



# INDIANA DEPARTMENT OF ENVIRONMENTAL MANAGEMENT

*We Protect Hoosiers and Our Environment.*

*Mitchell E. Daniels Jr.*  
Governor

*Thomas W. Easterly*  
Commissioner

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

TO: Interested Parties / Applicant

DATE: December 11, 2012

RE: Bunge North America (East), LLC / 001-32520-00005

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

## 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 enclosed matter. Pursuant to IC 13-17-3-4 and 326 IAC 2, this approval 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.

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) calendar 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.

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.

Enclosures  
FNPER-MOD.dot 12/3/07



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Ms. Christine Thomas  
Bunge North America (East), LLC  
1200 North 2<sup>nd</sup> Street  
Decatur, IN 46733

December 11, 2012

Re: 001-32520-00005  
Minor Source Modification to:  
Part 70 permit No.: T001-23640-00005

Dear Ms. Thomas:

Bunge North America (East), LLC was issued Part 70 Operating Permit Renewal No. T001-23640-00005 on April 8, 2008 for a stationary grain handling, soybean meal production, and soybean oil extraction plant. An application to modify the source was received on November 16, 2012. Pursuant to 326 IAC 2-7-10.5 the following emission units are approved for construction at the source:

- (fff) One (1) natural gas-fired boiler, identified as 9SP1, approved for construction in 2012, with a maximum heat input capacity of 99 MMBtu/hr, equipped with low NOx burners and flue gas recirculation (FGR) for NOx control, and exhausting to stack 9SP. This is an affected facility under the New Source Performance Standards for Small Industrial - Commercial - Institutional Steam Generating Units 40 CFR 60, Subpart Dc and an affected source under the National Emission Standards for Hazardous Air Pollutants for Industrial, Commercial, and Institutional Boilers and Process Heaters 40 CFR 63, Subpart DDDDD.

The following construction conditions are applicable to the proposed project:

General Construction Conditions

1. The data and information supplied with the application shall be considered part of this source modification approval. Prior to any proposed change in construction which may affect the potential to emit (PTE) of the proposed project, the change must be approved by the Office of Air Quality (OAQ).
2. This approval to construct does not relieve the Permittee of the responsibility to comply with the provisions of the Indiana Environmental Management Law (IC 13-11 through 13-20; 13-22 through 13-25; and 13-30), the Air Pollution Control Law (IC 13-17) and the rules promulgated thereunder, as well as other applicable local, state, and federal requirements.
3. Effective Date of the Permit  
Pursuant to IC 13-15-5-3, this approval becomes effective upon its issuance.

4. Pursuant to 326 IAC 2-1.1-9 and 326 IAC 2-7-10.5(j), the Commissioner may revoke this approval if construction is not commenced within eighteen (18) months after receipt of this approval or if construction is suspended for a continuous period of one (1) year or more.
5. All requirements and conditions of this construction approval shall remain in effect unless modified in a manner consistent with procedures established pursuant to 326 IAC 2.
6. Pursuant to 326 IAC 2-7-10.5(m) the emission units constructed under this approval shall not be placed into operation prior to revision of the source's Part 70 Operating Permit to incorporate the required operation conditions.

The source may begin construction when the source modification has been issued. The source must comply with the requirements of 326 IAC 2-7-10.5(m)(2) and 326 IAC 2-7-12 before operation of any of the proposed emission units can begin.

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 call (800) 451-6027, and ask for Brian Williams or extension 4-5375, or dial (317) 234-5375.

Sincerely,



Iryn Calilung, Section Chief  
Permits Branch  
Office of Air Quality

Attachments: Technical Support Document and revised permit

IC/BMW

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



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## Minor Source Modification to a Part 70 Source

### OFFICE OF AIR QUALITY

**Bunge North America (East), LLC**  
**1200 N. 2nd Street, Decatur, Indiana 46733**

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

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. This permit also addresses certain new source review requirements for existing equipment and is intended to fulfill the new source review procedures pursuant to 326 IAC 2-7-10.5, applicable to those conditions

Minor Source Modification No.:001-32520-00005	
Issued by:  Iryn Calilung, Section Chief Permits Branch Office of Air Quality	Issuance Date: December 11, 2012

## TABLE OF CONTENTS

<b>A</b>	<b>SOURCE SUMMARY</b>	<b>6</b>
A.1	General Information [326 IAC 2-7-4(c)] [326 IAC 2-7-5(15)] [326 IAC 2-7-1(22)]	
A.2	Emission Units and Pollution Control Equipment Summary [326 IAC 2-7-4(c)(3)] [326 IAC 2-7-5(15)]	
A.3	Specifically Regulated Insignificant Activities [326 IAC 2-7-1(21)] [326 IAC 2-7-4(c)] [326 IAC 2-7-5(15)]	
A.4	Insignificant Activities [326 IAC 2-7-1(21)] [326 IAC 2-7-4(c)] [326 IAC 2-7-5(15)]	
A.5	Part 70 Permit Applicability [326 IAC 2-7-2]	
<b>B</b>	<b>GENERAL CONDITIONS</b>	<b>17</b>
B.1	Definitions [326 IAC 2-7-1]	
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)]	
B.3	Term of Conditions [326 IAC 2-1.1-9.5]	
B.4	Enforceability [326 IAC 2-7-7] [IC 13-17-12]	
B.5	Severability [326 IAC 2-7-5(5)]	
B.6	Property Rights or Exclusive Privilege [326 IAC 2-7-5(6)(D)]	
B.7	Duty to Provide Information [326 IAC 2-7-5(6)(E)]	
B.8	Certification [326 IAC 2-7-4(f)] [326 IAC 2-7-6(1)] [326 IAC 2-7-5(3)(C)]	
B.9	Annual Compliance Certification [326 IAC 2-7-6(5)]	
B.10	Preventive Maintenance Plan [326 IAC 2-7-5(1),(3) and (13)] [326 IAC 2-7-6(1) and (6)] [326 IAC 1-6-3]	
B.11	Emergency Provisions [326 IAC 2-7-16]	
B.12	Permit Shield [326 IAC 2-7-15] [326 IAC 2-7-20] [326 IAC 2-7-12]	
B.13	Prior Permits Superseded [326 IAC 2-1.1-9.5] [326 IAC 2-7-10.5]	
B.14	Termination of Right to Operate [326 IAC 2-7-10] [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]	
B.16	Permit Renewal [326 IAC 2-7-3] [326 IAC 2-7-4] [326 IAC 2-7-8(e)]	
B.17	Permit Amendment or Modification [326 IAC 2-7-11] [326 IAC 2-7-12]	
B.18	Permit Revision Under Economic Incentives and Other Programs [326 IAC 2-7-5(8)] [326 IAC 2-7-12(b)(2)]	
B.19	Operational Flexibility [326 IAC 2-7-20] [326 IAC 2-7-10.5]	
B.20	Source Modification Requirement [326 IAC 2-7-10.5]	
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]	
B.22	Transfer of Ownership or Operational Control [326 IAC 2-7-11]	
B.23	Annual Fee Payment [326 IAC 2-7-19] [326 IAC 2-7-5(7)] [326 IAC 2-1.1-7]	
B.24	Advanced Source Modification Approval [326 IAC 2-7-5(16)] [326 IAC 2-7-10.5]	
B.25	Credible Evidence [326 IAC 2-7-5(3)] [326 IAC 2-7-6] [62 FR 8314] [326 IAC 1-1-6]	
<b>C</b>	<b>SOURCE OPERATION CONDITIONS</b>	<b>28</b>
	<b>Emission Limitations and Standards [326 IAC 2-7-5(1)]</b>	
C.1	Particulate Emission Limitations For Processes with Process Weight Rates Less Than One Hundred (100) Pounds per Hour [326 IAC 6-3-2]	
C.2	Opacity [326 IAC 5-1]	
C.3	Open Burning [326 IAC 4-1] [IC 13-17-9]	
C.4	Incineration [326 IAC 4-2] [326 IAC 9-1-2]	
C.5	Fugitive Dust Emissions [326 IAC 6-4]	
C.6	Stack Height [326 IAC 1-7]	
C.7	Asbestos Abatement Projects [326 IAC 14-10] [326 IAC 18] [40 CFR 61, Subpart M]	
	<b>Testing Requirements [326 IAC 2-7-6(1)]</b>	
C.8	Performance Testing [326 IAC 3-6]	

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

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

**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)]

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

**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]

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

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

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

**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]

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

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

**Stratospheric Ozone Protection**

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

**D.1 EMISSIONS UNIT OPERATION CONDITIONS**

**36**

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

D.1.1 PSD Minor Limits [326 IAC 2-2]

D.1.2 PSD Minor Limits [326 IAC 2-2]

D.1.3 Particulate Matter (PM) [326 IAC 6-3-2]

D.1.4 Preventive Maintenance Plan [326 IAC 2-7-5(13)]

**Compliance Determination Requirements [326 IAC 2-7-5(1)] [326 IAC 2-7-6(1)]**

D.1.5 Testing Requirements [326 IAC 2-7-6(1),(6)] [326 IAC 2-1.1-11]

D.1.6 Particulate Matter (PM) [40 CFR 64 (CAM)]

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

D.1.7 Visible Emissions Notations [40 CFR 64 (CAM)]

D.1.8 Parametric Monitoring [40 CFR 64 (CAM)]

D.1.9 Broken or Failed Bag Detection [40 CFR 64 (CAM)]

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

D.1.10 Record Keeping Requirements

D.1.11 Reporting Requirements

**D.2 EMISSIONS UNIT OPERATION CONDITIONS**

**43**

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

D.2.1 PSD Minor Limits [326 IAC 2-2]

D.2.2 Particulate Matter (PM) [326 IAC 6-3-2]

D.2.3 Preventive Maintenance Plan [326 IAC 2-7-5(13)]

**Compliance Determination Requirements [326 IAC 2-7-5(1)] [326 IAC 2-7-6(1)]**

D.2.4 Testing Requirements [326 IAC 2-7-6(1),(6)] [326 IAC 2-1.1-11]

D.2.5 Particulate Matter (PM) [40 CFR 64 (CAM)]

D.2.6 Particulate Matter (PM)

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

D.2.7 Visible Emissions Notations [40 CFR 64 (CAM)]

D.2.8 Parametric Monitoring [40 CFR 64 (CAM)]

D.2.9 Broken or Failed Bag Detection [40 CFR 64 (CAM)]

D.2.10 Cyclone Failure Detection [40 CFR 64 (CAM)]

	<b>Record Keeping and Reporting Requirement [326 IAC 2-7-5(3)] [326 IAC 2-7-19]</b>	
	D.2.11 Record Keeping Requirements	
	D.2.12 Reporting Requirements	
<b>D.3</b>	<b>EMISSIONS UNIT OPERATION CONDITIONS</b>	<b>52</b>
	<b>Emission Limitations and Standards [326 IAC 2-7-5(1)]</b>	
	D.3.1 Particulate Matter Limitation (PM) [326 IAC 6-2-3] [326 IAC 6-2-4]	
	D.3.2 Consent Decree Limits, Compliance, and Record Keeping Requirements	
	D.3.3 Sulfur Dioxide (SO <sub>2</sub> ) [326 IAC 7-1.1-1]	
	D.3.4 Preventive Maintenance Plan [326 IAC 2-7-5(13)]	
	<b>Compliance Determination Requirements [326 IAC 2-7-6(1)] [326 IAC 2-7-5(1)]</b>	
	D.3.5 Sulfur Dioxide Emissions and Sulfur Content [326 IAC 2-7-5(3)(A)] [326 IAC 2-7-6]	
	<b>Compliance Monitoring Requirements [326 IAC 2-7-6(1)] [326 IAC 2-7-5(1)]</b>	
	D.3.6 Visible Emissions Notations	
	D.3.7 Parametric Monitoring	
	D.3.8 Broken or Failed Bag Detection	
	D.3.9 Cyclone Failure Detection	
	<b>Record Keeping and Reporting Requirement [326 IAC 2-7-5(3)] [326 IAC 2-7-19]</b>	
	D.3.10 Record Keeping Requirements	
	D.3.11 Reporting Requirements	
	<b>Consent Decree</b>	
	D.3.12 Consent Decree Limits, Compliance, and Record Keeping Requirements	
<b>D.4</b>	<b>EMISSIONS UNIT OPERATION CONDITIONS</b>	<b>58</b>
	<b>Emission Limitations and Standards [326 IAC 2-7-5(1)]</b>	
	D.4.1 PSD Minor Limit [326 IAC 2-2]	
	D.4.2 Preventive Maintenance Plan [326 IAC 2-7-5(13)]	
	<b>Compliance Determination Requirements [326 IAC 2-7-6(1)] [326 IAC 2-7-5(1)]</b>	
	D.4.3 Volatile Organic Compounds (VOC)	
	<b>Compliance Monitoring Requirements [326 IAC 2-7-6(1)] [326 IAC 2-7-5(1)]</b>	
	D.4.4 Monitoring	
	<b>Record Keeping and Reporting Requirements [326 IAC 2-7-5(3)] [326 IAC 2-7-19]</b>	
	D.4.5 Record Keeping Requirements	
	D.4.6 Reporting Requirements	
	<b>Consent Decree</b>	
	D.4.7 Consent Decree Limits, Compliance, and Record Keeping Requirements	
<b>D.5</b>	<b>EMISSIONS UNIT OPERATION CONDITIONS</b>	<b>62</b>
	<b>Emission Limitations and Standards [326 IAC 2-7-5(1)]</b>	
	D.5.1 Particulate Emissions [326 IAC 6-3-2]	
<b>D.6</b>	<b>EMISSIONS UNIT OPERATION CONDITIONS</b>	<b>63</b>
	<b>Emission Limitations and Standards [326 IAC 2-7-5(1)]</b>	
	D.6.1 Particulate Matter (PM) [326 IAC 6-3-2]	
	D.6.2 Preventive Maintenance Plan [326 IAC 2-7-5(13)]	
	<b>Compliance Determination Requirements [326 IAC 2-7-6(1)] [326 IAC 2-7-5(1)]</b>	
	D.6.3 Particulate Control	
	<b>Compliance Monitoring Requirements [326 IAC 2-7-6(1)] [326 IAC 2-7-5(1)]</b>	
	D.6.4 Visible Emissions Notations	

	<b>Record Keeping and Reporting Requirements [326 IAC 2-7-5(3)] [326 IAC 2-7-19]</b>	
	D.6.5 Record Keeping Requirements	
<b>E.1</b>	<b>Standards of Performance for Grain Elevators [40 CFR 60, Subpart DD] [326 IAC 12]</b>	<b>65</b>
	<b>New Source Performance Standards (NSPS) [40 CFR 60]</b>	
E.1.1	General Provisions Relating to New Source Performance Standards [326 IAC 12-1] [40 CFR 60, Subpart A]	
E.1.2	Standards of Performance for Grain Elevators [40 CFR 60, Subpart DD] [326 IAC 12]	
<b>E.2</b>	<b>New Source Performance Standards (NSPS) For Small Industrial- Commercial-Institutional Steam Generating Units [40 CFR 60, Subpart Dc] [326 IAC 12]</b>	<b>67</b>
	<b>New Source Performance Standards (NSPS) [40 CFR 60]</b>	
E.2.1	General Provisions Relating to New Source Performance Standards [326 IAC 12-1] [40 CFR 60, Subpart A]	
E.2.2	Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units [40 CFR 60, Subpart Dc] [326 IAC 12]	
<b>E.3</b>	<b>National Emission Standards for Hazardous Air Pollutants: Solvent Extraction for Vegetable Oil Production [40 CFR 63, Subpart GGGG] [326 IAC 20-60]</b>	<b>69</b>
	<b>National Emission Standards for Hazardous Air Pollutants (NESHAP) [40 CFR 60]</b>	
E.3.1	General Provisions Relating to NESHAP GGGG [326 IAC 20-1] [40 CFR Part 63, Subpart A]	
E.3.2	National Emission Standards for Hazardous Air Pollutants: Solvent Extraction for Vegetable Oil Production NESHAP [326 IAC 20-60] [40 CFR Part 63, Subpart GGGG]	
<b>E.4</b>	<b>National Emission Standards for Hazardous Air Pollutants for Industrial, Commercial, and Institutional Boilers and Process Heaters [40 CFR 63, Subpart DDDDD] [326 IAC 20-95]</b>	<b>71</b>
	<b>National Emission Standards for Hazardous Air Pollutants (NESHAP) [40 CFR 60]</b>	
E.4.1	General Provisions Relating to NESHAP DDDDD [326 IAC 20-1] [40 CFR Part 63, Subpart A]	
E.4.2	National Emission Standards for Hazardous Air Pollutants for Industrial, Commercial, and Institutional Boilers and Process Heaters [326 IAC 20-95] [40 CFR Part 63, Subpart DDDDD]	
E.4.3	Testing Requirements [326 IAC 2-7-6(1),(6)] [326 IAC 2-1.1-11]	
	<b>Certification</b>	<b>74</b>
	<b>Emergency Occurrence Report</b>	<b>75</b>
	<b>Quarterly Reports</b>	<b>77</b>
	<b>Quarterly Deviation and Compliance Monitoring Report</b>	<b>80</b>
<b>Attachment A:</b>	<b>Standards of Performance for Grain Elevators [40 CFR 60, Subpart DD] [326 IAC 12]</b>	
<b>Attachment B:</b>	<b>New Source Performance Standards (NSPS) For Small Industrial- Commercial-Institutional Steam Generating Units [40 CFR 60, Subpart Dc] [326 IAC 12]</b>	
<b>Attachment C:</b>	<b>National Emission Standards for Hazardous Air Pollutants: Solvent Extraction for Vegetable Oil Production NESHAP [326 IAC 20-60] [40 CFR Part 63, Subpart GGGG]</b>	
<b>Attachment D:</b>	<b>National Emission Standards for Hazardous Air Pollutants for Industrial, Commercial, and Institutional Boilers and Process Heaters [326 IAC 20-95] [40 CFR Part 63, Subpart DDDDD]</b>	

## 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(15)] [326 IAC 2-7-1(22)]

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The Permittee owns and operates a stationary grain handling, soybean meal production, and soybean oil extraction plant.

