Particulate Matter (PM) [326 IAC 6-2-4]**

Pursuant to 326 IAC 6-2-4 (Particulate Matter Emission Limitations for Sources of Indirect Heating), the PM emissions from boiler 05, boiler 06, boiler 07 and boiler 08 shall each be limited to 0.28 lb/MMBtu. These limits were established by the following equation:

$$Pt = \frac{1.09}{Q^{0.26}}$$

- where Pt = pounds of particulate matter emitted per million Btu (lb/MMBtu) heat input; and
- Q = total source maximum operating capacity rating in million Btu per hour (MMBtu/hr) heat input.
- Q = 184.35 MMBtu/hr

#### D.1.6 Particulate Matter (PM) [326 IAC 6-3-2(e)]

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Pursuant to 326 IAC 6-3-2 (Particulate Emission Limitations for Manufacturing Processes), the allowable particulate emission rate from the Blood Meal, Feather meal and Poultry meal making shall be limited as specified in the equation below when operating at their respective process weight rate.

Interpolation of the data for the process weight rate up to sixty thousand (60,000) pounds per hour shall be accomplished by use of the equation:

$$E = 4.10 P^{0.67}$$

Where: E = rate of emission in pounds per hour; and

P = process weight rate in tons per hour

#### D.1.7 VOC [326 IAC 8-1-6]

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In order to render 326 IAC 8-1-6 not applicable, the uncontrolled VOC emissions from the Dupps dryer shall not exceed 5.68 pound per hour.

Compliance with this limit will limit the uncontrolled VOC emissions from the Dupps dryer to less than 25 tons per year, and renders the requirements of 326 IAC 8-1-6 not applicable to the Dupps dryer.

#### D.1.8 Preventive Maintenance Plan (PMP) [326 IAC 2-7-5(13)]

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A Preventive Maintenance Plan (PMP) is required for these facilities and their control devices. Section B - Preventive Maintenance Plan contains the Permittee's obligation with regard to the preventive maintenance plan required by this condition.

### Compliance Determination Requirements

#### D.1.9 Testing Requirements [326 IAC 2-7-6(1),(6)] [326 IAC 2-1.1-11]

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- (a) In order to determine the compliance with Condition D.1.3, the Permittee shall perform PM, PM10 and PM2.5 testing for Blood Meal making, Feather meal making and Poultry meal making processes, using methods as approved by the Commissioner. These tests shall be performed no later than one hundred eighty (180) days after the issuance of Part 70 Renewal No. T055-32418-00008 and shall be repeated at least once every five (5) years from the date of this valid compliance demonstration.
- (b) Not later than one hundred eighty (180) days after startup of the Dupps dryer and in order to demonstrate compliance with Condition D.1.7(a), the Permittee shall conduct performance testing on the Dupps dryer to verify the uncontrolled VOC emissions rate, using methods as approved by the Commissioner.

Testing shall be conducted in accordance with the provisions of 326 IAC 3-6 (Source Sampling Procedures). Section C – Performance Testing contains the Permittee's obligation with regard to the performance testing required by this condition.

#### D.1.10 Particulate Control

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- (a) In order to comply with Conditions D.1.3 and D.1.6, the Blood Centrifuge Venturi Scrubber (Venturi1C), Packed Bed Scrubber (Packed 1C) and In-Room Air Scrubber (Room 32B) for particulate control shall be in operation and control emissions from the Blood Meal making process at all times the Blood Meal making process is in operation.

- (b) In order to comply with Conditions D.1.3 and D.1.6, the Feather Plant Venturi Scrubber (Venturi10B), Feather Plant Packed Bed Scrubber (Packed 10B) and In-Room Air Scrubber (Room 32B) for particulate control shall be in operation and control emissions from the Feather meal making process at all times the Feather meal making process is in operation.
- (c) In order to comply with Conditions D.1.3 and D.1.6, the Meat Plant Venturi Scrubber (Venturi 3A), Meat Plant Packed Bed Scrubber (Packed 3A) and Meat Plant In-Room Air Scrubber (Room 32A) for particulate control shall be in operation and control emissions from the Poultry meal making process at all times the Poultry meal making process is in operation.

D.1.11 SO2 [326 IAC 2-7-6(1),(6)] [326 IAC 2-1.1-11]

- (a) In order to comply with Condition D.1.2, the Permittee shall determine SO2 emissions for each month as below.

Sulfur dioxide emission calculation

$$S = \frac{G(E_G) + O(E_O) + W(E_W) + P(E_P)}{2,000 \text{ lbs/ton}}$$

where:

- S=tons of sulfur dioxide emissions for 12 month consecutive period
- G = million cubic feet of natural gas used in previous 12 months
- O = gallons of No. 2 fuel oil used in previous 12 months
- W= gallons of waste oil used in the last 12 months less than or equal to 0.5% sulfur
- P = gallons of processed grease used for the last 12 months
  
- $E_G = 0.6$  pounds/million cubic feet of natural gas
- $E_O = 71$  pounds/1000 gallons of No. 2 fuel oil
- $E_W = 73$  pounds /1000 gallons of waste oil
- $E_P = 0.0375$  pounds/1000 gallons of processed grease

- (b) In order to comply with Condition D.1.2(b), the sulfur content shall be determined using one of the following options:
  - (a) Pursuant to 326 IAC 3-7-4, the Permittee shall demonstrate that the sulfur dioxide emissions by:
    - (1) Providing vendor analysis of fuel delivered, if accompanied by a vendor certification, or;
    - (2) Analyzing the oil sample to determine the sulfur content of the oil via the procedures in 40 CFR 60, Appendix A, Method 19.
      - (A) Oil samples may be collected from the fuel tank immediately after the fuel tank is filled and before any oil is combusted; and
      - (B) If a partially empty fuel tank is refilled, a new sample and analysis would be required upon filling.
  - (b) Compliance may also be determined by conducting a stack test for sulfur dioxide emissions from the boiler using 40 CFR 60, Appendix A, Method 6 in accordance with the procedures in 326 IAC 3-6.

A determination of noncompliance pursuant to any of the methods specified in (a) or (b) above shall not be refuted by evidence of compliance pursuant to the other method.

D.1.12 CO<sub>2</sub>e [326 IAC 2-7-6(1),(6)] [326 IAC 2-1.1-11]

- (a) In order to comply with Condition D.1.4, the Permittee shall determine CO<sub>2</sub>e emissions for each month as below.

Carbon Dioxide Equivalent (CO<sub>2</sub>e) emissions calculation

$$\text{CO}_2 = \frac{G(\text{EG}_{\text{CO}_2}) + O(\text{EO}_{\text{CO}_2}) + W(\text{EW}_{\text{CO}_2}) + P(\text{EP}_{\text{CO}_2})}{2,000 \text{ lbs/ton}}$$

$$\text{CH}_4 = \frac{G(\text{EG}_{\text{CH}_4}) + O(\text{EO}_{\text{CH}_4}) + W(\text{EW}_{\text{CH}_4}) + P(\text{EP}_{\text{CH}_4})}{2,000 \text{ lbs/ton}}$$

$$\text{N}_2\text{O} = \frac{G(\text{EG}_{\text{N}_2\text{O}}) + O(\text{EO}_{\text{N}_2\text{O}}) + W(\text{EW}_{\text{N}_2\text{O}}) + P(\text{EP}_{\text{N}_2\text{O}})}{2,000 \text{ lbs/ton}}$$

$$\text{CO}_2\text{e} = \sum[(\text{CO}_2 \times \text{CO}_2 \text{ GWP}) + (\text{CH}_4 \times \text{CH}_4 \text{ GWP}) + (\text{N}_2\text{O} \times \text{N}_2\text{O} \text{ GWP})]$$

Where:

CO<sub>2</sub> = tons of CO<sub>2</sub> emissions for previous 12 consecutive month period  
CH<sub>4</sub> = tons of CH<sub>4</sub> emissions for previous 12 consecutive month period  
N<sub>2</sub>O = tons of N<sub>2</sub>O emissions for previous 12 consecutive month period  
CO<sub>2</sub>e = tons of CO<sub>2</sub>e equivalent emissions for previous 12 consecutive month period

G = million cubic feet of natural gas used in previous 12 months  
O = gallons of No. 2 fuel oil used in previous 12 months  
W = gallons of waste oil used in the last 12 months less than or equal to 0.5% sulfur  
P = gallons of processed grease used for the last 12 months

EG<sub>CO<sub>2</sub></sub> = 120,000 pounds per million cubic feet of natural gas  
EO<sub>CO<sub>2</sub></sub> = 21,500 pounds per 1,000 gallons of No. 2 fuel oil  
EW<sub>CO<sub>2</sub></sub> = 22,706.4 pounds per 1,000 gallons of waste oil  
EP<sub>CO<sub>2</sub></sub> = 19,608.2 pounds per 1,000 gallons of processed grease

EG<sub>CH<sub>4</sub></sub> = 2.3 pounds per million cubic feet of natural gas  
EO<sub>CH<sub>4</sub></sub> = 0.22 pounds per 1,000 gallons of No. 2 fuel oil  
EW<sub>CH<sub>4</sub></sub> = 0.92 pounds per 1,000 gallons of waste oil  
EP<sub>CH<sub>4</sub></sub> = 0.30 pounds per 1,000 gallons of processed grease

EG<sub>N<sub>2</sub>O</sub> = 2.2 pounds per million cubic feet of natural gas  
EO<sub>N<sub>2</sub>O</sub> = 0.26 pounds per 1,000 gallons of No. 2 fuel oil  
EW<sub>N<sub>2</sub>O</sub> = 0.18 pounds per 1,000 gallons of waste oil  
EP<sub>N<sub>2</sub>O</sub> = 0.03 pounds per 1,000 gallons of processed grease

CO<sub>2</sub> GWP = CO<sub>2</sub> Global Warming Potentials (GWP) = 1  
CH<sub>4</sub> GWP = Methane Global Warming Potentials (GWP) = 25  
N<sub>2</sub>O GWP = Nitrous oxide Global Warming Potentials (GWP) = 298

## Compliance Monitoring Requirements [326 IAC 2-7-5(1)][326 IAC 2-7-6(1)]

### D.1.13 Visible Emissions Notations

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- (a) Daily visible emission notations of the exhaust from the Stacks RAS-1 and RAS-2 shall be performed during normal daylight operations when exhausting to the atmosphere. A trained employee shall record whether emissions are normal or abnormal.
- (b) For processes operated continuously, "normal" means those conditions prevailing, or expected to prevail, eighty percent (80%) of the time the process is in operation, not counting startup or shut down time.
- (c) In the case of batch or discontinuous operations, readings shall be taken during that part of the operation that would normally be expected to cause the greatest emissions.
- (d) A trained employee is an employee who has worked at the plant at least one (1) month and has been trained in the appearance and characteristics of normal visible emissions for that specific process.
- (e) If abnormal emissions are observed, the Permittee shall continue to take reasonable response steps. Section C - Response to Excursions or Exceedances contains the Permittee's obligation with regard to the reasonable response steps required by this condition. An abnormal visible emission notation is not a deviation from this permit. Failure to take response steps shall be considered a deviation from this permit.

### D.1.14 Scrubber Monitoring Requirements

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- (a) The Permittee shall monitor and record the pressure drop of all the scrubbers listed in this section, at least once per day when one or more of the associated emission units to these scrubbers is in operation. When for any one reading, the pressure drop across the scrubber is outside the normal range, the Permittee shall take a reasonable response. The normal ranges for each of these units is shown in the table below, unless a different upper-bound or lower-bound value for this range is determined during the latest stack test. Section C - Response to Excursions or Exceedances contains the Permittee's obligation with regard to the reasonable response steps required by this condition. A pressure reading that is outside the above mentioned range is not a deviation from this permit. Failure to take response steps shall be considered a deviation from this permit.

Scrubber	Pressure Drop Range (inches of water)
Meat Plant Venturi Scrubber (Venturi 3A)	0.2 to 6.0
Meat Plant Packed Bed Scrubber (Packed 3A)	0.1 to 6.0
Meat Plant In-Room Air Scrubber (Room32A)	0.2 to 6.0
Feather Plant Venturi Scrubber (Venturi10B)	0.2 to 6.0
Feather Plant Packed Bed Scrubber (Packed 10B)	0.2 to 6.0
In-Room Air Scrubber (Room 32B)	0.2 to 6.0
Blood Centrifuge Venturi Scrubber (Venturi1C)	0.1 to 6.0
Packed Bed Scrubber (Packed 1C)	0.2 to 6.0

- (b) The Permittee shall monitor and record the flow rate of all the scrubbers listed in this section at least once per day when one or more of the associated emission units to these scrubbers is in operation. When for any one reading, the flow rate of the scrubber is less than the flow rate specified below, or a minimum established during the latest stack test, the Permittee shall take reasonable response steps. A flow rate that is less than the flow rate specified below or a minimum flow rate established during the latest stack test.

Section C - Response to Excursions or Exceedances contains the Permittee's obligation with regard to the reasonable response steps required by this condition. Failure to take response steps shall be considered a deviation from this permit.

Scrubber	Minimum Flow Rate (gallons per minute)
Meat Plant Venturi Scrubber (Venturi 3A)	4
Meat Plant Packed Bed Scrubber (Packed 3A)	85
Meat Plant In-Room Air Scrubber (Room32A)	350
Feather Plant Venturi Scrubber (Venturi10B)	4
Feather Plant Packed Bed Scrubber (Packed 10B)	85
In-Room Air Scrubber (Room 32B)	350
Blood Centrifuge Venturi Scrubber (Venturi1C)	4
Packed Bed Scrubber (Packed 1C)	110

The instruments used for determining the pressure drop and flow rate shall comply with Section C - Instrument Specifications, of this permit, shall be subject to approval by IDEM, OAQ, and shall be calibrated or replaced at least once a year.

This condition satisfies CAM for the Feather meal making process (for PM).

#### D.1.15 Scrubber Detection

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In the event that a scrubber malfunction has been observed:

Failed units and the associated process will be shut down immediately until the failed units have been repaired or replaced. Operations may continue only if the event qualifies as an emergency and the Permittee satisfies the requirements of the emergency provisions of this permit (Section B - Emergency Provisions).

### Record Keeping and Reporting Requirements [326 IAC 2-7-5(3)] [326 IAC 2-7-19]

#### D.1.16 Record Keeping Requirements

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(a) To document the compliance status of Conditions D.1.1, D.1.2 and D.1.4, the Permittee shall maintain records for boilers 05, 06, 07 and 08 in accordance with (1) through (3) below. Records maintained for (1) through (3) shall be taken monthly and shall be complete and sufficient to establish compliance with the Conditions D.1.1, D.1.2 and D.1.4.

- (1) Calendar dates covered in the compliance determination period;
- (2) The actual No. 2 fuel oil usage, natural gas usage, actual processed grease usage, and actual waste/on spec used oil usage at all boilers; and
- (3) The actual sulfur content of the no. 2 fuel oil usage on a thirty (30) day average.

If the fuel supplier certification is used to demonstrate compliance the following shall be maintained:

- (A) Fuel supplier certifications;
- (B) A certification, signed by the owner or operator, that the records of the fuel supplier certifications represent all of the fuel combusted during the period; and

- (C) The name of the fuel supplier.
- (b) To document the compliance status with Condition D.1.13(a), the Permittee shall maintain records of daily visible emission notations of the exhaust from Stacks RAS-1 and RAS-2. The Permittee shall include in its daily record when a visible emission notation is not taken and the reason for the lack of visible emission notation (e.g. the process did not operate that day).
- (c) To document the compliance status with Condition D.1.14, the Permittee shall maintain daily records of pressure drop and flow rate for the scrubbers listed in this section. The Permittee shall include in its daily record when a pressure drop or flow rate is not taken and the reason for the lack of pressure drop or flow rate data (e.g. the process did not operate that day).
- (d) Section C - General Record Keeping Requirements contains the Permittee's obligations with regard to the records required by this condition.

#### D.1.17 Reporting Requirements

A quarterly summary of the information to document the compliance status with Conditions D.1.2(a) and D.1.4 shall be submitted using the reporting forms located at the end of this permit, or their equivalent, not later than thirty (30) days after the end of the quarter being reported. Section C - General Reporting Requirements contains the Permittee's obligation with regard to the reporting required by these conditions. The report submitted by the Permittee does require a certification that meets the requirements of 326 IAC 2-7-6(1) by a "responsible official" as defined by 326 IAC 2-7-1(35).

## SECTION E.1 FACILITY OPERATION CONDITIONS

### Facility Description [326 IAC 2-7-5(15)]

- (d) Four (4) boilers, identified as 05, 06, 07, and 08, approved for construction in 2008, used for supplying heat in rendering processes, each is capable of burning natural gas, processed grease, fuel oil no. 2, and waste/spec used oil. Each boiler 05, 06, and 07 has a heat input capacity of 50.2 million British thermal units per hour (MMBtu/hr), exhausting to stacks H, I, and J respectively, and boiler 08 has a heat input capacity of 33.746 MMBtu/hr, exhausting to stack K.

(The information describing the process contained in this facility description box is descriptive information and does not constitute enforceable conditions.)

#### E.1.1 General Provisions Relating to New Source Performance Standards [326 IAC 12-1] [40 CFR Part 60, Subpart A]

Pursuant to 40 CFR 60.1, the Permittee shall comply with the provisions of 40 CFR Part 60 Subpart A – General Provisions, which are incorporated by reference as 326 IAC 12-1, except as otherwise specified in 40 CFR Part 60, Subpart Dc.

#### E.1.2 Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units [40 CFR Part 60, Subpart Dc] [326 IAC 12]

Pursuant to CFR Part 60, Subpart Dc, the Permittee shall comply with the provisions of 40 CFR Part 60, Subpart Dc (included as 'Attachment A'):

- (a) 40 CFR 60.40c
- (b) 40 CFR 60.41c
- (c) 40 CFR 60.42c(d), (h)(1), (i)
- (d) 40 CFR 60.43c(c), (d), (e)(1) or (2)
- (e) 40 CFR 60.44c(g), (h)
- (f) 40 CFR 60.45c(a), (b)
- (g) 40 CFR 60.46c(e)
- (h) 40 CFR 60.47c(f)
- (i) 40 CFR 60.48c(a), (c), (d), (e)(1), (2), (3), (11), (f)(1), (g)(1), (2), (i), (j)

## SECTION E.2 FACILITY OPERATION CONDITIONS

### Facility Description [326 IAC 2-7-5(15)]

- (d) Four (4) boilers, identified as 05, 06, 07, and 08, approved for construction in 2008, used for supplying heat in rendering processes, each is capable of burning natural gas, processed grease, fuel oil no. 2, and waste/spec used oil. Each boiler 05, 06, and 07 has a heat input capacity of 50.2 million British thermal units per hour (MMBtu/hr), exhausting to stacks H, I, and J respectively, and boiler 08 has a heat input capacity of 33.746 MMBtu/hr, exhausting to stack K.

(The information describing the process contained in this facility description box is descriptive information and does not constitute enforceable conditions.)

#### E.2.1 General Provisions Relating to National Emission Standards for Hazardous Air Pollutants [326 IAC 20-1] [40 CFR Part 63, Subpart A]

The provisions of 40 CFR 63, Subpart A - General Provisions, which are incorporated as 326 IAC 20-1-1, apply to the facilities described in this section except when otherwise specified in 40 CFR 63, Subpart JJJJJJ.

#### E.2.2 National Emission Standards for Hazardous Air Pollutants for Industrial, Commercial, and Institutional Boilers Area Sources [40 CFR Part 63, Subpart JJJJJJ] [326 IAC 20]

Pursuant to CFR Part 63, Subpart JJJJJJ, the Permittee shall comply with the provisions of 40 CFR Part 63, Subpart JJJJJJ (included as 'Attachment B'):

- (1) 40 CFR 63.11193
- (2) 40 CFR 63.11196
- (3) 40 CFR 63.11201
- (4) 40 CFR 63.11205
- (5) 40 CFR 63.11210
- (6) 40 CFR 63.11211
- (7) 40 CFR 63.11214
- (8) 40 CFR 63.11223
- (9) 40 CFR 63.11225
- (10) 40 CFR 63.11237

**INDIANA DEPARTMENT OF ENVIRONMENTAL MANAGEMENT  
OFFICE OF AIR QUALITY  
COMPLIANCE AND ENFORCEMENT BRANCH  
PART 70 OPERATING PERMIT  
CERTIFICATION**

Source Name: Griffin Industries LLC  
Source Address: 7358 South Griffin Road, Newberry, Indiana, 47449  
Part 70 Permit No.: T055-32418-00008

**This certification shall be included when submitting monitoring, testing reports/results or other documents as required by this permit.**

Please check what document is being certified:

- Annual Compliance Certification Letter
- Test Result (specify)
- Report (specify)
- Notification (specify)
- Affidavit (specify)
- Other (specify)

I certify that, based on information and belief formed after reasonable inquiry, the statements and information in the document are true, accurate, and complete.

Signature:

Printed Name:

Title/Position:

Phone:

Date:

**INDIANA DEPARTMENT OF ENVIRONMENTAL MANAGEMENT  
OFFICE OF AIR QUALITY  
COMPLIANCE AND ENFORCEMENT BRANCH  
100 North Senate Avenue  
MC 61-53 IGCN 1003  
Indianapolis, Indiana 46204-2251  
Phone: (317) 233-0178  
Fax: (317) 233-6865**

**PART 70 OPERATING PERMIT  
EMERGENCY OCCURRENCE REPORT**

Source Name: Griffin Industries LLC  
Source Address: 7358 South Griffin Road, Newberry, Indiana, 47449  
Part 70 Permit No.: T055-32418-00008

**This form consists of 2 pages**

**Page 1 of 2**

- This is an emergency as defined in 326 IAC 2-7-1(12)
- The Permittee must notify the Office of Air Quality (OAQ), within four (4) business hours (1-800-451-6027 or 317-233-0178, ask for Compliance Section); and
  - The Permittee must submit notice in writing or by facsimile within two (2) working days (Facsimile Number: 317-233-6865), and follow the other requirements of 326 IAC 2-7-16.

If any of the following are not applicable, mark N/A

Facility/Equipment/Operation:
Control Equipment:
Permit Condition or Operation Limitation in Permit:
Description of the Emergency:
Describe the cause of the Emergency:

If any of the following are not applicable, mark N/A

**Page 2 of 2**

Date/Time Emergency started:
Date/Time Emergency was corrected:
Was the facility being properly operated at the time of the emergency?    Y    N
Type of Pollutants Emitted: TSP, PM-10, SO <sub>2</sub> , VOC, NO <sub>x</sub> , CO, Pb, other:
Estimated amount of pollutant(s) emitted during emergency:
Describe the steps taken to mitigate the problem:
Describe the corrective actions/response steps taken:
Describe the measures taken to minimize emissions:
If applicable, describe the reasons why continued operation of the facilities are necessary to prevent imminent injury to persons, severe damage to equipment, substantial loss of capital investment, or loss of product or raw materials of substantial economic value:

Form Completed by: \_\_\_\_\_

Title / Position: \_\_\_\_\_

Date: \_\_\_\_\_

Phone: \_\_\_\_\_

## INDIANA DEPARTMENT OF ENVIRONMENTAL MANAGEMENT OFFICE OF AIR QUALITY COMPLIANCE AND ENFORCEMENT BRANCH

### Part 70 Quarterly Report

Source Name: Griffin Industries LLC  
 Source Address: 7358 South Griffin Road, Newberry, Indiana, 47449  
 Part 70 Permit No.: T055-32418-00008  
 Facility: Boilers 05, 06, 07 and 08  
 Parameter: SO2 emissions  
 Limit: 249 and 99,999 tons per twelve (12) consecutive month period for SO2 and CO2e, respectively

Month	Fuel Types (units)	Column 1	Column 2	Column 1 + Column 2	Total SO2 Emissions From All Fuels Used (tons per 12 month consecutive period)	Total CO2e Emissions From All Fuels Used (tons per 12 month consecutive period)
		Usage This Month	Usage Previous 11 Months	Usage 12 Month Total		
Month 1	Natural gas (mmcf)					
	No. 2 fuel oil (gallons)					
	waste oil (gallons)					
	processed grease (gallons)					
Month 2	Natural gas (mmcf)					
	No. 2 fuel oil (gallons)					
	waste oil (gallons)					
	processed grease (gallons)					
Month 3	Natural gas (mmcf)					
	No. 2 fuel oil (gallons)					
	waste oil (gallons)					
	processed grease (gallons)					

- No deviation occurred in this quarter.
- Deviation/s occurred in this quarter.  
 Deviation has been reported on:

Submitted by: \_\_\_\_\_  
 Title / Position: \_\_\_\_\_  
 Signature: \_\_\_\_\_  
 Date: \_\_\_\_\_  
 Phone: \_\_\_\_\_

**INDIANA DEPARTMENT OF ENVIRONMENTAL MANAGEMENT  
OFFICE OF AIR QUALITY  
COMPLIANCE AND ENFORCEMENT BRANCH  
PART 70 OPERATING PERMIT  
QUARTERLY DEVIATION AND COMPLIANCE MONITORING REPORT**

Source Name: Griffin Industries LLC  
Source Address: 7358 South Griffin Road, Newberry, Indiana, 47449  
Part 70 Permit No.: T055-32418-00008

Months: \_\_\_\_\_ to \_\_\_\_\_ Year: \_\_\_\_\_

Page 1 of 2

<p>This report shall be submitted quarterly based on a calendar year. Proper notice submittal under Section B –Emergency Provisions satisfies the reporting requirements of paragraph (a) of Section C- General Reporting. Any deviation from the requirements of this permit, the date(s) of each deviation, the probable cause of the deviation, and the response steps taken must be reported. A deviation required to be reported pursuant to an applicable requirement that exists independent of the permit, shall be reported according to the schedule stated in the applicable requirement and does not need to be included in this report. Additional pages may be attached if necessary. If no deviations occurred, please specify in the box marked "No deviations occurred this reporting period".</p>	
<p><input type="checkbox"/> NO DEVIATIONS OCCURRED THIS REPORTING PERIOD.</p>	
<p><input type="checkbox"/> THE FOLLOWING DEVIATIONS OCCURRED THIS REPORTING PERIOD</p>	
<p><b>Permit Requirement</b> (specify permit condition #)</p>	
<p><b>Date of Deviation:</b></p>	<p><b>Duration of Deviation:</b></p>
<p><b>Number of Deviations:</b></p>	
<p><b>Probable Cause of Deviation:</b></p>	
<p><b>Response Steps Taken:</b></p>	
<p><b>Permit Requirement</b> (specify permit condition #)</p>	
<p><b>Date of Deviation:</b></p>	<p><b>Duration of Deviation:</b></p>
<p><b>Number of Deviations:</b></p>	
<p><b>Probable Cause of Deviation:</b></p>	
<p><b>Response Steps Taken:</b></p>	

<b>Permit Requirement (specify permit condition #)</b>	
<b>Date of Deviation:</b>	<b>Duration of Deviation:</b>
<b>Number of Deviations:</b>	
<b>Probable Cause of Deviation:</b>	
<b>Response Steps Taken:</b>	
<b>Permit Requirement (specify permit condition #)</b>	
<b>Date of Deviation:</b>	<b>Duration of Deviation:</b>
<b>Number of Deviations:</b>	
<b>Probable Cause of Deviation:</b>	
<b>Response Steps Taken:</b>	
<b>Permit Requirement (specify permit condition #)</b>	
<b>Date of Deviation:</b>	<b>Duration of Deviation:</b>
<b>Number of Deviations:</b>	
<b>Probable Cause of Deviation:</b>	
<b>Response Steps Taken:</b>	

Form Completed by: \_\_\_\_\_

Title / Position: \_\_\_\_\_

Date: \_\_\_\_\_

Phone: \_\_\_\_\_

**Attachment A to  
Part 70 Operating Permit Renewal No. T055-32418-00008**

[Downloaded from the eCFR on May 13, 2013]

**Electronic Code of Federal Regulations**

**Title 40: Protection of Environment**

**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 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 ( $E_{ho}$ ) and the 30-day average SO<sub>2</sub> emission rate ( $E_{ao}$ ). 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  $E_{ho}$  ( $E_{ho o}$ ) is used in Equation 19-19 of Method 19 of appendix A of this part to compute the adjusted  $E_{ao}$  ( $E_{ao o}$ ). The  $E_{ho o}$  is computed using the following formula:

$$E_{ho o} = \frac{E_{ho} - E_w(1 - X_1)}{X_1}$$

Where:

$E_{ho\ o}$  = 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:

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

Where:

$\%P_s$  = Potential  $SO_2$  emission rate, in percent;

$\%R_g$  =  $SO_2$  removal efficiency of the control device as determined by Method 19 of appendix A of this part, in percent; and

$\%R_f$  =  $SO_2$  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  $\%R_g$  ( $\%R_{g\ o}$ ) 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:

$$\%R_{g\ o} = 100 \left( 1 - \frac{E_w}{E_{ai\ o}} \right)$$

Where:

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

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

$E_{ai\ o}$  = Adjusted average  $SO_2$  inlet rate, ng/J (lb/MMBtu).