Source Address:	1200 N. 2nd Street, Decatur, Indiana 46733
General Source Phone Number:	(260)724-2101
SIC Code:	2075, 2079, 5153, 2048
County Location:	Adams
Source Location Status:	Attainment for all criteria pollutants
Source Status:	Part 70 Operating Permit Program Major Source, under PSD Rules Major 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(15)]

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

- (a) Truck Dump #2, identified as 1EL1, constructed in 1980, with a maximum capacity of 600 tons per hour, using a baghouse for particulate matter (PM) control, and exhausting to stack 1EL. This is an affected facility under the New Source Performance Standard for Grain Elevators 40 CFR 60.300, Subpart DD.
- (b) The following grain elevator East Workhouse components, together identified as 2EL1, with a maximum throughput of 270 tons per hour (Bottlenecked to 240 tons per hour), each, unless otherwise stated, using a baghouse and oil suppressant for PM control, and exhausting to stack 2EL, consisting of:
  - (1) One (1) dryer megatex enclosed conveyor, constructed in 1979;
  - (2) One (1) dryer rotex, constructed prior to 1977;
  - (3) One (1) #1 scalperator, approved in 2011 for construction, with a maximum throughput of 120 tons per hour. This is an affected facility under the New Source Performance Standard for Grain Elevators 40 CFR 60.300, Subpart DD;
  - (4) One (1) #2 scalperator, approved in 2011 for construction, with a maximum throughput of 120 tons per hour. This is an affected facility under the New Source Performance Standard for Grain Elevators 40 CFR 60.300, Subpart DD;
  - (5) One (1) ext. screening bin, constructed prior to 1977;
  - (6) One (1) screening bin, constructed prior to 1977;
  - (7) One (1) solvent screening leg, constructed prior to 1977;

- (8) One (1) #1 leg, constructed prior to 1977;
  - (9) One (1) #2 leg, constructed prior to 1977;
  - (10) One (1) #3 leg, constructed prior to 1977;
  - (11) One (1) west to east Hi-Roller, constructed prior to 1977;
  - (12) One (1) west to east belt loader, constructed prior to 1977;
  - (13) One (1) dry bean leg, constructed prior to 1977;
  - (14) One (1) #1 dryer Hi-Roller, constructed prior to 1977;
  - (15) One (1) weaver's belt, constructed prior to 1977; and
  - (16) One (1) 102 belt, constructed prior to 1977.
- (c) One (1) hammermill, permitted in 2010 for construction, identified as 2EL2, with a maximum capacity of 5.60 tons per hour, using a baghouse as control (Unit ID 2EL2), and exhausting to stack 2EL2.
- (d) One (1) pneumatic conveying system, permitted in 2010 for construction, identified as 2EL3, with a maximum capacity of 5.60 tons per hour, using a baghouse for control (Unit ID 22EX2) as control, and exhausting to stack 22EX2.
- (e) The following grain elevator components, together identified as 5EL1, with a maximum throughput of 900 tons per hour, each, using a baghouse and oil suppressant for PM control, and exhausting to stack 5EL, consisting of:
- (1) One (1) north tripper buggy, constructed prior to 1977;
  - (2) One (1) north galley belt loader, constructed prior to 1977;
  - (3) One (1) east west belt, constructed prior to 1977; and
  - (4) One (1) bin 102, constructed prior to 1977.
- (f) One (1) north west receiving house enclosed conveyor identified as 8EL1, constructed prior to 1977, with a maximum throughput of 360 tons per hour, using oil suppressant for PM control, with no aspiration.
- (g) The following grain elevator components together identified as 10EL1, with a maximum throughput of 720 tons per hour, each, using a baghouse and oil suppressant for PM control, and exhausting to stack 10EL, consisting of:
- (1) One (1) rail loadout, constructed in 1984. This is an affected facility under the New Source Performance Standard for Grain Elevators 40 CFR 60.300, Subpart DD;
  - (2) One (1) rail receiving, constructed in 1960;
  - (3) One (1) north leg, constructed prior to 1960; and
  - (4) One (1) south leg, constructed prior to 1960.

- (h) The following grain elevator components together identified as 14EL1, with a maximum throughput of 600 tons per hour, each, using a baghouse and oil suppressant for PM control, and exhausting to stack 14EL, consisting of:
  - (1) One (1) jumbo silo east galley belt, constructed prior to 1977;
  - (2) One (1) jumbo silo west galley belt, constructed prior to 1977;
  - (3) One (1) jumbo silo crossover galley belt, constructed prior to 1977;
- (i) One (1) natural gas fired grain dryer #2, identified as 19EL1, constructed in 1995, with a maximum capacity of 60 tons per hour and a maximum heat input capacity of 7 MMBtu/hr, using self-cleaning screens for PM control, and exhausting to vent 19EL. This is an affected facility under the New Source Performance Standard for Grain Elevators 40 CFR 60.300, Subpart DD.
- (j) One (1) truck dump #7, identified as 20EL1, constructed in 1997, with a maximum throughput of 450 tons per hour, consisting of one (1) weigh scale truck unloading pit, and two (2) enclosed bucket elevator legs, using two (2) baghouses in parallel for PM control, and exhausting to stack 20EL. This is an affected facility under the New Source Performance Standard for Grain Elevators 40 CFR 60.300, Subpart DD.
- (k) Silo bin vents, identified as 3EL1, constructed prior to 1977, with a maximum throughput of 900 tons per hour, total, using soybean oil as a dust suppressant, and exhausting to vent 3EL.
- (l) Silo direct loadout, identified as 4EL1, constructed prior to 1977, with a maximum throughput of 270 tons per hour, using soybean oil as a dust suppressant.
- (m) One (1) south tripper buggy, one (1) south galley belt loader, and one (1) north south belt, identified as 6EL1, all constructed prior to 1977, with a maximum throughput of 900 tons per hour, each, using a baghouse and oil suppressant for PM control, and exhausting to stack 6EL.
- (n) One (1) south west receiving house enclosed conveyor, identified as 7EL1, constructed prior to 1977, with a maximum throughput of 360 tons per hour, using oil suppressant for PM control with no aspiration.
- (o) One (1) truck dump #3, identified as 9EL1, constructed in 1976, with a maximum throughput of 900 tons per hour, using a baghouse for PM control, and exhausting to stack 9EL.
- (p) One (1) truck dump #5, identified as 12EL1, constructed prior to 1977, with a maximum throughput of 600 tons per hour, using a baghouse for PM control, and exhausting to stack 12EL.
- (q) One (1) jumbo silo east tunnel belt, one (1) jumbo silo west tunnel belt, and one (1) jumbo silo crossover tunnel belt, identified as 13EL1, all constructed prior to 1977, with a maximum throughput of 360 tons per hour, each, using a baghouse and oil suppressant for PM control, and exhausting to stack 13EL.
- (r) One (1) truck dump #6, identified as 15EL1, constructed prior to 1977, with a maximum throughput of 360 tons per hour, using a baghouse for PM control, and exhausting to stack 15EL.

- (s) One (1) natural gas fired grain dryer #1, identified as 16EL1, constructed in 1986, with a maximum capacity of 75 tons per hour and a maximum heat input capacity of 7 MMBtu/hr, using self-cleaning screens for PM control, and exhausting to stack 16EL. This is an affected facility under the New Source Performance Standard for Grain Elevators 40 CFR 60.300, Subpart DD.
- (t) Two (2) natural gas fired grain dryers, #4 and #5, identified as 17EL1, constructed in the 1960's, with a maximum capacity of 150 tons per hour and a maximum heat input capacity of 14 MMBtu/hr, total, using self-cleaning screens for PM control, and exhausting to vent 17EL.
- (u) One (1) Lec. Dept. filter aid unit, identified as 204RO1, constructed in 1980, with a maximum throughput of 2.5 tons per hour, using a baghouse for PM control, and exhausting to stack 204RO.
- (v) Daily use bins, identified as 102EO1, constructed in 1976, with a maximum throughput of 2.5 tons per hour, each, using a baghouse for PM control, and exhausting to stack 102EO.
- (w) Filter aid silos, identified as 103EO1, constructed in 1976, with a maximum throughput of 16 tons per hour, each, using a baghouse for PM control, and exhausting to stack 103EO.
- (x) One (1) natural gas fired hydrogen generator furnace, identified as 107EO1, constructed in 1992, with a maximum heat input capacity of 25.2 MMBtu/hr, and exhausting to stack 107EO. This is an affected source under the National Emission Standards for Hazardous Air Pollutants for Industrial, Commercial, and Institutional Boilers and Process Heaters 40 CFR 63, Subpart DDDDD.
- (y) Salt conveying, identified as 4SP1, constructed in 1981, with a maximum throughput of 21 tons per hour, using a baghouse for PM control, and exhausting to stack 4SP.
- (z) Six (6) flaking rolls, #1, #2, #3, #4, #5, and #6, constructed in 1996, and B flake n/s drag, constructed in 1991, all identified together as 1EX1, with a maximum throughput of 93.1 tons per hour, total, using fabric filters for PM control, and exhausting to stack 1EX.
- (aa) One (1) flaking roll #14 and flaking roll discharge #14, identified as 1EX2, constructed in 1991, with a maximum throughput of 93.1 tons per hour, each, using fabric filters for PM control, and exhausting to stack 1EX.
- (bb) The following soybean processing equipment, together identified as 3EX1, with a maximum throughput of 48.8 tons per hour, each, sharing a cyclone with 3EX2 for PM control, and exhausting to stack 3EX, consisting of:
  - (1) Four (4) flaking rolls, #9, #10, #11, and #12, constructed in 1978;
  - (2) One (1) flaking roll #13, constructed in 1985;
  - (3) One (1) 'A' flake n/s drag, constructed in 1993; and
  - (4) One (1) 'A' flake e/w drag, constructed in 1993.
- (cc) One (1) north run around drag, identified as 3EX2, constructed in 1984, with a maximum throughput of 48.8 tons per hour, sharing a cyclone with 3EX1, and exhausting to stack 3EX.

- (dd) The following soybean processing equipment, together identified as 4EX1, with a maximum throughput of 156.3 tons per hour, each, sharing a baghouse with 4EX2 and 4EX3 for PM control, and exhausting to stack 4EX, consisting of:
  - (1) One (1) whole bean scale, constructed in 1989;
  - (2) One (1) 'A' whole bean leg, constructed in 1997;
  - (3) One (1) 'A' surge bin, constructed prior to 1979;
  - (4) One (1) whole bean drag, constructed in 1981; and
  - (5) One (1) 'B' surge bin, constructed prior to 1979.
- (ee) A run around rework screw, identified as 4EX2, constructed in 1991, with a maximum throughput of 156.3 tons per hour, sharing a baghouse with 4EX1 and 4EX3 for PM control, and exhausting to stack 4EX.
- (ff) The following soybean processing equipment, together identified as 4EX3, with a maximum throughput of 156.3 tons per hour, each, sharing a baghouse with 4EX1 and 4EX2 for PM control, and exhausting to stack 4EX, consisting of:
  - (1) One (1) hull refining screw conveyor, constructed in 1991;
  - (2) One (1) hull refining process, constructed in 1991; and
  - (3) One (1) hull grinding process, constructed in 1987.
- (gg) Dehulling equipment, identified as 5EX1, constructed in 1997, with a maximum throughput of 156.3 tons per hour, sharing a baghouse with 5EX3 for PM control, and exhausting to stack 5EX.
- (hh) Hot dehulling equipment, identified as 5EX2, constructed in 1991, with a maximum throughput of 156.3 tons per hour, using a baghouse for PM control, and exhausting to stack 33EX.
- (ii) Screening aspiration, identified as 5EX3, constructed in 1988, with a maximum throughput of 156.3 tons per hour, sharing a baghouse with 5EX1 for PM control, and exhausting to stack 5EX.
- (jj) Truck meal loadout and rail meal loadout, identified as 6EX1, constructed in 1982, replaced in 1999, with a maximum throughput of 150 tons per hour, with truck meal loadout using a baghouse for PM control, and exhausting to stack 6EX, and rail meal loadout using a choke loader for intrinsic PM control of fugitive emissions.
- (kk) One (1) soybean meal sizing and grinding operation, collectively identified as 7EX, approved in 2010 for construction, using a baghouse for PM control, and exhausting to stack 7EX, consisting of:
  - (1) One (1) meal screener, identified as 7EX1, with a maximum capacity of 176 tons per hour;
  - (2) Four (4) meal grinders, identified as 7EX2 through 7EX5, each with a maximum capacity of 45 tons per hour; and

- (3) Associated conveyors.
- (ll) One (1) leg No. 2, one (1) mixing conveyor, and one (1) bin drag, together identified as 9EX1, all constructed in 1983, with a maximum throughput of 125 tons per hour, each, using a baghouse for PM control, and exhausting to stack 9EX.
- (mm) The following soybean processing equipment, together identified as 10EX1, with a maximum throughput of 333 tons per hour, each, using a baghouse for PM control, and exhausting to stack 10EX, consisting of:
  - (1) One (1) leg No. 3, constructed in the 1950's;
  - (2) One (1) tunnel drag, constructed in 1983; and
  - (3) One (1) meal loadout drag, constructed in 1982.
- (nn) One (1) kaolin bin, identified as 11EX1, constructed in the 1950's, with a maximum throughput of 15 tons per hour, using a baghouse for PM control, and exhausting to stack 11EX.
- (oo) One (1) meal loadout bin, identified as 12EX1, constructed in 1982, with a maximum throughput of 540 tons per hour, using a baghouse for PM control, and exhausting to stack 12EX.
- (pp) One (1) belt to storage bowls, one (1) large storage bowl, and one (1) small storage bowl, identified as 16EX1, 16EX2, and 16EX3, respectively, all constructed in 1982, with a maximum capacity of 93 tons per hour, each, with no PM control, and exhausting to stack 16EX.
- (qq) Whole bean bins, identified as 18EX1, constructed in the 1940's, with a maximum throughput of 156.3 tons per hour, total, with no PM control, and exhausting to stack 18EX.
- (rr) Meal storage silos with bin vents, identified as 23EX1, constructed in the 1950's, with a maximum throughput of 125 tons per hour, total, using one (1) bin vent filter as control, exhausting to stack 23EX.
- (ss) One (1) natural gas fired steam generator, identified as 110EO1, constructed in 2002, with a maximum heat input capacity of 14 MMBtu/hr, and exhausting to stack 110EO. This is an affected facility under the New Source Performance Standards for Small Industrial - Commercial - Institutional Steam Generating Units 40 CFR 60, Subpart Dc and an affected source under the National Emission Standards for Hazardous Air Pollutants for Industrial, Commercial, and Institutional Boilers and Process Heaters 40 CFR 63, Subpart DDDDD.
- (tt) One (1) natural gas fired steam generator #3, identified as 108EO1, constructed in 1994, with a maximum heat input capacity of 14 MMBtu/hr, and exhausting to stack 108EO. This is an affected facility under the New Source Performance Standards for Small Industrial - Commercial - Institutional Steam Generating Units 40 CFR 60, Subpart Dc and an affected source under the National Emission Standards for Hazardous Air Pollutants for Industrial, Commercial, and Institutional Boilers and Process Heaters 40 CFR 63, Subpart DDDDD.
- (uu) One (1) B & W coal fired boiler, identified as 1SP1, constructed in 1950, with a maximum heat input capacity of 108 MMBtu/hr, using multiple cyclones and a baghouse for control of particulate and HAPs, and exhausting to stack 1SP. This is an affected source under

the National Emission Standards for Hazardous Air Pollutants for Industrial, Commercial, and Institutional Boilers and Process Heaters 40 CFR 63, Subpart DDDDD.

- (vv) One (1) Keeler coal fired boiler, identified as 2SP1, constructed in 1963, with a maximum heat input capacity of 52.75 MMBtu/hr, using multiple cyclones and a baghouse for control of particulate and HAPs, and exhausting to stack 1SP. This is an affected source under the National Emission Standards for Hazardous Air Pollutants for Industrial, Commercial, and Institutional Boilers and Process Heaters 40 CFR 63, Subpart DDDDD.
- (ww) One (1) Murray natural gas fired, vegetable oil-fired, used oil-fired, and hazardous chemical fired boiler, identified as 3SP1, constructed in 1968, with a maximum heat input capacity of 110.2 MMBtu/hr, and exhausting to stack 1SP. This is an affected source under the National Emission Standards for Hazardous Air Pollutants for Industrial, Commercial, and Institutional Boilers and Process Heaters 40 CFR 63, Subpart DDDDD.
- (xx) One (1) hexane extraction system, identified collectively as 24EX, modified prior to 1980, with hexane emissions from the vent system controlled by a mineral oil absorber, and exhausting to stack 24EXA. For reporting purposes, all hexane emissions are collectively accounted for in the total hexane losses named 24EX.
  - (1) One (1) 'A' unit, identified as 24EX1, consisting of 'A' pre-DT, constructed in 1996, 'A' DT, constructed in 1980, and the 'A' Meal Dryer, constructed in 1980, with a maximum capacity of 109.4 tons per hour, each. 'A' pre-DT is on top of and feeds the 'A' DT, which is on top of and feeds the 'A' Meal Dryer. The 'A' pre-DT and the 'A' DT exhaust to the hexane solvent reclaim system. The 'A' Meal Dryer uses a cyclone for PM control, and exhausts to stack 24EX1. Hexane emissions are reported in 24EX.
  - (2) One (1) 'B' unit, identified as 24EX2, consisting of 'B' pre-DT, constructed in 1996, 'B' DT, constructed in 1980, and the 'B' Meal Dryer, constructed in 1980, with a maximum capacity of 109.4 tons per hour, each. 'B' pre-DT is on top of and feeds the 'B' DT which is on top of and feeds the 'B' Meal Dryer. The 'B' pre-DT and the 'B' DT exhaust to the hexane solvent reclaim system. The 'B' Meal Dryer uses a cyclone for PM control, and exhausts to stack 24EX2. Hexane emissions are reported in 24EX.
  - (3) One meal cooler, identified as 24EX3, constructed in 1996, with a maximum capacity of 110 tons per hour, using two (2) cyclones for PM control, exhausting to stacks 24EX3A and 24EX3B, respectively, with hexane emissions reported in 24EX.
  - (4) Two (2) hexane storage tanks, identified as 24EX4A and 24EX4B, constructed in 1995 and 2005, respectively, with emissions vented to the mineral oil absorber inlet, with hexane emissions reported in 24EX.
  - (5) One (1) wastewater system, identified as 24EX5, constructed prior to 1980, containing traces of hexane, exhausting to the extraction hot water separation pit, with hexane emissions reported in 24EX.
  - (6) One (1) refined oil hot well, identified as 24EX6, constructed in 1975, with hexane emissions reported in 24EX.
  - (7) One (1) sampling /hexane unloading port, identified as 24EX7, with hexane emissions reported in 24EX.

- (8) Oil tanks containing non-deodorized oil, identified as 24EX8, venting to the atmosphere, with hexane emissions reported at 24EX.

The hexane extraction system (24EX, consisting of 24EX1 through 24EX8) are affected facilities under the National Emission Standards for Hazardous Air Pollutants: Solvent Extraction for Vegetable Oil Production 40 CFR 63, Subpart GGGG.

- (yy) The following soybean processing equipment, identified as 17EX2, modified in 1987, with a maximum throughput of 156.3 tons per hour, each, using a cyclone for PM control, and exhausting to stack 17EX, consisting of:

- (1) One (1) flaking roll #8, constructed in 1981; and  
(2) One (1) 'B' flake e/w drag, constructed in 1980.

- (zz) Two (2) conditioners identified as 31EX1 and 31EX2 constructed in 2002, with a maximum capacity of 156.3 tons per hour for each conditioner, and exhausting internally.

- (aaa) One (1) enclosed pneumatic ash conveying and loading operation, constructed in the 1950's, identified as emission unit 8SP1, with a maximum throughput of 13.8 tons per hour, using a baghouse for emission control, and exhausting to stack 1SP. The ash loading operation uses water spray for fugitive emission mitigation.

- (bbb) One (1) batch enzyme bag unloader, with a maximum throughput rate of 51 tons per year, identified as 112EO1, approved in 2009 for construction, using a baghouse for emission control and exhausting to stack 112EO.

This emission unit is not an affected facility under the National Emission Standards for Hazardous Air Pollutants: Solvent Extraction for Vegetable Oil Production 40 CFR 63, Subpart GGGG.

- (ccc) One (1) pelletizer/pellet cooler to produce pellets from the existing dehulling/grinding (millfeed) system, approved in 2009 for construction, with a maximum rate of 10 tons per hour, identified as 32EX1, using a high efficiency cyclone for emission control and exhausting to stack 32EX.

- (ddd) One (1) totally enclosed conveyor, approved in 2009 for construction, with a maximum rate of 10 tons per hour, identified as 32EX2.

- (eee) One (1) loadout bin, identified as 29EX1, constructed in 1994, with a maximum throughput of 10 tons per hour, using a bin vent filter for PM control, and exhausting to stack 29EX.

- (fff) One (1) natural gas-fired boiler, identified as 9SP1, approved for construction in 2012, with a maximum heat input capacity of 99 MMBtu/hr, equipped with low NOx burners and flue gas recirculation (FGR) for NOx control, and exhausting to stack 9SP. This is an affected facility under the New Source Performance Standards for Small Industrial - Commercial - Institutional Steam Generating Units 40 CFR 60, Subpart Dc and an affected source under the National Emission Standards for Hazardous Air Pollutants for Industrial, Commercial, and Institutional Boilers and Process Heaters 40 CFR 63, Subpart DDDDD.

A.3 Specifically Regulated Insignificant Activities [326 IAC 2-7-1(21)] [326 IAC 2-7-4(c)]  
[326 IAC 2-7-5(15)]

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This stationary source also includes the following insignificant activities which are specifically regulated, as defined in 326 IAC 2-7-1(21):

Paved and unpaved roads and parking lots with public access [326 IAC 6-4].

A.4 Insignificant Activities [326 IAC 2-7-1(21)] [326 IAC 2-7-4(c)] [326 IAC 2-7-5(15)]

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This stationary source also includes the following insignificant activities:

- (a) Natural gas-fired combustion sources with heat input equal to or less than ten million (10,000,000) British thermal units per hour.
- (b) Propane or liquified petroleum gas, or butane-fired combustion sources with heat input equal to or less than six million (6,000,000) British thermal units per hour.
- (c) Combustion source flame safety purging on start-up.
- (d) A gasoline fuel transfer and dispensing operation handling less than or equal to 1,300 gallons per day, such as filling of tanks, locomotives, automobiles, having a storage capacity less than or equal to 10,500 gallons.
- (e) A petroleum fuel, other than gasoline, dispensing facility having a storage capacity less than or equal to 10,500 gallons, and dispensing less than or equal to 23,000 gallons per month.
- (f) Vessels storing lubricating oils, hydraulic oils, machining oils, and machining fluids.
- (g) Machining where an aqueous cutting coolant continuously floods the machining interface.
- (h) Degreasing operations that do not exceed 145 gallons per 12 months, and not subject to 326 IAC 20-6.
- (i) Cleaners and solvents characterized as follows:
  - (1) having a vapor pressure equal to or less than 2 kPa; 15 mmHg; or 0.3 psi measured at 38 degrees C (100°F); or
  - (2) having a vapor pressure equal to or less than 0.7 kPa; 5 mmHg; or 0.1 psi measured at 20 degrees C (68°F);the use of which for all cleaners and solvents combined does not exceed 145 gallons per 12 months.
- (j) Closed loop heating and cooling systems.
- (k) Activities associated with the treatment of wastewater streams with an oil and grease content less than or equal to 1% by volume.
- (l) Water based adhesives that are less than or equal to 5% by volume of VOCs, excluding HAPs.
- (m) Noncontact cooling tower systems with natural draft cooling towers not regulated under a NESHAP.

- (n) Replacement or repair of electrostatic precipitators, bags in baghouses, and filters in other filtrations equipment.
- (o) Heat exchanger cleaning and repair.
- (p) Process vessel degreasing and cleaning to prepare for internal repairs.
- (q) Underground conveyors.
- (r) Coal bunker and coal scale exhausts and associated dust collector vents.
- (s) Asbestos abatement projects regulated by 326 IAC 14-10.
- (t) Purging of gas lines and vessels that is related to routine maintenance and repair of buildings, structures, or vehicles at the source where air emissions from those activities would not be associated with any production process.
- (u) Equipment used to collect any material that might be released during a malfunction, process upset, or spill cleanup, including catch tanks, temporary liquid separators, tanks, and fluid handling equipment.
- (v) Blowdown for any of the following: sight glass, boiler, compressors, pumps, and cooling tower.
- (w) Stationary fire pumps.
- (x) Purge double block and bleed valves.
- (y) Filter or coalescer media changeout.
- (z) Vents from ash transport systems not operated at positive pressure.
- (aa) A laboratory as defined in 326 IAC 2-7-1(21)(D).
- (bb) Emission units with PM and PM10 emissions less than five (5) tons per year, SO<sub>2</sub>, NO<sub>x</sub>, and VOC emissions less than ten (10) tons per year, CO emissions less than twenty-five (25) tons per year, lead emissions less than two-tenths (0.2) tons per year, single HAP emissions less than one (1) ton per year, and combination of HAPs emissions less than two and a half (2.5) tons per year, consisting of:
  - (1) One (1) acetic anhydride storage tank.
  - (2) One (1) Hoffman vacuum system, for housekeeping.
  - (3) One (1) elevator/railcar pest control/fumigation.
  - (4) One (1) Millfeed storage bin, 22EX.
  - (5) One (1) Flake drag air brake fan, 15EX.
  - (6) One (1) Coal receiving operation, 6SP.

A.5 Part 70 Permit Applicability [326 IAC 2-7-2]

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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)]**

- (a) This permit, T001-23640-00005, 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)]**

- (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:
  - (i) it contains a certification by a "responsible official" as defined by 326 IAC 2-7-1(34), and
  - (ii) 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(34).

**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(34).

B.10 Preventive Maintenance Plan [326 IAC 2-7-5(1),(3) and (13)] [326 IAC 2-7-6(1) and (6)]  
[326 IAC 1-6-3]

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- (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(34).

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(34).
- (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]

- (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(34).

- (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)(9) 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 T001-23640-00005 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 combined permit, all previous registrations and permits are superseded by this combined new source review and 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]**

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- (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(34).
- (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)]**

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- (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(34).

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]

(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(34).

(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)]

(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]

(a) The Permittee may make any change or changes at the source that are described in 326 IAC 2-7-20(b),(c), or (e) 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),(c), or (e). 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), (c)(1), and (e)(2).

(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(34).

(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(34).

- (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]**

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- (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 Advanced Source Modification Approval [326 IAC 2-7-5(16)] [326 IAC 2-7-10.5]**

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- (a) The requirements to obtain a source modification approval under 326 IAC 2-7-10.5 or a permit modification under 326 IAC 2-7-12 are satisfied by this permit for the proposed emission units, control equipment or insignificant activities in Sections A.2 and A.3.
- (b) Pursuant to 326 IAC 2-1.1-9 any permit authorizing construction may be revoked if construction of the emission unit has not commenced within eighteen (18) months from the date of issuance of the permit, or if during the construction, work is suspended for a continuous period of one (1) year or more.

**B.25 Credible Evidence [326 IAC 2-7-5(3)] [326 IAC 2-7-6] [62 FR 8314] [326 IAC 1-1-6]**

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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 by using ambient air quality modeling pursuant to 326 IAC 1-7-4. 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(34).

- (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(34).

- (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(34).
- (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(34).

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.
- (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(34).

**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(a)(1), the Permittee shall submit by July 1 of each year 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(34).

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

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- (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. 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) If there is a reasonable possibility (as defined in 40 CFR 51.165(a)(6)(vi)(A), 40 CFR 51.165(a)(6)(vi)(B), 40 CFR 51.166(r)(6)(vi)(a), and/or 40 CFR 51.166(r)(6)(vi)(b)) that a "project" (as defined in 326 IAC 2-2-1(qq) and/or 326 IAC 2-3-1(II)) at an existing emissions unit, other than projects at a source with a Plantwide Applicability Limitation (PAL), which is not part of a "major modification" (as defined in 326 IAC 2-2-1(ee) and/or 326 IAC 2-3-1(z)) may result in significant emissions increase and the Permittee elects to utilize the "projected actual emissions" (as defined in 326 IAC 2-2-1(rr) and/or 326 IAC 2-3-1(mm)), the Permittee shall comply with following:
  - (1) Before beginning actual construction of the "project" (as defined in 326 IAC 2-2-1(qq) and/or 326 IAC 2-3-1(II)) at an existing emissions unit, document and maintain the following records:
    - (A) A description of the project.
    - (B) Identification of any emissions unit whose emissions of a regulated new source review pollutant could be affected by the project.
    - (C) A description of the applicability test used to determine that the project is not a major modification for any regulated NSR pollutant, including:
      - (i) Baseline actual emissions;
      - (ii) Projected actual emissions;
      - (iii) Amount of emissions excluded under section 326 IAC 2-2-1(rr)(2)(A)(iii) and/or 326 IAC 2-3-1 (mm)(2)(A)(iii); and

- (iv) An explanation for why the amount was excluded, and any netting calculations, if applicable.
- (d) If there is a reasonable possibility (as defined in 40 CFR 51.165(a)(6)(vi)(A) and/or 40 CFR 51.166(r)(6)(vi)(a)) that a "project" (as defined in 326 IAC 2-2-1(qq) and/or 326 IAC 2-3-1(II)) at an existing emissions unit, other than projects at a source with a Plantwide Applicability Limitation (PAL), which is not part of a "major modification" (as defined in 326 IAC 2-2-1(ee) and/or 326 IAC 2-3-1(z)) may result in significant emissions increase and the Permittee elects to utilize the "projected actual emissions" (as defined in 326 IAC 2-2-1(rr) and/or 326 IAC 2-3-1(mm)), the Permittee shall comply with following:
  - (1) Monitor the emissions of any regulated NSR pollutant that could increase as a result of the project and that is emitted by any existing emissions unit identified in (1)(B) above; and
  - (2) Calculate and maintain a record of the annual emissions, in tons per year on a calendar year basis, for a period of five (5) years following resumption of regular operations after the change, or for a period of ten (10) years following resumption of regular operations after the change if the project increases the design capacity of or the potential to emit that regulated NSR pollutant at the emissions unit.

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

- (a) The Permittee shall submit the attached Quarterly Deviation and Compliance Monitoring Report or its equivalent. 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(34). 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.
- (e) If the Permittee is required to comply with the recordkeeping provisions of (d) in Section C - General Record Keeping Requirements for any "project" (as defined in 326 IAC 2-2-1(qq) and/or 326 IAC 2-3-1(II)) at an existing emissions unit, and the project meets the following criteria, then the Permittee shall submit a report to IDEM, OAQ:

- (1) The annual emissions, in tons per year, from the project identified in (c)(1) in Section C- General Record Keeping Requirements exceed the baseline actual emissions, as documented and maintained under Section C- General Record Keeping Requirements (c)(1)(C)(i), by a significant amount, as defined in 326 IAC 2-2-1 (xx) and/or 326 IAC 2-3-1 (qq), for that regulated NSR pollutant, and
  - (2) The emissions differ from the preconstruction projection as documented and maintained under Section C - General Record Keeping Requirements (c)(1)(C)(ii).
- (f) The report for project at an existing emissions unit shall be submitted no later than sixty (60) days after the end of the year and contain the following:
- (1) The name, address, and telephone number of the major stationary source.
  - (2) The annual emissions calculated in accordance with (d)(1) and (2) in Section C - General Record Keeping Requirements.
  - (3) The emissions calculated under the actual-to-projected actual test stated in 326 IAC 2-2-2(d)(3) and/or 326 IAC 2-3-2(c)(3).
  - (4) Any other information that the Permittee wishes to include in this report such as an explanation as to why the emissions differ from the preconstruction projection.

Reports required in this part 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

- (g) The Permittee shall make the information required to be documented and maintained in accordance with (c) in Section C- General Record Keeping Requirements available for review upon a request for inspection by IDEM, OAQ. The general public may request this information from the IDEM, OAQ under 326 IAC 17.1.

### **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 EMISSIONS UNIT OPERATION CONDITIONS

### Emissions Unit Description: Grain Handling and Grain Drying Facilities

- (a) Truck Dump #2, identified as 1EL1, constructed in 1980, with a maximum capacity of 600 tons per hour, using a baghouse for particulate matter (PM) control, and exhausting to stack 1EL. This is an affected facility under the New Source Performance Standard for Grain Elevators 40 CFR 60.300, Subpart DD.
- (b) The following grain elevator East Workhouse components, together identified as 2EL1, with a maximum throughput of 270 tons per hour (Bottlenecked to 240 tons per hour), each, unless otherwise stated, using a baghouse and oil suppressant for PM control, and exhausting to stack 2EL, consisting of:
  - (1) One (1) dryer megatex enclosed conveyor, constructed in 1979;
  - (2) One (1) dryer rotex, constructed prior to 1977;
  - (3) One (1) #1 scalperator, approved in 2011 for construction, with a maximum throughput of 120 tons per hour. This is an affected facility under the New Source Performance Standard for Grain Elevators 40 CFR 60.300, Subpart DD;
  - (4) One (1) #2 scalperator, approved in 2011 for construction, with a maximum throughput of 120 tons per hour. This is an affected facility under the New Source Performance Standard for Grain Elevators 40 CFR 60.300, Subpart DD;
  - (5) One (1) ext. screening bin, constructed prior to 1977;
  - (6) One (1) screening bin, constructed prior to 1977;
  - (7) One (1) solvent screening leg, constructed prior to 1977;
  - (8) One (1) #1 leg, constructed prior to 1977;
  - (9) One (1) #2 leg, constructed prior to 1977;
  - (10) One (1) #3 leg, constructed prior to 1977;
  - (11) One (1) west to east Hi-Roller, constructed prior to 1977;
  - (12) One (1) west to east belt loader, constructed prior to 1977;
  - (13) One (1) dry bean leg, constructed prior to 1977;
  - (14) One (1) #1 dryer Hi-Roller, constructed prior to 1977;
  - (15) One (1) weaver's belt, constructed prior to 1977; and
  - (16) One (1) 102 belt, constructed prior to 1977.
- (c) One (1) hammermill, permitted in 2010 for construction, identified as 2EL2, with a maximum capacity of 5.60 tons per hour, using a baghouse as control (Unit ID 2EL2), and exhausting to stack 2EL2.
- (d) One (1) pneumatic conveying system, permitted in 2010 for construction, identified as 2EL3,

- with a maximum capacity of 5.60 tons per hour, using a baghouse for control (Unit ID 22EX2) as control, and exhausting to stack 22EX2.
- (e) The following grain elevator components, together identified as 5EL1, with a maximum throughput of 900 tons per hour, each, using a baghouse and oil suppressant for PM control, and exhausting to stack 5EL, consisting of:
- (1) One (1) north tripper buggy, constructed prior to 1977;
  - (2) One (1) north galley belt loader, constructed prior to 1977;
  - (3) One (1) east west belt, constructed prior to 1977; and
  - (4) One (1) bin 102, constructed prior to 1977.
- (f) One (1) north west receiving house enclosed conveyor identified as 8EL1, constructed prior to 1977, with a maximum throughput of 360 tons per hour, using oil suppressant for PM control, with no aspiration.
- (g) The following grain elevator components together identified as 10EL1, with a maximum throughput of 720 tons per hour, each, using a baghouse and oil suppressant for PM control, and exhausting to stack 10EL, consisting of:
- (1) One (1) rail loadout, constructed in 1984. This is an affected facility under the New Source Performance Standard for Grain Elevators 40 CFR 60.300, Subpart DD;
  - (2) One (1) rail receiving, constructed in 1960;
  - (3) One (1) north leg, constructed prior to 1960; and
  - (4) One (1) south leg, constructed prior to 1960.
- (h) The following grain elevator components together identified as 14EL1, with a maximum throughput of 600 tons per hour, each, using a baghouse and oil suppressant for PM control, and exhausting to stack 14EL, consisting of:
- (1) One (1) jumbo silo east galley belt, constructed prior to 1977;
  - (2) One (1) jumbo silo west galley belt, constructed prior to 1977; and
  - (3) One (1) jumbo silo crossover galley belt, constructed prior to 1977.
- (i) One (1) natural gas fired grain dryer #2, identified as 19EL1, constructed in 1995, with a maximum capacity 60 tons per hour and a maximum heat input capacity of 7 MMBtu/hr, using self-cleaning screens for PM control, and exhausting to vent 19EL. This is an affected facility under the New Source Performance Standard for Grain Elevators 40 CFR 60.300, Subpart DD.
- (j) One (1) truck dump #7, identified as 20EL1, constructed in 1997, with a maximum throughput of 450 tons per hour, consisting of one (1) weigh scale truck unloading pit, and two (2) enclosed bucket elevator legs, using two (2) baghouses in parallel for PM control, and exhausting to stack 20EL. This is an affected facility under the New Source Performance Standard for Grain Elevators 40 CFR 60.300, Subpart DD.
- (k) One (1) natural gas fired grain dryer #1, identified as 16EL1, constructed in 1986, with a

maximum capacity of 75 tons per hour and a maximum heat input capacity of 7 MMBtu/hr, using self-cleaning screens for PM control, and exhausting to stack 16EL. This is an affected facility under the New Source Performance Standard for Grain Elevators 40 CFR 60.300, Subpart DD.