(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:

$$E_{ai o} = \frac{E_{hi} - E_w(1 - X_k)}{X_k}$$

Where:

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

$E_{hi}$  = Hourly  $SO_2$  inlet 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 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  $SO_2$  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  $SO_2$  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.

[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 ±14 °C (320±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]

**Attachment B to  
Part 70 Operating Permit Renewal No. T055-32418-00008**

[Downloaded from the eCFR on May 13, 2013]

**Electronic Code of Federal Regulations**

**Title 40: Protection of Environment**

**Part 63, Subpart JJJJJJ—National Emission Standards for Hazardous Air Pollutants for Industrial, Commercial, and Institutional Boilers Area Sources**

Source: 76 FR 15591, Mar. 21, 2011, unless otherwise noted.

**What This Subpart Covers**

**§ 63.11193 Am I subject to this subpart?**

You are subject to this subpart if you own or operate an industrial, commercial, or institutional boiler as defined in § 63.11237 that is located at, or is part of, an area source of hazardous air pollutants (HAP), as defined in § 63.2, except as specified in § 63.11195.

**§ 63.11194 What is the affected source of this subpart?**

(a) This subpart applies to each new, reconstructed, or existing affected source as defined in paragraphs (a)(1) and (2) of this section.

(1) The affected source of this subpart is the collection of all existing industrial, commercial, and institutional boilers within a subcategory, as listed in § 63.11200 and defined in § 63.11237, located at an area source.

(2) The affected source of this subpart is each new or reconstructed industrial, commercial, or institutional boiler within a subcategory, as listed in § 63.11200 and as defined in § 63.11237, located at an area source.

(b) An affected source is an existing source if you commenced construction or reconstruction of the affected source on or before June 4, 2010.

(c) An affected source is a new source if you commenced construction of the affected source after June 4, 2010, and the boiler meets the applicability criteria at the time you commence construction.

(d) An affected source is a reconstructed source if the boiler meets the reconstruction criteria as defined in § 63.2, you commenced reconstruction after June 4, 2010, and the boiler meets the applicability criteria at the time you commence reconstruction.

(e) An existing dual-fuel fired boiler meeting the definition of gas-fired boiler, as defined in § 63.11237, that meets the applicability requirements of this subpart after June 4, 2010 due to a fuel switch from gaseous fuel to solid fossil fuel, biomass, or liquid fuel is considered to be an existing source under this subpart as long as the boiler was designed to accommodate the alternate fuel.

(f) If you are an owner or operator of an area source subject to this subpart, you are exempt from the obligation to obtain a permit under 40 CFR part 70 or part 71 as a result of this subpart. You may, however, be required to obtain a title V permit due to another reason or reasons. See 40 CFR 70.3(a) and (b) or 71.3(a) and (b). Notwithstanding the exemption from title V permitting for area sources under this subpart, you must continue to comply with the provisions of this subpart.

[76 FR 15591, Mar. 21, 2011, as amended at 78 FR 7506, Feb. 1, 2013]

**§ 63.11195 Are any boilers not subject to this subpart?**

The types of boilers listed in paragraphs (a) through (k) of this section are not subject to this subpart and to any requirements in this subpart.

(a) Any boiler specifically listed as, or included in the definition of, an affected source in another standard(s) under this part.

(b) Any boiler specifically listed as an affected source in another standard(s) established under section 129 of the Clean Air Act.

(c) A boiler required to have a permit under section 3005 of the Solid Waste Disposal Act or covered by subpart EEE of this part (e.g., hazardous waste boilers), unless such units do not combust hazardous waste and combust comparable fuels.

(d) A boiler that is used specifically for research and development. This exemption does not include boilers that solely or primarily provide steam (or heat) to a process or for heating at a research and development facility. This exemption does not prohibit the use of the steam (or heat) generated from the boiler during research and development, however, the boiler must be concurrently and primarily engaged in research and development for the exemption to apply.

(e) A gas-fired boiler as defined in this subpart.

(f) A hot water heater as defined in this subpart.

(g) Any boiler that is used as a control device to comply with another subpart of this part, or part 60, part 61, or part 65 of this chapter provided that at least 50 percent of the average annual heat input during any 3 consecutive calendar years to the boiler is provided by regulated gas streams that are subject to another standard.

(h) Temporary boilers as defined in this subpart.

(i) Residential boilers as defined in this subpart.

(j) Electric boilers as defined in this subpart.

(k) An electric utility steam generating unit (EGU) covered by subpart UUUUU of this part.

[76 FR 15591, Mar. 21, 2011, as amended at 78 FR 7506, Feb. 1, 2013]

**§ 63.11196 What are my compliance dates?**

(a) If you own or operate an existing affected boiler, you must achieve compliance with the applicable provisions in this subpart as specified in paragraphs (a)(1) through (3) of this section.

(1) If the existing affected boiler is subject to a work practice or management practice standard of a tune-up, you must achieve compliance with the work practice or management practice standard no later than March 21, 2014.

(2) If the existing affected boiler is subject to emission limits, you must achieve compliance with the emission limits no later than March 21, 2014.

(3) If the existing affected boiler is subject to the energy assessment requirement, you must achieve compliance with the energy assessment requirement no later than March 21, 2014.

(b) If you start up a new affected source on or before May 20, 2011, you must achieve compliance with the provisions of this subpart no later than May 20, 2011.

(c) If you start up a new affected source after May 20, 2011, you must achieve compliance with the provisions of this subpart upon startup of your affected source.

(d) If you own or operate an industrial, commercial, or institutional boiler and would be subject to this subpart except for the exemption in § 63.11195(b) for commercial and industrial solid waste incineration units covered by 40 CFR part 60, subpart CCCC or subpart DDDD, and you cease combusting solid waste, you must be in compliance with this subpart on the effective date of the waste to fuel switch as specified in § 60.2145(a)(2) and (3) of subpart CCCC or § 60.2710(a)(2) and (3) of subpart DDDD.

[76 FR 15591, Mar. 21, 2011, as amended at 78 FR 7506, Feb. 1, 2013]

### **Emission Limits, Work Practice Standards, Emission Reduction Measures, and Management Practices**

#### **§ 63.11200 What are the subcategories of boilers?**

The subcategories of boilers, as defined in § 63.11237 are:

- (a) Coal.
- (b) Biomass.
- (c) Oil.
- (d) Seasonal boilers.
- (e) Oil-fired boilers with heat input capacity of equal to or less than 5 million British thermal units (Btu) per hour.
- (f) Boilers with an oxygen trim system that maintains an optimum air-to-fuel ratio that would otherwise be subject to a biennial tune-up.
- (g) Limited-use boilers.

[78 FR 7506, Feb. 1, 2013]

#### **§ 63.11201 What standards must I meet?**

- (a) You must comply with each emission limit specified in Table 1 to this subpart that applies to your boiler.
- (b) You must comply with each work practice standard, emission reduction measure, and management practice specified in Table 2 to this subpart that applies to your boiler. An energy assessment completed on or after January 1, 2008 that meets or is amended to meet the energy assessment requirements in Table 2 to this subpart satisfies the energy assessment requirement. A facility that operates under an energy management program established through energy management systems compatible with ISO 50001, that includes the affected units, also satisfies the energy assessment requirement.
- (c) You must comply with each operating limit specified in Table 3 to this subpart that applies to your boiler.
- (d) These standards apply at all times the affected boiler is operating, except during periods of startup and shutdown as defined in § 63.11237, during which time you must comply only with Table 2 to this subpart.

[76 FR 15591, Mar. 21, 2011, as amended at 78 FR 7506, Feb. 1, 2013]

## General Compliance Requirements

### § 63.11205 What are my general requirements for complying with this subpart?

(a) At all times you must operate and maintain any affected source, including associated air pollution control equipment and monitoring equipment, in a manner consistent with safety and good air pollution control practices for minimizing emissions. The general duty to minimize emissions does not require you to make any further efforts to reduce emissions if levels required by this standard have been achieved. Determination of whether such operation and maintenance procedures are being used will be based on information available to the Administrator that may include, but is not limited to, monitoring results, review of operation and maintenance procedures, review of operation and maintenance records, and inspection of the source.

(b) You must demonstrate compliance with all applicable emission limits using performance stack testing, fuel analysis, or a continuous monitoring system (CMS), including a continuous emission monitoring system (CEMS), a continuous opacity monitoring system (COMS), or a continuous parameter monitoring system (CPMS), where applicable. You may demonstrate compliance with the applicable mercury emission limit using fuel analysis if the emission rate calculated according to § 63.11211(c) is less than the applicable emission limit. Otherwise, you must demonstrate compliance using stack testing.

(c) If you demonstrate compliance with any applicable emission limit through performance stack testing and subsequent compliance with operating limits (including the use of CPMS), with a CEMS, or with a COMS, you must develop a site-specific monitoring plan according to the requirements in paragraphs (c)(1) through (3) of this section for the use of any CEMS, COMS, or CPMS. This requirement also applies to you if you petition the EPA Administrator for alternative monitoring parameters under § 63.8(f).

(1) For each CMS required in this section (including CEMS, COMS, or CPMS), you must develop, and submit to the Administrator for approval upon request, a site-specific monitoring plan that addresses paragraphs (c)(1)(i) through (vi) of this section. You must submit this site-specific monitoring plan, if requested, at least 60 days before your initial performance evaluation of your CMS. This requirement to develop and submit a site-specific monitoring plan does not apply to affected sources with existing CEMS or COMS operated according to the performance specifications under appendix B to part 60 of this chapter and that meet the requirements of § 63.11224.

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

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

(iii) Performance evaluation procedures and acceptance criteria ( e.g., calibrations).

(iv) Ongoing operation and maintenance procedures in accordance with the general requirements of § 63.8(c)(1)(ii), (c)(3), and (c)(4)(ii);

(v) Ongoing data quality assurance procedures in accordance with the general requirements of § 63.8(d); and

(vi) Ongoing recordkeeping and reporting procedures in accordance with the general requirements of § 63.10(c) (as applicable in Table 8 to this subpart), (e)(1), and (e)(2)(i).

(2) You must conduct a performance evaluation of each CMS in accordance with your site-specific monitoring plan.

(3) You must operate and maintain the CMS in continuous operation according to the site-specific monitoring plan.

## Initial Compliance Requirements

### § 63.11210 What are my initial compliance requirements and by what date must I conduct them?

(a) You must demonstrate initial compliance with each emission limit specified in Table 1 to this subpart that applies to you by either conducting performance (stack) tests, as applicable, according to § 63.11212 and Table 4 to this subpart or, for mercury, conducting fuel analyses, as applicable, according to § 63.11213 and Table 5 to this subpart.

(b) For existing affected boilers that have applicable emission limits, you must demonstrate initial compliance with the applicable emission limits no later than 180 days after the compliance date that is specified in § 63.11196 and according to the applicable provisions in § 63.7(a)(2), except as provided in paragraph (j) of this section.

(c) For existing affected boilers that have applicable work practice standards, management practices, or emission reduction measures, you must demonstrate initial compliance no later than the compliance date that is specified in § 63.11196 and according to the applicable provisions in § 63.7(a)(2), except as provided in paragraph (j) of this section.

(d) For new or reconstructed affected boilers that have applicable emission limits, you must demonstrate initial compliance with the applicable emission limits no later than 180 days after March 21, 2011 or within 180 days after startup of the source, whichever is later, according to § 63.7(a)(2)(ix).

(e) For new or reconstructed oil-fired boilers that combust 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 emission limit under this subpart and that do not use a post-combustion technology (except a wet scrubber) to reduce particulate matter (PM) or sulfur dioxide emissions, you are not subject to the PM emission limit in Table 1 of this subpart providing you monitor and record on a monthly basis the type of fuel combusted. If you intend to burn a new type of fuel or fuel mixture that does not meet the requirements of this paragraph, you must conduct a performance test within 60 days of burning the new fuel.

(f) For new or reconstructed affected boilers that have applicable work practice standards or management practices, you are not required to complete an initial performance tune-up, but you are required to complete the applicable biennial or 5-year tune-up as specified in § 63.11223 no later than 25 months or 61 months, respectively, after the initial startup of the new or reconstructed affected source.

(g) For affected boilers that ceased burning solid waste consistent with § 63.11196(d) and for which your initial compliance date has passed, you must demonstrate compliance within 60 days of the effective date of the waste-to-fuel switch as specified in § 60.2145(a)(2) and (3) of subpart CCCC or § 60.2710(a)(2) and (3) of subpart DDDD. If you have not conducted your compliance demonstration for this subpart within the previous 12 months, you must complete all compliance demonstrations for this subpart before you commence or recommence combustion of solid waste.

(h) For affected boilers that switch fuels or make a physical change to the boiler that results in the applicability of a different subcategory within subpart JJJJJJ or the boiler becoming subject to subpart JJJJJJ, you must demonstrate compliance within 180 days of the effective date of the fuel switch or the physical change. Notification of such changes must be submitted according to § 63.11225(g).

(i) For boilers located at existing major sources of HAP that limit their potential to emit (e.g., make a physical change or take a permit limit) such that the existing major source becomes an area source, you must comply with the applicable provisions as specified in paragraphs (i)(1) through (3) of this section.

(1) Any such existing boiler at the existing source must demonstrate compliance with subpart JJJJJJ within 180 days of the later of March 21, 2014 or upon the existing major source commencing operation as an area source.

(2) Any new or reconstructed boiler at the existing source must demonstrate compliance with subpart JJJJJJ within 180 days of the later of March 21, 2011 or startup.

(3) Notification of such changes must be submitted according to § 63.11225(g).

(j) For existing affected boilers that have not operated between the effective date of the rule and the compliance date that is specified for your source in § 63.11196, you must comply with the applicable provisions as specified in paragraphs (j)(1) through (3) of this section.

(1) You must complete the initial compliance demonstration, if subject to the emission limits in Table 1 to this subpart, as specified in paragraphs (a) and (b) of this section, no later than 180 days after the re-start of the affected boiler and according to the applicable provisions in § 63.7(a)(2).

(2) You must complete the initial performance tune-up, if subject to the tune-up requirements in § 63.11223, by following the procedures described in § 63.11223(b) no later than 30 days after the re-start of the affected boiler.

(3) You must complete the one-time energy assessment, if subject to the energy assessment requirements specified in Table 2 to this subpart, no later than the compliance date specified in § 63.11196.

[76 FR 15591, Mar. 21, 2011, as amended at 78 FR 7507, Feb. 1, 2013]

### **§ 63.11211 How do I demonstrate initial compliance with the emission limits?**

(a) For affected boilers that demonstrate compliance with any of the emission limits of this subpart through performance (stack) testing, your initial compliance requirements include conducting performance tests according to § 63.11212 and Table 4 to this subpart, conducting a fuel analysis for each type of fuel burned in your boiler according to § 63.11213 and Table 5 to this subpart, establishing operating limits according to § 63.11222, Table 6 to this subpart and paragraph (b) of this section, as applicable, and conducting CMS performance evaluations according to § 63.11224. For affected boilers that burn a single type of fuel, you are exempted from the compliance requirements of conducting a fuel analysis for each type of fuel burned in your boiler. For purposes of this subpart, boilers that use a supplemental fuel only for startup, unit shutdown, and transient flame stability purposes still qualify as affected boilers that burn a single type of fuel, and the supplemental fuel is not subject to the fuel analysis requirements under § 63.11213 and Table 5 to this subpart.

(b) You must establish parameter operating limits according to paragraphs (b)(1) through (4) of this section.

(1) For a wet scrubber, you must establish the minimum scrubber liquid flow rate and minimum scrubber pressure drop as defined in § 63.11237, as your operating limits during the three-run performance stack test. If you use a wet scrubber and you conduct separate performance stack tests for PM and mercury emissions, you must establish one set of minimum scrubber liquid flow rate and pressure drop operating limits. If you conduct multiple performance stack tests, you must set the minimum scrubber liquid flow rate and pressure drop operating limits at the highest minimum values established during the performance stack tests.

(2) For an electrostatic precipitator operated with a wet scrubber, you must establish the minimum total secondary electric power (secondary voltage and secondary current), as defined in § 63.11237, as your operating limits during the three-run performance stack test.

(3) For activated carbon injection, you must establish the minimum activated carbon injection rate, as defined in § 63.11237, as your operating limit during the three-run performance stack test.

(4) The operating limit for boilers with fabric filters that demonstrate continuous compliance through bag leak detection systems is that a bag leak detection system be installed according to the requirements in § 63.11224, and that each fabric filter must be operated such that the bag leak detection system alarm does not sound more than 5 percent of the operating time during a 6-month period.

(c) If you elect to demonstrate compliance with an applicable mercury emission limit through fuel analysis, you must conduct fuel analyses according to § 63.11213 and Table 5 to this subpart and follow the procedures in paragraphs (c)(1) through (3) of this section.

(1) If you burn more than one fuel type, you must determine the fuel type, or mixture, you could burn in your boiler that would result in the maximum emission rates of mercury.

(2) You must determine the 90th percentile confidence level fuel mercury concentration of the composite samples analyzed for each fuel type using Equation 1 of this section.

$$P_{90} = \text{mean} + (SD * t) \quad (\text{Eq. 1})$$

Where:

$P_{90}$  = 90th percentile confidence level mercury concentration, in pounds per million Btu.

mean = Arithmetic average of the fuel mercury concentration in the fuel samples analyzed according to § 63.11213, in units of pounds per million Btu.

SD = Standard deviation of the mercury concentration in the fuel samples analyzed according to § 63.11213, in units of pounds per million Btu.

t = t distribution critical value for 90th percentile (0.1) probability for the appropriate degrees of freedom (number of samples minus one) as obtained from a Distribution Critical Value Table.

(3) To demonstrate compliance with the applicable mercury emission limit, the emission rate that you calculate for your boiler using Equation 1 of this section must be less than the applicable mercury emission limit.

[76 FR 15591, Mar. 21, 2011, as amended at 78 FR 7508, Feb. 1, 2013]

#### **§ 63.11212 What stack tests and procedures must I use for the performance tests?**

(a) You must conduct all performance tests according to § 63.7(c), (d), (f), and (h). You must also develop a site-specific test plan according to the requirements in § 63.7(c).

(b) You must conduct each stack test according to the requirements in Table 4 to this subpart. Boilers that use a CEMS for carbon monoxide (CO) are exempt from the initial CO performance testing in Table 4 to this subpart and the oxygen concentration operating limit requirement specified in Table 3 to this subpart.

(c) You must conduct performance stack tests at the representative operating load conditions while burning the type of fuel or mixture of fuels that have the highest emissions potential for each regulated pollutant, and you must demonstrate initial compliance and establish your operating limits based on these performance stack tests. For subcategories with more than one emission limit, these requirements could result in the need to conduct more than one performance stack test. Following each performance stack test and until the next performance stack test, you must comply with the operating limit for operating load conditions specified in Table 3 to this subpart.

(d) You must conduct a minimum of three separate test runs for each performance stack test required in this section, as specified in § 63.7(e)(3) and in accordance with the provisions in Table 4 to this subpart.

(e) To determine compliance with the emission limits, you must use the F-Factor methodology and equations in sections 12.2 and 12.3 of EPA Method 19 of appendix A-7 to part 60 of this chapter to convert the measured PM concentrations and the measured mercury concentrations that result from the performance test to pounds per million Btu heat input emission rates.

[76 FR 15591, Mar. 21, 2011, as amended at 78 FR 7508, Feb. 1, 2013]

#### **§ 63.11213 What fuel analyses and procedures must I use for the performance tests?**

(a) You must conduct fuel analyses according to the procedures in paragraphs (b) and (c) of this section and Table 5 to this subpart, as applicable. You are not required to conduct fuel analyses for fuels used for only startup, unit shutdown, and transient flame stability purposes. You are required to conduct fuel analyses only for fuels and units that are subject to emission limits for mercury in Table 1 of this subpart.

(b) At a minimum, you must obtain three composite fuel samples for each fuel type according to the procedures in Table 5 to this subpart. Each composite sample must consist of a minimum of three samples collected at approximately equal intervals during a test run period.

(c) Determine the concentration of mercury in the fuel in units of pounds per million Btu of each composite sample for each fuel type according to the procedures in Table 5 to this subpart.

**§ 63.11214 How do I demonstrate initial compliance with the work practice standard, emission reduction measures, and management practice?**

(a) If you own or operate an existing or new coal-fired boiler with a heat input capacity of less than 10 million Btu per hour, you must conduct a performance tune-up according to § 63.11223(b) and you must submit a signed statement in the Notification of Compliance Status report that indicates that you conducted a tune-up of the boiler.

(b) If you own or operate an existing or new biomass-fired boiler or an existing or new oil-fired boiler, you must conduct a performance tune-up according to § 63.11223(b) and you must submit a signed statement in the Notification of Compliance Status report that indicates that you conducted a tune-up of the boiler.

(c) If you own or operate an existing affected boiler with a heat input capacity of 10 million Btu per hour or greater, you must submit a signed certification in the Notification of Compliance Status report that an energy assessment of the boiler and its energy use systems was completed according to Table 2 to this subpart and is an accurate depiction of your facility.

(d) If you own or operate a boiler subject to emission limits in Table 1 of this subpart, you must minimize the boiler's startup and shutdown periods following the manufacturer's recommended procedures, if available. If manufacturer's recommended procedures are not available, you must follow recommended procedures for a unit of similar design for which manufacturer's recommended procedures are available. You must submit a signed statement in the Notification of Compliance Status report that indicates that you conducted startups and shutdowns according to the manufacturer's recommended procedures or procedures specified for a boiler of similar design if manufacturer's recommended procedures are not available.

[76 FR 15591, Mar. 21, 2011, as amended at 78 FR 7508, Feb. 1, 2013]

**Continuous Compliance Requirements**

**§ 63.11220 When must I conduct subsequent performance tests or fuel analyses?**

(a) If your boiler has a heat input capacity of 10 million British thermal units per hour or greater, you must conduct all applicable performance (stack) tests according to § 63.11212 on a triennial basis, except as specified in paragraphs (b) through (d) of this section. Triennial performance tests must be completed no more than 37 months after the previous performance test.

(b) When demonstrating initial compliance with the PM emission limit, if your boiler's performance test results show that your PM emissions are equal to or less than half of the PM emission limit, you do not need to conduct further performance tests for PM but must continue to comply with all applicable operating limits and monitoring requirements. If your initial performance test results show that your PM emissions are greater than half of the PM emission limit, you must conduct subsequent performance tests as specified in paragraph (a) of this section.

(c) If you demonstrate compliance with the mercury emission limit based on fuel analysis, you must conduct a fuel analysis according to § 63.11213 for each type of fuel burned as specified in paragraphs (c)(1) and (2) of this section. If you plan to burn a new type of fuel or fuel mixture, you must conduct a fuel analysis before burning the new type of fuel or mixture in your boiler. You must recalculate the mercury emission rate using Equation 1 of § 63.11211. The recalculated mercury emission rate must be less than the applicable emission limit.

(1) When demonstrating initial compliance with the mercury emission limit, if the mercury constituents in the fuel or fuel mixture are measured to be equal to or less than half of the mercury emission limit, you do not need to conduct further fuel analysis sampling but must continue to comply with all applicable operating limits and monitoring requirements.

(2) When demonstrating initial compliance with the mercury emission limit, if the mercury constituents in the fuel or fuel mixture are greater than half of the mercury emission limit, you must conduct quarterly sampling.

(d) For existing affected boilers that have not operated since the previous compliance demonstration and more than 3 years have passed since the previous compliance demonstration, you must complete your subsequent compliance demonstration no later than 180 days after the re-start of the affected boiler.

[78 FR 7508, Feb. 1, 2013]

**§ 63.11221 Is there a minimum amount of monitoring data I must obtain?**

(a) You must monitor and collect data according to this section and the site-specific monitoring plan required by § 63.11205(c).

(b) You must operate the monitoring system and collect data at all required intervals at all times the affected source is operating and compliance is required, except for periods of monitoring system malfunctions or out-of-control periods (see § 63.8(c)(7) of this part), repairs associated with monitoring system malfunctions or out-of-control periods, and required monitoring system quality assurance or quality control activities including, as applicable, calibration checks, required zero and span adjustments, and scheduled CMS maintenance as defined in your site-specific monitoring plan. A monitoring system malfunction is any sudden, infrequent, not reasonably preventable failure of the monitoring system to provide valid data. Monitoring system failures that are caused in part by poor maintenance or careless operation are not malfunctions. You are required to complete monitoring system repairs in response to monitoring system malfunctions or out-of-control periods and to return the monitoring system to operation as expeditiously as practicable.

(c) You may not use data collected during monitoring system malfunctions or out-of-control periods, repairs associated with monitoring system malfunctions or out-of-control periods, or required monitoring system quality assurance or quality control activities in calculations used to report emissions or operating levels. Any such periods must be reported according to the requirements in § 63.11225. You must use all the data collected during all other periods in assessing the operation of the control device and associated control system.

(d) Except for periods of monitoring system malfunctions or monitoring system out-of-control periods, repairs associated with monitoring system malfunctions or monitoring system out-of-control periods, and required monitoring system quality assurance or quality control activities (including, as applicable, calibration checks, required zero and span adjustments, and scheduled CMS maintenance as defined in your site-specific monitoring plan), failure to collect required data is a deviation of the monitoring requirements.

[76 FR 15591, Mar. 21, 2011, as amended at 78 FR 7508, Feb. 1, 2013]

**§ 63.11222 How do I demonstrate continuous compliance with the emission limits?**

(a) You must demonstrate continuous compliance with each emission limit and operating limit in Tables 1 and 3 to this subpart that applies to you according to the methods specified in Table 7 to this subpart and to paragraphs (a)(1) through (4) of this section.

(1) Following the date on which the initial compliance demonstration is completed or is required to be completed under §§ 63.7 and 63.11196, whichever date comes first, you must continuously monitor the operating parameters. Operation above the established maximum, below the established minimum, or outside the allowable range of the operating limits specified in paragraph (a) of this section constitutes a deviation from your operating limits established under this subpart, except during performance tests conducted to determine compliance with the emission and operating limits or to establish new operating limits. Operating limits are confirmed or reestablished during performance tests.

(2) If you have an applicable mercury or PM emission limit, you must keep records of the type and amount of all fuels burned in each boiler during the reporting period to demonstrate that all fuel types and mixtures of fuels burned would result in lower emissions of mercury than the applicable emission limit (if you demonstrate compliance through fuel analysis), or result in lower fuel input of mercury than the maximum values calculated during the last performance stack test (if you demonstrate compliance through performance stack testing).

(3) If you have an applicable mercury emission limit and you plan to burn a new type of fuel, you must determine the mercury concentration for any new fuel type in units of pounds per million Btu, using the procedures in Equation 1 of § 63.11211 based on supplier data or your own fuel analysis, and meet the requirements in paragraphs (a)(3)(i) or (ii) of this section.

(i) The recalculated mercury emission rate must be less than the applicable emission limit.

(ii) If the mercury concentration is higher than mercury fuel input during the previous performance test, then you must conduct a new performance test within 60 days of burning the new fuel type or fuel mixture according to the procedures in § 63.11212 to demonstrate that the mercury emissions do not exceed the emission limit.