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

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

#### **D.1.1 PSD Minor Limits [326 IAC 2-2]**

- (a) Pursuant to CP 001-4673-00005, issued May 10, 1996, and AA 001-9930-00005, issued September 17, 1998:
- (1) The amount of soybean grains processed after the grain dryers shall be limited to less than 1,368,750 tons per twelve (12) consecutive month period, with compliance determined at the end of each month, and
  - (2) The PM emissions from emission unit 19EL1 shall be limited to less than 1.36 pounds per hour and the PM<sub>10</sub> emissions from emission unit 19EL1 shall be limited to less than 0.283 pounds per hour.

These limits, in combination with the limits in Condition D.2.1, restrict the net increases of PM and PM<sub>10</sub> emissions from the modification in 1996 to below the PSD significant levels of twenty-five (25) and fifteen (15) tons per year, respectively. This will render the requirements of 326 IAC 2-2 (Prevention of Significant Deterioration) not applicable to the modification performed in 1996.

#### **D.1.2 PSD Minor Limits [326 IAC 2-2]**

In order to make the requirements of 326 IAC 2-2 not applicable, the Permittee shall comply with the following:

- (a) The total emissions from #1 scalperator and #2 scalperator shall be limited to the following:
- (1) The PM emission rate from #1 scalperator and #2 scalperator, controlled by the baghouse for 2EL1, shall not exceed 5.7 pounds per hour,
  - (2) The PM<sub>10</sub> emission rate from #1 scalperator and #2 scalperator, controlled by the baghouse for 2EL1, shall not exceed 3.40 pounds per hour, and
  - (3) The PM<sub>2.5</sub> emission rate from #1 scalperator and #2 scalperator, controlled by the baghouse for 2EL1, shall not exceed 2.28 pounds per hour.

Compliance with these limits shall limit the potential to emit from this modification to less than twenty-five (25) tons of PM, less than fifteen (15) tons of PM<sub>10</sub> and less than ten (10) tons of PM<sub>2.5</sub> per twelve (12) consecutive month period and render the requirements of 326 IAC 2-2 not applicable.

- (b) The PM/PM<sub>10</sub> emissions from the hammermill plenum baghouse filter, Unit ID 2EL2, shall not exceed 0.17 lb/hr.
- (c) The PM/PM<sub>10</sub> emissions from the screenings pneumatic conveyor baghouse filter, Unit ID 2EL3, shall not exceed 0.03 lb/hr.

Compliance with these limits shall limit the potential to emit from this modification to less than twenty-five (25) tons of PM and less than fifteen (15) tons of PM<sub>10</sub> per twelve (12) consecutive month period and render the requirements of 326 IAC 2-2 not applicable.

**D.1.3 Particulate Matter (PM) [326 IAC 6-3-2]**

Pursuant to 326 IAC 6-3-2 (Particulate Emission Limitations for Manufacturing Processes), particulate emissions from each of following operations shall not exceed the pound per hour limit listed in the table below:

Unit	Process Weight Rate (ton/hr)	PM Limit (lb/hr)
1EL1	600	71.16
2EL1	240	60.50
2EL2	5.6	13.00
2EL3	5.6	13.00
5EL1	900	76.23
8EL1	360	65.09
10EL1	720	73.41
14EL1	600	71.16
16EL1	75	48.43
19EL1	60	46.29
20EL1	450	67.70

The pounds per hour limitations were calculated using the following equations:

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:

$$E = 4.10 P^{0.67} \quad \text{where } E = \text{rate of emission in pounds per hour and} \\ P = \text{process weight rate in tons per hour}$$

Interpolation and extrapolation of the data for the process weight rate in excess of 60,000 pounds per hour shall be accomplished by use of the equation:

$$E = 55.0 P^{0.11} - 40 \quad \text{where } E = \text{rate of emission in pounds per hour; and} \\ P = \text{process weight rate in tons per hour}$$

**D.1.4 Preventive Maintenance Plan [326 IAC 2-7-5(13)]**

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

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

### **D.1.5 Testing Requirements [326 IAC 2-7-6(1),(6)] [326 IAC 2-1.1-11]**

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- (a) In order to demonstrate compliance with Condition D.1.2(a)(1), (2), (3), and D.1.3 the Permittee shall perform PM, PM<sub>10</sub>, and PM<sub>2.5</sub> testing on #1 scalperator and #2 scalperator, within sixty (60) days after achieving the maximum capacity, but not later than one hundred eighty (180) days after initial startup, utilizing methods as approved by the Commissioner at least once every five (5) years from the date of the most recent valid compliance demonstration. 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. Testing shall be conducted in accordance with Section C - Performance Testing. PM<sub>10</sub> and PM<sub>2.5</sub> includes filterable and condensable PM<sub>10</sub> and PM<sub>2.5</sub>.
- (b) In order to demonstrate compliance with Condition D.1.2(a), the Permittee shall perform PM and PM<sub>10</sub> testing of the hammermill plenum baghouse filter, unit ID 2EL2, no later than 180 days of publication of the new or revised condensable PM test method(s) referenced in the U.S. EPA's Final Rule for Implementation of the New Source Review (NSR) Program for Particulate Matter Less Than 2.5 Micrometers (PM<sub>2.5</sub>), signed on May 8th, 2008. This testing shall be conducted utilizing methods as approved by the Commissioner. These tests shall be repeated at least once every five (5) years from the date of this valid compliance demonstration. 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. PM<sub>10</sub> includes filterable and condensable PM.

### **D.1.6 Particulate Matter (PM) [40 CFR 64 (CAM)]**

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- (a) In order to comply with Conditions D.1.1, D.1.2, and D.1.3 the baghouses for particulate control shall be in operation and control emissions from 1EL1, 2EL1, #1 scalperator, #2 scalperator, 2EL2, 2EL3, 5EL1, 10EL1, 14EL1, and 20EL1 at all times that these processes are in operation.
- (b) In order to comply with Conditions D.1.1 and D.1.3, the self-cleaning screens for PM control shall be in operation and control emissions from 19EL1 and 16 EL1 at all times that these processes are in operation.
- (c) In order to comply with Conditions D.1.1 and D.1.3, dust control oil shall be applied on all grain received at the dump pits serving the emission units identified as 2EL1, 5EL1, 8EL1, 10EL1, and 14EL1.
- (d) In the event that bag failure is observed in a multi-compartment baghouse, if operations will continue for ten (10) days or more after the failure is observed before the failed units will be repaired or replaced, the Permittee shall promptly notify the IDEM, OAQ of the expected date the failed units will be repaired or replaced. The notification shall also include the status of the applicable compliance monitoring parameters with respect to normal, and the results of any response actions taken up to the time of notification.

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

### **D.1.7 Visible Emissions Notations [40 CFR 64 (CAM)]**

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- (a) Daily visible emission notations of the grain handling and grain drying stack exhausts/vents (1EL, 2EL, 2EL2, 22EX2, 5EL, 10EL, 14EL, 19EL, 20EL, 16EL) shall be performed during normal daylight operations. 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 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.

#### D.1.8 Parametric Monitoring [40 CFR 64 (CAM)]

The Permittee shall record the pressure drop across the baghouses used in conjunction with 1EL1, 2EL1, 2EL2, 2EL3, 5EL1, 10EL1, 14EL1, and 20EL1 at least once per day when these facilities are in operation. When for any one reading, the pressure drop across the baghouse is outside the normal range of 0.5 and 10.0 inches of water or a range established during the latest stack test, the Permittee shall take reasonable response. 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.

The instrument used for determining the pressure 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 every six (6) months.

#### D.1.9 Broken or Failed Bag Detection [40 CFR 64 (CAM)]

- (a) For a single compartment baghouses controlling emissions from a process operated continuously, a failed unit and the associated process shall be shut down immediately until the failed unit has 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).
- (b) For a single compartment baghouse controlling emissions from a batch process, the feed to the process shall be shut down immediately until the failed unit have been repaired or replaced. The emissions unit shall be shut down no later than the completion of the processing of the material in emissions unit. 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).

Bag failure can be indicated by a significant drop in the baghouse's pressure reading with abnormal visible emissions, by an opacity violation, or by other means such as gas temperature, flow rate, air infiltration, leaks, dust traces or triboflows.

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

### **D.1.10 Record Keeping Requirements**

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- (a) To document the compliance status with Condition D.1.1, the Permittee shall maintain monthly records of the amount of soybean grains processed after the grain dryers.
- (b) To document the compliance status with Condition D.1.7, the Permittee shall maintain a daily record of visible emission notations of the grain handling processes' stack exhausts. 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.1.8, the Permittee shall maintain a daily record of the pressure drop across the baghouses controlling the grain handling processes. The Permittee shall include in its daily record when a pressure drop reading is not taken and the reason for the lack of a pressure drop reading (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.1.11 Reporting Requirements**

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A quarterly summary of the information to document compliance status with Condition D.1.1(a)(1) 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, not later than thirty (30) days after the end of the quarter being reported. Section C - General Reporting contains the Permittee's obligation with regard to the reporting required by this condition. 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(34).

## SECTION D.2 EMISSIONS UNIT OPERATION CONDITIONS

### Emissions Unit Description: Grain Handling and Soybean Meal Production Facilities

- (a) Silo bin vents, identified as 3EL1, constructed prior to 1977, with a maximum throughput of 900 tons per hour, total, using soybean oil as a dust suppressant, and exhausting to vent 3EL.
- (b) Silo direct loadout, identified as 4EL1, constructed prior to 1977, with a maximum throughput of 270 tons per hour, using soybean oil as a dust suppressant.
- (c) One (1) south tripper buggy, one (1) south galley belt loader, and one (1) north south belt, identified as 6EL1, all constructed prior to 1977, with a maximum throughput of 900 tons per hour, each, using a baghouse and oil suppressant for PM control, and exhausting to stack 6EL.
- (d) One (1) south west receiving house enclosed conveyor, identified as 7EL1, constructed prior to 1977, with a maximum throughput of 360 tons per hour, using oil suppressant for PM control with no aspiration.
- (e) One (1) truck dump #3, identified as 9EL1, constructed in 1976, with a maximum throughput of 900 tons per hour, using a baghouse for PM control, and exhausting to stack 9EL.
- (f) One (1) truck dump #5, identified as 12EL1, constructed prior to 1977, with a maximum throughput of 600 tons per hour, using a baghouse for PM control, and exhausting to stack 12EL.
- (g) One (1) jumbo silo east tunnel belt, one (1) jumbo silo west tunnel belt, and one (1) jumbo silo crossover tunnel belt, identified as 13EL1, all constructed prior to 1977, with a maximum throughput of 360 tons per hour, each, using a baghouse and oil suppressant for PM control, and exhausting to stack 13EL.
- (h) One (1) truck dump #6, identified as 15EL1, constructed prior to 1977, with a maximum throughput of 360 tons per hour, using a baghouse for PM control, and exhausting to stack 15EL.
- (i) Two (2) natural gas fired grain dryers, #4 and #5, identified as 17EL1, constructed in the 1960's, with a maximum capacity of 150 tons per hour and a maximum heat input capacity of 14 MMBtu/hr, total, using self-cleaning screens for PM control, and exhausting to vent 17EL.
- (j) One (1) Lec. Dept. filter aid unit, identified as 204RO1, constructed in 1980, with a maximum throughput of 2.5 tons per hour, using a baghouse for PM control, and exhausting to stack 204RO.
- (k) Daily use bins, identified as 102EO1, constructed in 1976, with a maximum throughput of 2.5 tons per hour, each, using a baghouse for PM control, and exhausting to stack 102EO.
- (l) Filter aid silos, identified as 103EO1, constructed in 1976, with a maximum throughput of 16 tons per hour, each, using a baghouse for PM control, and exhausting to stack 103EO.
- (m) Salt conveying, identified as 4SP1, constructed in 1981, with a maximum throughput of 21 tons per hour, using a baghouse for PM control, and exhausting to stack 4SP.
- (n) Six (6) flaking rolls, #1, #2, #3, #4, #5, and #6, constructed in 1996, and B flake n/s drag, constructed in 1991, all identified together as 1EX1, with a maximum throughput of 93.1 tons per hour, total, using fabric filters for PM control, and exhausting to stack 1EX.

- (o) One (1) flaking roll #14 and flaking roll discharge #14, identified as 1EX2, constructed in 1991, with a maximum throughput of 93.1 tons per hour, each, using fabric filters for PM control, and exhausting to stack 1EX.
- (p) The following soybean processing equipment, together identified as 3EX1, with a maximum throughput of 48.8 tons per hour, each, sharing a cyclone with 3EX2 for PM control, and exhausting to stack 3EX, consisting of:
  - (1) Four (4) flaking rolls, #9, #10, #11, and #12, constructed in 1978;
  - (2) One (1) flaking roll #13, constructed in 1985;
  - (3) One (1) 'A' flake n/s drag, constructed in 1993; and
  - (4) One (1) 'A' flake e/w drag, constructed in 1993.
- (q) One (1) north run around drag, identified as 3EX2, constructed in 1984, with a maximum throughput of 48.8 tons per hour, sharing a cyclone with 3EX1, and exhausting to stack 3EX.
- (r) The following soybean processing equipment, together identified as 4EX1, with a maximum throughput of 156.3 tons per hour, each, sharing a baghouse with 4EX2 and 4EX3 for PM control, and exhausting to stack 4EX, consisting of:
  - (1) One (1) whole bean scale, constructed in 1989;
  - (2) One (1) 'A' whole bean leg, constructed in 1997;
  - (3) One (1) 'A' surge bin, constructed prior to 1979;
  - (4) One (1) whole bean drag, constructed in 1981; and
  - (5) One (1) 'B' surge bin, constructed prior to 1979.
- (s) A run around rework screw, identified as 4EX2, constructed in 1991, with a maximum throughput of 156.3 tons per hour, sharing a baghouse with 4EX1 and 4EX3 for PM control, and exhausting to stack 4EX.
- (t) The following soybean processing equipment, together identified as 4EX3, with a maximum throughput of 156.3 tons per hour, each, sharing a baghouse with 4EX1 and 4EX2 for PM control, and exhausting to stack 4EX, consisting of:
  - (1) One (1) hull refining screw conveyor, constructed in 1991;
  - (2) One (1) hull refining process, constructed in 1991; and
  - (3) One (1) hull grinding process, constructed in 1987.
- (u) Dehulling equipment, identified as 5EX1, constructed in 1997, with a maximum throughput of 156.3 tons per hour, sharing a baghouse with 5EX3 for PM control, and exhausting to stack 5EX.
- (v) Hot dehulling equipment, identified as 5EX2, constructed in 1991, with a maximum throughput of 156.3 tons per hour, using a baghouse for PM control, and exhausting to stack 33EX.
- (w) Screening aspiration, identified as 5EX3, constructed in 1988, with a maximum throughput of

- 156.3 tons per hour, sharing a baghouse with 5EX1 for PM control, and exhausting to stack 5EX.
- (x) Truck meal loadout and rail meal loadout, identified as 6EX1, constructed in 1982, replaced in 1999, with a maximum throughput of 150 tons per hour, with truck meal loadout using a baghouse for PM control, and exhausting to stack 6EX, and rail meal loadout using a choke loader for intrinsic PM control of fugitive emissions.
  - (y) One (1) soybean meal sizing and grinding operation, collectively identified as 7EX, approved in 2010 for construction, using a baghouse for PM control, and exhausting to stack 7EX, consisting of:
    - (1) One (1) meal screener, identified as 7EX1, with a maximum capacity of 176 tons per hour;
    - (2) Four (4) meal grinders, identified as 7EX2 through 7EX5, each with a maximum capacity of 45 tons per hour; and
    - (3) Associated conveyors.
  - (z) One (1) leg No. 2, one (1) mixing conveyor, and one (1) bin drag, together identified as 9EX1, all constructed in 1983, with a maximum throughput of 125 tons per hour, each, using a baghouse for PM control, and exhausting to stack 9EX.
  - (aa) The following soybean processing equipment, together identified as 10EX1, with a maximum throughput of 333 tons per hour, each, using a baghouse for PM control, and exhausting to stack 10EX, consisting of:
    - (1) One (1) leg No. 3, constructed in the 1950's;
    - (2) One (1) tunnel drag, constructed in 1983; and
    - (3) One (1) meal loadout drag, constructed in 1982.
  - (bb) One (1) kaolin bin, identified as 11EX1, constructed in the 1950's, with a maximum throughput of 15 tons per hour, using a baghouse for PM control, and exhausting to stack 11EX.
  - (cc) One (1) meal loadout bin, identified as 12EX1, constructed in 1982, with a maximum throughput of 540 tons per hour, using a baghouse for PM control, and exhausting to stack 12EX.
  - (dd) One (1) belt to storage bowls, one (1) large storage bowl, and one (1) small storage bowl, identified as 16EX1, 16EX2, and 16EX3, respectively, all constructed in 1982, with a maximum capacity of 93 tons per hour, each, with no PM control, and exhausting to stack 16EX.
  - (ee) Whole bean bins, identified as 18EX1, constructed in the 1940's, with a maximum throughput of 156.3 tons per hour, total, with no PM control, and exhausting to stack 18EX.
  - (ff) Meal storage silos with bin vents, identified as 23EX1, constructed in the 1950's, with a maximum throughput of 125 tons per hour, total, using one (1) bin vent filter as control, exhausting to stack 23EX.
  - (gg) One (1) hexane extraction system, identified collectively as 24EX, modified prior to 1980, with

hexane emissions from the vent system controlled by a mineral oil absorber, and exhausting to stack 24EXA. For reporting purposes, all hexane emissions are collectively accounted for in the total hexane losses named 24EX.

- (1) One (1) 'A' unit, identified as 24 EX1, consisting of 'A' pre-DT, constructed in 1996, 'A' DT, constructed in 1980, and the 'A' Meal Dryer, constructed in 1980 with a maximum capacity of 109.4 tons per hour, each. 'A' pre-DT is on top of and feeds the 'A' DT, which is on top of and feeds the 'A' Meal Dryer. The 'A' pre-DT and the 'A' DT exhaust to the hexane solvent reclaim system. The 'A' Meal Dryer uses a cyclone for PM control, and exhausts to stack 24EX1. Hexane emissions are reported in 24EX.
  - (2) One (1) 'B' unit, identified as 24EX2, consisting of 'B' pre-DT, constructed in 1996, 'B' DT, constructed in 1980, and the 'B' Meal Dryer, constructed in 1980 with a maximum capacity of 109.4 tons per hour, each. 'B' pre-DT is on top of and feeds the 'B' DT which is on top of and feeds the 'B' Meal Dryer. The 'B' pre-DT and the 'B' DT exhaust to the hexane solvent reclaim system. The 'B' Meal Dryer uses a cyclone for PM control, and exhausts to stack 24EX2. Hexane emissions are reported in 24EX.
  - (3) One meal cooler, identified as 24EX3, constructed in 1996, with a maximum capacity of 110 tons per hour, using two (2) cyclones for PM control, exhausting to stacks 24EX3A and 24EX3B, respectively, with hexane emissions reported in 24EX.
- (hh) The following soybean processing equipment, identified as 17EX2, modified in 1987, with a maximum throughput of 156.3 tons per hour, each, using a cyclone for PM control, and exhausting to stack 17EX, consisting of:
- (1) One (1) flaking roll #8, constructed in 1981; and
  - (2) One (1) 'B' flake e/w drag, constructed in 1980.
- (ii) Two (2) conditioners identified as 31EX1 and 31EX2 constructed in 2002, with a maximum capacity of 156.3 tons per hour for each conditioner, and exhausting internally.
- (jj) One (1) enclosed pneumatic ash conveying and loading operation, constructed in the 1950's, identified as emission unit 8SP1, with a maximum throughput of 13.8 tons per hour, using a baghouse for emission control, and exhausting to stack 1SP. The ash loading operation uses water spray for fugitive emission mitigation.

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

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

### **D.2.1 PSD Minor Limits [326 IAC 2-2]**

The Permittee shall comply with the following:

- (a) The amount of soybean grains processed after the grain dryers shall be limited to less than 1,368,750 tons per twelve (12) consecutive month period, with compliance determined at the end of each month, and

- (b) Pursuant to CP 001-4673-00005, issued May 10, 1996 and AA 001-9930-00005, issued September 17, 1998, the PM and PM<sub>10</sub> emissions shall be limited as follows:

EU ID	Stack ID	PM Limit (lb/hr)	PM <sub>10</sub> Limit (lb/hr)
19EL1	19EL	1.36	0.283
1EX1, 1EX2	1EX	0.474	0.474
4EX1, 4EX2, 4EX3	4EX	1.441	1.441
5EX1, 5EX3	5EX	1.505	1.505
5EX2	33EX	0.171	0.171
24EX1	24EX1	6.79	6.79
24EX2	24EX2	6.79	6.79
24EX3	24EX3A, 24EX3B	2.18, each	2.18, each
23EX1	23EX	0.021	0.021
6EX1	6EX	2.218	2.218

These limits, in combination with the limits in Condition D.1.1 and D.2.1(a), restrict the net increases of PM and PM<sub>10</sub> emissions from the modification in 1996 to below the PSD significant levels of twenty-five (25) and fifteen (15) tons per year, respectively. This will render the requirements of 326 IAC 2-2 (Prevention of Significant Deterioration) not applicable to the modification performed in 1996.

- (c) Pursuant to SSM No. 001-29100-00005, the PM and PM<sub>10</sub> emissions shall be limited as follows:

EU ID	Stack ID	PM Limit (lb/hr)	PM <sub>10</sub> Limit (lb/hr)
7EX	7EX	0.514	0.514

These limits, in combination with the limits in Condition D.2.1(a), restrict the increase of PM and PM<sub>10</sub> emissions from SSM No. 001-29100-00005 to below the PSD significant levels of twenty-five (25) and fifteen (15) tons per year, respectively. This will render the requirements of 326 IAC 2-2 (Prevention of Significant Deterioration) not applicable to SSM No. 001-29100-00005.

**D.2.2 Particulate Matter (PM) [326 IAC 6-3-2]**

Pursuant to 326 IAC 6-3-2 (Particulate Emission Limitations for Manufacturing Processes), particulate emissions from each of following operations shall not exceed the pound per hour limit listed in the table below:

Unit	Process Weight Rate (ton/hr)	PM Limit (lb/hr)
3EL1	900	76.23
4EL1	270	61.82
6EL1	900	76.23
7EL1	360	65.09
8EL1	360	65.09
9EL1	900	76.23
12EL1	600	71.16
13EL1	360	65.09
15EL1	360	65.09
17EL1	150	55.44
19EL1	60	46.29
204RO1	2.5	7.58
102EO1	2.5	7.58
103EO1	16	26.28

Unit	Process Weight Rate (ton/hr)	PM Limit (lb/hr)
4SP1	21	31.53
1EX1	93.1	50.56
1EX2	93.1	50.56
3EX1	48.8	44.35
3EX2	48.8	44.35
4EX1	156.3	55.87
4EX2	156.3	55.87
4EX3	156.3	55.87
5EX1	156.3	55.87
5EX2	156.3	55.87
5EX3	156.3	55.87
6EX1	150	55.44
7EX1	176	57.13
7EX2	45	43.60
7EX3	45	43.60
7EX4	45	43.60
7EX5	45	43.60
Conveyor (each)	176	57.13
9EX1	125	53.55
10EX1	333	64.19
11EX1	15	25.16
12EX1	540	69.88
24EX1	109.4	52.18
24EX2	109.4	52.18
24EX3	110	52.24
16EX1	93	50.55
16EX2	93	50.55
16EX3	93	50.55
18EX1	156.3	55.87
23EX1	125	53.55
8SP1	13.8	23.80
17EX2	156.3	55.87
31EX1	156.3	55.87
31EX2	156.3	55.87

The pounds per hour limitations were calculated using the following equations:

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:

$$E = 4.10 P^{0.67} \quad \text{where } E = \text{rate of emission in pounds per hour and} \\ P = \text{process weight rate in tons per hour}$$

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

$$E = 55.0 P^{0.11} - 40 \quad \text{where } E = \text{rate of emission in pounds per hour and} \\ P = \text{process weight rate in tons per hour}$$

**D.2.3 Preventive Maintenance Plan [326 IAC 2-7-5(13)]**

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

**Compliance Determination Requirements [326 IAC 2-7-5(1)] [326 IAC 2-7-6(1)]**

**D.2.4 Testing Requirements [326 IAC 2-7-6(1),(6)] [326 IAC 2-1.1-11]**

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- (a) In order to demonstrate compliance with Condition D.2.1(c), the Permittee shall perform PM and PM<sub>10</sub> testing of the meal sizing and grinding operation, unit ID 7EX, no later than 180 days of publication of the new or revised condensable PM test method(s) referenced in the U. S. EPA's Final Rule for Implementation of the New Source Review (NSR) Program for Particulate Matter Less Than 2.5 Micrometers (PM<sub>2.5</sub>), signed on May 8th, 2008. This testing shall be conducted utilizing methods as approved by the Commissioner. These tests shall be repeated at least once every five (5) years from the date of this valid compliance demonstration. 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. PM<sub>10</sub> includes filterable and condensable PM.
- (b) In order to demonstrate compliance with Condition D.2.1(b), the Permittee shall perform PM and PM<sub>10</sub> testing of the hot dehulling equipment (5EX2), within sixty (60) days after achieving the maximum capacity, but not later than one hundred eighty (180) days after initial startup, utilizing methods as approved by the Commissioner at least once every five (5) years from the date of the most recent valid compliance demonstration. 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. Testing shall be conducted in accordance with Section C - Performance Testing. PM<sub>10</sub> includes filterable and condensable PM<sub>10</sub>.

**D.2.5 Particulate Matter (PM) [40 CFR 64 (CAM)]**

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- (a) In order to comply with Conditions D.2.1 and D.2.2, the baghouses, filters, and cyclones for PM control shall be in operation and control emissions from the listed facilities at all times that these facilities are in operation.
- (b) In order to comply with Conditions D.2.1 and D.2.2, dust control oil shall be applied on all grain received at the dump pits serving the emission units identified as 3EL1, 4EL1, 6EL1, 7EL1, and 13 EL1.
- (c) In order to comply with Conditions D.2.1 and D.2.2, the self-cleaning screens for PM control shall be in operation and control emissions from the grain dryers #4 and #5 (17EL1) at all times that these facilities are in operation.
- (d) In the event that bag failure is observed in a multi-compartment baghouse, if operations will continue for ten (10) days or more after the failure is observed before the failed units will be repaired or replaced, the Permittee shall promptly notify the IDEM, OAQ of the expected date the failed units will be repaired or replaced. The notification shall also include the status of the applicable compliance monitoring parameters with respect to normal, and the results of any response actions taken up to the time of notification.

**D.2.6 Particulate Matter (PM)**

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In order to comply with Condition D.2.1(c), the baghouse shall be in operation and control emissions from the meal sizing and grinding operation, unit ID 7EX, at all times when the equipment is in operation.

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

### D.2.7 Visible Emissions Notations [40 CFR 64 (CAM)]

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- (a) Daily visible emission notations of the grain handling, grain drying, and soybean meal production stack exhausts/vents (6EL, 9EL, 12EL, 13EL, 15EL, 17EL, 204RO, 102EO, 103EO, 4SP, 1EX, 3EX, 4EX, 5EX, 6EX, 7EX, 9EX, 10EX, 11EX, 12EX, 24EX1, 24EX2, 24EX3A, 24EX3B, 23EX, 33EX, 1SP, and 17EX) shall be performed during normal daylight operations. 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 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.

### D.2.8 Parametric Monitoring [40 CFR 64 (CAM)]

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The Permittee shall record the pressure drop across the baghouses used in conjunction with 6EL1, 9EL1, 12EL1, 13EL1, 15EL1, 204RO1, 102EO1, 103EO1, 4SP1, 1EX1, 1EX2, 4EX1, 4EX2, 4EX3, 5EX1, 5EX2, 5EX3, 6EX1, 7EX, 9EX1, 10EX1, 11EX1, 12EX1, and 8SP1 at least once per day when these facilities are in operation. When for any one reading, the pressure drop across the baghouse is outside the normal range of 0.5 and 12.0 inches of water or a range established during the latest stack test, the Permittee shall 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. 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.

The instrument used for determining the pressure 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 every six (6) months.

### D.2.9 Broken or Failed Bag Detection [40 CFR 64 (CAM)]

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- (a) For a single compartment baghouses controlling emissions from a process operated continuously, a failed unit and the associated process shall be shut down immediately until the failed unit has 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).
- (b) For a single compartment baghouse controlling emissions from a batch process, the feed to the process shall be shut down immediately until the failed unit have been repaired or replaced. The emissions unit shall be shut down no later than the completion of the processing of the material in emissions unit. 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).

Bag failure can be indicated by a significant drop in the baghouse's pressure reading with abnormal visible emissions, by an opacity violation, or by other means such as gas temperature, flow rate, air infiltration, leaks, dust traces or triboflows.

#### D.2.10 Cyclone Failure Detection [40 CFR 64 (CAM)]

In the event that cyclone failure has been observed:

Failed units and the associated process will be shut down immediately until the failed units have been repaired or replaced. The emissions unit shall be shut down no later than the completion of the processing of the material in the emission unit. 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 Requirement [326 IAC 2-7-5(3)] [326 IAC 2-7-19]**

#### D.2.11 Record Keeping Requirements

- (a) To document the compliance status with Condition D.2.1, the Permittee shall maintain monthly records of the amount of soybean grains processed after the grain dryers.
- (b) To document the compliance status with Condition D.2.7, the Permittee shall maintain a daily record of visible emission notations of the grain handling and soybean meal production processes' stack exhausts. 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.2.8, the Permittee shall maintain a daily record of the pressure drop across the baghouses controlling the grain handling and soybean meal production processes. The Permittee shall include in its daily record when a pressure drop reading is not taken and the reason for the lack of a pressure drop reading (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.2.12 Reporting Requirements

A quarterly summary of the information to document the compliance status with Condition D.2.1(a)(1) shall be submitted not later than thirty (30) days after the end of the quarter being reported. Section C - General Reporting contains the Permittee's obligation with regard to the reporting required by this condition. 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(34).

### SECTION D.3 EMISSIONS UNIT OPERATION CONDITIONS

#### Emissions Unit Description: Boilers and Heaters

- (a) One (1) natural gas fired hydrogen generator furnace, identified as 107EO1, constructed in 1992, with a maximum heat input capacity of 25.2 MMBtu/hr, and exhausting to stack 107EO. This is an affected source under the National Emission Standards for Hazardous Air Pollutants for Industrial, Commercial, and Institutional Boilers and Process Heaters 40 CFR 63, Subpart DDDDD.
- (b) One (1) natural gas fired steam generator, identified as 110EO1, constructed in 2002, with a maximum heat input capacity of 14 MMBtu/hr, and exhausting to stack 110EO. This is an affected facility under the New Source Performance Standards for Small Industrial - Commercial - Institutional Steam Generating Units 40 CFR 60, Subpart Dc and an affected source under the National Emission Standards for Hazardous Air Pollutants for Industrial, Commercial, and Institutional Boilers and Process Heaters 40 CFR 63, Subpart DDDDD.
- (c) One (1) natural gas fired steam generator #3, identified as 108EO1, constructed in 1994, with a maximum heat input capacity of 14 MMBtu/hr, and exhausting to stack 108EO. This is an affected facility under the New Source Performance Standards for Small Industrial - Commercial - Institutional Steam Generating Units 40 CFR 60, Subpart Dc and an affected source under the National Emission Standards for Hazardous Air Pollutants for Industrial, Commercial, and Institutional Boilers and Process Heaters 40 CFR 63, Subpart DDDDD.
- (d) One (1) B & W coal fired boiler, identified as 1SP1, constructed in 1950, with a maximum heat input capacity of 108 MMBtu/hr, using multiple cyclones and a baghouse for control of particulate and HAPs, and exhausting to stack 1SP. This is an affected source under the National Emission Standards for Hazardous Air Pollutants for Industrial, Commercial, and Institutional Boilers and Process Heaters 40 CFR 63, Subpart DDDDD.
- (e) One (1) Keeler coal fired boiler, identified as 2SP1, constructed in 1963, with a maximum heat input capacity of 52.75 MMBtu/hr, using multiple cyclones and a baghouse for control of particulate and HAPs, and exhausting to stack 1SP. This is an affected source under the National Emission Standards for Hazardous Air Pollutants for Industrial, Commercial, and Institutional Boilers and Process Heaters 40 CFR 63, Subpart DDDDD.
- (f) One (1) Murray natural gas fired, vegetable oil-fired, used oil-fired, and hazardous chemical fired boiler, identified as 3SP1, constructed in 1968, with a maximum heat input capacity of 110.2 MMBtu/hr, and exhausting to stack 1SP. This is an affected source under the National Emission Standards for Hazardous Air Pollutants for Industrial, Commercial, and Institutional Boilers and Process Heaters 40 CFR 63, Subpart DDDDD.
- (g) One (1) natural gas-fired boiler, identified as 9SP1, approved for construction in 2012, with a maximum heat input capacity of 99 MMBtu/hr, equipped with low NOx burners and flue gas recirculation (FGR) for NOx control, and exhausting to stack 9SP. This is an affected facility under the New Source Performance Standards for Small Industrial - Commercial - Institutional Steam Generating Units 40 CFR 60, Subpart Dc and an affected source under the National Emission Standards for Hazardous Air Pollutants for Industrial, Commercial, and Institutional Boilers and Process Heaters 40 CFR 63, Subpart DDDDD.

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

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

#### D.3.1 Particulate Matter Limitation (PM) [326 IAC 6-2-3] [326 IAC 6-2-4]

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- (a) Pursuant to 326 IAC 6-2-3(d) (Particulate Emission Limitations for Sources of Indirect Heating), the particulate matter (PM) emissions from the boilers identified as 1SP1, 2SP1, and 3SP1 shall each be limited to less than 0.8 pounds per MMBtu of heat input. The emission limit was calculated by the following equation:

$$Pt = \frac{C \times a \times h}{76.5 \times Q^{0.75} \times N^{0.25}}$$

Where:

- C = max ground level concentration (= 50 µm/m<sup>3</sup>)  
Pt = emission rate limit (lbs/MMBtu)  
Q = total source heat input capacity (MMBtu/hr) = 271 MMBtu  
N = number of stacks = 1  
A = plume rise factor = 0.67  
H = stack height (ft) = 184

- (b) Pursuant to 326 IAC 6-2-4 (Particulate Emission Limitations for Source of Indirect Heating), the particulate matter (PM) emissions from the boiler identified as 107EO1 shall be limited to less than 0.25 pounds per MMBtu of heat input.
- (c) Pursuant to 326 IAC 6-2-4 (Particulate Emission Limitations for Source of Indirect Heating), the particulate matter (PM) emissions from the boiler identified as 108EO1 shall be limited to less than 0.245 pounds per MMBtu of heat input.
- (d) Pursuant to 326 IAC 6-2-4 (Particulate Emission Limitations for Source of Indirect Heating), the particulate matter (PM) emissions from the boiler identified as 110EO1 shall be limited to less than 0.24 pounds per MMBtu of heat input.
- (e) Pursuant to 326 IAC 6-2-4 (Particulate Emission Limitations for Source of Indirect Heating), the particulate matter (PM) emissions from the boiler identified as 9SP1 shall be limited to less than 0.23 pounds per MMBtu of heat input.

The emission limits for boilers 107EO1, 108EO1, 110EO1, and 9SP1 were calculated by the following equation:

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

- Where Pt = emission rate limit (lbs/MMBtu)  
Q = total source heat input capacity (MMBtu/hr)  
Q = 423.15 MMBtu/hr for 9SP1

#### D.3.2 Consent Decree Limits, Compliance, and Record Keeping Requirements

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- (a) As used in this section, "Consent Decree" shall mean the consent decree entered on January 16, 2007, in Civil Action No. 2:06-CV-02209, United States District Court for the Central District of Illinois, in which the Permittee and IDEM were parties. As required by Section 41.a of the Consent Decree, the Permittee shall modify their existing Part 70 Operating Permit to incorporate the emission limits set forth in the Control Technology Plan (CTP).

- (b) As required by Section 41.a of the Consent Decree and the Control Technology Plan (CTP), the particulate matter (PM) emissions from the boilers identified as 1SP1 and 2SP1 shall each be limited to less than 0.07 pounds per MMBtu of heat input.

**D.3.3 Sulfur Dioxide (SO<sub>2</sub>) [326 IAC 7-1.1-1]**

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Pursuant to 326 IAC 7-1.1-2(a)(1), (Sulfur Dioxide Emission Limitations) the sulfur dioxide emissions from the B&W boiler (1SP1) and the Keeler boiler (2SP1), when combusting coal, shall be less than 6.0 pounds per MMBtu. Pursuant to 326 IAC 7-2-1, compliance shall be demonstrated on a calendar month average in accordance with the coal sampling requirements indicated in Condition D.3.4, Sulfur Dioxide Emissions and Sulfur Content.