(4) If your unit is controlled with a fabric filter, and you demonstrate continuous compliance using a bag leak detection system, you must initiate corrective action within 1 hour of a bag leak detection system alarm and operate and maintain the fabric filter system such that the alarm does not sound more than 5 percent of the operating time during a 6-month period. You must also keep records of the date, time, and duration of each alarm, the time corrective action was initiated and completed, and a brief description of the cause of the alarm and the corrective action taken. You must also record the percent of the operating time during each 6-month period that the alarm sounds. In calculating this operating time percentage, if inspection of the fabric filter demonstrates that no corrective action is required, no alarm time is counted. If corrective action is required, each alarm is counted as a minimum of 1 hour. If you take longer than 1 hour to initiate corrective action, the alarm time is counted as the actual amount of time taken to initiate corrective action.

(b) You must report each instance in which you did not meet each emission limit and operating limit in Tables 1 and 3 to this subpart that apply to you. These instances are deviations from the emission limits in this subpart. These deviations must be reported according to the requirements in § 63.11225.

#### **§ 63.11223 How do I demonstrate continuous compliance with the work practice and management practice standards?**

(a) For affected sources subject to the work practice standard or the management practices of a tune-up, you must conduct a performance tune-up according to paragraph (b) of this section and keep records as required in § 63.11225(c) to demonstrate continuous compliance. You must conduct the tune-up while burning the type of fuel (or fuels in the case of boilers that routinely burn two types of fuels at the same time) that provided the majority of the heat input to the boiler over the 12 months prior to the tune-up.

(b) Except as specified in paragraphs (c) through (f) of this section, you must conduct a tune-up of the boiler biennially to demonstrate continuous compliance as specified in paragraphs (b)(1) through (7) of this section. Each biennial tune-up must be conducted no more than 25 months after the previous tune-up. For a new or reconstructed boiler, the first biennial tune-up must be no later than 25 months after the initial startup of the new or reconstructed boiler.

(1) As applicable, inspect the burner, and clean or replace any components of the burner as necessary (you may delay the burner inspection until the next scheduled unit shutdown, not to exceed 36 months from the previous inspection). Units that produce electricity for sale may delay the burner inspection until the first outage, not to exceed 36 months from the previous inspection.

(2) Inspect the flame pattern, as applicable, and adjust the burner as necessary to optimize the flame pattern. The adjustment should be consistent with the manufacturer's specifications, if available.

(3) Inspect the system controlling the air-to-fuel ratio, as applicable, and ensure that it is correctly calibrated and functioning properly (you may delay the inspection until the next scheduled unit shutdown, not to exceed 36 months from the previous inspection). Units that produce electricity for sale may delay the inspection until the first outage, not to exceed 36 months from the previous inspection.

(4) Optimize total emissions of CO. This optimization should be consistent with the manufacturer's specifications, if available, and with any nitrogen oxide requirement to which the unit is subject.

(5) Measure the concentrations in the effluent stream of CO in parts per million, by volume, and oxygen in volume percent, before and after the adjustments are made (measurements may be either on a dry or wet basis, as long as it is the same basis before and after the adjustments are made). Measurements may be taken using a portable CO analyzer.

(6) Maintain on-site and submit, if requested by the Administrator, a report containing the information in paragraphs (b)(6)(i) through (iii) of this section.

(i) The concentrations of CO in the effluent stream in parts per million, by volume, and oxygen in volume percent, measured at high fire or typical operating load, before and after the tune-up of the boiler.

(ii) A description of any corrective actions taken as a part of the tune-up of the boiler.

(iii) The type and amount of fuel used over the 12 months prior to the tune-up of the boiler, but only if the unit was physically and legally capable of using more than one type of fuel during that period. Units sharing a fuel meter may estimate the fuel use by each unit.

(7) If the unit is not operating on the required date for a tune-up, the tune-up must be conducted within 30 days of startup.

(c) Boilers with an oxygen trim system that maintains an optimum air-to-fuel ratio that would otherwise be subject to a biennial tune-up must conduct a tune-up of the boiler every 5 years as specified in paragraphs (b)(1) through (7) of this section. Each 5-year tune-up must be conducted no more than 61 months after the previous tune-up. For a new or reconstructed boiler with an oxygen trim system, the first 5-year tune-up must be no later than 61 months after the initial startup. You may delay the burner inspection specified in paragraph (b)(1) of this section and inspection of the system controlling the air-to-fuel ratio specified in paragraph (b)(3) of this section until the next scheduled unit shutdown, but you must inspect each burner and system controlling the air-to-fuel ratio at least once every 72 months.

(d) Seasonal boilers must conduct a tune-up every 5 years as specified in paragraphs (b)(1) through (7) of this section. Each 5-year tune-up must be conducted no more than 61 months after the previous tune-up. For a new or reconstructed seasonal boiler, the first 5-year tune-up must be no later than 61 months after the initial startup. You may delay the burner inspection specified in paragraph (b)(1) of this section and inspection of the system controlling the air-to-fuel ratio specified in paragraph (b)(3) of this section until the next scheduled unit shutdown, but you must inspect each burner and system controlling the air-to-fuel ratio at least once every 72 months. Seasonal boilers are not subject to the emission limits in Table 1 to this subpart or the operating limits in Table 3 to this subpart.

(e) Oil-fired boilers with a heat input capacity of equal to or less than 5 million Btu per hour must conduct a tune-up every 5 years as specified in paragraphs (b)(1) through (7) of this section. Each 5-year tune-up must be conducted no more than 61 months after the previous tune-up. For a new or reconstructed oil-fired boiler with a heat input capacity of equal to or less than 5 million Btu per hour, the first 5-year tune-up must be no later than 61 months after the initial startup. You may delay the burner inspection specified in paragraph (b)(1) of this section and inspection of the system controlling the air-to-fuel ratio specified in paragraph (b)(3) of this section until the next scheduled unit shutdown, but you must inspect each burner and system controlling the air-to-fuel ratio at least once every 72 months.

(f) Limited-use boilers must conduct a tune-up every 5 years as specified in paragraphs (b)(1) through (7) of this section. Each 5-year tune-up must be conducted no more than 61 months after the previous tune-up. For a new or reconstructed limited-use boiler, the first 5-year tune-up must be no later than 61 months after the initial startup. You may delay the burner inspection specified in paragraph (b)(1) of this section and inspection of the system controlling the air-to-fuel ratio specified in paragraph (b)(3) of this section until the next scheduled unit shutdown, but you must inspect each burner and system controlling the air-to-fuel ratio at least once every 72 months. Limited-use boilers are not subject to the emission limits in Table 1 to this subpart, the energy assessment requirements in Table 2 to this subpart, or the operating limits in Table 3 to this subpart.

(g) If you own or operate a boiler subject to emission limits in Table 1 of this subpart, you must minimize the boiler's startup and shutdown periods following the manufacturer's recommended procedures, if available. If manufacturer's recommended procedures are not available, you must follow recommended procedures for a unit of similar design for which manufacturer's recommended procedures are available. You must submit a signed statement in the Notification

of Compliance Status report that indicates that you conducted startups and shutdowns according to the manufacturer's recommended procedures or procedures specified for a boiler of similar design if manufacturer's recommended procedures are not available.

[76 FR 15591, Mar. 21, 2011, as amended at 78 FR 7509, Feb. 1, 2013]

**§ 63.11224 What are my monitoring, installation, operation, and maintenance requirements?**

(a) If your boiler is subject to a CO emission limit in Table 1 to this subpart, you must either install, operate, and maintain a CEMS for CO and oxygen according to the procedures in paragraphs (a)(1) through (6) of this section, or install, calibrate, operate, and maintain an oxygen analyzer system, as defined in § 63.11237, according to the manufacturer's recommendations and paragraphs (a)(7) and (d) of this section, as applicable, by the compliance date specified in § 63.11196. Where a certified CO CEMS is used, the CO level shall be monitored at the outlet of the boiler, after any add-on controls or flue gas recirculation system and before release to the atmosphere. Boilers that use a CO CEMS are exempt from the initial CO performance testing and oxygen concentration operating limit requirements specified in § 63.11211(a) of this subpart. Oxygen monitors and oxygen trim systems must be installed to monitor oxygen in the boiler flue gas, boiler firebox, or other appropriate intermediate location.

(1) Each CO CEMS must be installed, operated, and maintained according to the applicable procedures under Performance Specification 4, 4A, or 4B at 40 CFR part 60, appendix B, and each oxygen CEMS must be installed, operated, and maintained according to Performance Specification 3 at 40 CFR part 60, appendix B. Both the CO and oxygen CEMS must also be installed, operated, and maintained according to the site-specific monitoring plan developed according to paragraph (c) of this section.

(2) You must conduct a performance evaluation of each CEMS according to the requirements in § 63.8(e) and according to Performance Specifications 3 and 4, 4A, or 4B at 40 CFR part 60, appendix B.

(3) Each CEMS must complete a minimum of one cycle of operation (sampling, analyzing, and data recording) every 15 minutes. You must have CEMS data values from a minimum of four successive cycles of operation representing each of the four 15-minute periods in an hour, or at least two 15-minute data values during an hour when CEMS calibration, quality assurance, or maintenance activities are being performed, to have a valid hour of data.

(4) The CEMS data must be reduced as specified in § 63.8(g)(2).

(5) You must calculate hourly averages, corrected to 3 percent oxygen, from each hour of CO CEMS data in parts per million CO concentrations and determine the 10-day rolling average of all recorded readings, except as provided in § 63.11221(c). Calculate a 10-day rolling average from all of the hourly averages collected for the 10-day operating period using Equation 2 of this section.

$$\text{10-day average} = \frac{\sum_{i=1}^n Hpvi}{n} \quad (\text{Eq. 2})$$

Where:

Hpvi = the hourly parameter value for hour i

n = the number of valid hourly parameter values collected over 10 boiler operating days

(6) For purposes of collecting CO data, you must operate the CO CEMS as specified in § 63.11221(b). For purposes of calculating data averages, you must use all the data collected during all periods in assessing compliance, except that you must exclude certain data as specified in § 63.11221(c). Periods when CO data are unavailable may constitute monitoring deviations as specified in § 63.11221(d).

(7) You must operate the oxygen analyzer system at or above the minimum oxygen level that is established as the operating limit according to Table 6 to this subpart when firing the fuel or fuel mixture utilized during the most recent CO performance stack test. Operation of oxygen trim systems to meet these requirements shall not be done in a manner which compromises furnace safety.

(b) If you are using a control device to comply with the emission limits specified in Table 1 to this subpart, you must maintain each operating limit in Table 3 to this subpart that applies to your boiler as specified in Table 7 to this subpart. If you use a control device not covered in Table 3 to this subpart, or you wish to establish and monitor an alternative operating limit and alternative monitoring parameters, you must apply to the United States Environmental Protection Agency (EPA) Administrator for approval of alternative monitoring under § 63.8(f).

(c) If you demonstrate compliance with any applicable emission limit through stack testing and subsequent compliance with operating limits, you must develop a site-specific monitoring plan according to the requirements in paragraphs (c)(1) through (4) of this section. This requirement also applies to you if you petition the EPA Administrator for alternative monitoring parameters under § 63.8(f).

(1) For each CMS required in this section, you must develop, and submit to the EPA Administrator for approval upon request, a site-specific monitoring plan that addresses paragraphs (c)(1)(i) through (iii) of this section. You must submit this site-specific monitoring plan (if requested) at least 60 days before your initial performance evaluation of your CMS.

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

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

(iii) Performance evaluation procedures and acceptance criteria ( e.g., calibrations).

(2) In your site-specific monitoring plan, you must also address paragraphs (c)(2)(i) through (iii) of this section.

(i) Ongoing operation and maintenance procedures in accordance with the general requirements of § 63.8(c)(1), (3), and (4)(ii).

(ii) Ongoing data quality assurance procedures in accordance with the general requirements of § 63.8(d).

(iii) Ongoing recordkeeping and reporting procedures in accordance with the general requirements of § 63.10(c), (e)(1), and (e)(2)(i).

(3) You must conduct a performance evaluation of each CMS in accordance with your site-specific monitoring plan.

(4) You must operate and maintain the CMS in continuous operation according to the site-specific monitoring plan.

(d) If you have an operating limit that requires the use of a CMS, you must install, operate, and maintain each CPMS according to the procedures in paragraphs (d)(1) through (4) of this section.

(1) The CPMS must complete a minimum of one cycle of operation every 15 minutes. You must have data values from a minimum of four successive cycles of operation representing each of the four 15-minute periods in an hour, or at least two 15-minute data values during an hour when CMS calibration, quality assurance, or maintenance activities are being performed, to have a valid hour of data.

(2) You must calculate hourly arithmetic averages from each hour of CPMS data in units of the operating limit and determine the 30-day rolling average of all recorded readings, except as provided in § 63.11221(c). Calculate a 30-day rolling average from all of the hourly averages collected for the 30-day operating period using Equation 3 of this section.

$$\text{30-day average} = \frac{\sum_{i=1}^n Hpvi}{n} \quad \text{[Eq. 3]}$$

Where:

$H_{pvi}$  = the hourly parameter value for hour  $i$

$n$  = the number of valid hourly parameter values collected over 30 boiler operating days

(3) For purposes of collecting data, you must operate the CPMS as specified in § 63.11221(b). For purposes of calculating data averages, you must use all the data collected during all periods in assessing compliance, except that you must exclude certain data as specified in § 63.11221(c). Periods when CPMS data are unavailable may constitute monitoring deviations as specified in § 63.11221(d).

(4) Record the results of each inspection, calibration, and validation check.

(e) If you have an applicable opacity operating limit under this rule, you must install, operate, certify and maintain each COMS according to the procedures in paragraphs (e)(1) through (8) of this section by the compliance date specified in § 63.11196.

(1) Each COMS must be installed, operated, and maintained according to Performance Specification 1 of 40 CFR part 60, appendix B.

(2) You must conduct a performance evaluation of each COMS according to the requirements in § 63.8 and according to Performance Specification 1 of 40 CFR part 60, appendix B.

(3) As specified in § 63.8(c)(4)(i), each COMS must complete a minimum of one cycle of sampling and analyzing for each successive 10-second period and one cycle of data recording for each successive 6-minute period.

(4) The COMS data must be reduced as specified in § 63.8(g)(2).

(5) You must include in your site-specific monitoring plan procedures and acceptance criteria for operating and maintaining each COMS according to the requirements in § 63.8(d). At a minimum, the monitoring plan must include a daily calibration drift assessment, a quarterly performance audit, and an annual zero alignment audit of each COMS.

(6) You must operate and maintain each COMS according to the requirements in the monitoring plan and the requirements of § 63.8(e). You must identify periods the COMS is out of control including any periods that the COMS fails to pass a daily calibration drift assessment, a quarterly performance audit, or an annual zero alignment audit.

(7) You must calculate and record 6-minute averages from the opacity monitoring data and determine and record the daily block average of recorded readings, except as provided in § 63.11221(c).

(8) For purposes of collecting opacity data, you must operate the COMS as specified in § 63.11221(b). For purposes of calculating data averages, you must use all the data collected during all periods in assessing compliance, except that you must exclude certain data as specified in § 63.11221(c). Periods when COMS data are unavailable may constitute monitoring deviations as specified in § 63.11221(d).

(f) If you use a fabric filter bag leak detection system to comply with the requirements of this subpart, you must install, calibrate, maintain, and continuously operate the bag leak detection system as specified in paragraphs (f)(1) through (8) of this section.

(1) You must install and operate a bag leak detection system for each exhaust stack of the fabric filter.

(2) Each bag leak detection system must be installed, operated, calibrated, and maintained in a manner consistent with the manufacturer's written specifications and recommendations and in accordance with EPA-454/R-98-015 (incorporated by reference, see § 63.14).

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

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

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

(6) The bag leak detection system must be equipped with an audible or visual alarm system that will activate automatically when an increase in relative particulate matter emissions over a preset level is detected. The alarm must be located where it is easily heard or seen by plant operating personnel.

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

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

[76 FR 15591, Mar. 21, 2011, as amended at 78 FR 7510, Feb. 1, 2013]

### **§ 63.11225 What are my notification, reporting, and recordkeeping requirements?**

(a) You must submit the notifications specified in paragraphs (a)(1) through (5) of this section to the administrator.

(1) You must submit all of the notifications in §§ 63.7(b); 63.8(e) and (f); and 63.9(b) through (e), (g), and (h) that apply to you by the dates specified in those sections except as specified in paragraphs (a)(2) and (4) of this section.

(2) An Initial Notification must be submitted no later than January 20, 2014 or within 120 days after the source becomes subject to the standard.

(3) If you are required to conduct a performance stack test you must submit a Notification of Intent to conduct a performance test at least 60 days before the performance stack test is scheduled to begin.

(4) You must submit the Notification of Compliance Status no later than 120 days after the applicable compliance date specified in § 63.11196 unless you must conduct a performance stack test. If you must conduct a performance stack test, you must submit the Notification of Compliance Status within 60 days of completing the performance stack test. You must submit the Notification of Compliance Status in accordance with paragraphs (a)(4)(i) and (vi) of this section. The Notification of Compliance Status must include the information and certification(s) of compliance in paragraphs (a)(4)(i) through (v) of this section, as applicable, and signed by a responsible official.

(i) You must submit the information required in § 63.9(h)(2), except the information listed in § 63.9(h)(2)(i)(B), (D), (E), and (F). If you conduct any performance tests or CMS performance evaluations, you must submit that data as specified in paragraph (e) of this section. If you conduct any opacity or visible emission observations, or other monitoring procedures or methods, you must submit that data to the Administrator at the appropriate address listed in § 63.13.

(ii) "This facility complies with the requirements in § 63.11214 to conduct an initial tune-up of the boiler."

(iii) "This facility has had an energy assessment performed according to § 63.11214(c)."

(iv) For units that install bag leak detection systems: "This facility complies with the requirements in § 63.11224(f)."

(v) For units that do not qualify for a statutory exemption as provided in section 129(g)(1) of the Clean Air Act: "No secondary materials that are solid waste were combusted in any affected unit."

(vi) The notification must be submitted electronically using the Compliance and Emissions Data Reporting Interface (CEDRI) that is accessed through EPA's Central Data Exchange (CDX) ( [www.epa.gov/cdx](http://www.epa.gov/cdx) ). However, if the reporting form specific to this subpart is not available in CEDRI at the time that the report is due, the written Notification of Compliance Status must be submitted to the Administrator at the appropriate address listed in § 63.13.

(5) If you are using data from a previously conducted emission test to serve as documentation of conformance with the emission standards and operating limits of this subpart, you must include in the Notification of Compliance Status the date of the test and a summary of the results, not a complete test report, relative to this subpart.

(b) You must prepare, by March 1 of each year, and submit to the delegated authority upon request, an annual compliance certification report for the previous calendar year containing the information specified in paragraphs (b)(1) through (4) of this section. You must submit the report by March 15 if you had any instance described by paragraph (b)(3) of this section. For boilers that are subject only to a requirement to conduct a biennial or 5-year tune-up according to § 63.11223(a) and not subject to emission limits or operating limits, you may prepare only a biennial or 5-year compliance report as specified in paragraphs (b)(1) and (2) of this section.

(1) Company name and address.

(2) Statement by a responsible official, with the official's name, title, phone number, email address, and signature, certifying the truth, accuracy and completeness of the notification and a statement of whether the source has complied with all the relevant standards and other requirements of this subpart. Your notification must include the following certification(s) of compliance, as applicable, and signed by a responsible official:

(i) "This facility complies with the requirements in § 63.11223 to conduct a biennial or 5-year tune-up, as applicable, of each boiler."

(ii) For units that do not qualify for a statutory exemption as provided in section 129(g)(1) of the Clean Air Act: "No secondary materials that are solid waste were combusted in any affected unit."

(iii) "This facility complies with the requirement in §§ 63.11214(d) and 63.11223(g) to minimize the boiler's time spent during startup and shutdown and to conduct startups and shutdowns according to the manufacturer's recommended procedures or procedures specified for a boiler of similar design if manufacturer's recommended procedures are not available."

(3) If the source experiences any deviations from the applicable requirements during the reporting period, include a description of deviations, the time periods during which the deviations occurred, and the corrective actions taken.

(4) The total fuel use by each affected boiler subject to an emission limit, for each calendar month within the reporting period, including, but not limited to, a description of the fuel, whether the fuel has received a non-waste determination by you or EPA through a petition process to be a non-waste under § 241.3(c), whether the fuel(s) were processed from discarded non-hazardous secondary materials within the meaning of § 241.3, and the total fuel usage amount with units of measure.

(c) You must maintain the records specified in paragraphs (c)(1) through (7) of this section.

(1) As required in § 63.10(b)(2)(xiv), you must keep a copy of each notification and report that you submitted to comply with this subpart and all documentation supporting any Initial Notification or Notification of Compliance Status that you submitted.

(2) You must keep records to document conformance with the work practices, emission reduction measures, and management practices required by § 63.11214 and § 63.11223 as specified in paragraphs (c)(2)(i) through (vi) of this section.

(i) Records must identify each boiler, the date of tune-up, the procedures followed for tune-up, and the manufacturer's specifications to which the boiler was tuned.

(ii) For operating units that combust non-hazardous secondary materials that have been determined not to be solid waste pursuant to § 241.3(b)(1) of this chapter, you must keep a record which documents how the secondary material meets each of the legitimacy criteria under § 241.3(d)(1). If you combust a fuel that has been processed from a discarded non-hazardous secondary material pursuant to § 241.3(b)(4) of this chapter, you must keep records as to how the operations that produced the fuel satisfies the definition of processing in § 241.2 and each of the legitimacy criteria in § 241.3(d)(1) of this chapter. If the fuel received a non-waste determination pursuant to the petition process submitted under § 241.3(c) of this chapter, you must keep a record that documents how the fuel satisfies the

requirements of the petition process. For operating units that combust non-hazardous secondary materials as fuel per § 241.4, you must keep records documenting that the material is a listed non-waste under § 241.4(a).

(iii) For each boiler required to conduct an energy assessment, you must keep a copy of the energy assessment report.

(iv) For each boiler subject to an emission limit in Table 1 to this subpart, you must also keep records of monthly fuel use by each boiler, including the type(s) of fuel and amount(s) used.

(v) For each boiler that meets the definition of seasonal boiler, you must keep records of days of operation per year.

(vi) For each boiler that meets the definition of limited-use boiler, you must keep a copy of the federally enforceable permit that limits the annual capacity factor to less than or equal to 10 percent and records of fuel use for the days the boiler is operating.

(3) For sources that demonstrate compliance through fuel analysis, a copy of all calculations and supporting documentation that were done to demonstrate compliance with the mercury emission limits. Supporting documentation should include results of any fuel analyses. You can use the results from one fuel analysis for multiple boilers provided they are all burning the same fuel type.

(4) Records of the occurrence and duration of each malfunction of the boiler, or of the associated air pollution control and monitoring equipment.

(5) Records of actions taken during periods of malfunction to minimize emissions in accordance with the general duty to minimize emissions in § 63.11205(a), including corrective actions to restore the malfunctioning boiler, air pollution control, or monitoring equipment to its normal or usual manner of operation.

(6) You must keep the records of all inspection and monitoring data required by §§ 63.11221 and 63.11222, and the information identified in paragraphs (c)(6)(i) through (vi) of this section for each required inspection or monitoring.

(i) The date, place, and time of the monitoring event.

(ii) Person conducting the monitoring.

(iii) Technique or method used.

(iv) Operating conditions during the activity.

(v) Results, including the date, time, and duration of the period from the time the monitoring indicated a problem to the time that monitoring indicated proper operation.

(vi) Maintenance or corrective action taken (if applicable).

(7) If you use a bag leak detection system, you must keep the records specified in paragraphs (c)(7)(i) through (iii) of this section.

(i) Records of the bag leak detection system output.

(ii) Records of bag leak detection system adjustments, including the date and time of the adjustment, the initial bag leak detection system settings, and the final bag leak detection system settings.

(iii) The date and time of all bag leak detection system alarms, and for each valid alarm, the time you initiated corrective action, the corrective action taken, and the date on which corrective action was completed.

(d) Your records must be in a form suitable and readily available for expeditious review. You must keep each record for 5 years following the date of each recorded action. You must keep each record on-site or be accessible from a central location by computer or other means that instantly provide access at the site for at least 2 years after the date of each recorded action. You may keep the records off site for the remaining 3 years.

(e)(1) Within 60 days after the date of completing each performance test (defined in § 63.2) as required by this subpart you must submit the results of the performance tests, including any associated fuel analyses, required by this subpart to EPA's WebFIRE database by using CEDRI that is accessed through EPA's CDX ([www.epa.gov/cdx](http://www.epa.gov/cdx)). Performance test data must be submitted in the file format generated through use of EPA's Electronic Reporting Tool (ERT) (see <http://www.epa.gov/ttn/chief/ert/index.html>). Only data collected using test methods on the ERT Web site are subject to this requirement for submitting reports electronically to WebFIRE. Owners or operators who claim that some of the information being submitted for performance tests is confidential business information (CBI) must submit a complete ERT file including information claimed to be CBI on a compact disk or other commonly used electronic storage media (including, but not limited to, flash drives) to EPA. The electronic media must be clearly marked as CBI and mailed to U.S. EPA/OAPQS/CORE CBI Office, Attention: WebFIRE Administrator, MD C404-02, 4930 Old Page Rd., Durham, NC 27703. The same ERT file with the CBI omitted must be submitted to EPA via CDX as described earlier in this paragraph. At the discretion of the delegated authority, you must also submit these reports, including CBI, to the delegated authority in the format specified by the delegated authority. For any performance test conducted using test methods that are not listed on the ERT Web site, the owner or operator shall submit the results of the performance test in paper submissions to the Administrator at the appropriate address listed in § 63.13.

(2) Within 60 days after the date of completing each CEMS performance evaluation test as defined in § 63.2, you must submit relative accuracy test audit (RATA) data to EPA's CDX by using CEDRI in accordance with paragraph (e)(1) of this section. Only RATA pollutants that can be documented with the ERT (as listed on the ERT Web site) are subject to this requirement. For any performance evaluations with no corresponding RATA pollutants listed on the ERT Web site, the owner or operator shall submit the results of the performance evaluation in paper submissions to the Administrator at the appropriate address listed in § 63.13.

(f) If you intend to commence or recommence combustion of solid waste, you must provide 30 days prior notice of the date upon which you will commence or recommence combustion of solid waste. The notification must identify:

(1) The name of the owner or operator of the affected source, the location of the source, the boiler(s) that will commence burning solid waste, and the date of the notice.

(2) The currently applicable subcategory under this subpart.

(3) The date on which you became subject to the currently applicable emission limits.

(4) The date upon which you will commence combusting solid waste.

(g) If you have switched fuels or made a physical change to the boiler and the fuel switch or change resulted in the applicability of a different subcategory within subpart JJJJJJ, in the boiler becoming subject to subpart JJJJJJ, or in the boiler switching out of subpart JJJJJJ due to a change to 100 percent natural gas, or you have taken a permit limit that resulted in you being subject to subpart JJJJJJ, you must provide notice of the date upon which you switched fuels, made the physical change, or took a permit limit within 30 days of the change. The notification must identify:

(1) The name of the owner or operator of the affected source, the location of the source, the boiler(s) that have switched fuels, were physically changed, or took a permit limit, and the date of the notice.

(2) The date upon which the fuel switch, physical change, or permit limit occurred.

[76 FR 15591, Mar. 21, 2011, as amended at 78 FR 7511, Feb. 1, 2013] .

#### **§ 63.11226 Affirmative defense for violation of emission standards during malfunction.**

In response to an action to enforce the standards set forth in § 63.11201 you may assert an affirmative defense to a claim for civil penalties for violations of such standards that are caused by malfunction, as defined at 40 CFR 63.2.

Appropriate penalties may be assessed if you fail to meet your burden of proving all of the requirements in the affirmative defense. The affirmative defense shall not be available for claims for injunctive relief.

(a) *Assertion of affirmative defense.* To establish the affirmative defense in any action to enforce such a standard, you must timely meet the reporting requirements in paragraph (b) of this section, and must prove by a preponderance of evidence that:

(1) The violation:

(i) Was caused by a sudden, infrequent, and unavoidable failure of air pollution control equipment, process equipment, or a process to operate in a normal or usual manner; and

(ii) Could not have been prevented through careful planning, proper design or better operation and maintenance practices; and

(iii) Did not stem from any activity or event that could have been foreseen and avoided, or planned for; and

(iv) Was not part of a recurring pattern indicative of inadequate design, operation, or maintenance; and

(2) Repairs were made as expeditiously as possible when a violation occurred; and

(3) The frequency, amount, and duration of the violation (including any bypass) were minimized to the maximum extent practicable; and

(4) If the violation resulted from a bypass of control equipment or a process, then the bypass was unavoidable to prevent loss of life, personal injury, or severe property damage; and

(5) All possible steps were taken to minimize the impact of the violation on ambient air quality, the environment, and human health; and

(6) All emissions monitoring and control systems were kept in operation if at all possible, consistent with safety and good air pollution control practices; and

(7) All of the actions in response to the violation were documented by properly signed, contemporaneous operating logs; and

(8) At all times, the affected source was operated in a manner consistent with good practices for minimizing emissions; and

(9) A written root cause analysis has been prepared, the purpose of which is to determine, correct, and eliminate the primary causes of the malfunction and the violation resulting from the malfunction event at issue. The analysis shall also specify, using best monitoring methods and engineering judgment, the amount of any emissions that were the result of the malfunction.

(b) *Report.* The owner or operator seeking to assert an affirmative defense shall submit a written report to the Administrator with all necessary supporting documentation, that it has met the requirements set forth in paragraph (a) of this section. This affirmative defense report shall be included in the first periodic compliance, deviation report or excess emission report otherwise required after the initial occurrence of the violation of the relevant standard (which may be the end of any applicable averaging period). If such compliance, deviation report or excess emission report is due less than 45 days after the initial occurrence of the violation, the affirmative defense report may be included in the second compliance, deviation report or excess emission report due after the initial occurrence of the violation of the relevant standard.

## Other Requirements and Information

### § 63.11235 What parts of the General Provisions apply to me?

Table 8 to this subpart shows which parts of the General Provisions in §§ 63.1 through 63.15 apply to you.

### § 63.11236 Who implements and enforces this subpart?

(a) This subpart can be implemented and enforced by EPA or an administrator such as your state, local, or tribal agency. If the EPA Administrator has delegated authority to your state, local, or tribal agency, then that agency has the authority to implement and enforce this subpart. You should contact your EPA Regional Office to find out if implementation and enforcement of this subpart is delegated to your state, local, or tribal agency.

(b) In delegating implementation and enforcement authority of this subpart to a state, local, or tribal agency under 40 CFR part 63, subpart E, the authorities contained in paragraphs (c) of this section are retained by the EPA Administrator and are not transferred to the state, local, or tribal agency.

(c) The authorities that cannot be delegated to state, local, or tribal agencies are specified in paragraphs (c)(1) through (5) of this section.

(1) Approval of an alternative non-opacity emission standard and work practice standards in § 63.11223(a).

(2) Approval of alternative opacity emission standard under § 63.6(h)(9).

(3) Approval of major change to test methods under § 63.7(e)(2)(ii) and (f). A "major change to test method" is defined in § 63.90.

(4) Approval of a major change to monitoring under § 63.8(f). A "major change to monitoring" is defined in § 63.90.

(5) Approval of major change to recordkeeping and reporting under § 63.10(f). A "major change to recordkeeping/reporting" is defined in § 63.90.

[76 FR 15591, Mar. 21, 2011, as amended at 78 FR 7513, Feb. 1, 2013]

### § 63.11237 What definitions apply to this subpart?

Terms used in this subpart are defined in the Clean Air Act, in § 63.2 (the General Provisions), and in this section as follows:

*10-day rolling average* means the arithmetic mean of all valid hours of data from 10 successive operating days, except for periods of startup and shutdown and periods when the unit is not operating.

*30-day rolling average* means the arithmetic mean of all valid hours of data from 30 successive operating days, except for periods of startup and shutdown and periods when the unit is not operating.

*Affirmative defense* means, in the context of an enforcement proceeding, a response or defense put forward by a defendant, regarding which the defendant has the burden of proof, and the merits of which are independently and objectively evaluated in a judicial or administrative proceeding.

*Annual heat input* means the heat input for the 12 months preceding the compliance demonstration.

*Bag leak detection system* means a group of instruments that are capable of monitoring particulate matter loadings in the exhaust of a fabric filter ( *i.e.*, baghouse) in order to detect bag failures. A bag leak detection system includes, but is not limited to, an instrument that operates on electrodynamic, triboelectric, light scattering, light transmittance, or other principle to monitor relative particulate matter loadings.

*Biodiesel* means a mono-alkyl ester derived from biomass and conforming to ASTM D6751-11b, Standard Specification for Biodiesel Fuel Blend Stock (B100) for Middle Distillate Fuels (incorporated by reference, see § 63.14).

*Biomass* means any biomass-based solid fuel that is not a solid waste. This includes, but is not limited to, wood residue and wood products (e.g., trees, tree stumps, tree limbs, bark, lumber, sawdust, sander dust, chips, scraps, slabs, millings, and shavings); animal manure, including litter and other bedding materials; vegetative agricultural and silvicultural materials, such as logging residues (slash), nut and grain hulls and chaff ( e.g., almond, walnut, peanut, rice, and wheat), bagasse, orchard prunings, corn stalks, coffee bean hulls and grounds. This definition of biomass is not intended to suggest that these materials are or are not solid waste.

*Biomass subcategory* includes any boiler that burns any biomass and is not in the coal subcategory.

*Boiler* means an enclosed device using controlled flame combustion in which water is heated to recover thermal energy in the form of steam and/or hot water. Controlled flame combustion refers to a steady-state, or near steady-state, process wherein fuel and/or oxidizer feed rates are controlled. A device combusting solid waste, as defined in § 241.3 of this chapter, is not a boiler unless the device is exempt from the definition of a solid waste incineration unit as provided in section 129(g)(1) of the Clean Air Act. Waste heat boilers, process heaters, and autoclaves are excluded from the definition of *Boiler*.

*Boiler system* means the boiler and associated components, such as, feedwater systems, combustion air systems, fuel systems (including burners), blowdown systems, combustion control systems, steam systems, and condensate return systems, directly connected to and serving the energy use systems.

*Calendar year* means the period between January 1 and December 31, inclusive, for a given year.

*Coal* means all solid fuels classifiable as anthracite, bituminous, sub-bituminous, or lignite by the American Society for Testing and Materials in ASTM D388 (incorporated by reference, see § 63.14), coal refuse, and petroleum coke. For the purposes of this subpart, this definition of "coal" includes synthetic fuels derived from coal including, but not limited to, solvent-refined coal, coal-oil mixtures, and coal-water mixtures. Coal derived gases are excluded from this definition.

*Coal subcategory* includes any boiler that burns any solid fossil fuel and no more than 15 percent biomass on an annual heat input basis.

*Commercial boiler* means a boiler used in commercial establishments such as hotels, restaurants, and laundries to provide electricity, steam, and/or hot water.

*Common stack* means the exhaust of emissions from two or more affected units through a single flue. Affected units with a common stack may each have separate air pollution control systems located before the common stack, or may have a single air pollution control system located after the exhausts come together in a single flue.

*Daily block average* means the arithmetic mean of all valid emission concentrations or parameter levels recorded when a unit is operating measured over the 24-hour period from 12 a.m. (midnight) to 12 a.m. (midnight), except for periods of startup and shutdown and periods when the unit is not operating.

*Deviation* (1) Means any instance in which an affected source subject to this subpart, or an owner or operator of such a source:

(i) Fails to meet any applicable requirement or obligation established by this subpart including, but not limited to, any emission limit, operating limit, or work practice standard; or

(ii) Fails to meet any term or condition that is adopted to implement an applicable requirement in this subpart and that is included in the operating permit for any affected source required to obtain such a permit.

(2) A deviation is not always a violation.

*Distillate oil* means fuel oils that contain 0.05 weight percent nitrogen or less and comply with the specifications for fuel oil numbers 1 and 2, as defined by the American Society of Testing and Materials in ASTM D396 (incorporated by reference, see § 63.14) or diesel fuel oil numbers 1 and 2, as defined by the American Society for Testing and Materials in ASTM D975 (incorporated by reference, see § 63.14), kerosene, and biodiesel as defined by the American Society of Testing and Materials in ASTM D6751-11b (incorporated by reference, see § 63.14).

*Dry scrubber* means an add-on air pollution control system that injects dry alkaline sorbent (dry injection) or sprays an alkaline sorbent (spray dryer) to react with and neutralize acid gas in the exhaust stream forming a dry powder material. Sorbent injection systems used as control devices in fluidized bed boilers and process heaters are included in this definition. A dry scrubber is a dry control system.

*Electric boiler* means a boiler in which electric heating serves as the source of heat. Electric boilers that burn gaseous or liquid fuel during periods of electrical power curtailment or failure are included in this definition.

*Electric utility steam generating unit (EGU)* means a fossil fuel-fired combustion unit of more than 25 megawatts that serves a generator that produces electricity for sale. A fossil fuel-fired unit that cogenerates steam and electricity and supplies more than one-third of its potential electric output capacity and more than 25 megawatts electrical output to any utility power distribution system for sale is considered an electric utility steam generating unit. To be "capable of combusting" fossil fuels, an EGU would need to have these fuels allowed in their operating permits and have the appropriate fuel handling facilities on-site or otherwise available ( e.g., coal handling equipment, including coal storage area, belts and conveyers, pulverizers, etc.; oil storage facilities). In addition, fossil fuel-fired EGU means any EGU that fired fossil fuel for more than 10.0 percent of the average annual heat input in any 3 consecutive calendar years or for more than 15.0 percent of the annual heat input during any one calendar year after April 16, 2015.

*Electrostatic precipitator (ESP)* means an add-on air pollution control device used to capture particulate matter by charging the particles using an electrostatic field, collecting the particles using a grounded collecting surface, and transporting the particles into a hopper. An electrostatic precipitator is usually a dry control system.

*Energy assessment* means the following for the emission units covered by this subpart:

(1) The energy assessment for facilities with affected boilers with less than 0.3 trillion Btu per year (TBtu/year) heat input capacity will be 8 on-site technical labor hours in length maximum, but may be longer at the discretion of the owner or operator of the affected source. The boiler system(s) and any on-site energy use system(s) accounting for at least 50 percent of the affected boiler(s) energy ( e.g., steam, hot water, or electricity) production, as applicable, will be evaluated to identify energy savings opportunities, within the limit of performing an 8-hour energy assessment.

(2) The energy assessment for facilities with affected boilers with 0.3 to 1.0 TBtu/year heat input capacity will be 24 on-site technical labor hours in length maximum, but may be longer at the discretion of the owner or operator of the affected source. The boiler system(s) and any on-site energy use system(s) accounting for at least 33 percent of the affected boiler(s) energy ( e.g., steam, hot water, or electricity) production, as applicable, will be evaluated to identify energy savings opportunities, within the limit of performing a 24-hour energy assessment.

(3) The energy assessment for facilities with affected boilers with greater than 1.0 TBtu/year heat input capacity will be up to 24 on-site technical labor hours in length for the first TBtu/year plus 8 on-site technical labor hours for every additional 1.0 TBtu/year not to exceed 160 on-site technical hours, but may be longer at the discretion of the owner or operator of the affected source. The boiler system(s) and any on-site energy use system(s) accounting for at least 20 percent of the affected boiler(s) energy ( e.g., steam, hot water, or electricity) production, as applicable, will be evaluated to identify energy savings opportunities.

(4) The on-site energy use system(s) serving as the basis for the percent of affected boiler(s) energy production, as applicable, in paragraphs (1), (2), and (3) of this definition may be segmented by production area or energy use area as most logical and applicable to the specific facility being assessed ( e.g., product X manufacturing area; product Y drying area; Building Z).

*Energy management program* means a program that includes a set of practices and procedures designed to manage energy use that are demonstrated by the facility's energy policies, a facility energy manager and other staffing responsibilities, energy performance measurement and tracking methods, an energy saving goal, action plans, operating procedures, internal reporting requirements, and periodic review intervals used at the facility. Facilities may establish their program through energy management systems compatible with ISO 50001.

*Energy use system* (1) Includes the following systems located on the site of the affected boiler that use energy provided by the boiler:

(i) Process heating; compressed air systems; machine drive (motors, pumps, fans); process cooling; facility heating, ventilation, and air conditioning systems; hot water systems; building envelop; and lighting; or

(ii) Other systems that use steam, hot water, process heat, or electricity, provided by the affected boiler.

(2) Energy use systems are only those systems using energy clearly produced by affected boilers.

*Equivalent* means the following only as this term is used in Table 5 to this subpart:

(1) An equivalent sample collection procedure means a published voluntary consensus standard or practice (VCS) or

EPA method that includes collection of a minimum of three composite fuel samples, with each composite consisting of a minimum of three increments collected at approximately equal intervals over the test period.

(2) An equivalent sample compositing procedure means a published VCS or EPA method to systematically mix and obtain a representative subsample (part) of the composite sample.

(3) An equivalent sample preparation procedure means a published VCS or EPA method that: Clearly states that the standard, practice or method is appropriate for the pollutant and the fuel matrix; or is cited as an appropriate sample preparation standard, practice or method for the pollutant in the chosen VCS or EPA determinative or analytical method.

(4) An equivalent procedure for determining heat content means a published VCS or EPA method to obtain gross calorific (or higher heating) value.

(5) An equivalent procedure for determining fuel moisture content means a published VCS or EPA method to obtain moisture content. If the sample analysis plan calls for determining mercury using an aliquot of the dried sample, then the drying temperature must be modified to prevent vaporizing this metal. On the other hand, if metals analysis is done on an "as received" basis, a separate aliquot can be dried to determine moisture content and the mercury concentration mathematically adjusted to a dry basis.

(6) An equivalent mercury determinative or analytical procedure means a published VCS or EPA method that clearly states that the standard, practice, or method is appropriate for mercury and the fuel matrix and has a published detection limit equal or lower than the methods listed in Table 5 to this subpart for the same purpose.

*Fabric filter* means an add-on air pollution control device used to capture particulate matter by filtering gas streams through filter media, also known as a baghouse. A fabric filter is a dry control system.

*Federally enforceable* means all limitations and conditions that are enforceable by the EPA Administrator, including, but not limited to, the requirements of 40 CFR parts 60, 61, 63, and 65, 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 boiler* means a boiler utilizing a fluidized bed combustion process that is not a pulverized coal boiler.

*Fluidized bed combustion* means a process where a fuel is burned in a bed of granulated particles, which are maintained in a mobile suspension by the forward flow of air and combustion products.

*Fuel type* means each category of fuels that share a common name or classification. Examples include, but are not limited to, bituminous coal, sub-bituminous coal, lignite, anthracite, biomass, distillate oil, residual oil. Individual fuel types received from different suppliers are not considered new fuel types.

*Gaseous fuels* includes, but is not limited to, natural gas, process gas, landfill gas, coal derived gas, refinery gas, hydrogen, and biogas.

*Gas-fired boiler* includes any boiler that burns gaseous fuels not combined with any solid fuels and burns liquid fuel only during periods of gas curtailment, gas supply interruption, startups, or periodic testing on liquid fuel. Periodic testing of liquid fuel shall not exceed a combined total of 48 hours during any calendar year.

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

*Hot water heater* means a closed vessel with a capacity of no more than 120 U.S. gallons in which water is heated by combustion of gaseous, liquid, or biomass fuel and hot water is withdrawn for use external to the vessel. Hot water boilers ( *i.e.*, not generating steam) combusting gaseous, liquid, or biomass fuel with a heat input capacity of less than 1.6 million Btu per hour are included in this definition. The 120 U.S. gallon capacity threshold to be considered a hot water heater is independent of the 1.6 million Btu per hour heat input capacity threshold for hot water boilers. Hot water heater also means a tankless unit that provides on-demand hot water.

*Hourly average* means the arithmetic average of at least four CMS data values representing the four 15-minute periods in an hour, or at least two 15-minute data values during an hour when CMS calibration, quality assurance, or maintenance activities are being performed.

*Industrial boiler* means a boiler used in manufacturing, processing, mining, and refining or any other industry to provide steam, hot water, and/or electricity.

*Institutional boiler* means a boiler used in institutional establishments such as, but not limited to, medical centers, nursing homes, research centers, institutions of higher education, elementary and secondary schools, libraries, religious establishments, and governmental buildings to provide electricity, steam, and/or hot water.

*Limited-use boiler* means any boiler that burns any amount of solid or liquid fuels and has a federally enforceable average annual capacity factor of no more than 10 percent.

*Liquid fuel* includes, but is not limited to, distillate oil, residual oil, any form of liquid fuel derived from petroleum, used oil meeting the specification in 40 CFR 279.11, liquid biofuels, biodiesel, and vegetable oil, and comparable fuels as defined under 40 CFR 261.38.

*Load fraction* means the actual heat input of a boiler divided by heat input during the performance test that established the minimum sorbent injection rate or minimum activated carbon injection rate, expressed as a fraction ( *e.g.*, for 50 percent load the load fraction is 0.5).

*Minimum activated carbon injection rate* means load fraction multiplied by the lowest hourly average activated carbon injection rate measured according to Table 6 to this subpart during the most recent performance stack test demonstrating compliance with the applicable emission limit.

*Minimum oxygen level* means the lowest hourly average oxygen level measured according to Table 6 to this subpart during the most recent performance stack test demonstrating compliance with the applicable carbon monoxide emission limit.

*Minimum scrubber liquid flow rate* means the lowest hourly average scrubber liquid flow rate ( *e.g.*, to the particulate matter scrubber) measured according to Table 6 to this subpart during the most recent performance stack test demonstrating compliance with the applicable emission limit.

*Minimum scrubber pressure drop* means the lowest hourly average scrubber pressure drop measured according to Table 6 to this subpart during the most recent performance stack test demonstrating compliance with the applicable emission limit.

*Minimum total secondary electric power* means the lowest hourly average total secondary electric power determined from the values of secondary voltage and secondary current to the electrostatic precipitator measured according to Table 6 to this subpart during the most recent performance stack test demonstrating compliance with the applicable emission limits.

*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 gas, as defined by the American Society for Testing and Materials in ASTM D1835 (incorporated by reference, see § 63.14); or

(3) A mixture of hydrocarbons that maintains a gaseous state at ISO conditions ( *i.e.*, a temperature of 288 Kelvin, a relative humidity of 60 percent, and a pressure of 101.3 kilopascals). Additionally, natural gas must either be composed of at least 70 percent methane by volume or have a gross calorific value between 35 and 41 megajoules (MJ) per dry standard cubic meter (950 and 1,100 Btu per dry standard cubic foot); or

(4) Propane or propane-derived synthetic natural gas. Propane means a colorless gas derived from petroleum and natural gas, with the molecular structure  $C_3H_8$ .

*Oil subcategory* includes any boiler that burns any liquid fuel and is not in either the biomass or coal subcategories. Gas-fired boilers that burn liquid fuel only during periods of gas curtailment, gas supply interruptions, startups, or for periodic testing are not included in this definition. Periodic testing on liquid fuel shall not exceed a combined total of 48 hours during any calendar year.

*Opacity* means the degree to which emissions reduce the transmission of light and obscure the view of an object in the background.

*Operating day* means a 24-hour period between 12 midnight and the following midnight during which any fuel is combusted at any time in the boiler unit. It is not necessary for fuel to be combusted for the entire 24-hour period.

*Oxygen analyzer system* means all equipment required to determine the oxygen content of a gas stream and used to monitor oxygen in the boiler flue gas, boiler firebox, or other appropriate intermediate location. This definition includes oxygen trim systems.

*Oxygen trim system* means a system of monitors that is used to maintain excess air at the desired level in a combustion device. A typical system consists of a flue gas oxygen and/or carbon monoxide monitor that automatically provides a feedback signal to the combustion air controller.

*Particulate matter (PM)* means any finely divided solid or liquid material, other than uncombined water, as measured by the test methods specified under this subpart, or an approved alternative method.

*Performance testing* means the collection of data resulting from the execution of a test method used (either by stack testing or fuel analysis) to demonstrate compliance with a relevant emission standard.

*Period of gas curtailment or supply interruption* means a period of time during which the supply of gaseous fuel to an affected boiler is restricted or halted for reasons beyond the control of the facility. The act of entering into a contractual agreement with a supplier of natural gas established for curtailment purposes does not constitute a reason that is under the control of a facility for the purposes of this definition. An increase in the cost or unit price of natural gas due to normal market fluctuations not during periods of supplier delivery restriction does not constitute a period of natural gas curtailment or supply interruption. On-site gaseous fuel system emergencies or equipment failures qualify as periods of supply interruption when the emergency or failure is beyond the control of the facility.

*Process heater* means an enclosed device using controlled flame, and the unit's primary purpose is to transfer heat indirectly to a process material (liquid, gas, or solid) or to a heat transfer material (e.g., glycol or a mixture of glycol and water) for use in a process unit, instead of generating steam. Process heaters are devices in which the

combustion gases do not come into direct contact with process materials. Process heaters include units that heat water/water mixtures for pool heating, sidewalk heating, cooling tower water heating, power washing, or oil heating.

*Qualified energy assessor* means:

(1) Someone who has demonstrated capabilities to evaluate energy savings opportunities for steam generation and major energy using systems, including, but not limited to:

(i) Boiler combustion management.

(ii) Boiler thermal energy recovery, including

(A) Conventional feed water economizer,

(B) Conventional combustion air preheater, and

(C) Condensing economizer.

(iii) Boiler blowdown thermal energy recovery.

(iv) Primary energy resource selection, including

(A) Fuel (primary energy source) switching, and

(B) Applied steam energy versus direct-fired energy versus electricity.

(v) Insulation issues.

(vi) Steam trap and steam leak management.

(vii) Condensate recovery.

(viii) Steam end-use management.

(2) Capabilities and knowledge includes, but is not limited to:

(i) Background, experience, and recognized abilities to perform the assessment activities, data analysis, and report preparation.

(ii) Familiarity with operating and maintenance practices for steam or process heating systems.

(iii) Additional potential steam system improvement opportunities including improving steam turbine operations and reducing steam demand.

(iv) Additional process heating system opportunities including effective utilization of waste heat and use of proper process heating methods.

(v) Boiler-steam turbine cogeneration systems.

(vi) Industry specific steam end-use systems.

*Regulated gas stream* means an offgas stream that is routed to a boiler for the purpose of achieving compliance with a standard under another subpart of this part or part 60, part 61, or part 65 of this chapter.

*Residential boiler* means a boiler used to provide heat and/or hot water and/or as part of a residential combined heat and power system. This definition includes boilers located at an institutional facility ( e.g., university campus, military base, church grounds) or commercial/industrial facility ( e.g., farm) used primarily to provide heat and/or hot water for:

- (1) A dwelling containing four or fewer families, or
- (2) A single unit residence dwelling that has since been converted or subdivided into condominiums or apartments.

*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 of Testing and Materials in ASTM D396-10 (incorporated by reference, see § 63.14(b)).

*Responsible official* means responsible official as defined in § 70.2.

*Seasonal boiler* means a boiler that undergoes a shutdown for a period of at least 7 consecutive months (or 210 consecutive days) each 12-month period due to seasonal conditions, except for periodic testing. Periodic testing shall not exceed a combined total of 15 days during the 7-month shutdown. This definition only applies to boilers that would otherwise be included in the biomass subcategory or the oil subcategory.

*Shutdown* means the cessation of operation of a boiler for any purpose. Shutdown begins either when none of the steam or heat from the boiler is supplied for heating and/or producing electricity, or for any other purpose, or at the point of no fuel being fired in the boiler, whichever is earlier. Shutdown ends when there is no steam and no heat being supplied and no fuel being fired in the boiler.

*Solid fossil fuel* includes, but is not limited to, coal, coke, petroleum coke, and tire-derived fuel.

*Solid fuel* means any solid fossil fuel or biomass or bio-based solid fuel.

*Startup* means either the first-ever firing of fuel in a boiler for the purpose of supplying steam or heat for heating and/or producing electricity, or for any other purpose, or the firing of fuel in a boiler after a shutdown event for any purpose. Startup ends when any of the steam or heat from the boiler is supplied for heating and/or producing electricity, or for any other purpose.

*Temporary boiler* means any gaseous or liquid fuel boiler that 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 boiler is not a temporary boiler if any one of the following conditions exists:

- (1) The equipment is attached to a foundation.
- (2) The boiler or a replacement remains at a location within the facility and performs the same or similar function for more than 12 consecutive months, unless the regulatory agency approves an extension. An extension may be granted by the regulating agency upon petition by the owner or operator of a unit specifying the basis for such a request. Any temporary boiler that replaces a temporary boiler at a location within the facility and performs the same or similar function will be included in calculating the consecutive time period unless there is a gap in operation of 12 months or more.
- (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 within the facility but continues to perform the same or similar function and serve the same electricity, steam, and/or hot water system in an attempt to circumvent the residence time requirements of this definition.

*Tune-up* means adjustments made to a boiler in accordance with the procedures outlined in § 63.11223(b).

*Vegetable oil* means oils extracted from vegetation.

*Voluntary Consensus Standards (VCS)* mean technical standards ( e.g., materials specifications, test methods, sampling procedures, business practices) developed or adopted by one or more voluntary consensus bodies. EPA/Office of Air Quality Planning and Standards, by precedent, has only used VCS that are written in English. Examples of VCS bodies are: American Society of Testing and Materials (ASTM 100 Barr Harbor Drive, P.O. Box CB700, West Conshohocken, Pennsylvania 19428-B2959, (800) 262-1373, <http://www.astm.org> ), American Society of Mechanical Engineers (ASME ASME, Three Park Avenue, New York, NY 10016-5990, (800) 843-2763, <http://www.asme.org> ), International Standards Organization (ISO 1, ch. de la Voie-Creuse, Case postale 56, CH-1211 Geneva 20, Switzerland, +41 22 749 01 11, <http://www.iso.org/iso/home.htm> ), Standards Australia (AS Level 10, The Exchange Centre, 20 Bridge Street, Sydney, GPO Box 476, Sydney NSW 2001, + 61 2 9237 6171 <http://www.stadards.org.au> ), British Standards Institution (BSI, 389 Chiswick High Road, London, W4 4AL, United Kingdom, +44 (0)20 8996 9001, <http://www.bsigroup.com> ), Canadian Standards Association (CSA 5060 Spectrum Way, Suite 100, Mississauga, Ontario L4W 5N6, Canada, 800-463-6727, <http://www.csa.ca> ), European Committee for Standardization (CEN CENELEC Management Centre Avenue Marnix 17 B-1000 Brussels, Belgium +32 2 550 08 11, <http://www.cen.eu/cen> ), and German Engineering Standards (VDI VDI Guidelines Department, P.O. Box 10 11 39 40002, Duesseldorf, Germany, +49 211 6214-230, <http://www.vdi.eu> ). The types of standards that are not considered VCS are standards developed by: the United States, e.g., California (CARB) and Texas (TCEQ); industry groups, such as American Petroleum Institute (API), Gas Processors Association (GPA), and Gas Research Institute (GRI); and other branches of the U.S. government, e.g., Department of Defense (DOD) and Department of Transportation (DOT). This does not preclude EPA from using standards developed by groups that are not VCS bodies within their rule. When this occurs, EPA has done searches and reviews for VCS equivalent to these non-EPA methods.

*Waste heat boiler* means a device that recovers normally unused energy ( i.e., hot exhaust gas) and converts it to usable heat. Waste heat boilers are also referred to as heat recovery steam generators. Waste heat boilers are heat exchangers generating steam from incoming hot exhaust gas from an industrial ( e.g., thermal oxidizer, kiln, furnace) or power ( e.g., combustion turbine, engine) equipment. Duct burners are sometimes used to increase the temperature of the incoming hot exhaust gas.