**D.3.4 Preventive Maintenance Plan [326 IAC 2-7-5(13)]**

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

**Compliance Determination Requirements[326 IAC 2-7-6(1)] [326 IAC 2-7-5(1)]**

**D.3.5 Sulfur Dioxide Emissions and Sulfur Content [326 IAC 2-7-5(3)(A)] [326 IAC 2-7-6]**

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- (a) Pursuant to 326 IAC 7-2-1(c)(2), The Permittee shall submit quarterly reports of the calendar month average coal sulfur content, coal heat content, the sulfur dioxide emission rate in pounds per MMBtu, and the total monthly coal consumption.
- (b) Pursuant to 326 IAC 7-2-1(e), coal sampling and analysis data shall be collected pursuant to the procedures specified in 326 IAC 3-7-2(b) or 326 IAC 3-7-3 as follows:
- (1) Minimum Coal Sampling Requirements and Analysis Methods:
    - (A) The coal sample acquisition point shall be at a location where representative samples of the total coal flow to be combusted by the facility or facilities may be obtained. A single as-bunkered or as-burned sampling station may be used to represent the coal to be combusted by multiple facilities using the same stockpile feed system;
    - (B) Coal shall be sampled at least one (1) time per day;
    - (C) Minimum sample size shall be five hundred (500) grams;
    - (D) Samples shall be composited and analyzed at the end of each calendar month;
    - (E) Preparation of the coal sample, heat content analysis, and sulfur content analysis shall be determined pursuant to 326 IAC 3-7-2(c); or
  - (2) Sample and analyze the coal pursuant to 326 IAC 3-7-3.

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

**D.3.6 Visible Emissions Notations**

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- (a) Visible emission notations of the boiler's (1SP1, 2SP1, 3SP1) stack exhaust (1SP) shall be performed once per day during normal daylight operations. 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 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.

#### D.3.7 Parametric Monitoring

The Permittee shall record the pressure drop across the baghouse used in conjunction with 1SP1 and 2SP1 at least once per day when these boilers are in operation. When for any one reading, the pressure drop across the baghouse is outside the normal range of 0.5 and 12.0 inches of water or a range established during the latest stack test, the Permittee shall 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. 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.

The instrument used for determining the pressure 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 every six (6) months.

#### D.3.8 Broken or Failed Bag Detection

- (a) For a single compartment baghouses controlling emissions from a process operated continuously, a failed unit and the associated process shall be shut down immediately until the failed unit has 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).
- (b) For a single compartment baghouse controlling emissions from a batch process, the feed to the process shall be shut down immediately until the failed unit have been repaired or replaced. The emissions unit shall be shut down no later than the completion of the processing of the material in emissions unit. 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).

Bag failure can be indicated by a significant drop in the baghouse's pressure reading with abnormal visible emissions, by an opacity violation, or by other means such as gas temperature, flow rate, air infiltration, leaks, dust traces or triboflows.

#### D.3.9 Cyclone Failure Detection

In the event that cyclone failure has been observed:

Failed units and the associated process will be shut down immediately until the failed units have been repaired or replaced. The emissions unit shall be shut down no later than the completion of the processing of the material in the emission unit. 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 Requirement [326 IAC 2-7-5(3)] [326 IAC 2-7-19]**

### **D.3.10 Record Keeping Requirements**

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- (a) To document the compliance status with Conditions D.3.2 and D.3.4, the Permittee shall maintain records in accordance with (1) through (5) below. Records maintained for (1) through (5) shall be taken monthly and shall be complete and sufficient to establish compliance with the PM and SO<sub>2</sub> emission limits established in Conditions D.3.2 and D.3.4.
- (1) Calendar dates covered in the compliance determination period;
  - (2) Actual coal usage since last compliance determination period;
  - (3) Sulfur content, heat content, and ash content;
  - (4) Sulfur dioxide emission rates; and
  - (5) Independent laboratory analysis of coal.
- (b) To document the compliance status with Condition D.3.6, the Permittee shall maintain a daily record of visible emission notations of the boiler's stack exhaust (SP1). 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.3.7, the Permittee shall maintain a daily record of the pressure drop across the baghouses controlling the boilers. The Permittee shall include in its daily record when a pressure drop reading is not taken and the reason for the lack of a pressure drop reading (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.3.11 Reporting Requirements**

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A quarterly summary of the information to document the compliance status with Conditions D.3.2 and D.3.4 shall be submitted not later than thirty (30) days after the end of the quarter being reported. Section C - General Reporting contains the Permittee's obligation with regard to the reporting required by this condition. 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(34).

## **Consent Decree**

### **D.3.12 Consent Decree Limits, Compliance, and Record Keeping Requirements**

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- (a) As used in this section, "Consent Decree" shall mean the consent decree entered on January 16, 2007 and modified on June 14, 2011, in Civil Action No. 2:06-CV-02209, United States District Court for the Central District of Illinois, in which the Permittee and IDEM were parties. As required by Paragraph 23.b.(i) of the Consent Decree, the Permittee shall perform the following two (2) projects:
- (1) install a new heat exchange system on the make-up water system to recover wasted flash steam presently going to the atmosphere and the energy on hot water now sent to the sewer; and

- (2) capture steam escaping from the turbine seals to heat make-up water by using an ejector, heat exchangers, and associated control system to condense most of the captured steam.
- (b) As required by Paragraph 23.b.(i) of the Consent Decree, the Permittee shall commence installation and begin operation of the projects identified in paragraphs (a)(1) and (a)(2) of this condition no later than December 31, 2011.
- (c) After installation of the projects identified in paragraphs (a)(1) and (a)(2) of this condition, the Permittee shall demonstrate that the projects result in the following emissions reductions:
  - (1) 0.24 tons per year (tpy) of PM;
  - (2) 0.24 tons per year (tpy) of PM<sub>10</sub>;
  - (3) 0.24 tons per year (tpy) of PM<sub>2.5</sub>;
  - (4) 1.50 tons per year (tpy) of CO;
  - (5) 12.44 tons per year (tpy) of SO<sub>2</sub>;
  - (6) 2.99 tons per year (tpy) of NO<sub>x</sub>; and
  - (7) 1,593 tons per year (tpy) of CO<sub>2</sub>.
- (d) The U.S. EPA shall extend the Compliance Date upon receiving the written statement of basis for extension by the Permittee demonstrating to EPA that third parties involved in the projects identified in paragraphs (a)(1) and (a)(2) of this condition require additional time (e.g., the equipment fabrication, delivery and availability schedules provided by third party vendors and the construction availability schedules of third party contractors). The Permittee shall take all reasonable steps to limit the duration of any extension of the Compliance Date under this provision. Court approval shall not be required for an extension of the Compliance Date pursuant to this provision. Any such extension beyond March 31, 2012, may require additional emission reductions from other projects if U.S. EPA determines that the delay has caused significant lost emission reductions.
- (e) The Permittee shall demonstrate that the emission reduction targets specified in paragraphs (c)(1) through (c)(7) of this condition were achieved by measuring the reduction in energy losses during the first three (3) months of operation of the projects identified in paragraphs (a)(1) and (a)(2) of this condition and comparing it with the energy losses occurring prior to the installation of the projects. The Permittee shall then calculate the annualized emissions reductions resulting from the reduction in energy losses assuming that the fuel mix was the same as the average fuel mix during the during the years 2007 through 2008 (Emissions Target Report).
- (f) The Permittee shall submit the Emissions Target Report required by paragraph (e) of this condition no later than sixty (60) days after completion of the first three (3) months of operation of the projects identified in paragraphs (a)(1) and (a)(2) of this condition.
- (g) The Permittee shall be deemed to have achieved the emission reduction targets specified in paragraphs (c)(1) through (c)(7) of this condition as long as the Emissions Target Report required by paragraph (e) of this condition demonstrates that the projects identified in paragraphs (a)(1) and (a)(2) of this condition achieved at least ninety percent (90%) of the emission reduction targets.

## SECTION D.4 EMISSIONS UNIT OPERATION CONDITIONS

### Emissions Unit Description: Hexane Extraction System

- (a) One (1) hexane extraction system, identified collectively as 24EX, modified prior to 1980, with hexane emissions from the vent system controlled by a mineral oil absorber, and exhausting to stack 24EXA. For reporting purposes, all hexane emissions are collectively accounted for in the total hexane losses named 24EX.
- (1) One (1) 'A' unit, identified as 24 EX1, consisting of 'A' pre-DT, constructed in 1996, 'A' DT, constructed in 1980, and the 'A' Meal Dryer, constructed in 1980 with a maximum capacity of 109.4 tons per hour, each. 'A' pre-DT is on top of and feeds the 'A' DT, which is on top of and feeds the 'A' Meal Dryer. The 'A' pre-DT and the 'A' DT exhaust to the hexane solvent reclaim system. The 'A' Meal Dryer uses a cyclone for PM control, and exhausts to stack 24EX1. Hexane emissions are reported in 24EX.
  - (2) One (1) 'B' unit, identified as 24EX2, consisting of 'B' pre-DT, constructed in 1996, 'B' DT, constructed in 1980, and the 'B' Meal Dryer, constructed in 1980, with a maximum capacity of 109.4 tons per hour, each. 'B' pre-DT is on top of and feeds the 'B' DT which is on top of and feeds the 'B' Meal Dryer. The 'B' pre-DT and the 'B' DT exhaust to the hexane solvent reclaim system. The 'B' Meal Dryer uses a cyclone for PM control, and exhausts to stack 24EX2. Hexane emissions are reported in 24EX.
  - (3) One meal cooler, identified as 24EX3, constructed in 1996, with a maximum capacity of 110 tons per hour, using two (2) cyclones for PM control, exhausting to stacks 24EX3A and 24EX3B, respectively, with hexane emissions reported in 24EX.
  - (4) Two (2) hexane storage tanks, identified as 24EX4A and 24EX4B, constructed in 1995 and 2005, respectively, with emissions vented to the mineral oil absorber inlet, with hexane emissions reported in 24EX.
  - (5) One (1) wastewater system, identified as 24 EX5, constructed prior to 1980, containing traces of hexane, exhausting to the extraction hot water separation pit, with hexane emissions reported in 24EX.
  - (6) One (1) refined oil hot well, identified as 24 EX6, constructed in 1975, with hexane emissions reported in 24EX.
  - (7) One (1) sampling /hexane unloading port, identified as 24 EX7, with hexane emissions reported in 24EX.
  - (8) Oil tanks containing non-deodorized oil, identified as 24EX8, venting to the atmosphere, with hexane emissions reported at 24EX.

The hexane extraction system (24EX, consisting of 24EX1 through 24EX8) are affected facilities under the National Emission Standards for Hazardous Air Pollutants: Solvent Extraction for Vegetable Oil Production 40 CFR 63, Subpart GGGG.

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

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

### **D.4.1 PSD Minor Limit [326 IAC 2-2]**

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Pursuant to CP (002) 2005, issued August 23, 1991, the hexane usage for all of the oil extraction facilities (24EX, consisting of 24EX1 through 24EX8) combined shall be limited to less than 330,000 gallons per twelve (12) consecutive month period, with compliance determined at the end of each month, to ensure that the increase in hexane emissions from these units remains below 39.2 tons per year. This will ensure that 326 IAC 2-2 (Prevention of Significant Deterioration) does not apply to this modification.

### **D.4.2 Preventive Maintenance Plan [326 IAC 2-7-5(13)]**

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

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

### **D.4.3 Volatile Organic Compounds (VOC)**

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In order to comply with Condition D.4.1, the mineral oil absorber for VOC control shall be in operation and control emissions from the listed facilities at all times when the facilities are in operation.

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

### **D.4.4 Monitoring**

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To document compliance with Condition D.4.1, the mineral oil absorption vent VOC (hexane) emission rate shall be determined daily by measuring the airflow rate and the concentration of hexane in the air stream. This concentration will be determined daily by measuring percent Lower Explosive Limit (LEL). If the air flow meter proves unreliable, airflow can be determined by calculations.

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

### **D.4.5 Record Keeping Requirements**

- 
- (a) To document the compliance status with Condition D.4.1, the Permittee shall maintain records of the hexane usage for the oil extraction facilities.
  - (b) Section C - General Record Keeping Requirements contains the Permittee's obligations with regard to the records required by this condition.

### **D.4.6 Reporting Requirements**

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A quarterly summary of the information to document the compliance status with Condition D.4.1 shall be submitted not later than thirty (30) days after the end of the quarter being reported. Section C - General Reporting contains the Permittee's obligation with regard to the reporting required by this condition. 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(34).

## **Consent Decree**

### **D.4.7 Consent Decree Limits, Compliance, and Record Keeping Requirements**

- 
- (a) As used in this section, "Consent Decree" shall mean the consent decree entered on January 16, 2007, in Civil Action No. 2:06-CV-02209, United States District Court for the Central District of Illinois, in which the Permittee and IDEM were parties.

- (b) The provisions of this subsection are designed to ensure compliance with the final volatile organic compound solvent loss ratio requirements of the consent decree entered into between the Permittee and IDEM on October 26, 2006. Nothing in this subsection is intended to expand, restrict or otherwise alter the obligations imposed on The Permittee by the consent decree.
- (c) The VOC solvent loss ratio (SLR) for this facility shall be 0.15 gallons of solvent lost per ton of oilseed processed for conventional soybean processing at this existing source. To determine compliance with the VOC SLR limit, the Permittee shall maintain a Compliance Ratio of less than or equal to 1.0, which compliance ratio shall be calculated as follows:

$$\text{Compliance Ratio} = \text{Actual Solvent Loss (gal)} / \text{Allowable Solvent Loss (gal)}$$

Where:

Actual Solvent Loss (gal) = Gallons of solvent loss during previous 12 operating months

Allowable Solvent Loss = Oilseed (tons) x VOC Solvent Loss Ratio

Oilseed (tons) = Tons of each oilseed processed during the previous 12 operating months

VOC Solvent Loss Ratio (SLR) = 0.15 gallons per ton of oilseed

- (d) Solvent losses and quantities of oilseed processed during startup and shutdown periods shall not be excluded in determining solvent losses.
- (e) For purposes of calculating SLR, the Permittee may apply the provisions of 40 CFR Part 63, Subpart GGGG, pertaining to malfunction periods when both of the following conditions are met:
- (1) The malfunction results in a total plant shutdown, which means a shutdown of the solvent extraction system; and
  - (2) The total amount of solvent loss to which the provisions of 40 CFR Part 63, Subpart GGGG relating to malfunctions is applied in a rolling 12-month period does not exceed the Allowable Malfunction Volume as determined below. The Allowable Malfunction Volume in gallons is equal to the facility's 12-month Crush capacity times its final VOC SLR limit (0.15 gal/ton) times 0.024, as follows:

$$\text{Allowable Malfunction Volume (gal)} = \text{12-month Crush capacity (tons)} \times \text{Final VOC SLR limit (0.15 gal/ton)} \times 0.024$$

Except as otherwise set forth herein, the Permittee shall include all solvent losses when determining compliance with the VOC SLR limits. The total solvent loss corresponding to a malfunction period shall be calculated as the difference in the solvent inventory, as defined in 40 CFR 63.2862(c)(1), for the day before the malfunction period began and the solvent inventory on the day the plant resumes normal operation. During a malfunction period, the facility shall comply with the Startup, Shutdown, Malfunction (SSM) Plan as required under Subpart GGGG.

- (f) To document the compliance status with the Consent Decree, the Permittee shall maintain the following records in accordance with (1) through (5) below. Records maintained for (1) through (5) shall be taken monthly and shall be complete and sufficient to establish compliance with the VOC SLR limits established in paragraph (c) above. Records necessary to demonstrate compliance shall be available within 30 days of the end of each compliance period.
- (1) The amount of oilseed processed, in tons, on a monthly basis.

- (2) The total solvent loss due to malfunction, in gallons, for each month.
- (3) The total solvent loss during normal operations, in gallons, for each month.
- (4) The adjusted solvent loss (total solvent loss - allowable malfunction volume), in gallons, for each month.
- (5) The solvent loss ratio.

## SECTION D.5

## EMISSIONS UNIT OPERATION CONDITIONS

### Emissions Unit Description:

- (a) One (1) batch enzyme bag unloader, with a maximum throughput rate of 51 tons per year, identified as 112EO1, approved in 2009 for construction, using a baghouse for emission control and exhausting to stack 112EO.

This emission unit is not an affected facility under the National Emission Standards for Hazardous Air Pollutants: Solvent Extraction for Vegetable Oil Production 40 CFR 63, Subpart GGGG.

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

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

#### D.5.1 Particulate Emissions [326 IAC 6-3-2]

Pursuant to 326 IAC 6-3-2, the particulate emission from the Batch Enzyme Bag Unloader, 112EO1, shall be limited to 9.1 pounds per hour at a process weight rate of 3.3 tons per hour. This particulate emissions limit shall be determined using the following equation:

Interpolation of the data in this table for process weight rates 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  
P = Process weight rate in tons per hour

**SECTION D.6**

**EMISSIONS UNIT OPERATION CONDITIONS**

**Emissions Unit Description: Pelletizer/Pellet Cooler System**

- (a) One (1) pelletizer/pellet cooler to produce pellets from the existing dehulling/grinding (millfeed) system, approved in 2009 for construction, with a maximum rate of 10 tons per hour, identified as 32EX1, using a high efficiency cyclone for emission control and exhausting to stack 32EX.
- (b) One (1) totally enclosed conveyor, approved in 2009 for construction, with a maximum rate of 10 tons per hour, identified as 32EX2.
- (c) One (1) loadout bin, identified as 29EX1, constructed in 1994, with a maximum capacity of 10 tons per hour, using a bin vent filter for PM control, and exhausting to stack 29EX.

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

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

**D.6.1 Particulate Matter (PM) [326 IAC 6-3-2]**

Pursuant to 326 IAC 6-3-2 (Process Operations), particulate emissions from each of following operations shall not exceed the pound per hour limit listed in the table below:

Unit	Process Weight Rate (ton/hr)	PM Limit (lb/hr)
29EX1	10	19.18
32EX1	10	19.18
32EX2	10	19.18

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:

$$E = 4.10 P^{0.67} \quad \text{where } E = \text{rate of emission in pounds per hour and} \\ P = \text{process weight rate in tons per hour}$$

**D.6.2 Preventive Maintenance Plan [326 IAC 2-7-5(13)]**

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

**Compliance Determination Requirements [326 IAC 2-7-6(1)] [326 IAC 2-7-5(1)]**

**D.6.3 Particulate Control**

The cyclone shall be in operation at all times when the pelletizer/pellet cooler is in operation.

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

**D.6.4 Visible Emissions Notations**

- (a) Daily visible emission notations of pelletizer/pellet cooler cyclone stack 32EX and loadout bin stack 29EX shall be performed during normal daylight operations. 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 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.

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

#### **D.6.5 Record Keeping Requirements**

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- (a) To document the compliance status with Condition D.6.5, the Permittee shall maintain records of daily visible emission notations of the pelletizer/pellet cooler cyclone stack 32EX and loadout bin stack 29EX. 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 pelletizer/pellet cooler did not operate that day; loadout bin was not loaded, etc.).
- (b) Section C - General Record Keeping Requirements contains the Permittee's obligations with regard to the records required by this condition.