*Wet scrubber* means any add-on air pollution control device that mixes an aqueous stream or slurry with the exhaust gases from a boiler to control emissions of particulate matter or to absorb and neutralize acid gases, such as hydrogen chloride. A wet scrubber creates an aqueous stream or slurry as a byproduct of the emissions control process.

*Work practice standard* means any design, equipment, work practice, or operational standard, or combination thereof, which is promulgated pursuant to section 112(h) of the Clean Air Act.

[76 FR 15591, Mar. 21, 2011, as amended at 78 FR 7513, Feb. 1, 2013]

**Table 1 to Subpart JJJJJJ of Part 63—Emission Limits**

As stated in § 63.11201, you must comply with the following applicable emission limits:

If your boiler is in this subcategory . . .	For the following pollutants . . .	You must achieve less than or equal to the following emission limits, except during periods of startup and shutdown . . .
1. New coal-fired boilers with heat input capacity of 30 million British thermal units per hour (MMBtu/hr) or greater that do not meet the definition of limited-use boiler	a. PM (Filterable) b. Mercury c. CO	3.0E-02 pounds(lb) per million British thermal units (MMBtu) of heat input. 2.2E-05 lb per MMBtu of heat input. 420 parts per million (ppm) by volume on a dry basis corrected to 3 percent oxygen (3-run average or 10-day rolling average).

If your boiler is in this subcategory . . .	For the following pollutants . . .	You must achieve less than or equal to the following emission limits, except during periods of startup and shutdown . . .
2. New coal-fired boilers with heat input capacity of between 10 and 30 MMBtu/hr that do not meet the definition of limited-use boiler	a. PM (Filterable) b. Mercury c. CO	4.2E-01 lb per MMBtu of heat input. 2.2E-05 lb per MMBtu of heat input. 420 ppm by volume on a dry basis corrected to 3 percent oxygen (3-run average or 10-day rolling average).
3. New biomass-fired boilers with heat input capacity of 30 MMBtu/hr or greater that do not meet the definition of seasonal boiler or limited-use boiler	PM (Filterable)	3.0E-02 lb per MMBtu of heat input.
4. New biomass fired boilers with heat input capacity of between 10 and 30 MMBtu/hr that do not meet the definition of seasonal boiler or limited-use boiler	PM (Filterable)	7.0E-02 lb per MMBtu of heat input.
5. New oil-fired boilers with heat input capacity of 10 MMBtu/hr or greater that do not meet the definition of seasonal boiler or limited-use boiler	PM (Filterable)	3.0E-02 lb per MMBtu of heat input.
6. Existing coal-fired boilers with heat input capacity of 10 MMBtu/hr or greater that do not meet the definition of limited-use boiler	a. Mercury b. CO	2.2E-05 lb per MMBtu of heat input. 420 ppm by volume on a dry basis corrected to 3 percent oxygen.

[78 FR 7517, Feb. 1, 2013]

**Table 2 to Subpart JJJJJ of Part 63—Work Practice Standards, Emission Reduction Measures, and Management Practices**

As stated in § 63.11201, you must comply with the following applicable work practice standards, emission reduction measures, and management practices:

If your boiler is in this subcategory . . .	You must meet the following . . .
1. Existing or new coal-fired, new biomass-fired, or new oil-fired boilers (units with heat input capacity of 10 MMBtu/hr or greater)	Minimize the boiler's startup and shutdown periods and conduct startups and shutdowns according to the manufacturer's recommended procedures. If manufacturer's recommended procedures are not available, you must follow recommended procedures for a unit of similar design for which manufacturer's recommended procedures are available.
2. Existing coal-fired boilers with heat input capacity of less than 10 MMBtu/hr that do not meet the definition of limited-use boiler, or use an oxygen trim system that maintains an optimum air-to-fuel ratio	Conduct an initial tune-up as specified in § 63.11214, and conduct a tune-up of the boiler biennially as specified in § 63.11223.
3. New coal-fired boilers with heat input capacity of less than 10 MMBtu/hr that do not meet the definition of limited-use boiler, or use an oxygen trim system that maintains an optimum air-to-fuel ratio	Conduct a tune-up of the boiler biennially as specified in § 63.11223.
4. Existing oil-fired boilers with heat input capacity greater than 5 MMBtu/hr that do not meet the definition of seasonal boiler or limited-use boiler, or use an oxygen trim system that maintains an optimum air-to-fuel ratio	Conduct an initial tune-up as specified in § 63.11214, and conduct a tune-up of the boiler biennially as specified in § 63.11223.

If your boiler is in this subcategory . . .	You must meet the following . . .
5. New oil-fired boilers with heat input capacity greater than 5 MMBtu/hr that do not meet the definition of seasonal boiler or limited-use boiler, or use an oxygen trim system that maintains an optimum air-to-fuel ratio	Conduct a tune-up of the boiler biennially as specified in § 63.11223.
6. Existing biomass-fired boilers that do not meet the definition of seasonal boiler or limited-use boiler, or use an oxygen trim system that maintains an optimum air-to-fuel ratio	Conduct an initial tune-up as specified in § 63.11214, and conduct a tune-up of the boiler biennially as specified in § 63.11223.
7. New biomass-fired boilers that do not meet the definition of seasonal boiler or limited-use boiler, or use an oxygen trim system that maintains an optimum air-to-fuel ratio	Conduct a tune-up of the boiler biennially as specified in § 63.11223.
8. Existing seasonal boilers	Conduct an initial tune-up as specified in § 63.11214, and conduct a tune-up of the boiler every 5 years as specified in § 63.11223.
9. New seasonal boilers	Conduct a tune-up of the boiler every 5 years as specified in § 63.11223.
10. Existing limited-use boilers	Conduct an initial tune-up as specified in § 63.11214, and conduct a tune-up of the boiler every 5 years as specified in § 63.11223.
11. New limited-use boilers	Conduct a tune-up of the boiler every 5 years as specified in § 63.11223.
12. Existing oil-fired boilers with heat input capacity of equal to or less than 5 MMBtu/hr	Conduct an initial tune-up as specified in § 63.11214, and conduct a tune-up of the boiler every 5 years as specified in § 63.11223.
13. New oil-fired boilers with heat input capacity of equal to or less than 5 MMBtu/hr	Conduct a tune-up of the boiler every 5 years as specified in § 63.11223.
14. Existing coal-fired, biomass-fired, or oil-fired boilers with an oxygen trim system that maintains an optimum air-to-fuel ratio that would otherwise be subject to a biennial tune-up	Conduct an initial tune-up as specified in § 63.11214, and conduct a tune-up of the boiler every 5 years as specified in § 63.11223.
15. New coal-fired, biomass-fired, or oil-fired boilers with an oxygen trim system that maintains an optimum air-to-fuel ratio that would otherwise be subject to a biennial tune-up	Conduct a tune-up of the boiler every 5 years as specified in § 63.11223.
16. Existing coal-fired, biomass-fired, or oil-fired boilers (units with heat input capacity of 10 MMBtu/hr and greater), not including limited-use boilers	<p>Must have a one-time energy assessment performed by a qualified energy assessor. An energy assessment completed on or after January 1, 2008, that meets or is amended to meet the energy assessment requirements in this table satisfies the energy assessment requirement. Energy assessor approval and qualification requirements are waived in instances where past or amended energy assessments are used to meet the energy assessment requirements. A facility that operates under an energy management program compatible with ISO 50001 that includes the affected units also satisfies the energy assessment requirement. The energy assessment must include the following with extent of the evaluation for items (1) to (4) appropriate for the on-site technical hours listed in § 63.11237:</p>
	(1) A visual inspection of the boiler system,
	(2) An evaluation of operating characteristics of the affected boiler systems, specifications of energy use systems, operating and maintenance procedures, and unusual operating constraints,

If your boiler is in this subcategory . . .	You must meet the following . . .
	(3) An inventory of major energy use systems consuming energy from affected boiler(s) and which are under control of the boiler owner or operator,
	(4) A review of available architectural and engineering plans, facility operation and maintenance procedures and logs, and fuel usage,
	(5) A list of major energy conservation measures that are within the facility's control,
	(6) A list of the energy savings potential of the energy conservation measures identified, and
	(7) A comprehensive report detailing the ways to improve efficiency, the cost of specific improvements, benefits, and the time frame for recouping those investments.

[78 FR 7518, Feb. 1, 2013]

**Table 3 to Subpart JJJJJJ of Part 63—Operating Limits for Boilers With Emission Limits**

As stated in § 63.11201, you must comply with the applicable operating limits:

If you demonstrate compliance with applicable emission limits using . . .	You must meet these operating limits except during periods of startup and shutdown . . .
1. Fabric filter control	a. Maintain opacity to less than or equal to 10 percent opacity (daily block average); OR b. Install and operate a bag leak detection system according to § 63.11224 and operate the fabric filter such that the bag leak detection system alarm does not sound more than 5 percent of the operating time during each 6-month period.
2. Electrostatic precipitator control	a. Maintain opacity to less than or equal to 10 percent opacity (daily block average); OR b. Maintain the 30-day rolling average total secondary electric power of the electrostatic precipitator at or above the minimum total secondary electric power as defined in § 63.11237.
3. Wet scrubber control	Maintain the 30-day rolling average pressure drop across the wet scrubber at or above the minimum scrubber pressure drop as defined in § 63.11237 and the 30-day rolling average liquid flow rate at or above the minimum scrubber liquid flow rate as defined in § 63.11237.
4. Dry sorbent or activated carbon injection control	Maintain the 30-day rolling average sorbent or activated carbon injection rate at or above the minimum sorbent injection rate or minimum activated carbon injection rate as defined in § 63.11237. When your boiler operates at lower loads, multiply your sorbent or activated carbon injection rate by the load fraction (e.g., actual heat input divided by the heat input during the performance stack test; for 50 percent load, multiply the injection rate operating limit by 0.5).
5. Any other add-on air pollution control type.	This option is for boilers that operate dry control systems. Boilers must maintain opacity to less than or equal to 10 percent opacity (daily block average).
6. Fuel analysis	Maintain the fuel type or fuel mixture (annual average) such that the mercury emission rate calculated according to § 63.11211(c) are less than the applicable emission limit for mercury.
7. Performance stack testing	For boilers that demonstrate compliance with a performance stack test, maintain the operating load of each unit such that it does not exceed 110 percent of the average operating load recorded during the most recent performance stack test.
8. Oxygen analyzer system	For boilers subject to a CO emission limit that demonstrate compliance with an oxygen analyzer system as specified in § 63.11224(a), maintain the 30-day rolling average oxygen level at or above the minimum oxygen level as defined in § 63.11237. This requirement does not apply to units that install an oxygen trim system since these units will set the trim system to the level specified in § 63.11224(a)(7).

[78 FR 7519, Feb. 1, 2013]

**Table 4 to Subpart JJJJJ of Part 63—Performance (Stack) Testing Requirements**

As stated in § 63.11212, you must comply with the following requirements for performance (stack) test for affected sources:

<b>To conduct a performance test for the following pollutant. . .</b>	<b>You must. . .</b>	<b>Using. . .</b>
1. Particulate Matter	a. Select sampling ports location and the number of traverse points	Method 1 in appendix A-1 to part 60 of this chapter.
	b. Determine velocity and volumetric flow-rate of the stack gas	Method 2, 2F, or 2G in appendix A-2 to part 60 of this chapter.
	c. Determine oxygen and carbon dioxide concentrations of the stack gas	Method 3A or 3B in appendix A-2 to part 60 of this chapter, or ASTM D6522-00 (Reapproved 2005), <sup>a</sup> or ANSI/ASME PTC 19.10-1981. <sup>a</sup>
	d. Measure the moisture content of the stack gas	Method 4 in appendix A-3 to part 60 of this chapter.
	e. Measure the particulate matter emission concentration	Method 5 or 17 (positive pressure fabric filters must use Method 5D) in appendix A-3 and A-6 to part 60 of this chapter and a minimum 1 dscm of sample volume per run.
	f. Convert emissions concentration to lb/MMBtu emission rates	Method 19 F-factor methodology in appendix A-7 to part 60 of this chapter.
2. Mercury	a. Select sampling ports location and the number of traverse points	Method 1 in appendix A-1 to part 60 of this chapter.
	b. Determine velocity and volumetric flow-rate of the stack gas	Method 2, 2F, or 2G in appendix A-2 to part 60 of this chapter.
	c. Determine oxygen and carbon dioxide concentrations of the stack gas	Method 3A or 3B in appendix A-2 to part 60 of this chapter, or ASTM D6522-00 (Reapproved 2005), <sup>a</sup> or ANSI/ASME PTC 19.10-1981. <sup>a</sup>
	d. Measure the moisture content of the stack gas	Method 4 in appendix A-3 to part 60 of this chapter.
	e. Measure the mercury emission concentration	Method 29, 30A, or 30B in appendix A-8 to part 60 of this chapter or Method 101A in appendix B to part 61 of this chapter or ASTM Method D6784-02. <sup>a</sup> Collect a minimum 2 dscm of sample volume with Method 29 of 101A per run. Use a minimum run time of 2 hours with Method 30A.
	f. Convert emissions concentration to lb/MMBtu emission rates	Method 19 F-factor methodology in appendix A-7 to part 60 of this chapter.
3. Carbon Monoxide	a. Select the sampling ports location and the number of traverse points	Method 1 in appendix A-1 to part 60 of this chapter.
	b. Determine oxygen and carbon dioxide concentrations of the stack gas	Method 3A or 3B in appendix A-2 to part 60 of this chapter, or ASTM D6522-00 (Reapproved 2005), <sup>a</sup> or ANSI/ASME PTC 19.10-1981. <sup>a</sup>

<b>To conduct a performance test for the following pollutant. . .</b>	<b>You must. . .</b>	<b>Using. . .</b>
	c. Measure the moisture content of the stack gas	Method 4 in appendix A-3 to part 60 of this chapter.
	d. Measure the carbon monoxide emission concentration	Method 10, 10A, or 10B in appendix A-4 to part 60 of this chapter or ASTM D6522-00 (Reapproved 2005) <sup>a</sup> and a minimum 1 hour sampling time per run.

<sup>a</sup> Incorporated by reference, see § 63.14.

**Table 5 to Subpart JJJJJJ of Part 63—Fuel Analysis Requirements**

As stated in § 63.11213, you must comply with the following requirements for fuel analysis testing for affected sources:

<b>To conduct a fuel analysis for the following pollutant . . .</b>	<b>You must. . .</b>	<b>Using . . .</b>
1. Mercury	a. Collect fuel samples	Procedure in § 63.11213(b) or ASTM D2234/D2234M <sup>a</sup> (for coal) or ASTM D6323 <sup>a</sup> (for biomass) or equivalent.
	b. Compose fuel samples	Procedure in § 63.11213(b) or equivalent.
	c. Prepare composited fuel samples	EPA SW-846-3050B <sup>a</sup> (for solid samples) or EPA SW-846-3020A <sup>a</sup> (for liquid samples) or ASTM D2013/D2013M <sup>a</sup> (for coal) or ASTM D5198 <sup>a</sup> (for biomass) or equivalent.
	d. Determine heat content of the fuel type	ASTM D5865 <sup>a</sup> (for coal) or ASTM E711 <sup>a</sup> (for biomass) or equivalent.
	e. Determine moisture content of the fuel type	ASTM D3173 <sup>a</sup> or ASTM E871 <sup>a</sup> or equivalent.
	f. Measure mercury concentration in fuel sample	ASTM D6722 <sup>a</sup> (for coal) or EPA SW-846-7471B <sup>a</sup> (for solid samples) or EPA SW-846-7470A <sup>a</sup> (for liquid samples) or equivalent.
	g. Convert concentrations into units of lb/MMBtu of heat content	

<sup>a</sup> Incorporated by reference, see § 63.14.

**Table 6 to Subpart JJJJJJ of Part 63—Establishing Operating Limits**

As stated in § 63.11211, you must comply with the following requirements for establishing operating limits:

If you have an applicable emission limit for . . .	And your operating limits are based on . . .	You must . . .	Using . . .	According to the following requirements
1. PM or mercury	a. Wet scrubber operating parameters	Establish site-specific minimum scrubber pressure drop and minimum scrubber liquid flow rate operating limits according to § 63.11211(b)	Data from the pressure drop and liquid flow rate monitors and the PM or mercury performance stack tests	(a) You must collect pressure drop and liquid flow rate data every 15 minutes during the entire period of the performance stack tests;
				(b) Determine the average pressure drop and liquid flow rate for each individual test run in the three-run performance stack test by computing the average of all the 15-minute readings taken during each test run.
	b. Electrostatic precipitator operating parameters	Establish a site-specific minimum total secondary electric power operating limit according to § 63.11211(b)	Data from the secondary electric power monitors and the PM or mercury performance stack tests	(a) You must collect secondary electric power data every 15 minutes during the entire period of the performance stack tests;
				(b) Determine the average total secondary electric power for each individual test run in the three-run performance stack test by computing the average of all the 15-minute readings taken during each test run.
2. Mercury	Dry sorbent or activated carbon injection rate operating parameters	Establish a site-specific minimum sorbent or activated carbon injection rate operating limit according to § 63.11211(b)	Data from the sorbent or activated carbon injection rate monitors and the mercury performance stack tests	(a) You must collect sorbent or activated carbon injection rate data every 15 minutes during the entire period of the performance stack tests;
				(b) Determine the average sorbent or activated carbon injection rate for each individual test run in the three-run performance stack test by computing the average of all the 15-minute readings taken during each test run.

If you have an applicable emission limit for . . .	And your operating limits are based on . . .	You must . . .	Using . . .	According to the following requirements
				(c) When your unit operates at lower loads, multiply your sorbent or activated carbon injection rate by the load fraction (e.g., actual heat input divided by heat input during performance stack test, for 50 percent load, multiply the injection rate operating limit by 0.5) to determine the required injection rate.
3. CO	Oxygen	Establish a unit-specific limit for minimum oxygen level	Data from the oxygen analyzer system specified in § 63.11224(a)	(a) You must collect oxygen data every 15 minutes during the entire period of the performance stack tests;
				(b) Determine the average hourly oxygen concentration for each individual test run in the three-run performance stack test by computing the average of all the 15-minute readings taken during each test run.
4. Any pollutant for which compliance is demonstrated by a performance stack test	Boiler operating load	Establish a unit-specific limit for maximum operating load according to § 63.11212(c)	Data from the operating load monitors (fuel feed monitors or steam generation monitors)	(a) You must collect operating load data (fuel feed rate or steam generation data) every 15 minutes during the entire period of the performance test.
				(b) Determine the average operating load by computing the hourly averages using all of the 15-minute readings taken during each performance test.
				(c) Determine the average of the three test run averages during the performance test, and multiply this by 1.1 (110 percent) as your operating limit.

[78 FR 7520, Feb. 1, 2013]

**Table 7 to Subpart JJJJJ of Part 63—Demonstrating Continuous Compliance**

As stated in § 63.11222, you must show continuous compliance with the emission limitations for affected sources according to the following:

If you must meet the following operating limits . . .	You must demonstrate continuous compliance by . . .
1. Opacity	a. Collecting the opacity monitoring system data according to § 63.11224(e) and § 63.11221; and
	b. Reducing the opacity monitoring data to 6-minute averages; and
	c. Maintaining opacity to less than or equal to 10 percent (daily block average).

<b>If you must meet the following operating limits . . .</b>	<b>You must demonstrate continuous compliance by . . .</b>
2. Fabric Filter Bag Leak Detection Operation	Installing and operating a bag leak detection system according to § 63.11224(f) and operating the fabric filter such that the requirements in § 63.11222(a)(4) are met.
3. Wet Scrubber Pressure Drop and Liquid Flow Rate	a. Collecting the pressure drop and liquid flow rate monitoring system data according to §§ 63.11224 and 63.11221; and
	b. Reducing the data to 30-day rolling averages; and
	c. Maintaining the 30-day rolling average pressure drop and liquid flow rate at or above the minimum pressure drop and minimum liquid flow rate according to § 63.11211.
4. Dry Scrubber Sorbent or Activated Carbon Injection Rate	a. Collecting the sorbent or activated carbon injection rate monitoring system data for the dry scrubber according to §§ 63.11224 and 63.11221; and
	b. Reducing the data to 30-day rolling averages; and
	c. Maintaining the 30-day rolling average sorbent or activated carbon injection rate at or above the minimum sorbent or activated carbon injection rate according to § 63.11211.
5. Electrostatic Precipitator Total Secondary Electric Power	a. Collecting the total secondary electric power monitoring system data for the electrostatic precipitator according to §§ 63.11224 and 63.11221; and
	b. Reducing the data to 30-day rolling averages; and
	c. Maintaining the 30-day rolling average total secondary electric power at or above the minimum total secondary electric power according to § 63.11211.
6. Fuel Pollutant Content	a. Only burning the fuel types and fuel mixtures used to demonstrate compliance with the applicable emission limit according to § 63.11213 as applicable; and
	b. Keeping monthly records of fuel use according to §§ 63.11222(a)(2) and 63.11225(b)(4).
7. Oxygen content	a. Continuously monitoring the oxygen content of flue gas according to § 63.11224 (This requirement does not apply to units that install an oxygen trim system since these units will set the trim system to the level specified in § 63.11224(a)(7)); and
	b. Reducing the data to 30-day rolling averages; and
	c. Maintaining the 30-day rolling average oxygen content at or above the minimum oxygen level established during the most recent CO performance test.
8. CO emissions	a. Continuously monitoring the CO concentration in the combustion exhaust according to §§ 63.11224 and 63.11221; and
	b. Correcting the data to 3 percent oxygen, and reducing the data to 1-hour averages; and
	c. Reducing the data from the hourly averages to 10-day rolling averages; and
	d. Maintaining the 10-day rolling average CO concentration at or below the applicable emission limit in Table 1 to this subpart.
9. Boiler operating load	a. Collecting operating load data (fuel feed rate or steam generation data) every 15 minutes; and
	b. Reducing the data to 30-day rolling averages; and
	c. Maintaining the 30-day rolling average at or below the operating limit established during the performance test according to § 63.11212(c) and Table 6 to this subpart.

**Table 8 to Subpart JJJJJJ of Part 63—Applicability of General Provisions to Subpart JJJJJJ**

As stated in § 63.11235, you must comply with the applicable General Provisions according to the following:

General provisions cite	Subject	Does it apply?
§ 63.1	Applicability	Yes.
§ 63.2	Definitions	Yes. Additional terms defined in § 63.11237.
§ 63.3	Units and Abbreviations	Yes.
§ 63.4	Prohibited Activities and Circumvention	Yes.
§ 63.5	Preconstruction Review and Notification Requirements	No
§ 63.6(a), (b)(1)-(b)(5), (b)(7), (c), (f)(2)-(3), (g), (i), (j)	Compliance with Standards and Maintenance Requirements	Yes.
§ 63.6(e)(1)(i)	General Duty to minimize emissions	No. See § 63.11205 for general duty requirement.
§ 63.6(e)(1)(ii)	Requirement to correct malfunctions ASAP	No.
§ 63.6(e)(3)	SSM Plan	No.
§ 63.6(f)(1)	SSM exemption	No.
§ 63.6(h)(1)	SSM exemption	No.
§ 63.6(h)(2) to (9)	Determining compliance with opacity emission standards	Yes.
§ 63.7(a), (b), (c), (d), (e)(2)-(e)(9), (f), (g), and (h)	Performance Testing Requirements	Yes.
§ 63.7(e)(1)	Performance testing	No. See § 63.11210.
§ 63.8(a), (b), (c)(1), (c)(1)(ii), (c)(2) to (c)(9), (d)(1) and (d)(2), (e), (f), and (g)	Monitoring Requirements	Yes.
§ 63.8(c)(1)(i)	General duty to minimize emissions and CMS operation	No.
§ 63.8(c)(1)(iii)	Requirement to develop SSM Plan for CMS	No.
§ 63.8(d)(3)	Written procedures for CMS	Yes, except for the last sentence, which refers to an SSM plan. SSM plans are not required.
§ 63.9	Notification Requirements	Yes, excluding the information required in § 63.9(h)(2)(i)(B), (D), (E) and (F). See § 63.11225.
§ 63.10(a) and (b)(1)	Recordkeeping and Reporting Requirements	Yes.
§ 63.10(b)(2)(i)	Recordkeeping of occurrence and duration of startups or shutdowns	No.
§ 63.10(b)(2)(ii)	Recordkeeping of malfunctions	No. See § 63.11225 for recordkeeping of (1) occurrence and duration and (2) actions taken during malfunctions.
§ 63.10(b)(2)(iii)	Maintenance records	Yes.
§ 63.10(b)(2)(iv) and (v)	Actions taken to minimize emissions during SSM	No.
§ 63.10(b)(2)(vi)	Recordkeeping for CMS malfunctions	Yes.

General provisions cite	Subject	Does it apply?
§ 63.10(b)(2)(vii) to (xiv)	Other CMS requirements	Yes.
§ 63.10(b)(3)	Recordkeeping requirements for applicability determinations	No.
§ 63.10(c)(1) to (9)	Recordkeeping for sources with CMS	Yes.
§ 63.10(c)(10)	Recording nature and cause of malfunctions	No. See § 63.11225 for malfunction recordkeeping requirements.
§ 63.10(c)(11)	Recording corrective actions	No. See § 63.11225 for malfunction recordkeeping requirements.
§ 63.10(c)(12) and (13)	Recordkeeping for sources with CMS	Yes.
§ 63.10(c)(15)	Allows use of SSM plan	No.
§ 63.10(d)(1) and (2)	General reporting requirements	Yes.
§ 63.10(d)(3)	Reporting opacity or visible emission observation results	No.
§ 63.10(d)(4)	Progress reports under an extension of compliance	Yes.
§ 63.10(d)(5)	SSM reports	No. See § 63.11225 for malfunction reporting requirements.
§ 63.10(e)	Additional reporting requirements for sources with CMS	Yes.
§ 63.10(f)	Waiver of recordkeeping or reporting requirements	Yes.
§ 63.11	Control Device Requirements	No.
§ 63.12	State Authority and Delegation	Yes.
§ 63.13-63.16	Addresses, Incorporation by Reference, Availability of Information, Performance Track Provisions	Yes.
§ 63.1(a)(5), (a)(7)-(a)(9), (b)(2), (c)(3)-(4), (d), 63.6(b)(6), (c)(3), (c)(4), (d), (e)(2), (e)(3)(ii), (h)(3), (h)(5)(iv), 63.8(a)(3), 63.9(b)(3), (h)(4), 63.10(c)(2)-(4), (c)(9)	Reserved	No.

[76 FR 15591, Mar. 21, 2011, as amended at 78 FR 7521, Feb. 1, 2013]

**Indiana Department of Environmental Management  
Office of Air Quality**

Addendum to the Technical Support Document (ATSD) for a  
Significant Source Modification and Significant Permit Modification

**Source Background and Description**

<b>Source Name:</b>	Griffin Industries LLC
<b>Source Location:</b>	7358 South Griffin Road, Newberry, Indiana, 47449
<b>County:</b>	Greene
<b>SIC Code:</b>	2077 (Animal and Marine Fats and Oils)
<b>Operation Permit No.:</b>	T055-32418-00008
<b>Operation Permit Issuance Date:</b>	October 16, 2013
<b>Significant Source Modification No.:</b>	055-34253-00008
<b>Significant Permit Modification No.:</b>	055-34320-00008
<b>Permit Reviewer:</b>	Nida Habeeb

On July 11, 2014 the Office of Air Quality (OAQ) had a notice published in The Greene County Daily World, Linton, Indiana, stating that Griffin Industries LLC had applied for a Significant Source Modification and a Significant Permit Modification to their Part 70 Operating Permit relating to a modification of the blood meal making process, consisting of the replacement of natural gas-fired Blood Dryer 04 with a steam generated Dupps Dryer, the replacement of the existing blood dryer scrubber with a packed bed scrubber, and the addition of an in-room air scrubber. The notice also stated that the OAQ proposed to issue a Significant Source Modification and a Significant Permit Modification for this operation and provided information on how the public could review the proposed permit and other documentation. Finally, the notice informed interested parties that there was a period of thirty (30) days to provide comments on whether or not this permit should be issued as proposed.

**Comments and Responses**

On August 11, 2014 Griffin Industries LLC submitted comments to IDEM, OAQ on the draft Significant Source Modification and Significant Permit Modification.

The Technical Support Document (TSD) is used by IDEM, OAQ for historical purposes. IDEM, OAQ does not make any changes to the original TSD, but the Permit will have the updated changes. The comments and revised permit language are provided below with deleted language as ~~strikeouts~~ and new language **bolded**.

**Comment 1:**

The source has requested that the wet scrubber pressure drop ranges in Condition D.1.14(a) be changed to the following:

- |                                       |  |
|---------------------------------------|--|
| • Meat plant Venturi Scrubber:        | 0.2 inches of water to 6.0 inches of water |
| • Meat plant packed bed scrubber:     | 0.1 inches of water to 6.0 inches of water |
| • Meat plant in-room air scrubber:    | 0.2 inches of water to 6.0 inches of water |
| • Feather plant Venturi Scrubber:     | 0.2 inches of water to 6.0 inches of water |
| • Feather plant packed bed scrubber:  | 0.2 inches of water to 6.0 inches of water |
| • Feather plant in-room air scrubber: | 0.2 inches of water to 6.0 inches of water |
| • Blood centrifuge Venturi scrubber:  | 0.1 inches of water to 6.0 inches of water |
| • Packed bed scrubber (1C):           | 0.2 inches of water to 6.0 inches of water |

**Response to Comment 1:**

IDEM agrees with the recommended changes. The permit has been revised as follows:

\*\*\*

**D.1.14 Scrubber Monitoring Requirements**

- (a) The Permittee shall monitor and record the pressure drop of all the scrubbers listed in this section, at least once per day when one or more of the associated emission units to these scrubbers is in operation. When for any one reading, the pressure drop across the scrubber is outside the normal range, the Permittee shall take a reasonable response. The normal ranges for **each of these units is shown in the table below**, ~~a pressure drop between two (2.0) and eight (8.0) inches of water~~ unless a different upper-bound or lower-bound value for this range is determined during the latest stack test. Section C - Response to Excursions or Exceedances contains the Permittee's obligation with regard to the reasonable response steps required by this condition. A pressure reading that is outside the above mentioned range is not a deviation from this permit. Failure to take response steps shall be considered a deviation from this permit.

Scrubber	Pressure Drop Range (inches of water)
Meat Plant Venturi Scrubber (Venturi 3A)	0.2 to 6.0
Meat Plant Packed Bed Scrubber (Packed 3A)	0.1 to 6.0
Meat Plant In-Room Air Scrubber (Room32A)	0.2 to 6.0
Feather Plant Venturi Scrubber (Venturi10B)	0.2 to 6.0
Feather Plant Packed Bed Scrubber (Packed 10B)	0.2 to 6.0
In-Room Air Scrubber (Room 32B)	0.2 to 6.0
Blood Centrifuge Venturi Scrubber (Venturi1C)	0.1 to 6.0
Packed Bed Scrubber (Packed 1C)	0.2 to 6.0

\*\*\*

**Comment 2:**

The source has requested the scrubber liquid flow rates in Condition D.1.14(b) be changed to the following:

- Meat plant Venturi Scrubber: change from 5 gpm to 4 gpm.
- Meat plant packed bed scrubber: change from 100 gpm to 85 gpm
- Meat plant in-room air scrubber: change from 400 gpm to 350 gpm
- Feather plant Venturi Scrubber: change from 5 gpm to 4 gpm.
- Feather plant packed bed scrubber: change from 100 gpm to 85 gpm
- Feather plant in-room air scrubber: change from 400 gpm to 350 gpm
- Blood centrifuge Venturi scrubber: change from 5 gpm to 4 gpm

**Response to Comment 2:**

IDEM agrees with the recommended changes. The permit has been revised as follows:

\*\*\*

**D.1.14 Scrubber Monitoring Requirements**

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- (b) The Permittee shall monitor and record the flow rate of all the scrubbers listed in this section at least once per day when one or more of the associated emission units to these scrubbers is in operation. When for any one reading, the flow rate of the scrubber is less than the flow rate specified below, or a minimum established during the latest stack test, the Permittee shall take reasonable response steps. A flow rate that is less than the flow rate specified below or a minimum flow rate established during the latest stack test. Section C - Response to Excursions or Exceedances contains the Permittee's obligation with regard to the reasonable response steps required by this condition. Failure to take response steps shall be considered a deviation from this permit.

Scrubber	Minimum Flow Rate in G (gallons per minute)
Meat Plant Venturi Scrubber (Venturi 3A)	<del>5</del> 4
Meat Plant Packed Bed Scrubber (Packed 3A)	400 85
Meat Plant In-Room Air Scrubber (Room32A)	400 350
Feather Plant Venturi Scrubber (Venturi10B)	<del>5</del> 4
Feather Plant Packed Bed Scrubber (Packed 10B)	400 85
In-Room Air Scrubber (Room 32B)	400 350
Blood Centrifuge Venturi Scrubber (Venturi1C)	<del>5</del> 4
Packed Bed Scrubber (Packed 1C)	110

\*\*\*

On August 22, 2014 Griffin Industries LLC submitted additional comments to IDEM, OAQ on the proposed Significant Permit Modification.

**Comment 3:**

The source has requested that all references to the Blood Dryer 04 be removed throughout the permit, since this unit has been removed. Additionally, the source requested a typographical error be corrected regarding the permit number in the Part 70 Quarterly Report Form.

**Response to Comment 3:**

IDEM agrees with the recommended changes. The permit has been revised as follows:

\*\*\*

**A.2 Emission Units and Pollution Control Equipment Summary**  
[326 IAC 2-7-4(c)(3)][326 IAC 2-7-5(14)]

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This stationary source consists of the following emission units and pollution control devices:

- (a1) ~~Blood meal making process, constructed in 1968 (except Blood Dryer 04, constructed in 1994), with a maximum production rate of 1.1 ton of blood meal per hour, controlled by a series of 2 scrubbers with sequence as Blood Centrifuge Venturi Scrubber (Venturi1C), and Blood Dryer Scrubber (Spray13C), exhausting to Stack BDS-3 and consisting of the following:~~

- ~~(I) Blood receiving~~
- ~~(II) Coagulator~~

- (III) — Centrifuge
- (IV) — ~~One (1) natural gas-fired blood dryer, identified as Blood Dryer 04, constructed in 1994, with a heat input capacity of 20 million Btu per hour, using No. 2 fuel oil as a backup fuel, two (2) cyclone centrifugal separators, and exhausting to Stack D.~~
- (V) — Screen
- (VI) — Storage

\*\*\*

## SECTION D.1 EMISSION UNIT OPERATION CONDITIONS

Facility Description [326 IAC 2-7-5(15)]

\*\*\*

(a1) — ~~Blood meal making process, constructed in 1968 (except Dupps dryer, approved in 2014 for construction), with a maximum production rate of 1.0 ton of blood meal per hour, controlled by a series of 3 scrubbers with sequence as Blood Centrifuge Venturi Scrubber (Venturi1C), Packed Bed Scrubber (Packed 1C) and In-Room Air Scrubber (Room 32B), exhausting to Stack RAS-2 and consisting of the following:~~

- (I) — Blood receiving
- (II) — Coagulator
- (III) — Centrifuge
- (IV) — ~~One (1) steam heated dryer, identified as Dupps dryer, approved in 2014 for construction, with a maximum production rate of 1.0 ton of blood meal per hour and exhausting to Stack RAS-2.~~
- (V) — Screen
- (VI) — Storage

\*\*\*

### Emission Limitations and Standards [326 IAC 2-7-5(1)]

#### D.1.1 Sulfur Dioxide (SO<sub>2</sub>) [326 IAC 7-1.1-2]

Pursuant to 326 IAC 7-1.2 (SO<sub>2</sub> Emissions Limitations), the SO<sub>2</sub> emissions from ~~Blood Dryer 04~~, boiler 05, boiler 06, boiler 07 and boiler 08 shall each not exceed five-tenths (0.5) pounds per MMBtu heat input when combusting No. 2 fuel oil.

Pursuant to 326 IAC 7-2-1, compliance shall be demonstrated on a calendar month average.

#### D.1.2 PSD Minor Limit - SO<sub>2</sub> [326 IAC 2-2]

- (a) The combined SO<sub>2</sub> emissions from combusting natural gas, No. 2 fuel oil, waste oil and processed grease in ~~Blood Dryer 04~~ and boilers 05, 06, 07 and 08, shall not exceed 249 tons per twelve (12) consecutive month period, with compliance determined at the end of each month.
- (b) The sulfur content of the no. 2 fuel oil usage at the boilers and ~~Blood Dryer~~ shall not exceed 0.5% based on a calendar month average.

Compliance with these limits shall limit the source-wide SO<sub>2</sub> emissions to less than 250 tons per 12 consecutive month period and renders 326 IAC 2-2, not applicable.

\*\*\*

D.1.4 PSD Minor Limit - CO<sub>2</sub>e [326 IAC 2-2]

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The combined CO<sub>2</sub>e emissions from combusting natural gas, No. 2 fuel oil, waste oil and processed grease in ~~Blood Dryer 04~~ and boilers 05, 06, 07 and 08, shall not exceed 99,999 tons per twelve (12) consecutive month period, with compliance determined at the end of each month.

Compliance with this limit will render this source minor under 326 IAC 2-2 (Prevention of Significant Deterioration (PSD)).

\*\*\*

D.1.7 VOC [326 IAC 8-1-6]

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~~(a) In order to render 326 IAC 8-1-6 not applicable, the uncontrolled VOC emissions from the Dupps dryer shall not exceed 5.68 pound per hour.~~

Compliance with this limit will limit the uncontrolled VOC emissions from the Dupps dryer to less than 25 tons per year, and renders the requirements of 326 IAC 8-1-6 not applicable to the Dupps dryer.

~~(b) In order to render 326 IAC 8-1-6 not applicable, the uncontrolled VOC emissions from the Blood Dryer 04 shall not exceed 5.68 pound per hour.~~

Compliance with this limit will limit the uncontrolled VOC emissions from Blood Dryer 04 to less than 25 tons per year, and renders the requirements of 326 IAC 8-1-6 not applicable to Blood Dryer 04.

\*\*\*

Compliance Determination Requirements

D.1.9 Testing Requirements [326 IAC 2-7-6(1),(6)] [326 IAC 2-1.1-11]

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~~(c) In order to determine the compliance with Condition D.1.7(b), the Permittee shall verify uncontrolled VOC emissions rate by conducting performance test for Blood Dryer 04, using methods as approved by the Commissioner. This test shall be performed no later than one hundred eighty (180) days after the issuance of Part 70 Renewal No. T055-32418-00008.~~

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D.1.10 Particulate Control

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~~(a1) Until replacement of the Blood Dryer 04 with the Dupps Dryer, and in order to comply with Conditions D.1.3 and D.1.6, the Blood Centrifuge Venturi Scrubber (Venturi1C) and Blood Dryer Scrubber (Spray13C) for particulate control shall be in operation and control emissions from the Blood Meal making process at all times the Blood Meal making process is in operation.~~

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Compliance Monitoring Requirements [326 IAC 2-7-5(1)][326 IAC 2-7-6(1)]

D.1.13 Visible Emissions Notations

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~~(a1) Until replacement of the Blood Dryer 04 with the Dupps Dryer, daily visible emission notations of the exhaust from the Stack BDS-3 shall be performed during normal daylight operations when exhausting to the atmosphere. A trained employee shall record whether emissions are normal or abnormal.~~

\*\*\*

Record Keeping and Reporting Requirements [326 IAC 2-7-5(3)] [326 IAC 2-7-19]

D.1.16 Record Keeping Requirements

(a) To document the compliance status of Conditions D.1.1, D.1.2 and D.1.4, the Permittee shall maintain records for ~~Blood Dryer 04~~, boilers 05, 06, 07 and 08 in accordance with (1) through (3) below. Records maintained for (1) through (3) shall be taken monthly and shall be complete and sufficient to establish compliance with the Conditions D.1.1, D.1.2 and D.1.4.

- (1) Calendar dates covered in the compliance determination period;
- (2) The actual No. 2 fuel oil usage, natural gas usage, actual processed grease usage, and actual waste/on spec used oil usage at all boilers and ~~Blood Dryer~~; and

\*\*\*

~~(b1) To document the compliance status with Condition D.1.13(a1), the Permittee shall maintain records of daily visible emission notations of the exhaust from Stack BDS3. The Permittee shall include in its daily record when a visible emission notation is not taken and the reason for the lack of visible emission notation (e.g. the process did not operate that day).~~

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INDIANA DEPARTMENT OF ENVIRONMENTAL MANAGEMENT  
OFFICE OF AIR QUALITY  
COMPLIANCE AND ENFORCEMENT BRANCH

Part 70 Quarterly Report

Source Name: Griffin Industries LLC  
Source Address: 7358 South Griffin Road, Newberry, Indiana, 47449  
Part 70 Permit No.: T055-324198-00008  
Facility: ~~Blood Dryer 04 and b~~Boilers 05, 06, 07 and 08  
Parameter: SO2 emissions  
Limit: 249 and 99,999 tons per twelve (12) consecutive month period for SO2 and CO2e, respectively

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**IDEM Contact**

- (a) Questions regarding this proposed Significant Source Modification and Significant Permit Modification can be directed to Nida Habeeb at the Indiana Department Environmental Management, Office of Air Quality, Permits Branch, 100 North Senate Avenue, MC 61-53 IGCN 1003, Indianapolis, Indiana 46204-2251 or by telephone at (317) 234-8531 or toll free at 1-800-451-6027 extension 4-8531.
- (b) A copy of the permit is available on the Internet at: <http://www.in.gov/ai/appfiles/idem-caats/>
- (c) For additional information about air permits and how the public and interested parties can participate, refer to the IDEM Permit Guide on the Internet at: <http://www.in.gov/idem/5881.htm>; and the Citizens' Guide to IDEM on the Internet at: <http://www.in.gov/idem/6900.htm>.

**Indiana Department of Environmental Management  
Office of Air Quality**

**Technical Support Document (TSD) for a Part 70 Significant Source  
Modification and Significant Permit Modification**

**Source Description and Location**

Source Name:	Griffin Industries LLC
Source Location:	7358 South Griffin Road, Newberry, Indiana, 47449
County:	Greene
SIC Code:	2077 (Animal and Marine Fats and Oils)
Operation Permit No.:	T055-32418-00008
Operation Permit Issuance Date:	October 16, 2013
Significant Permit Modification No.:	055-34320-00008
Significant Source Modification No.:	055-34253-00008
Permit Reviewer:	Nida Habeeb

**Existing Approvals**

The source was issued Part 70 Operating Permit No. T055-32418-00008 on October 16, 2013. There have been no subsequent approvals issued.

**County Attainment Status**

The source is located in Greene County.

Pollutant	Designation
SO <sub>2</sub>	Better than national standards.
CO	Unclassifiable or attainment effective November 15, 1990.
O <sub>3</sub>	Unclassifiable or attainment effective July 20, 2012, for the 2008 8-hour ozone standard. <sup>1</sup>
PM <sub>2.5</sub>	Unclassifiable or attainment effective April 5, 2005, for the annual PM <sub>2.5</sub> standard.
PM <sub>2.5</sub>	Unclassifiable or attainment effective December 13, 2009, for the 24-hour PM <sub>2.5</sub> standard.
PM <sub>10</sub>	Unclassifiable effective November 15, 1990.
NO <sub>2</sub>	Cannot be classified or better than national standards.
Pb	Unclassifiable or attainment effective December 31, 2011.
<sup>1</sup> Unclassifiable or attainment effective October 18, 2000, for the 1-hour ozone standard which was revoked effective June 15, 2005.	

- (a) Ozone Standards  
Volatile organic compounds (VOC) and Nitrogen Oxides (NO<sub>x</sub>) are regulated under the Clean Air Act (CAA) for the purposes of attaining and maintaining the National Ambient Air Quality Standards (NAAQS) for ozone. Therefore, VOC and NO<sub>x</sub> emissions are considered when evaluating the rule applicability relating to ozone. Greene County has been designated as attainment or unclassifiable for ozone. Therefore, VOC and NO<sub>x</sub> emissions were reviewed pursuant to the requirements for Prevention of Significant Deterioration (PSD), 326 IAC 2-2.

- (b) **PM<sub>2.5</sub>**  
 Greene County has been classified as attainment for PM<sub>2.5</sub>. On May 8, 2008, U.S. EPA promulgated the requirements for Prevention of Significant Deterioration (PSD) for PM<sub>2.5</sub> emissions. These rules became effective on July 15, 2008. On May 4, 2011, the air pollution control board issued an emergency rule establishing the direct PM<sub>2.5</sub> significant level at ten (10) tons per year. This rule became effective June 28, 2011. Therefore, direct PM<sub>2.5</sub>, SO<sub>2</sub>, and NO<sub>x</sub> emissions were reviewed pursuant to the requirements for Prevention of Significant Deterioration (PSD), 326 IAC 2-2.
- (c) **Other Criteria Pollutants**  
 Greene County has been classified as attainment or unclassifiable in Indiana for all other criteria pollutants. Therefore, these emissions were reviewed pursuant to the requirements for Prevention of Significant Deterioration (PSD), 326 IAC 2-2.

**Fugitive Emissions**

Since this type of operation is not one of the twenty-eight (28) listed source categories under 326 IAC 2-2, 326 IAC 2-3, or 326 IAC 2-7, and there is no applicable New Source Performance Standard that was in effect on August 7, 1980, fugitive emissions are not counted toward the determination of PSD, Emission Offset, and Part 70 Permit applicability.

Note: The boilers 05, 06, 07 and 08, are subject to New Source Performance Standard, Subpart Dc. However, this NSPS was not in effect on August 7, 1980.

**Source Status**

The table below summarizes the potential to emit of the entire source, prior to the proposed modification, after consideration of all enforceable limits established in the effective permits:

<b>Pollutant</b>	<b>Emissions (ton/yr)</b>
PM	244.57
PM <sub>10</sub>	192.90
PM <sub>2.5</sub>	186.49
SO <sub>2</sub>	249
NO <sub>x</sub>	122.88
VOC	79.53
CO	73.71
GHGs as CO <sub>2</sub> e	99,999
Single HAP (H <sub>2</sub> S)	4.95
Combined HAPs	<25

- (a) This existing source is not a major stationary source, under PSD (326 IAC 2-2), because no regulated pollutant, excluding GHGs, is emitted at a rate of two hundred fifty (250) tons per year or more, emissions of GHGs are less than one hundred thousand (100,000) tons of CO<sub>2</sub> equivalent emissions (CO<sub>2</sub>e) per year, and it is not one of the twenty-eight (28) listed source categories, as specified in 326 IAC 2-2-1(ff)(1).
- (b) This existing source is not a major source of HAPs, as defined in 40 CFR 63.2, because HAPs emissions are less than ten (10) tons per year for any single HAP and less than twenty-five (25) tons per year of a combination of HAPs. Therefore, this source is an area source under Section 112 of the Clean Air Act (CAA).
- (c) These emissions are based upon the Appendix A calculations for Part 70 Operating Permit Renewal T055-32418-00008.

### Description of Proposed Modification

The Office of Air Quality (OAQ) has reviewed a modification application, submitted by Griffin Industries, LLC on March 03, 2014 relating to a modification of the blood meal making process, consisting of the replacement of natural gas-fired Blood Dryer 04 with a steam generated Dupps Dryer, the replacement of the existing blood dryer scrubber with a packed bed scrubber, and the addition of an in-room air scrubber. The modification of the blood meal making process reduces the maximum production rate of the process from 1.1 tons of blood meal per hour to 1.0 tons of blood meal per hour.

The following is a list of the modified emission units and pollution control devices:

- (a) Blood meal making process, constructed in 1968 (except Blood Dryer 04, constructed in 1994), with a maximum production rate of 1.1 tons of blood meal per hour, controlled by a series of 2 scrubbers with sequence as Blood Centrifuge Venturi Scrubber (Venturi1C), and Blood Dryer Scrubber (Spray13C), exhausting to Stack BDS-3, and consisting of the following:
  - (I) Blood receiving
  - (II) Coagulator
  - (III) Centrifuge
  - (IV) One (1) natural gas-fired blood dryer, identified as Blood Dryer 04, constructed in 1994, with a heat input capacity of 20 million Btu per hour, using No. 2 fuel oil as a backup fuel, two (2) cyclone centrifugal separators, and exhausting to Stack D.
  - (V) Screen
  - (VI) Storage

The following is a list of the emission units and pollution control devices to be removed:

- (a) One (1) natural gas-fired blood dryer, identified as Blood Dryer 04, constructed in 1994, with a heat input capacity of 20 million Btu per hour, using No. 2 fuel oil as a backup fuel, two (2) cyclone centrifugal separators, and exhausting to stack D.
- (b) One (1) Blood Dryer Scrubber (Spray 13C)

### Enforcement Issues

There are no pending enforcement actions.

### Emission Calculations

See Appendix A of this Technical Support Document for detailed emission calculations.

### Permit Level Determination – Part 70

Pursuant to 326 IAC 2-1.1-1(16), Potential to Emit is defined as “the maximum capacity of a stationary source or emission unit to emit any air pollutant under its physical and operational design. Any physical or operational limitation on the capacity of a source to emit an air pollutant, including air pollution control equipment and restrictions on hours of operation or type or amount of material combusted, stored, or processed shall be treated as part of its design if the limitation is enforceable by the U. S. EPA, IDEM, or the appropriate local air pollution control agency.”

The following table is used to determine the appropriate permit level under 326 IAC 2-7-10.5. This table reflects the PTE before controls. Control equipment is not considered federally enforceable until it has been required in a federally enforceable permit.

<b>Increase in PTE Before Controls of the Modification</b>	
<b>Pollutant</b>	<b>Potential To Emit (ton/yr)</b>
PM	53.44
PM <sub>10</sub>	53.44
PM <sub>2.5</sub>	20.15
SO <sub>2</sub>	0
NO <sub>x</sub>	0
VOC	24.9
CO	0
H <sub>2</sub> S	1.75

Appendix A of this TSD reflects the unrestricted potential emissions of the modification.

This source modification is subject to 326 IAC 2-7-10.5(g)(4) because the potential to emit of PM, PM10, and PM2.5 are each greater than twenty-five (25) tons per year before control. Additionally, the modification will be incorporated into the Part 70 Operating Permit through a significant permit modification issued pursuant to 326 IAC 2-7-12(d), because the modification requires significant changes in existing monitoring Part 70 permit terms and conditions.

**Permit Level Determination – PSD**

The table below summarizes the potential to emit, reflecting all limits, of the emission units. Any control equipment is considered federally enforceable only after issuance of this Part 70 source and permit modification, and only to the extent that the effect of the control equipment is made practically enforceable in the permit.

<b>Process / Emission Unit</b>	<b>Potential to Emit (ton/yr)</b>								
	<b>PM</b>	<b>PM<sub>10</sub></b>	<b>PM<sub>2.5</sub><sup>*</sup></b>	<b>SO<sub>2</sub></b>	<b>NO<sub>x</sub></b>	<b>VOC</b>	<b>CO</b>	<b>GHGs</b>	<b>H<sub>2</sub>S</b>
Fuel Combustion	208.2	165.9	165.9	249.00 <sub>(b)</sub>	110.37	5.81	29.04	99,999 <sup>(c)</sup>	N/A
Poultry meal/fat making operation	4.22	2.62	1.60	N/A	N/A	24.90	N/A	N/A	3.56
Feather meal making operation	15.39	15.39	5.80	N/A	N/A	24.90	N/A	N/A	1.01
Blood meal making operation	5.34 <sup>(a)</sup>	5.34 <sup>(a)</sup>	2.01 <sup>(a)</sup>	N/A	N/A	24.90	N/A	N/A	0.35
Silos	9.64	9.64	9.64	N/A	N/A	N/A	N/A	N/A	N/A
<b>Source-wide Total Potential to Emit after Modification</b>	<b>242.78</b>	<b>198.89</b>	<b>184.96</b>	<b>249.00</b>	<b>110.37</b>	<b>80.51</b>	<b>29.04</b>	<b>99,999</b>	<b>4.92</b>
PSD Major Source Thresholds	250	250	250	250	250	250	250	100,000 CO <sub>2</sub> e	250

\*PM<sub>2.5</sub> listed is direct PM<sub>2.5</sub>.

- (a) Particulate Emissions are limited by the following PSD Minor Limits:

Emission Units	PSD Minor limit (lb/hr)		
	PM	PM10	PM2.5
Poultry meal making process	1.0	0.63	0.38
Feather meal making process	3.51	3.51	1.32
Blood Meal making process	1.34	1.22	0.51

Note: The PSD limits for the feather meal making and the blood meal making operations have been revised from those included in Part 70 Operating Permit Renewal No. T055-32418-00008, in order to incorporate PM<sub>10</sub> condensable emissions. This change has been made to ensure that both condensable PM<sub>10</sub> and filterable PM<sub>10</sub> emissions are being accounted for in the PM<sub>10</sub> emission limits. The previous Part 70 Operating Permit Renewal No. T055-32418-00008, issued on October 16, 2013, based the emission limits on only the filterable PM<sub>10</sub> emission factor.

This change is a Title I change.

- (b) SO<sub>2</sub> emissions are limited by the following PSD Minor Limit:

- (1) The combined SO<sub>2</sub> emissions from combusting natural gas, No. 2 fuel oil, waste oil and processed grease in Blood Dryer 04 and boilers 05, 06 07 and 08, shall not exceed 249 tons per twelve (12) consecutive month period, with compliance determined at the end of each month.
- (2) The sulfur content of the no. 2 fuel oil usage at the boilers and Blood Dryer shall not exceed 0.5% based on a calendar month average.

Note: *There is no change to this limitation due to this modification. Upon completion of the replacement of the Blood Dryer 04 with the Dupps Dryer, the source may submit an administrative amendment application for the removal of the Blood Dryer 04's associated permit requirements.*

- (c) CO<sub>2</sub>e emissions are limited by the following PSD Minor Limit:

The combined CO<sub>2</sub>e emissions from combusting natural gas, No. 2 fuel oil, waste oil and processed grease in Blood Dryer 04 and boilers 05, 06 07 and 08, shall not exceed 99,999 tons per twelve (12) consecutive month period, with compliance determined at the end of each month.

Note: *There is no change to this limitation due to this modification. Upon completion of the replacement of the Blood Dryer 04 with the Dupps Dryer, the source may submit an administrative amendment application for the removal of the Blood Dryer 04's associated permit requirements.*

This modification to an existing minor stationary source is not major because the emissions increase is less than the PSD major source thresholds. Therefore, pursuant to 326 IAC 2-2, the PSD requirements do not apply.

<b>Federal Rule Applicability Determination</b>
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The following federal rules are applicable to the source due to this modification:

**New Source Performance Standards (NSPS):**

- (a) There are no New Source Performance Standards (NSPS)(326 IAC 12 and 40 CFR Part 60) applicable to this proposed modification.

**National Emission Standards for Hazardous Air Pollutants (NESHAP):**

- (b) There are no National Emission Standards for Hazardous Air Pollutants (NESHAPs) (326 IAC 14, 326 IAC 20 and 40 CFR Part 63) applicable to this proposed modification.

**Compliance Assurance Monitoring (CAM):**

- (c) Pursuant to 40 CFR 64.2, Compliance Assurance Monitoring (CAM) is applicable to new or modified emission units that involve a pollutant-specific emission unit and meet the following criteria:
- (1) has a potential to emit before controls equal to or greater than the Part 70 major source threshold for the pollutant involved;
  - (2) is subject to an emission limitation or standard for that pollutant; and
  - (3) uses a control device, as defined in 40 CFR 64.1, to comply with that emission limitation or standard.

CAM Applicability Analysis								
Emission Unit	Pollutant	Control Device Used	Emission Limitation (Y/N)	Uncontrolled PTE (ton/yr)	Controlled PTE (ton/yr)	Part 70 Major Source Threshold (ton/yr)	CAM Applicable (Y/N)	Large Unit (Y/N)
Blood Meal making process	PM	Y	Y	53.44	5.34	100	N	N
	PM10	Y	Y	53.44	5.34	100	N	N
	PM2.5	Y	Y	20.15	5.34	100	N	N
	VOC	N	Y	24.90	1.69	100	N	N
	HAPs	N	N	1.75 / 1.75	0.35 / 0.35	10 / 25	N	N

Based on this evaluation, the requirements of 40 CFR Part 64, CAM are not applicable to any of the new units as part of this modification.