**SECTION E.1 Standards of Performance for Grain Elevators [40 CFR 60, Subpart DD]  
[326 IAC 12]**

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

- (a) Truck Dump #2, identified as 1EL1, constructed in 1980, with a maximum capacity of 600 tons per hour, using a baghouse for particulate matter (PM) control, and exhausting to stack 1EL. This is an affected facility under the New Source Performance Standard for Grain Elevators 40 CFR 60.300, Subpart DD.
- (b) The following grain elevator East Workhouse components, together identified as 2EL1, with a maximum throughput of 270 tons per hour (Bottlenecked to 240 tons per hour), each, unless otherwise stated, using a baghouse and oil suppressant for PM control, and exhausting to stack 2EL, consisting of:
  - (1) One (1) #1 scalperator, approved in 2011 for construction, with a maximum throughput of 120 tons per hour. This is an affected facility under the New Source Performance Standard for Grain Elevators 40 CFR 60.300, Subpart DD;
  - (2) One (1) #2 scalperator, approved in 2011 for construction, with a maximum throughput of 120 tons per hour. This is an affected facility under the New Source Performance Standard for Grain Elevators 40 CFR 60.300, Subpart DD;
- (c) The following grain elevator components together identified as 10EL1, with a maximum throughput of 720 tons per hour, each, using a baghouse and oil suppressant for PM control, and exhausting to stack 10EL, consisting of:
  - (1) One (1) rail loadout, constructed in 1984. This is an affected facility under the New Source Performance Standard for Grain Elevators 40 CFR 60.300, Subpart DD;
- (d) One (1) natural gas fired grain dryer #2, identified as 19EL1, constructed in 1995, with a maximum capacity 60 tons per hour and a maximum heat input capacity of 7 MMBtu/hr, using self-cleaning screens for PM control, and exhausting to vent 19EL. This is an affected facility under the New Source Performance Standard for Grain Elevators 40 CFR 60.300, Subpart DD.
- (e) One (1) truck dump #7, identified as 20EL1, constructed in 1997, with a maximum throughput of 450 tons per hour, consisting of one (1) weigh scale truck unloading pit, and two (2) enclosed bucket elevator legs, using two (2) baghouses in parallel for PM control, and exhausting to stack 20EL. This is an affected facility under the New Source Performance Standard for Grain Elevators 40 CFR 60.300, Subpart DD.
- (f) One (1) natural gas fired grain dryer #1, identified as 16EL1, constructed in 1986, with a maximum capacity of 75 tons per hour and a maximum heat input capacity of 7 MMBtu/hr, using self-cleaning screens for PM control, and exhausting to stack 16EL. This is an affected facility under the New Source Performance Standard for Grain Elevators 40 CFR 60.300, Subpart DD.

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

## **New Source Performance Standards (NSPS) [40 CFR 60]**

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

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(a) The provisions of 40 CFR 60, Subpart A – General Provisions, which are incorporated by reference in 326 IAC 12-1, apply to the facilities described in this SECTION E.1, except when otherwise specified in 40 CFR 60, Subpart DD.

(b) Pursuant to 40 CFR 60.19, the Permittee shall submit all required notifications and reports to:

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

### **E.1.2 Standards of Performance for Grain Elevators [40 CFR 60, Subpart DD] [326 IAC 12]**

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Pursuant to 40 CFR 60, Subpart DD, the Permittee shall comply with the provisions of Standards of Performance Standards of Performance for Grain Elevators, which are incorporated by reference as 326 IAC 12, (included as attachment A of this permit) as specified as follows:

- (1) 40 CFR 60.300
- (2) 40 CFR 60.301
- (3) 40 CFR 60.302(b), (c)
- (4) 40 CFR 60.303
- (5) 40 CFR 60.304

**SECTION E.2 New Source Performance Standards (NSPS) For Small Industrial-Commercial-Institutional Steam Generating Units [40 CFR 60, Subpart Dc]  
[326 IAC 12]**

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

- (a) One (1) natural gas fired hydrogen generator furnace, identified as 107EO1, constructed in 1992, with a maximum heat input capacity of 25.2 MMBtu/hr, and exhausting to stack 107EO. This is an affected source under the National Emission Standards for Hazardous Air Pollutants for Industrial, Commercial, and Institutional Boilers and Process Heaters 40 CFR 63, Subpart DDDDD.
- (b) One (1) natural gas fired steam generator, identified as 110EO1, constructed in 2002, with a maximum heat input capacity of 14 MMBtu/hr, and exhausting to stack 110EO. This is an affected facility under the New Source Performance Standards for Small Industrial - Commercial - Institutional Steam Generating Units 40 CFR 60, Subpart Dc and an affected source under the National Emission Standards for Hazardous Air Pollutants for Industrial, Commercial, and Institutional Boilers and Process Heaters 40 CFR 63, Subpart DDDDD.
- (c) One (1) natural gas fired steam generator #3, identified as 108EO1, constructed in 1994, with a maximum heat input capacity of 14 MMBtu/hr, and exhausting to stack 108EO. This is an affected facility under the New Source Performance Standards for Small Industrial - Commercial - Institutional Steam Generating Units 40 CFR 60, Subpart Dc and an affected source under the National Emission Standards for Hazardous Air Pollutants for Industrial, Commercial, and Institutional Boilers and Process Heaters 40 CFR 63, Subpart DDDDD.
- (d) One (1) natural gas-fired boiler, identified as 9SP1, approved for construction in 2012, with a maximum heat input capacity of 99 MMBtu/hr, equipped with low NOx burners and flue gas recirculation (FGR) for NOx control, and exhausting to stack 9SP. This is an affected facility under the New Source Performance Standards for Small Industrial - Commercial - Institutional Steam Generating Units 40 CFR 60, Subpart Dc and an affected source under the National Emission Standards for Hazardous Air Pollutants for Industrial, Commercial, and Institutional Boilers and Process Heaters 40 CFR 63, Subpart DDDDD.

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

**New Source Performance Standards (NSPS) [40 CFR 60]**

**E.2.1 General Provisions Relating to New Source Performance Standards [326 IAC 12-1] [40 CFR 60, Subpart A]**

- (a) The provisions of 40 CFR 60, Subpart A – General Provisions, which are incorporated by reference in 326 IAC 12-1, apply to the facilities described in this SECTION E.2, except when otherwise specified in 40 CFR 60, Subpart Dc.
- (b) Pursuant to 40 CFR 60.19, the Permittee shall submit all required notifications and reports to:

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

E.2.2 Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units  
[40 CFR 60, Subpart Dc] [326 IAC 12]

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Pursuant to 40 CFR 60, Subpart Dc, the Permittee shall comply with the provisions of Standards of Performance Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units, which are incorporated by reference as 326 IAC 12, (included as attachment B of this permit) as specified as follows:

- (1) 40 CFR 60.40c (a) and (b)
- (2) 40 CFR 60.41c
- (3) 40 CFR 60.48c (a)(1), (g), and (i)

**SECTION E.3 National Emission Standards for Hazardous Air Pollutants: Solvent Extraction for Vegetable Oil Production [40 CFR 63, Subpart GGGG] [326 IAC 20-60]**

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

- (a) One (1) hexane extraction system, identified collectively as 24EX, modified prior to 1980, with hexane emissions from the vent system controlled by a mineral oil absorber, and exhausting to stack 24EXA. For reporting purposes, all hexane emissions are collectively accounted for in the total hexane losses named 24EX.
- (1) One (1) 'A' unit, identified as 24 EX1, consisting of 'A' pre-DT, constructed in 1996, 'A' DT, constructed in 1980, and the 'A' Meal Dryer, constructed in 1980 with a maximum capacity of 109.4 tons per hour, each. 'A' pre-DT is on top of and feeds the 'A' DT, which is on top of and feeds the 'A' Meal Dryer. The 'A' pre-DT and the 'A' DT exhaust to the hexane solvent reclaim system. The 'A' Meal Dryer uses a cyclone for PM control, and exhausts to stack 24EX1. Hexane emissions are reported in 24EX.
  - (2) One (1) 'B' unit, identified as 24EX2, consisting of 'B' pre-DT, constructed in 1996, 'B' DT, constructed in 1980, and the 'B' Meal Dryer, constructed in 1980 with a maximum capacity of 109.4 tons per hour, each. 'B' pre-DT is on top of and feeds the 'B' DT which is on top of and feeds the 'B' Meal Dryer. The 'B' pre-DT and the 'B' DT exhaust to the hexane solvent reclaim system. The 'B' Meal Dryer uses a cyclone for PM control, and exhausts to stack 24EX2. Hexane emissions are reported in 24EX.
  - (3) One meal cooler, identified as 24EX3, constructed in 1996, with a maximum capacity of 110 tons per hour, using two (2) cyclones for PM control, exhausting to stacks 24EX3A and 24EX3B, respectively, with hexane emissions reported in 24EX.
  - (4) Two (2) hexane storage tanks, identified as 24EX4A and 24EX4B, constructed in 1995 and 2005, respectively, with emissions vented to the mineral oil absorber inlet, with hexane emissions reported in 24EX.
  - (5) One (1) wastewater system, identified as 24 EX5, constructed prior to 1980, containing traces of hexane, exhausting to the extraction hot water separation pit, with hexane emissions reported in 24EX.
  - (6) One (1) refined oil hot well, identified as 24 EX6, constructed in 1975, with hexane emissions reported in 24EX.
  - (7) One (1) sampling /hexane unloading port, identified as 24 EX7, with hexane emissions reported in 24EX.
  - (8) Oil tanks containing non-deodorized oil, identified as 24EX8, venting to the atmosphere, with hexane emissions reported at 24EX.

The hexane extraction system (24EX, consisting of 24EX1 through 24EX8) are affected facilities under the National Emission Standards for Hazardous Air Pollutants: Solvent Extraction for Vegetable Oil Production 40 CFR 63, Subpart GGGG.

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

### **National Emission Standards for Hazardous Air Pollutants (NESHAP) [40 CFR 60]**

#### **E.3.1 General Provisions Relating to NESHAP GGGG [326 IAC 20-1] [40 CFR Part 63, Subpart A]**

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(a) Pursuant to 40 CFR 63.4480, the Permittee shall comply with the provisions of 40 CFR Part 63, Subpart A – General Provisions, which are incorporated by reference as 326 IAC 20-1-1, as specified in 40 CFR Part 63, Subpart GGGG in accordance with schedule in 40 CFR 63 Subpart GGGG.

(b) Pursuant to 40 CFR 63.10, the Permittee shall submit all required notifications and reports 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

#### **E.3.2 National Emission Standards for Hazardous Air Pollutants: Solvent Extraction for Vegetable Oil Production NESHAP [326 IAC 20-60] [40 CFR Part 63, Subpart GGGG]**

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The Permittee which engages in production of vegetable oil shall comply with the following provisions of 40 CFR 63, Subpart GGGG (included as Attachment C of this permit), as specified as follows:

- (1) 40 CFR 63.2830
- (2) 40 CFR 63.2831
- (3) 40 CFR 63.2832
- (4) 40 CFR 63.2833(a), (d)
- (5) 40 CFR 63.2834
- (6) 40 CFR 63.2840(a), (b), (c), (d)
- (7) 40 CFR 63.2850(a), (b), (e)
- (8) 40 CFR 63.2851
- (9) 40 CFR 63.2852
- (10) 40 CFR 63.2853
- (11) 40 CFR 63.2854
- (12) 40 CFR 63.2855
- (13) 40 CFR 63.2860(a), (c), (d)
- (14) 40 CFR 63.2861
- (15) 40 CFR 63.2862
- (16) 40 CFR 63.2863
- (17) 40 CFR 63.2870
- (18) 40 CFR 63.2871
- (19) 40 CFR 63.2872

**SECTION E.4 National Emission Standards for Hazardous Air Pollutants for Industrial, Commercial, and Institutional Boilers and Process Heaters [40 CFR 63, Subpart DDDDD] [326 IAC 20-95]**

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

- (a) One (1) natural gas fired hydrogen generator furnace, identified as 107EO1, constructed in 1992, with a maximum heat input capacity of 25.2 MMBtu/hr, and exhausting to stack 107EO. This is an affected source under the National Emission Standards for Hazardous Air Pollutants for Industrial, Commercial, and Institutional Boilers and Process Heaters 40 CFR 63, Subpart DDDDD.
- (b) One (1) natural gas fired steam generator, identified as 110EO1, constructed in 2002, with a maximum heat input capacity of 14 MMBtu/hr, and exhausting to stack 110EO. This is an affected facility under the New Source Performance Standards for Small Industrial - Commercial - Institutional Steam Generating Units 40 CFR 60, Subpart Dc and an affected source under the National Emission Standards for Hazardous Air Pollutants for Industrial, Commercial, and Institutional Boilers and Process Heaters 40 CFR 63, Subpart DDDDD.
- (c) One (1) natural gas fired steam generator #3, identified as 108EO1, constructed in 1994, with a maximum heat input capacity of 14 MMBtu/hr, and exhausting to stack 108EO. This is an affected facility under the New Source Performance Standards for Small Industrial - Commercial - Institutional Steam Generating Units 40 CFR 60, Subpart Dc and an affected source under the National Emission Standards for Hazardous Air Pollutants for Industrial, Commercial, and Institutional Boilers and Process Heaters 40 CFR 63, Subpart DDDDD.
- (d) One (1) B & W coal fired boiler, identified as 1SP1, constructed in 1950, with a maximum heat input capacity of 108 MMBtu/hr, using multiple cyclones and a baghouse for control of particulate and HAPs, and exhausting to stack 1SP. This is an affected source under the National Emission Standards for Hazardous Air Pollutants for Industrial, Commercial, and Institutional Boilers and Process Heaters 40 CFR 63, Subpart DDDDD.
- (e) One (1) Keeler coal fired boiler, identified as 2SP1, constructed in 1963, with a maximum heat input capacity of 52.75 MMBtu/hr, using multiple cyclones and a baghouse for control of particulate and HAPs, and exhausting to stack 1SP. This is an affected source under the National Emission Standards for Hazardous Air Pollutants for Industrial, Commercial, and Institutional Boilers and Process Heaters 40 CFR 63, Subpart DDDDD.
- (f) One (1) Murray natural gas fired, vegetable oil-fired, used oil-fired, and hazardous chemical fired boiler, identified as 3SP1, constructed in 1968, with a maximum heat input capacity of 110.2 MMBtu/hr, and exhausting to stack 1SP. This is an affected source under the National Emission Standards for Hazardous Air Pollutants for Industrial, Commercial, and Institutional Boilers and Process Heaters 40 CFR 63, Subpart DDDDD.
- (g) One (1) natural gas-fired boiler, identified as 9SP1, approved for construction in 2012, with a maximum heat input capacity of 99 MMBtu/hr, equipped with low NOx burners and flue gas recirculation (FGR) for NOx control, and exhausting to stack 9SP. This is an affected facility under the New Source Performance Standards for Small Industrial - Commercial - Institutional Steam Generating Units 40 CFR 60, Subpart Dc and an affected source under the National Emission Standards for Hazardous Air Pollutants for Industrial, Commercial, and Institutional Boilers and Process Heaters 40 CFR 63, Subpart DDDDD.

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

## **National Emission Standards for Hazardous Air Pollutants (NESHAP) [40 CFR 60]**

### E.4.1 General Provisions Relating to NESHAP DDDDD [326 IAC 20-1] [40 CFR Part 63, Subpart A]

(a) Pursuant to 40 CFR 63.7565, the Permittee shall comply with the provisions of 40 CFR Part 63, Subpart A – General Provisions, which are incorporated by reference as 326 IAC 20-1-1, as specified in 40 CFR Part 63, Subpart DDDDD.

(b) Pursuant to 40 CFR 63.10, the Permittee shall submit all required notifications and reports 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

### E.4.2 National Emission Standards for Hazardous Air Pollutants for Industrial, Commercial, and Institutional Boilers and Process Heaters [326 IAC 20-95] [40 CFR Part 63, Subpart DDDDD]

The Permittee shall comply with the following provisions of 40 CFR 63, Subpart DDDDD (included as Attachment D of this permit), which are incorporated by reference as 326 IAC 20-95:

- (1) 40 CFR 63.7480
- (2) 40 CFR 63.7485
- (3) 40 CFR 63.7490
- (4) 40 CFR 63.7495(a), (b), and (d)
- (5) 40 CFR 63.7499
- (6) 40 CFR 63.7500
- (7) 40 CFR 63.7505
- (8) 40 CFR 63.7506(b)
- (9) 40 CFR 63.7507
- (10) 40 CFR 63.7510(a), (b), (c), (d), and (g)
- (11) 40 CFR 63.7515
- (12) 40 CFR 63.7520(a), (b), (d), (e), (f), and (g)
- (13) 40 CFR 63.7521
- (14) 40 CFR 63.7522
- (15) 40 CFR 63.7525
- (16) 40 CFR 63.7530(a), (c), (d), and (e)
- (17) 40 CFR 63.7535
- (18) 40 CFR 63.7540
- (19) 40 CFR 63.7541
- (20) 40 CFR 63.7545(a), (b), (c), (d), (e)(1-7), and (e)(9)
- (21) 40 CFR 63.7550
- (22) 40 CFR 63.7555
- (23) 40 CFR 63.7560
- (24) 40 CFR 63.7565
- (25) 40 CFR 63.7570
- (26) 40 CFR 63.7575
- (27) Table 1 to 40 CFR 63

- (28) Table 2 to 40 CFR 63
- (29) Table 3 to 40 CFR 63
- (30) Table 4 to 40 CFR 63
- (31) Table 5 to 40 CFR 63
- (32) Table 6 to 40 CFR 63
- (33) Table 7 to 40 CFR 63
- (34) Table 8 to 40 CFR 63
- (35) Table 9 to 40 CFR 63
- (36) Table 10 to 40 CFR 63
- (37) Appendix A to 40 CFR 63

E.4.3 Testing Requirements [326 IAC 2-7-6(1),(6)] [326 IAC 2-1.1-11]

The Permittee shall perform the stack testing required under NESHAP 40 CFR 63, Subpart DDDDD, utilizing methods as approved by the Commissioner to document compliance with Condition E.4.2. These tests shall be repeated at least once every five (5) years from the date of the last valid compliance demonstration. 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.