**State Rule Applicability Determination**

The following state rules are applicable to the source due to the modification:

**326 IAC 2-2 (PSD)**

PSD applicability is discussed under the Permit Level Determination – PSD section.

**326 IAC 2-4.1 (Major Sources of Hazardous Air Pollutants (HAP))**

The operation of the Dupps dryer will emit less than ten (10) tons per year for a single HAP and less than twenty-five (25) tons per year for a combination of HAPs. Therefore, 326 IAC 2-4.1 does not apply.

**326 IAC 2-6 (Emission Reporting)**

Since this source is required to have an operating permit under 326 IAC 2-7, Part 70 Permit Program, this source is subject to 326 IAC 2-6 (Emission Reporting). In accordance with the compliance schedule in 326 IAC 2-6-3(a)(2), an emission statement must be submitted triennially. The first report is due no later than July 1, 2006, and subsequent reports are due every three (3) years thereafter. The emission statement shall contain, at a minimum, the information specified in 326 IAC 2-6-4.

**326 IAC 6-3-2 (Particulate Emission Limitations for Manufacturing Processes)**

Pursuant to 326 IAC 6-3-2, the particulate matter (PM) from the Dupps dryer shall not exceed 4.10 pounds per hour when operating at a process weight rate of 1.0 tons per hour. The pound per hour limitation was calculated with the following equation:

Interpolation of the data for the process weight rate up to sixty thousand (60,000) pounds per hour shall be accomplished by use of the equation:

$$E = 4.10 P^{0.67} \quad \text{where } E = \text{rate of emission in pounds per hour and} \\ P = \text{process weight rate in tons per hour}$$

Based on calculations, the scrubbers equipped on blood meal operation shall be in operation at all times the blood meal operation is in operation.

**326 IAC 8-1-6 (New facilities; general reduction requirements)**

- (a) Equipment in the Blood meal making, Feather meal making and Poultry meal making processes constructed in 1968.

Except for Dupps dryer (approved in 2014 for construction), all the equipment in the Blood meal making, Feather meal making and Poultry meal making processes was constructed in 1968. Therefore, the requirements of this rule do not apply to all the equipment in the Blood meal making, Feather meal making and Poultry meal making processes (except Dupps dryer). There are no limitations and standards specified in 326 IAC 8 for all the equipment (other than Dupps dryer) that is listed in the Blood meal making, Feather meal making and Poultry meal making processes.

- (b) Dupps dryer  
Based on the use of test data from a similar facility at Griffin's Butler, Kentucky, the uncontrolled VOC emissions from Dupps Dryer are less than 25 tons/year. Since the uncontrolled VOC emissions are based on an alternative source specific emission factor, a one-time testing requirement will be added in the permit to verify the non-applicability of 326 IAC 8-1-6.

In order to render 326 IAC 8-1-6 not applicable, the uncontrolled VOC emission from Dupps Dryer shall not exceed 5.68 pound per hour.

The above limit is calculated as follows:

$$\begin{aligned} \text{VOC limit (lb/hr)} &= \text{Uncontrolled VOC Emissions (tons/yr)} \times 2000 \text{ (lbs/ton)} / 8760 \\ &\quad \text{(hours/year)} \\ &= (24.9 \text{ tons per year}) \times 2000 \text{ lbs/ton} / 8760 \text{ hours/year} \\ &= 5.68 \text{ lb/hr} \end{aligned}$$

**Compliance Determination and Monitoring Requirements**

Permits issued under 326 IAC 2-7 are required to ensure that sources can demonstrate compliance with all applicable state and federal rules on a continuous basis. All state and federal rules contain compliance provisions; however, these provisions do not always fulfill the requirement for a continuous demonstration. When this occurs, IDEM, OAQ, in conjunction with the source, must develop specific conditions to satisfy 326 IAC 2-7-5. As a result, Compliance Determination Requirements are included in the permit. The Compliance Determination Requirements in Section D of the permit are those conditions that are found directly within state and federal rules and the violation of which serves as grounds for enforcement action.

If the Compliance Determination Requirements are not sufficient to demonstrate continuous compliance, they will be supplemented with Compliance Monitoring Requirements, also in Section D of the permit. Unlike Compliance Determination Requirements, failure to meet

Compliance Monitoring conditions would serve as a trigger for corrective actions and not grounds for enforcement action. However, a violation in relation to a compliance monitoring condition will arise through a source's failure to take the appropriate corrective actions within a specific time period.

#### **Compliance Determination Requirements**

The Compliance Determination Requirements applicable to this modification are as follows:

- (a) **Testing Requirements**  
Not later than one hundred eighty (180) days after startup of the Dupps Dryer the Permittee shall conduct performance testing on the Dupps Dryer to verify the uncontrolled VOC emission rate, using methods as approved by the Commissioner.
- (b) **Emission Controls Operation**  
The Venturi Scrubber (Venturi1C), Packed Bed Scrubber (Packed 1C), and In-Room Air Scrubber (Room 32B), for particulate emissions control shall be in operation and control particulate emissions at all times the blood meal making process is in operation. The PM, PM10, and PM2.5 emissions from this unit are limited to 1.34 pounds per hour, 1.22 pounds per hour, and 0.51 pounds per hour, respectively.

These compliance monitoring requirements are necessary because the Scrubbers must operate properly to ensure compliance with 326 IAC 2-2 (PSD) and 326 IAC 6-3 (Particulate Emission Limitations).

#### **Compliance Monitoring Requirements**

The compliance monitoring requirements applicable to this modification are as follows:

- (a) **Visible Emissions Notations**  
The Permittee shall perform daily visible emission notations of the exhaust from the Stack RAS-2. Daily visible emissions shall be performed during normal daylight operations when exhausting to the atmosphere. A trained employee shall record whether emissions are normal or abnormal.
- (b) **Scrubber Parametric Monitoring**  
The Permittee shall record the pressure drop across the scrubbers associated with the blood meal making process, at least once per day when the blood meal making process is in operation.
- (c) **Flow Rate Monitoring**  
The Permittee shall monitor and record the flow rate of all the scrubbers associated with the blood meal making process at least once per day when the blood meal making process is in operation.

These monitoring conditions are necessary because the baghouse for the blood meal making processing facility must operate properly to ensure compliance with 326 IAC 6-3 (Particulate Emission Limitations for Manufacturing Processes) and 326 IAC 2-7 (Part 70)).

<b>Proposed Changes</b>
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The changes listed below have been made to Part 70 Operating Permit No. T055-32418-00008. Deleted language appears as ~~strike throughs~~ and new language appears in **bold**:

1. Entire Permit - The emission unit descriptions for the modified blood meal making operation have been added.
2. Entire Permit - The emission unit descriptions have been revised to reflect the proposed changes to the emission unit description of the Feather Plant In-Room Air Scrubber (Room 32B), by

replacing all applicable references to the "Feather Plant In-Room Air Scrubber (Room 32B)" with the "In-Room Air Scrubber (Room 32B)".

3. Condition D.1.3 - Particulate Emission Limitations [326 IAC 2-2] has been revised to include the revision of the PM<sub>10</sub> emission limits due to the inclusion of PM<sub>10</sub> condensable emissions.
4. Compliance Determination, Compliance Monitoring, and Recordkeeping Requirements have been added for the new Dupps Dryer and its associated control devices.
5. Additional typographical errors have been corrected.

*Note: Upon completion of the replacement of the Blood Dryer 04 with the Dupps Dryer, the source may submit an administrative amendment application for the removal of the Blood Dryer04 description and its associated permit requirements.*

...

A.1 General Information [326 IAC 2-7-4(c)][326 IAC 2-7-5(14)][326 IAC 2-7-1(22)]

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The Permittee owns and operates a stationary ~~stationary~~ animal and agricultural byproducts rendering operation.

Source Address: 7358 South Griffin Road, Newberry, Indiana, 47499-9729 ~~47449~~ **47449**

...

A.2 Emission Units and Pollution Control Equipment Summary  
[326 IAC 2-7-4(c)(3)][326 IAC 2-7-5(14)]

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This stationary source consists of the following emission units and pollution control devices:

- (a) **Blood meal making process, constructed in 1968 (except Dupps dryer, approved in 2014 for construction), with a maximum production rate of 1.0 ton of blood meal per hour, controlled by a series of 3 scrubbers with sequence as Blood Centrifuge Venturi Scrubber (Venturi1C), Packed Bed Scrubber (Packed 1C) and In-Room Air Scrubber (Room 32B), exhausting to Stack RAS-2 and consisting of the following:**

- (I) Blood receiving
- (II) Coagulator
- (III) Centrifuge
- (IV) One (1) steam heated dryer, identified as Dupps dryer, approved in 2014 for construction, with a maximum production rate of 1.0 ton of blood meal per hour and exhausting to Stack RAS-2.
- (V) Screen
- (VI) Storage

- (a1) Blood meal making process, constructed in 1968 (except Blood Dryer 04, constructed in 1994), with a maximum production rate of 1.1 ton of blood meal per hour, controlled by a series of 2 scrubbers with sequence as Blood Centrifuge Venturi Scrubber (Venturi1C), and Blood Dryer Scrubber (Spray13C), exhausting to Stack BDS-3 and consisting of the following:

- (I) Blood receiving
- (II) Coagulator
- (III) Centrifuge
- (IV) One (1) natural gas-fired blood dryer, identified as Blood Dryer 04, constructed in 1994, with a heat input capacity of 20 million Btu per hour, using No. 2 fuel oil as a backup fuel, two (2) cyclone centrifugal separators, and exhausting to Stack D.
- (V) Screen
- (VI) Storage

- (b) Feather meal making process, constructed in 1968, with a maximum production rate of 2.88 tons of feather meal per hour, controlled by a series of 3 scrubbers with sequence

as Feather Plant Venturi Scrubber (Venturi10B), Feather Plant Packed Bed Scrubber (Packed 10B) and Feather Plant In-Room Air Scrubber (Room 32B), exhausting to Stack RAS-2, and consisting of the following:

- (I) Feather receiving and spreader
- (II) Hydrolizer
- (III) Feather Press
- (IV) Feather Dryer, identified as Feather Dryer
- (V) Shell and tube Condensers and cooling tower

...

C.16 Emission Statement [326 IAC 2-7-5(3)(C)(iii)][326 IAC 2-7-5(7)][326 IAC 2-7-19(c)][326 IAC 2-6] Pursuant to 326 IAC 2-6-3(b)(23), starting in ~~2005~~2006 and every three (3) years thereafter, the Permittee shall submit by July 1 an emission statement covering the previous calendar year. The emission statement shall contain, at a minimum, the information specified in 326 IAC 2-6-4(c) and shall meet the following requirements:

- (1) Indicate estimated actual emissions of all pollutants listed in 326 IAC 2-6-4(a);
- (2) Indicate estimated actual emissions of regulated pollutants as defined by 326 IAC 2-7-1(32) ("Regulated pollutant, which is used only for purposes of Section 19 of this rule") from the source, for purpose of fee assessment.

The statement must be submitted to:

Indiana Department of Environmental Management  
Technical Support and Modeling Section, Office of Air Quality  
100 North Senate Avenue  
MC 61-50 IGCN 1003  
Indianapolis, Indiana 46204-2251

The emission statement does require a certification that meets the requirements of 326 IAC 2-7-6(1) by a "responsible official" as defined by 326 IAC 2-7-1(35).

...

#### SECTION D.1 FACILITY OPERATION CONDITIONS

Facility Description [326 IAC 2-7-5(15)]

- (a) **Blood meal making process, constructed in 1968 (except Dupps dryer, approved in 2014 for construction), with a maximum production rate of 1.0 ton of blood meal per hour, controlled by a series of 3 scrubbers with sequence as Blood Centrifuge Venturi Scrubber (Venturi1C), Packed Bed Scrubber (Packed 1C) and In-Room Air Scrubber (Room 32B), exhausting to Stack RAS-2 and consisting of the following:**
  - (I) **Blood receiving**
  - (II) **Coagulator**
  - (III) **Centrifuge**
  - (IV) **One (1) steam heated dryer, identified as Dupps dryer, approved in 2014 for construction, with a maximum production rate of 1.0 ton of blood meal per hour and exhausting to Stack RAS-2.**
  - (V) **Screen**
  - (VI) **Storage**
- (a1) Blood meal making process, constructed in 1968 (except Blood Dryer 04, constructed in 1994), with a maximum production rate of 1.1 ton of blood meal per hour, controlled by a series of 2 scrubbers with sequence as Blood Centrifuge Venturi Scrubber

(Venturi1C), and Blood Dryer Scrubber (Spray13C), exhausting to Stack BDS-3 and consisting of the following:

- (I) Blood receiving
- (II) Coagulator
- (III) Centrifuge
- (IV) One (1) natural gas-fired blood dryer, identified as Blood Dryer 04, constructed in 1994, with a heat input capacity of 20 million Btu per hour, using No. 2 fuel oil as a backup fuel, two (2) cyclone centrifugal separators, and exhausting to Stack D.
- (V) Screen
- (VI) Storage

(b) Feather meal making process, constructed in 1968, with a maximum production rate of 2.88 tons of feather meal per hour, controlled by a series of 3 scrubbers with sequence as Feather Plant Venturi Scrubber (Venturi10B), Feather Plant Packed Bed Scrubber (Packed 10B) and Feather Plant In-Room Air Scrubber (Room 32B), exhausting to Stack RAS-2, and consisting of the following:

- (I) Feather receiving and spreader
- (II) Hydrolizer
- (III) Feather Press
- (IV) Feather Dryer, identified as Feather Dryer
- (V) Shell and tube Condensers and cooling tower

...

(The information describing the process contained in this facility description box is descriptive information and does not constitute enforceable conditions.)

D.1.3 PSD Minor Limit - Particulate [326 IAC 2-2]

In order to render 326 IAC 2-2 not applicable, the Permittee shall comply with the after control limitations specified in the following table:

Emission Units	PSD Minor limit (lb/hr)		
	PM	PM10	PM2.5
Blood Meal making process	1.34	<del>0.84</del> <b>1.22</b>	0.51
Feather meal making process	3.51	<del>2.19</del> <b>3.51</b>	1.32
Poultry meal making process	<b>1.0</b>	0.63	0.38

D.1.4 PSD Minor Limit - CO<sub>2</sub>e [326 IAC 2-2]

Compliance with this limit will render this source minor source under ~~Green House Gas Rule~~ **326 IAC 2-2 (Prevention of Significant Deterioration (PSD))**.

D.1.7 VOC [326 IAC 8-1-6]

(a) In order to render 326 IAC 8-1-6 not applicable, the uncontrolled VOC emissions from the Dupps dryer shall not exceed 5.68 pound per hour.

Compliance with this limit will limit the uncontrolled VOC emissions from the Dupps dryer to less than 25 tons per year, and renders the requirements of 326 IAC 8-1-6 not applicable to the Dupps dryer.

- (b) In order to render 326 IAC 8-1-6 not applicable, the uncontrolled VOC emissions from the Blood Dryer 04 shall not exceed 5.68 pound per hour.

Compliance with this limit will limit the uncontrolled VOC emissions from Blood Dryer 04 to less than 25 tons per year, and renders the requirements of 326 IAC 8-1-6 not applicable to Blood Dryer 04.

...

D.1.9 Testing Requirements [326 IAC 2-7-6(1),(6)] [326 IAC 2-1.1-11]

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- (a) In order to determine the compliance with Condition D.1.3, the Permittee shall perform PM, PM10 and PM2.5 testing for Blood Meal making, Feather meal making and Poultry meal making processes, using methods as approved by the Commissioner. These tests shall be performed no later than hundred eight (180) days after the issuance of Part 70 Renewal No. T055-32418-00008 and shall be repeated at least once every five (5) years from the date of this valid compliance demonstration.
- (b) **Not later than one hundred eighty (180) days after startup of the Dupps dryer and in order to demonstrate compliance with Condition D.1.7(a), the Permittee shall conduct performance testing on the Dupps dryer to verify the uncontrolled VOC emissions rate, using methods as approved by the Commissioner.**
- (c) In order to determine the compliance with Condition D.1.7(b), the Permittee shall verify uncontrolled VOC emissions rate by conducting performance test for Blood Dryer 04, using methods as approved by the Commissioner. This test shall be performed no later than **one** hundred eighty (180) days after the issuance of Part 70 Renewal No. T055-32418-00008.

...

D.1.10 Particulate Control

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- (a) **In order to comply with Conditions D.1.3 and D.1.6, the Blood Centrifuge Venturi Scrubber (Venturi1C), Packed Bed Scrubber (Packed 1C) and In-Room Air Scrubber (Room 32B) for particulate control shall be in operation and control emissions from the Blood Meal making process at all times the Blood Meal making process is in operation.**
- (a1) **Until replacement of the Blood Dryer 04 with the Dupps Dryer, and in order to comply with Conditions D.1.3 and D.1.6, the Blood Centrifuge Venturi Scrubber (Venturi1C) and Blood Dryer Scrubber (Spray13C) for particulate control shall be in operation and control emissions from the Blood Meal making process at all times the Blood Meal making process is in operation.**
- (b) In order to comply with Conditions D.1.3 and D.1.6, the Feather Plant Venturi Scrubber (Venturi10B), Feather Plant Packed Bed Scrubber (Packed 10B) and ~~Feather Plant~~ In-Room Air Scrubber (Room 32B) for particulate control shall be in operation and control emissions from the Feather meal making process at all times the Feather meal making process is in operation.

...

D.1.12 CO<sub>2</sub>e [326 IAC 2-7-6(1),(6)] [326 IAC 2-1.1-11]

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- (a) In order to comply with Condition D.1.4, the Permittee shall determine CO<sub>2</sub>e emissions for each month as below.

...

CO<sub>2</sub> GWP = CO<sub>2</sub> Global Warming Potentials (GWP) = 1

CH<sub>4</sub> GWP = Methane Global Warming Potentials (GWP) = ~~24~~ **25**

N<sub>2</sub>O GWP = Nitrous oxide Global Warming Potentials (GWP) = ~~340~~ **298**

...

#### D.1.13 Visible Emissions Notations

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- (a) Daily visible emission notations of the exhaust from the Stacks RAS-1, ~~BDS-3~~ and RAS-2 shall be performed during normal daylight operations when exhausting to the atmosphere. A trained employee shall record whether emissions are normal or abnormal.
- (a1) Until replacement of the Blood Dryer 04 with the Dupps Dryer, daily visible emission notations of the exhaust from the Stack BDS-3 shall be performed during normal daylight operations when exhausting to the atmosphere. A trained employee shall record whether emissions are normal or abnormal.**
- ...
- (e) ~~Section C - General Record Keeping Requirements contains the Permittee's obligations with regard to the records required by this condition. If abnormal emissions are observed, the Permittee shall continue to take reasonable response steps. Section C - Response to Excursions or Exceedances contains the Permittee's obligation with regard to the reasonable response steps required by this condition. An abnormal visible emission notation is not a deviation from this permit. Failure to take response steps shall be considered a deviation from this permit.~~

#### D.1.14 Scrubber Monitoring Requirements

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- (a) The Permittee shall monitor and record the pressure drop of all the scrubbers listed in this section, at least once per day when one or more of the associated emission units to these scrubbers is in operation. When for any one reading, the pressure drop across the scrubber is outside the normal range, **the Permittee shall take a reasonable response.** ~~of 2.0 and 8.0 inches of water, or a range established during the latest stack test, the Permittee shall take reasonable response steps in accordance with Section C - Response to Excursions or Exceedances. The normal range for this unit is a pressure drop between two (2.0) and eight (8.0) inches of water unless a different upper-bound or lower-bound value for this range is determined during the latest stack test. Section C - Response to Excursions or Exceedances contains the Permittee's obligation with regard to the reasonable response steps required by this condition.~~ A pressure reading that is outside the above mentioned range is not a deviation from this permit. ~~Failure to take response steps in accordance with Section C - Response to Excursions or Exceedances shall be considered a deviation from this permit. Failure to take response steps shall be considered a deviation from this permit.~~
- (b) The Permittee shall monitor and record the flow rate of all the scrubbers listed in this section at least once per day when one or more of the associated emission units to these scrubbers is in operation. When for any one reading, the flow rate of the scrubber is less than the flow rate specified below, or a minimum established during the latest stack test, the Permittee shall take reasonable response steps ~~in accordance with Section C - Response to Excursions or Exceedances.~~ A flow rate that is less than the flow rate specified below or a minimum flow rate established during the latest stack test. **Section C - Response to Excursions or Exceedances contains the Permittee's obligation with regard to the reasonable response steps required by this condition.** ~~is not a deviation from this permit. Failure to take response steps in accordance with Section C - Response to Excursions or Exceedances shall be considered a deviation from this permit. Failure to take response steps shall be considered a deviation from this permit.~~

Scrubber	Flow Rate in Gallons per minute
Meat Plant Venturi Scrubber (Venturi 3A)	5
Meat Plant Packed Bed Scrubber (Packed 3A)	100
Meat Plant In-Room Air Scrubber (Room32A)	400
Feather Plant Venturi Scrubber (Venturi10B)	5
Feather Plant Packed Bed Scrubber (Packed 10B)	100
Feather Plant In-Room Air Scrubber (Room 32B)	400
Blood Centrifuge Venturi Scrubber (Venturi1C)	5
Blood Dryer Scrubber (Spray13C)	110
<b>Packed Bed Scrubber (Packed 1C)</b>	<b>110</b>

The instruments used for determining the pressure drop and flow rate shall comply with Section C - Instrument Specifications, of this permit, shall be subject to approval by IDEM, OAQ, and shall be calibrated **or replaced** at least once a year.

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#### D.1.15 Scrubber Detection

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In the event that a scrubber malfunction has been observed:

Failed units and the associated process will be shut down immediately until the failed units have been repaired or replaced. Operations may continue only if the event qualifies as an emergency and the Permittee satisfies the requirements of the emergency provisions of this permit (Section B - Emergency Provisions). ~~Failure to take response steps in accordance with Section C - Response to Excursions or Exceedances shall be considered a deviation from this permit.~~

#### D.1.16 Record Keeping Requirements

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...

(b) To document the compliance status with Condition D.1.13(a), the Permittee shall maintain records of daily visible emission notations of the exhaust from Stacks RAS-1, ~~BDS-3~~ and RAS-2. The Permittee shall include in its daily record when a visible emission notation is not taken and the reason for the lack of visible emission notation (e.g. the process did not operate that day).

**(b1) To document the compliance status with Condition D.1.13(a1), the Permittee shall maintain records of daily visible emission notations of the exhaust from Stack BDS3. The Permittee shall include in its daily record when a visible emission notation is not taken and the reason for the lack of visible emission notation (e.g. the process did not operate that day).**

...

#### D.1.17 Reporting Requirements

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A quarterly summary of the information to document the compliance status with Conditions D.1.2(a) and D.1.4 shall be submitted ~~to the address listed in Section C - General Reporting Requirements, of this permit,~~ using the reporting forms located at the end of this permit, or their equivalent, **within no later than thirty (30) days** after the end of the quarter being reported. Section C - General Reporting Requirements contains the Permittee's obligation with regard to the reporting required by these conditions. The report submitted by the Permittee does require a certification that meets the requirements of 326 IAC 2-7-6(1) by a "responsible official" as defined by 326 IAC 2-7-1(35).

...

INDIANA DEPARTMENT OF ENVIRONMENTAL MANAGEMENT  
OFFICE OF AIR QUALITY  
COMPLIANCE AND ENFORCEMENT BRANCH

Part 70 Quarterly Report

Source Name: Griffin Industries LLC  
Source Address: 7358 South Griffin Road, Newberry, Indiana, 47499-9729 **47449**

...

**Conclusion and Recommendation**

The construction of this proposed modification shall be subject to the conditions of the attached proposed Part 70 Significant Source Modification No. 055-34253-00008 and Significant Permit Modification No. 055-34320-00008. The staff recommends to the Commissioner that these Part 70 Significant Source and Significant Permit Modifications be approved.

**IDEM Contact**

- (a) Questions regarding this proposed permit can be directed to Nida Habeeb at the Indiana Department Environmental Management, Office of Air Quality, Permits Branch, 100 North Senate Avenue, MC 61-53 IGCN 1003, Indianapolis, Indiana 46204-2251 or by telephone at (317) 317-234-8531 or toll free at 1-800-451-6027 extension 4-8531.
- (b) A copy of the findings is available on the Internet at: <http://www.in.gov/ai/appfiles/idem-caats/>
- (c) For additional information about air permits and how the public and interested parties can participate, refer to the IDEM's Guide for Citizen Participation and Permit Guide on the Internet at: [www.idem.in.gov](http://www.idem.in.gov)

**Appendix A: Emissions Calculations  
Natural Gas Combustion**

**Company Name:** Griffin Industries LLC  
**Address City IN Zip:** 7358 South Griffin Road, Newberry, Indiana, 47499-9729  
**Significant Permit Modification Number:** 055-34320-00008  
**Significant Source Modification Number:** 055-34253-00008  
**Reviewer:** Nida Habeeb  
**Application Received:** 03/03/2014

Heat Input Capax HHV Potential Throughput  
 MMBtu/hr  $\frac{\text{mmBtu}}{\text{mmscf}}$  MMBtu/yr

Boiler 05	50.2	1020	431.1
Boiler 06	50.2	1020	431.1
Boiler 07	50.2	1020	431.1
Boiler 08	33.746	1020	289.8

Emission Factor in lb/MMCF Emission Rate in lb/MMBtu	Pollutant (tons/yr)						
	PM*	PM10*	direct PM2.5*	SO2	NOx	VOC	CO
	1.9	7.6	7.6	0.6	100 **	5.5	84
	0.0019	0.0075	0.0075	0.0006	0.0980	0.0054	0.0824
Boiler 05	0.41	1.64	1.64	0.13	21.56	1.19	18.11
Boiler 06	0.41	1.64	1.64	0.13	21.56	1.19	18.11
Boiler 07	0.41	1.64	1.64	0.13	21.56	1.19	18.11
Boiler 08	0.28	1.10	1.10	0.09	14.49	0.80	12.17
<b>Total</b>	<b>1.50</b>	<b>6.02</b>	<b>6.02</b>	<b>0.47</b>	<b>79.16</b>	<b>4.35</b>	<b>66.49</b>

\*PM emission factor is filterable PM only. PM10 emission factor is filterable and condensable PM10 combined.  
 PM2.5 emission factor is filterable and condensable PM2.5 combined.  
 \*\*Emission Factors for NOx: Uncontrolled = 100, Low NOx Burner = 50, Low NOx Burners/Flue gas recirculation = 32

**Methodology**

All emission factors are based on normal firing.  
 MMBtu = 1,000,000 Btu  
 MMCF = 1,000,000 Cubic Feet of Gas  
 Emission Rate in lb/MMBtu = Emission Factor (lb/MMCF) / 1020 (MMBtu/MMCF)  
 Emission Factors are from AP 42, Chapter 1.4, Tables 1.4-1, 1.4-2, 1.4-3, SCC #1-02-006-02, 1-01-006-02, 1-03-006-02, and 1-03-006-03  
 Potential Throughput (MMCF) = Heat Input Capacity (MMBtu/hr) x 8,760 hrs/yr x 1 MMCF/1,020 MMBtu  
 Emission (tons/yr) = Throughput (MMCF/yr) x Emission Factor (lb/MMCF)/2,000 lb/ton

**HAPs Emissions**

Emission Factor in lb/MMcf	HAPs - Organics (tons/yr)				
	Benzene	Dichlorobenzene	Formaldehyde	Hexane	Toluene
	2.1E-03	1.2E-03	7.5E-02	1.8E+00	3.4E-03
Boiler 05	4.527E-04	2.587E-04	1.617E-02	3.880E-01	7.329E-04
Boiler 06	4.527E-04	2.587E-04	1.617E-02	3.880E-01	7.329E-04
Boiler 07	4.527E-04	2.587E-04	1.617E-02	3.880E-01	7.329E-04
Boiler 08	3.043E-04	1.739E-04	1.087E-02	2.608E-01	4.927E-04
<b>Total</b>	<b>1.66E-03</b>	<b>9.50E-04</b>	<b>5.94E-02</b>	<b>1.42E+00</b>	<b>2.69E-03</b>

**HAPs - Metals (tons/yr)**

Emission Factor in lb/MMcf	HAPs - Metals (tons/yr)				
	Lead	Cadmium	Chromium	Manganese	Nickel
	5.0E-04	1.1E-03	1.4E-03	3.8E-04	2.1E-03
Boiler 05	1.078E-04	2.371E-04	3.018E-04	8.191E-05	4.527E-04
Boiler 06	1.078E-04	2.371E-04	3.018E-04	8.191E-05	4.527E-04
Boiler 07	1.078E-04	2.371E-04	3.018E-04	8.191E-05	4.527E-04
Boiler 08	7.245E-05	1.594E-04	2.029E-04	5.507E-05	3.043E-04
<b>Total</b>	<b>3.96E-04</b>	<b>8.71E-04</b>	<b>1.11E-03</b>	<b>3.01E-04</b>	<b>1.66E-03</b>

Methodology is the same as above.  
 The five highest organic and metal HAPs emission factors are provided above.  
 Additional HAPs emission factors are available in AP-42, Chapter 1.4.

**Greenhouse Gas Emissions**

Emission Factor in lb/MMcf	Greenhouse Gas (tons/yr)		
	CO2	CH4	N2O
	120,000	2.3	2.2
Boiler 05	25,868	0.5	0.5
Boiler 06	25,868	0.5	0.5
Boiler 07	25,868	0.5	0.5
Boiler 08	17,389	0.3	0.3
Boiler 05		26.021	
Boiler 06		26.021	
Boiler 07		26.021	
Boiler 08		17.492	
<b>CO2e Total (tons/yr)</b>		<b>95.557</b>	

**Methodology**

The N2O Emission Factor for uncontrolled is 2.2. The N2O Emission Factor for low Nox burner is 0.64.  
 Emission Factors are from AP 42, Table 1.4-2 SCC #1-02-006-02, 1-01-006-02, 1-03-006-02, and 1-03-006-03.  
 Global Warming Potentials (GWP) from Table A-1 of 40 CFR Part 98 Subpart A.  
 Emission (tons/yr) = Throughput (MMCF/yr) x Emission Factor (lb/MMCF)/2,000 lb/ton  
 CO2e (tons/yr) = CO2 Potential Emission ton/yr x CO2 GWP (1) + CH4 Potential Emission ton/yr x CH4 GWP (25) + N2O Potential Emission ton/yr x N2O GWP (298).

**Appendix A: Emissions Calculations**  
**Commercial/Institutional/Residential Combustors (< 100 mmBtu/hr)**  
**No. 2 Fuel Oil**

**Company Name:** Griffin Industries LLC  
**Address City IN Zip:** 7358 South Griffin Road, Newberry, Indiana, 47499-9729  
**Significant Permit Modification Number:** 055-34320-00008  
**Significant Source Modification Number:** 055-34253-00008  
**Reviewer:** Nida Habeeb  
**Application Received:** 03/03/2014

	Heat Input Capacity MMBtu/hr	Potential Throughput kgals/year	S = Weight % Sulfur <span style="border: 1px solid black; padding: 2px;">0.5</span>
Boiler 05	50.2	3141.09	
Boiler 06	50.2	3141.09	
Boiler 07	50.2	3141.09	
Boiler 08	33.746	2111.54	

Emission Factor in lb/kgal	Pollutant (tons/yr)						
	PM*	PM10	direct PM2.5	SO2 71 (142.0S)	NOx 20.0	VOC 0.34	CO 5.0
Emission Rate in lb/MMBtu	0.014	0.017	0.015	0.507	0.143	0.002	0.036
Boiler 05	3.1	3.7	3.3	111.5	31.4	0.5	7.9
Boiler 06	3.1	3.7	3.3	111.5	31.4	0.5	7.9
Boiler 07	3.1	3.7	3.3	111.5	31.4	0.5	7.9
Boiler 08	2.1	2.5	2.2	75.0	21.1	0.4	5.3
<b>0</b>	<b>11.5</b>	<b>13.7</b>	<b>12.3</b>	<b>409.5</b>	<b>115.3</b>	<b>2.0</b>	<b>28.8</b>

**Methodology**

Heating Value of No.2 Oil = 140 MMBtu/kgal  
 1 gallon of No. 2 Fuel Oil has a heating value of 140,000 Btu  
 Potential Throughput (kgals/year) = Heat Input Capacity (MMBtu/hr) x 8,760 hrs/yr x 1kgal per 1000 gallon x 1 gal per 0.140 MM Btu  
 Emission Factors are from AP 42, Tables 1.3-1, 1.3-2, and 1.3-3 (SCC 1-03-005-01/02/03) Supplement E 9/98.  
 \*PM emission factor is filterable PM only. Condensable PM emission factor is 1.3 lb/kgal.  
 Emission (tons/yr) = Throughput (kgals/ yr) x Emission Factor (lb/kgal)/2,000 lb/ton  
 Emission Rate in lb/MMBtu = Emission Factor (lb/kgal) / 140 (MMBtu/kgal)

**HAPs Emissions**

Emission Factor in lb/mmBtu	HAPs - Metals (tons/yr)				
	Arsenic 4.0E-06	Beryllium 3.0E-06	Cadmium 3.0E-06	Chromium 3.0E-06	Lead 9.0E-06
Boiler 05	8.80E-04	6.60E-04	6.60E-04	6.60E-04	1.98E-03
Boiler 06	8.80E-04	6.60E-04	6.60E-04	6.60E-04	1.98E-03
Boiler 07	8.80E-04	6.60E-04	6.60E-04	6.60E-04	1.98E-03
Boiler 08	5.91E-04	4.43E-04	4.43E-04	4.43E-04	1.33E-03
<b>0</b>	<b>3.23E-03</b>	<b>2.42E-03</b>	<b>2.42E-03</b>	<b>2.42E-03</b>	<b>7.27E-03</b>

Emission Factor in lb/mmBtu	HAPs - Metals (tons/yr)			
	Mercury 3.0E-06	Manganese 6.0E-06	Nickel 3.0E-06	Selenium 1.5E-05
Boiler 05	6.60E-04	1.32E-03	6.60E-04	3.30E-03
Boiler 06	6.60E-04	1.32E-03	6.60E-04	3.30E-03
Boiler 07	6.60E-04	1.32E-03	6.60E-04	3.30E-03
Boiler 08	4.43E-04	8.87E-04	4.43E-04	2.22E-03
<b>0</b>	<b>2.42E-03</b>	<b>4.84E-03</b>	<b>2.42E-03</b>	<b>1.21E-02</b>

**Methodology**

No data was available in AP-42 for organic HAPs.  
 Potential Emissions (tons/year) = Throughput (mmBtu/hr)\*Emission Factor (lb/mmBtu)\*8,760 hrs/yr / 2,000 lb/ton

**Greenhouse Gas Emissions**

Emission Factor in lb/kgal	Greenhouse Gas		
	CO2 21,500	CH4 0.216	N2O 0.26
Boiler 05	33,767	0.3	0.4
Boiler 06	33,767	0.3	0.4
Boiler 07	33,767	0.3	0.4
Boiler 08	22,699	0.2	0.3
Boiler 05	33,897		
Boiler 06	33,897		
Boiler 07	33,897		
Boiler 08	22,787		
<b>CO2e Total (tons/yr)</b>	<b>124,477</b>		

**Methodology**

The CO2 Emission Factor for No. 1 Fuel Oil is 21500. The CO2 Emission Factor for No. 2 Fuel Oil is 22300.  
 Emission Factors are from AP 42, Tables 1.3-3, 1.3-8, and 1.3-12 (SCC 1-03-005-01/02/03) Supplement E 9/99 (see erata file)  
 Global Warming Potentials (GWP) from Table A-1 of 40 CFR Part 98 Subpart A.  
 Emission (tons/yr) = Throughput (kgals/ yr) x Emission Factor (lb/kgal)/2,000 lb/ton  
 CO2e (tons/yr) = CO2 Potential Emission ton/yr x CO2 GWP (1) + CH4 Potential Emission ton/yr x CH4 GWP (25) + N2O Potential Emission ton/yr x N2O GWP (298).

**Appendix A: Emissions Calculations  
Waste Oil Combustion  
Small Boiler**

**Company Name:** Griffin Industries LLC  
**Address City IN Zip:** 7358 South Griffin Road, Newberry, Indiana, 47499-9729  
**Significant Permit Modification Number:** 055-34320-00008  
**Significant Source Modification Number:** 055-34253-00008  
**Reviewer:** Nida Habeeb  
**Application Received:** 03/03/2014

Heating Value of Waste Oil = 139 MMBtu/kgal

Heat Input Capacity MMBtu/hr	Potential Throughput kgals/year	A = Weight % Ash =	S = Weight % Sulfur =
Boiler 05	50.2	3163.68	0.56
Boiler 06	50.2	3163.68	0.5
Boiler 07	50.2	3163.68	
Boiler 08	33.746	2126.73	

Emission Factor in lb/kgal	Pollutant (tons/yr)						
	PM*	PM10*	PM2.5**	SO2	NOx	VOC	CO
	35.8 (64A)	28.56 (51A)	28.56 (51A)	73.5 (147S)	19.0	1.0	5.0
Emission Rate in lb/MMBtu	0.258	0.205	0.205	0.529	0.137	0.007	0.036
Boiler 05	56.7	45.2	45.2	116.3	30.1	1.6	7.9
Boiler 06	56.7	45.2	45.2	116.3	30.1	1.6	7.9
Boiler 07	56.7	45.2	45.2	116.3	30.1	1.6	7.9
Boiler 08	38.1	30.4	30.4	78.2	20.2	1.1	5.3
0	208.2	165.9	165.9	427.0	110.4	5.8	29.0

\*No information was given in AP-42 regarding whether the PM/PM10 emission factors included filterable and condensable PM.  
 \*\* No direct PM2.5 emission factor was given. Direct PM2.5 is a subset of PM10. If one assumes all PM10 to be all direct PM2.5, then a worst case assumption of direct PM2.5 can be made, notwithstanding the filterable and condensable issue for mentioned.

**Methodology**

Heating Value of Waste Oil = 139 MMBtu/kgal  
 Emission Factor Units are lb/1000 gal  
 Emission Rate in lb/MMBtu = Emission Factor (lb/kgal) / 139 (MMBtu/kgal)  
 A = weight% ash in fuel, L = weight% lead in fuel, S = weight % sulfur in fuel  
 Potential Throughput (kgals/year) = Heat Input Capacity (MMBtu/hr) x 8,760 hrs/yr x 1kgal per 1000 gallon x 1 gal per 0.139 MM Btu  
 Emission Factors from AP-42, Chapter 1.11, SCC 1-03-013-02 (Supplement B 10/96)  
 Emission (tons/yr) = Throughput kgals per year x Emission Factor (lb/kgal)/2,000 lb/ton

**HAPs Calculations**

Emission Factor in lb/kgal	Pollutant (tons/yr)					
	Arsenic	Cadmium	Chromium	Manganese	Nickel	Cobalt
	1.1E-01	9.3E-03	2.0E-02	6.8E-02	1.1E-02	2.1E-04
Boiler 05	1.74E-01	1.47E-02	3.16E-02	1.08E-01	1.74E-02	3.32E-04
Boiler 06	1.74E-01	1.47E-02	3.16E-02	1.08E-01	1.74E-02	3.32E-04
Boiler 07	1.74E-01	1.47E-02	3.16E-02	1.08E-01	1.74E-02	3.32E-04
Boiler 08	1.17E-01	9.89E-03	2.13E-02	7.23E-02	1.17E-02	2.23E-04
0	6.39E-01	5.40E-02	1.16E-01	3.95E-01	6.39E-02	1.22E-03
						1.27E+00

Methodology is the same as above.

**Greenhouse Gas Calculations**

Emission Factor in kg/mmBtu	Greenhouse Gas (tons/yr)		
	CO2	CH4	N2O
Emission Factor in kg/mmBtu	74	0.003	0.0006
Emission Factor in lb/mmBtu	163.36	0.007	0.001
Emission Factor in lb/kgal	22706.40	0.92	0.18
Boiler 05	35,871	1.5	0.3
Boiler 06	35,871	1.5	0.3
Boiler 07	35,871	1.5	0.3
Boiler 08	24,114	1.0	0.2
Boiler 05		35,994	
Boiler 06		35,994	
Boiler 07		35,994	
Boiler 08		24,196	
CO2e Total (tons/yr)		132,178	

**Methodology**

Emission Factor Units are in kg/mmBtu.  
 Emission Factors from Tables C-1 and 2 of 40 CFR Part 98 Subpart C. Waste oil is called Used oil in 40 CFR 98.  
 Global+A35 Warming Potentials (GWP) from Table A-1 of 40 CFR Part 98 Subpart A.  
 Emission Factor (lb/kgal) = Emission Factor (lb/mmBtu) \* Heating Value of Waste Oil (MMBtu/kgal)  
 Potential Emission (tons/yr) = Heat Input Capacity mmBtu/hr x Emission Factor (kg/mmBtu) x 2.20462 lb/kg x 8760 hrs/yr /2,000 lb/ton  
 CO2e (tons/yr) = CO2 Potential Emission ton/yr x CO2 GWP (1) + CH4 Potential Emission ton/yr x CH4 GWP (25) + N2O Potential Emission ton/yr x N2O GWP (298).

**Appendix A: Emissions Calculations  
Processed Grease Combustion**

**Company Name:** Griffin Industries LLC  
**Address City IN Zip:** 7358 South Griffin Road, Newberry, Indiana, 47499-9729  
**Significant Permit Modification Number:** 055-34320-00008  
**Significant Source Modification Number:** 055-34253-00008  
**Reviewer:** Nida Habeeb  
**Application Received:** 03/03/2014

Heating Value of processed grease = 125.00 MMBtu/kgal

	Heat Input Capacity MMBtu/hr
Boiler 05	50.2
Boiler 06	50.2
Boiler 07	50.2
Boiler 08	33.7
	184.3

Emission Factor in lb/MMBtu	Pollutant (tons/yr)						
	PM*	PM10*	PM2.5	SO2	NOx	VOC	CO
	0.010	0.010	0.010	0.0003	0.159	0.00	0.022
Boiler 05	2.20	2.20	2.20	0.07	34.96	0.00	4.84
Boiler 06	2.20	2.20	2.20	0.07	34.96	0.00	4.84
Boiler 07	2.20	2.20	2.20	0.07	34.96	0.00	4.84
Boiler 08	1.48	1.48	1.48	0.04	23.50	0.00	3.25
<b>Total</b>	<b>8.07</b>	<b>8.07</b>	<b>8.07</b>	<b>0.24</b>	<b>128.38</b>	<b>0.00</b>	<b>17.76</b>

\*PM emission factor is filterable PM only. PM10 emission factor is filterable and condensable PM10 combined.  
 The processed grease emission factors used were based on stack test performed for existing boilers in 2001.

**Methodology**

Processed grease Heating Value = 125,000 Btu/gal  
 Emission (tons/yr) = MMBtu/hr x Emission Factor (lb/MMBtu) x 8760 hrs/yr x ton/2000 lb

Emission Factor in kg/mmBtu from 40 CFR 98	Greenhouse Gas (tons/yr)		
	CO2	CH4	N2O
Emission Factor in lb/kgal	71.06	0.0011	0.00011
	19,608.17	0.30	0.03
Boiler 05	34,446	0.5	0.1
Boiler 06	34,446	0.5	0.1
Boiler 07	34,446	0.5	0.1
Boiler 08	23,156	0.4	0.0
Boiler 05	34,475		
Boiler 06	34,475		
Boiler 07	34,475		
Boiler 08	23,175		
<b>CO2e Total (tons/yr)</b>	<b>126,600</b>		

**Methodology**

Emission Factors from Tables C-1 and 2 of 40 CFR Part 98 Subpart C.  
 Global+A35 Warming Potentials (GWP) from Table A-1 of 40 CFR Part 98 Subpart A.  
 Emission Factor (lb/kgal) = Emission Factor (kg/mmBtu) \* 2.20462 (lb/kg) \* Heating Value of Processed Grease (MMBtu/kgal)  
 Potential Emission (tons/yr) = Heat Input Capacity mmBtu/hr x Emission Factor (kg/mmBtu) x 2.20462 lb/kg x 8760 hrs/yr /2,000 lb/ton  
 CO2e (tons/yr) = CO2 Potential Emission ton/yr x CO2 GWP (1) + CH4 Potential Emission ton/yr x CH4 GWP (25) + N2O Potential Emission ton/yr x N2O GWP (298).

**Appendix A: Emissions Calculations  
Rendering Operation and Silos**

**Company Name:** Griffin Industries LLC  
**Address City IN Zip:** 7358 South Griffin Road, Newberry, Indiana, 47499-9729  
**Significant Permit Modification Number:** 055-34320-00008  
**Significant Source Modification Number:** 055-34253-00008  
**Reviewer:** Nida Habeeb  
**Application Received:** 03/03/2014

**Animal and agricultural byproducts rendering operation**

		Poultry meal/fat making operation	Feather meal making operation	Blood meal making operation	
	Production Rate	tons/hr	10.15	2.88	1.00
Controlled Emission Factor (lb/ton)	VOC	lb/ton	0.39 *	0.34 *	0.39 *
	PM	lb/ton	0.10 *	1.22 ** ***	1.22 ** ***
	PM10	lb/ton	0.06 *	1.22 **	1.22 **
	PM2.5	lb/ton	0.04 *	0.46 **	0.46 **
	H2S	lb/ton	0.08 *	0.08 **	0.08 **
Controlled Emission Rate (tons/yr)	VOC	tpy	24.90	4.34	1.69
	PM	tpy	4.22	15.39	5.34
	PM10	tpy	2.62	15.39	5.34
	PM2.5	tpy	1.60	5.80	2.01
	H2S	tpy	3.56	1.01	0.35
Uncontrolled Emission Rate (tons/yr)	VOC	tpy	24.9	24.9	24.9
	PM	tpy	42.2	153.9	53.4
	PM10	tpy	26.2	153.9	53.4
	PM2.5	tpy	16.0	58.0	20.1
	H2S	tpy	35.6	5.0	1.75

**Methodology**

\* Emission factors are supplied by the source and which are derived from the stack test conducted at similar facility Griffin's Butler, Kentucky.

\*\* AP42 Table 9.5.3-2 emission factors have been used. Although these emission factors are specified for blood dryer process, these emission factors are also used for Feather meal making process for calculation purpose.

\*\*\* AP42 Table 9.5.3-2 states that the filterable PM was found to be 100 percent PM-10.

Controlled Emission Rate (tons/yr) = production rate (tons/hr) x Controlled Emission Factor (lb/ton) x 8760 hrs/yr x ton/2000 lb

VOC testing requirement has been added in the permit to determine uncontrolled emission rates.

Uncontrolled PM, PM10, PM2.5 and H2S Emission Rate (tons/yr) = Controlled Emission Rate (tons/yr) / (1-(Scrubber Efficiency /100))

Scrubber Efficiencies are assumed as follows: 90% for PM, PM10 and PM2.5 and 80% for H2S

**Silos**

Uncontrolled Emission Rate for each silo (lb/hr)	# silos	Uncontrolled Emission Rate (tons/yr)
less than 0.55	4	9.64

**Methodology**

Uncontrolled Emission Rate (tons/yr) = Uncontrolled Emission Rate for each silo (lb/hr) x # silos x 8760 hrs/yr x ton/2000 lb

**Appendix A: Emissions Calculations  
Summary of Modification**

**Company Name:** Griffin Industries LLC  
**Address City IN Zip:** 7358 South Griffin Road, Newberry, Indiana, 47499-9729  
**Significant Permit Modification Number:** 055-34320-00008  
**Significant Source Modification Number:** 055-34253-00008  
**Reviewer:** Nida Habeeb  
**Application Received:** 03/03/2014

Uncontrolled PTE of Modifications (tons/yr)

Process or Emission Unit Modified	PM	PM10	direct PM2.5	SO2***	NOx	VOC*	CO	CO2e **	H2S
Blood meal making operation	53.44	53.44	20.15	-	-	24.90	-	-	1.75
<b>Uncontrolled PTE of the Modification (TPY)</b>	<b>53.44</b>	<b>53.44</b>	<b>20.15</b>	<b>0.00</b>	<b>0.00</b>	<b>24.90</b>	<b>0.00</b>	<b>0.00</b>	<b>1.75</b>

Controlled/ Limited PTE of Modifications (tons/yr)

Process or Emission Unit Modified	PM	PM10	direct PM2.5	SO2***	NOx	VOC*	CO	CO2e **	H2S
Blood meal making operation	5.34	5.34	2.01	-	-	24.90	-	-	0.35
<b>Controlled PTE of the Modification (TPY)</b>	<b>5.34</b>	<b>5.34</b>	<b>2.01</b>	<b>0.00</b>	<b>0.00</b>	<b>24.90</b>	<b>0.00</b>	<b>0.00</b>	<b>0.35</b>

\* VOC controls are not federally enforceable in the permit. Therefore, uncontrolled numbers have been used.

\*\* CO2e PTE is based on PSD Minor Limit - CO2e [326 IAC 2-2] in the permit.

\*\*\* SO2 PTE is based on the PSD Minor Limit - SO2 [326 IAC 2-2] in the permit

**Appendix A: Emissions Calculations  
Summary**

**Company Name:** Griffin Industries LLC  
**Address City IN Zip:** 7358 South Griffin Road, Newberry, Indiana, 47499-9729  
**Significant Permit Modification Number:** 055-34320-00008  
**Significant Source Modification Number:** 055-34253-00008  
**Reviewer:** Nida Habeeb  
**Application Received:** 03/03/2014

Uncontrolled Emissions (tons/yr)

Process or Emission Unit Modified	PM	PM10	direct PM2.5	SO2***	NOx	VOC*	CO	CO2e **	H2S
Fuel Combustion	208.19	165.90	165.90	426.95	110.37	5.81	29.04	126,600	-
Poultry meal/fat making operation	42.23	26.23	16.00	-	-	24.90	-	-	35.57
Feather meal making operation	153.90	153.90	58.03	-	-	24.90	-	-	5.05
Blood meal making operation	53.44	53.44	20.15	-	-	24.90	-	-	1.75
Silos	9.64	9.64	9.64	-	-	-	-	-	-
<b>Total</b>	<b>467.39</b>	<b>409.10</b>	<b>269.72</b>	<b>426.95</b>	<b>110.37</b>	<b>80.51</b>	<b>29.04</b>	<b>126,600</b>	<b>42.36</b>

Controlled/Limited Emissions (tons/yr)

Process or Emission Unit Modified	PM	PM10	direct PM2.5	SO2***	NOx	VOC*	CO	CO2e **	H2S
Fuel Combustion	208.19	165.90	165.90	249.00	110.37	5.81	29.04	99,999	-
Poultry meal/fat making operation	4.22	2.62	1.60	-	-	24.90	-	-	3.56
Feather meal making operation	15.39	15.39	5.80	-	-	24.90	-	-	1.01
Blood meal making operation	5.34	5.34	2.01	-	-	24.90	-	-	0.35
Silos	9.64	9.64	9.64	-	-	-	-	-	-
<b>Total</b>	<b>242.78</b>	<b>198.89</b>	<b>184.96</b>	<b>249.00</b>	<b>110.37</b>	<b>80.51</b>	<b>29.04</b>	<b>99,999</b>	<b>4.92</b>

\* VOC controls are not federally enforceable in the permit. Therefore, uncontrolled numbers have been used.

\*\* CO2e PTE is based on PSD Minor Limit - CO2e [326 IAC 2-2] in the permit.

\*\*\* SO2 PTE is based on the PSD Minor Limit - SO2 [326 IAC 2-2] in the permit



# INDIANA DEPARTMENT OF ENVIRONMENTAL MANAGEMENT

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*Governor*

**Thomas W. Easterly**  
*Commissioner*

## SENT VIA U.S. MAIL: CONFIRMED DELIVERY AND SIGNATURE REQUESTED

**TO:** F Michael Schmidt  
Griffin Industries LLC  
4221 Alexandria Pike  
Cold Spring, KY 41076-1897

**DATE:** September 4, 2014

**FROM:** Matt Stuckey, Branch Chief  
Permits Branch  
Office of Air Quality

**SUBJECT:** Final Decision  
Title V - Significant Permit Modification  
055 - 34320 - 00008

Enclosed is the final decision and supporting materials for the air permit application referenced above. Please note that this packet contains the original, signed, permit documents.

The final decision is being sent to you because our records indicate that you are the contact person for this application. However, if you are not the appropriate person within your company to receive this document, please forward it to the correct person.

A copy of the final decision and supporting materials has also been sent via standard mail to:  
Don Muchow, District Manager  
OAQ Permits Branch Interested Parties List

If you have technical questions regarding the enclosed documents, please contact the Office of Air Quality, Permits Branch at (317) 233-0178, or toll-free at 1-800-451-6027 (ext. 3-0178), and ask to speak to the permit reviewer who prepared the permit. If you think you have received this document in error, please contact Joanne Smiddie-Brush of my staff at 1-800-451-6027 (ext 3-0185), or via e-mail at [jbrush@idem.IN.gov](mailto:jbrush@idem.IN.gov).

Final Applicant Cover letter.dot 6/13/2013



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**Michael R. Pence**  
*Governor*

**Thomas W. Easterly**  
*Commissioner*

September 4, 2014

TO: Bloomfield Eastern Greene Co Public Library 125 S Franklin St Bloomfield IN

From: Matthew Stuckey, Branch Chief  
Permits Branch  
Office of Air Quality

Subject: **Important Information for Display Regarding a Final Determination**

**Applicant Name: Griffin Industries LLC**  
**Permit Number: 055 - 34320 - 00008**

You previously received information to make available to the public during the public comment period of a draft permit. Enclosed is a copy of the final decision and supporting materials for the same project. Please place the enclosed information along with the information you previously received. To ensure that your patrons have ample opportunity to review the enclosed permit, **we ask that you retain this document for at least 60 days.**

The applicant is responsible for placing a copy of the application in your library. If the permit application is not on file, or if you have any questions concerning this public review process, please contact Joanne Smiddie-Brush, OAQ Permits Administration Section at 1-800-451-6027, extension 3-0185.

Enclosures  
Final Library.dot 6/13/2013

# Mail Code 61-53

IDEM Staff	LPOGOST 9/4/2014 Griffin Industries, LLC - Newberry 055 - 34320 - 00008 /final)		AFFIX STAMP HERE IF USED AS CERTIFICATE OF MAILING	
Name and address of Sender		Indiana Department of Environmental Management Office of Air Quality – Permits Branch 100 N. Senate Indianapolis, IN 46204	Type of Mail:  <b>CERTIFICATE OF MAILING ONLY</b>	

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											Remarks
1		F Michael Schmidt Griffin Industries, LLC - Newberry 4221 Alexandria Pike Cold Spring KY 41076-1897 (Source CAATS) Via confirmed delivery									
2		Don Muchow District Manager Griffin Industries, LLC - Newberry 7358 S Griffin Rd Newberry IN 47449 (RO CAATS)									
3		Bloomfield Eastern Greene Co Public Library 125 S Franklin St Bloomfield IN 47424-1406 (Library)									
4		Greene County Health Department 217 East Spring Street #1 Bloomfield IN 47424-1440 (Health Department)									
5		Bledsoe Resident 411 N. Co. Road 525 E. Sullivan IN 47882 (Affected Party)									
6		Newberry Town Council P.O. Box 7 Newberry IN 47449 (Local Official)									
7		Greene County Board of Commissioners Court house Square #133 C/O Auditor office Bloomfield IN 47424 (Local Official)									
8		Mr. Kevin Keller 761 Walnut Street Newberry IN 47449 (Affected Party)									
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