## INDIANA DEPARTMENT OF ENVIRONMENTAL MANAGEMENT OFFICE OF AIR QUALITY

### PART 70 OPERATING PERMIT CERTIFICATION

Source Name: Bunge North America (East), LLC  
Source Address: 1200 North 2nd Street, Decatur, Indiana 46733  
Part 70 Permit No.: T001-23640-00005

**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: Bunge North America (East), LLC  
Source Address: 1200 North 2nd Street, Decatur, Indiana 46733  
Part 70 Permit No.: T001-23640-00005

This form consists of 2 pages

Page 1 of 2

<input type="checkbox"/> This is an emergency as defined in 326 IAC 2-7-1(12) <ul style="list-style-type: none"><li>• The Permittee must notify the Office of Air Quality (OAQ), no later than four (4) daytime business hours (1-800-451-6027 or 317-233-0178, ask for Compliance and Enforcement Branch); and</li><li>• The Permittee must submit notice in writing or by facsimile no later than two (2) days (Facsimile Number: 317-233-6865), and follow the other requirements of 326 IAC 2-7-16.</li></ul>
---

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? <input type="checkbox"/> Y <input type="checkbox"/> N Describe:
Type of Pollutants Emitted: <input type="checkbox"/> TSP <input type="checkbox"/> PM-10 <input type="checkbox"/> SO <sub>2</sub> <input type="checkbox"/> VOC <input type="checkbox"/> NO <sub>x</sub> <input type="checkbox"/> CO <input type="checkbox"/> Pb <input type="checkbox"/> 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: Bunge North America (East), LLC  
Source Address: 1200 North 2nd Street, Decatur, Indiana 46733  
Part 70 Permit No.: T001-23640-00005  
Facility: Oil Extraction facilities  
Parameter: Hexane Usage  
Limit: Less than 330,000 gallons per twelve consecutive month period.

QUARTER: \_\_\_\_\_ YEAR: \_\_\_\_\_

Month	Hexane Usage for This Month (gal)	Hexane Usage for Previous 11 Months (gal)	Hexane Usage for 12-Month Period (gal)

- No deviation occurred in this quarter.
- Deviations 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 Quarterly Report**

Source Name: Bunge North America (East), LLC  
Source Address: 1200 North 2nd Street, Decatur, Indiana 46733  
Part 70 Permit No.: T001-23640-00005  
Facility: Grain Processing facilities  
Parameter: Soybean grain processed after the grain dryers  
Limit: Less than 1,368,750 tons per twelve consecutive month period

QUARTER: \_\_\_\_\_ YEAR: \_\_\_\_\_

Month	Soybean grain processed for This Month (tons)	Soybean grain processed for Previous 11 Months (tons)	Soybean grain processed for 12-Month Period (tons)

- No deviation occurred in this quarter.
- Deviations 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 Quarterly Report**

Source Name: Bunge North America (East), LLC  
Source Address: 1200 North 2nd Street, Decatur, Indiana 46733  
Part 70 Permit No.: T001-23640-00005  
Facility: Coal-fired Boilers (1SP1 and 2SP1)  
Parameter: SO<sub>2</sub> Emissions  
Limit: Less than 6.0 pounds per MMBtu

QUARTER: \_\_\_\_\_ YEAR: \_\_\_\_\_

Month	Coal Sulfur Content (lb/ton)	Coal Heat Content (MMBtu/ton)	SO <sub>2</sub> Emission Rate (lb/MMBtu)	Coal Consumption (tons)
Month 1				
Month 2				
Month 3				

- No deviation occurred in this quarter.
- Deviations 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: Bunge North America (East), LLC  
Source Address: 1200 North 2nd Street, Decatur, Indiana 46733  
Part 70 Permit No.: T001-23640-00005

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

Page 1 of 2

<p>This report shall be submitted quarterly based on a calendar year. 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>	
<input type="checkbox"/> NO DEVIATIONS OCCURRED THIS REPORTING PERIOD.	
<input type="checkbox"/> THE FOLLOWING DEVIATIONS OCCURRED THIS REPORTING PERIOD	
<b>Permit Requirement</b> (specify permit condition #)	
<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</b> (specify permit condition #)	
<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</b> (specify permit condition #)	
<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</b> (specify permit condition #)	
<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</b> (specify permit condition #)	
<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: \_\_\_\_\_

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

**Attachment A  
to a Part 70 Operating Permit Renewal**

**Source Background and Description**

<b>Source Name:</b>	Bunge North America (East), LLC
<b>Source Location:</b>	1200 N. 2nd Street, Decatur, Indiana 46733
<b>County:</b>	Adams
<b>SIC Code:</b>	2075, 2079, 5153, 2048
<b>Permit Renewal No.:</b>	T001-23640-00005

**Title 40: Protection of Environment**

[PART 60—STANDARDS OF PERFORMANCE FOR NEW STATIONARY SOURCES](#)

**Subpart DD—Standards of Performance for Grain Elevators**

**Source:** 43 FR 34347, Aug. 3, 1978, unless otherwise noted.

**§ 60.300 Applicability and designation of affected facility.**

(a) The provisions of this subpart apply to each affected facility at any grain terminal elevator or any grain storage elevator, except as provided under §60.304(b). The affected facilities are each truck unloading station, truck loading station, barge and ship unloading station, barge and ship loading station, railcar loading station, railcar unloading station, grain dryer, and all grain handling operations.

(b) Any facility under paragraph (a) of this section which commences construction, modification, or reconstruction after August 3, 1978, is subject to the requirements of this part.

[43 FR 34347, Aug. 3, 1978, as amended at 52 FR 42434, Nov. 5, 1988]

**§ 60.301 Definitions.**

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

(a) *Grain* means corn, wheat, sorghum, rice, rye, oats, barley, and soybeans.

(b) *Grain elevator* means any plant or installation at which grain is unloaded, handled, cleaned, dried, stored, or loaded.

(c) *Grain terminal elevator* means any grain elevator which has a permanent storage capacity of more than 88,100 m<sup>3</sup> (ca. 2.5 million U.S. bushels), except those located at animal food manufacturers, pet food manufacturers, cereal manufacturers, breweries, and livestock feedlots.

(d) *Permanent storage capacity* means grain storage capacity which is inside a building, bin, or silo.

(e) *Railcar* means railroad hopper car or boxcar.

(f) *Grain storage elevator* means any grain elevator located at any wheat flour mill, wet corn mill, dry corn mill (human consumption), rice mill, or soybean oil extraction plant which has a permanent grain storage capacity of 35,200 m<sup>3</sup> (ca. 1 million bushels).

- (g) *Process emission* means the particulate matter which is collected by a capture system.
- (h) *Fugitive emission* means the particulate matter which is not collected by a capture system and is released directly into the atmosphere from an affected facility at a grain elevator.
- (i) *Capture system* means the equipment such as sheds, hoods, ducts, fans, dampers, etc. used to collect particulate matter generated by an affected facility at a grain elevator.
- (j) *Grain unloading station* means that portion of a grain elevator where the grain is transferred from a truck, railcar, barge, or ship to a receiving hopper.
- (k) *Grain loading station* means that portion of a grain elevator where the grain is transferred from the elevator to a truck, railcar, barge, or ship.
- (l) *Grain handling operations* include bucket elevators or legs (excluding legs used to unload barges or ships), scale hoppers and surge bins (garners), turn heads, scalpers, cleaners, trippers, and the headhouse and other such structures.
- (m) *Column dryer* means any equipment used to reduce the moisture content of grain in which the grain flows from the top to the bottom in one or more continuous packed columns between two perforated metal sheets.
- (n) *Rack dryer* means any equipment used to reduce the moisture content of grain in which the grain flows from the top to the bottom in a cascading flow around rows of baffles (racks).
- (o) *Unloading leg* means a device which includes a bucket-type elevator which is used to remove grain from a barge or ship.

[43 FR 34347, Aug. 3, 1978, as amended at 65 FR 61759, Oct. 17, 2000]

**§ 60.302 Standard for particulate matter.**

(a) On and after the 60th day of achieving the maximum production rate at which the affected facility will be operated, but no later than 180 days after initial startup, no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere any gases which exhibit greater than 0 percent opacity from any:

- (1) Column dryer with column plate perforation exceeding 2.4 mm diameter (ca. 0.094 inch).
- (2) Rack dryer in which exhaust gases pass through a screen filter coarser than 50 mesh.

(b) On and after the date on which the performance test required to be conducted by §60.8 is completed, no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any affected facility except a grain dryer any process emission which:

- (1) Contains particulate matter in excess of 0.023 g/dscm (ca. 0.01 gr/dscf).
- (2) Exhibits greater than 0 percent opacity.

(c) On and after the 60th day of achieving the maximum production rate at which the affected facility will be operated, but no later than 180 days after initial startup, no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere any fugitive emission from:

- (1) Any individual truck unloading station, railcar unloading station, or railcar loading station, which exhibits greater than 5 percent opacity.
- (2) Any grain handling operation which exhibits greater than 0 percent opacity.

(3) Any truck loading station which exhibits greater than 10 percent opacity.

(4) Any barge or ship loading station which exhibits greater than 20 percent opacity.

(d) The owner or operator of any barge or ship unloading station shall operate as follows:

(1) The unloading leg shall be enclosed from the top (including the receiving hopper) to the center line of the bottom pulley and ventilation to a control device shall be maintained on both sides of the leg and the grain receiving hopper.

(2) The total rate of air ventilated shall be at least 32.1 actual cubic meters per cubic meter of grain handling capacity (ca. 40 ft<sup>3</sup> /bu).

(3) Rather than meet the requirements of paragraphs (d)(1) and (2) of this section the owner or operator may use other methods of emission control if it is demonstrated to the Administrator's satisfaction that they would reduce emissions of particulate matter to the same level or less.

### **§ 60.303 Test methods and procedures.**

(a) In conducting the performance tests required in §60.8, the owner or operator shall use as reference methods and procedures the test methods in appendix A of this part or other methods and procedures as specified in this section, except as provided in §60.8(b). Acceptable alternative methods and procedures are given in paragraph (c) of this section.

(b) The owner or operator shall determine compliance with the particulate matter standards in §60.302 as follows:

(1) Method 5 shall be used to determine the particulate matter concentration and the volumetric flow rate of the effluent gas. The sampling time and sample volume for each run shall be at least 60 minutes and 1.70 dscm (60 dscf). The probe and filter holder shall be operated without heaters.

(2) Method 2 shall be used to determine the ventilation volumetric flow rate.

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

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

(1) For Method 5, Method 17 may be used.

[54 FR 6674, Feb. 14, 1989]

### **§ 60.304 Modifications.**

(a) The factor 6.5 shall be used in place of "annual asset guidelines repair allowance percentage," to determine whether a capital expenditure as defined by §60.2 has been made to an existing facility.

(b) The following physical changes or changes in the method of operation shall not by themselves be considered a modification of any existing facility:

(1) The addition of gravity loadout spouts to existing grain storage or grain transfer bins.

(2) The installation of automatic grain weighing scales.

(3) Replacement of motor and drive units driving existing grain handling equipment.

(4) The installation of permanent storage capacity with no increase in hourly grain handling capacity.

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

**Attachment B  
to a Part 70 Operating Permit**

**Source Background and Description**

<b>Source Name:</b>	Bunge North America (East), LLC
<b>Source Location:</b>	1200 N. 2nd Street, Decatur, Indiana 46733
<b>County:</b>	Adams
<b>SIC Code:</b>	2075, 2079, 5153, 2048
<b>Permit Renewal No.:</b>	T001-23640-00005

**Title 40: Protection of Environment**

[PART 60—STANDARDS OF PERFORMANCE FOR NEW STATIONARY SOURCES](#)

**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/hr)) or less, but greater than or equal to 2.9 MW (10 MMBtu/hr).

(b) In delegating implementation and enforcement authority to a State under section 111(c) of the Clean Air Act, §60.48c(a)(4) shall be retained by the Administrator and not transferred to a State.

(c) Steam generating units 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) Heat recovery steam generators that are associated with combined cycle gas 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 that are capable of combusting more than or equal to 2.9 MW (10 MMBtu/hr) heat input of fossil fuel but less than or equal to 29 MW (100 MMBtu/hr) heat input of fossil fuel. If the heat recovery steam generator is subject to this subpart, only emissions resulting from combustion of fuels in the steam generating unit are subject to this subpart. (The gas turbine emissions are subject to subpart GG or KKKK, as applicable, of this part).

(f) Any facility covered by subpart AAAA of this part is not subject by this subpart.

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

[72 FR 32759, June 13, 2007, as amended at 74 FR 5090, Jan. 28, 2009]

### **§ 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.

*Cogeneration steam generating unit* means a steam generating unit that simultaneously produces both electrical (or mechanical) and thermal energy from the same primary energy source.

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

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

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

*Distillate oil* means fuel oil that complies with the specifications for fuel oil numbers 1 or 2, as defined by the American Society for Testing and Materials in ASTM D396 (incorporated by reference, see §60.17) or 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).

*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.

*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]

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

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

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

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

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

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

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

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

(ii) Cause to be discharged into the atmosphere from that affected facility any gases that contain SO<sub>2</sub> in excess of 260 ng/J (0.60 lb/MMBtu) heat input. If coal is combusted with other fuels, the affected facility is subject to the 50 percent

SO<sub>2</sub> reduction requirement specified in this paragraph and the emission limit determined pursuant to paragraph (e)(2) of this section.

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

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

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

(3) Affected facilities located in a noncontinental area.

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

(d) On and after the date on which the initial performance test is completed or required to be completed under §60.8, 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; 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/hr); and

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

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

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

Where:

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

K<sub>a</sub> = 520 ng/J (1.2 lb/MMBtu);

$K_b = 260 \text{ ng/J (0.60 lb/MMBtu)}$ ;

$K_c = 215 \text{ ng/J (0.50 lb/MMBtu)}$ ;

$H_a$  = 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  $\text{SO}_2$  emission rate through fuel pretreatment is not credited toward the percent reduction requirement under paragraph (b)(2) of this section unless:

- (1) Fuel pretreatment results in a 50 percent (0.50) or greater reduction in the potential  $\text{SO}_2$  emission rate; and
- (2) Emissions from the pretreated fuel (without either combustion or post-combustion  $\text{SO}_2$  control) are equal to or less than the emission limits specified under paragraph (b)(2) of this section.

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

(h) For affected facilities listed under paragraphs (h)(1), (2), or (3) of this section, compliance with the emission limits or fuel oil sulfur limits under this section may be determined based on a certification from the fuel supplier, as described under §60.48c(f), 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 facilities with heat input capacities between 2.9 and 8.7 MW (10 and 30 MMBtu/hr).

(i) The  $\text{SO}_2$  emission limits, fuel oil sulfur limits, and percent reduction requirements under this section apply at all times, including periods of startup, shutdown, and malfunction.

(j) 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]

#### **§ 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/hr) or greater, shall cause to be discharged into the atmosphere from that affected facility any gases that contain PM in excess of the following emission limits:

- (1) 22 ng/J (0.051 lb/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/hr) or greater, shall cause to be discharged into the atmosphere from that affected facility any gases that contain PM in excess of the following emissions limits:

(1) 43 ng/J (0.10 lb/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 can combust coal, wood, or oil and has a heat input capacity of 8.7 MW (30 MMBtu/hr) or greater shall cause to be discharged into the atmosphere from that affected facility any gases that exhibit greater than 20 percent opacity (6-minute average), except for one 6-minute period per hour of not more than 27 percent opacity. 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.

(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/hr) 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/hr) 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) 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, 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]

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

(a) Except as provided in paragraphs (g) and (h) of this section and §60.8(b), performance tests required under §60.8 shall be conducted following the procedures specified in paragraphs (b), (c), (d), (e), and (f) of this section, as applicable. Section 60.8(f) does not apply to this section. The 30-day notice required in §60.8(d) applies only to the initial performance test unless otherwise specified by the Administrator.

(b) The initial performance test required under §60.8 shall be conducted over 30 consecutive operating days of the steam generating unit. Compliance with the percent reduction requirements and SO<sub>2</sub> emission limits under §60.42c shall be determined using a 30-day average. The first operating day included in the initial performance test shall be scheduled within 30 days after achieving the maximum production rate at which the affected facility will be operated, but not later than 180 days after the initial startup of the facility. The steam generating unit load during the 30-day period does not have to be the maximum design heat input capacity, but must be representative of future operating conditions.

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

(d) If only coal, only oil, or a mixture of coal and oil is combusted in an affected facility, the procedures in Method 19 of appendix A of this part are used to determine the hourly SO<sub>2</sub> emission rate (E<sub>ho</sub>) and the 30-day average SO<sub>2</sub> emission rate (E<sub>ao</sub>). The hourly averages used to compute the 30-day averages are obtained from the CEMS. Method 19 of appendix A of this part shall be used to calculate E<sub>ao</sub> 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<sub>ho</sub> (E<sub>ho0</sub>) is used in Equation 19–19 of Method 19 of appendix A of this part to compute the adjusted E<sub>ao</sub> (E<sub>ao0</sub>). The E<sub>ho0</sub> is computed using the following formula:

$$E_{ho0} = \frac{E_{ho} - E_w(1 - X_1)}{X_1}$$

Where:

E<sub>ho0</sub> = Adjusted E<sub>ho</sub>, ng/J (lb/MMBtu);

E<sub>ho</sub> = Hourly SO<sub>2</sub> emission rate, ng/J (lb/MMBtu);

E<sub>w</sub> = SO<sub>2</sub> concentration in fuels other than coal and oil combusted in the affected facility, as determined by fuel sampling and analysis procedures in Method 9 of appendix A of this part, ng/J (lb/MMBtu). The value E<sub>w</sub> 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<sub>w</sub> if the owner or operator elects to assume E<sub>w</sub> = 0.

X<sub>k</sub> = Fraction of the total heat input from fuel combustion derived from coal and oil, as determined by applicable procedures in Method 19 of appendix A of this part.

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

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

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

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

Where:

$\%P_s$  = Potential  $SO_2$  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  $\%R_g$  ( $\%R_{gO}$ ) is computed from  $E_{aoO}$  from paragraph (e)(1) of this section and an adjusted average  $SO_2$  inlet rate ( $E_{aiO}$ ) using the following formula:

$$\%R_{gO} = 100 \left( 1 - \frac{E_{aoO}}{E_{aiO}} \right)$$

Where:

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

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

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

(ii) To compute  $E_{aiO}$ , an adjusted hourly  $SO_2$  inlet rate ( $E_{hiO}$ ) is used. The  $E_{hiO}$  is computed using the following formula:

$$E_{hiO} = \frac{E_{hi} - E_w(1 - X_1)}{X_1}$$

Where:

$E_{hiO}$  = 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  $160 \pm 14$  °C ( $320 \pm 25$  °F).

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

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

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

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

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

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

(c) In place of PM testing with Method 5 or 5B of appendix A–3 of this part or Method 17 of appendix A–6 of this part, an owner or operator may elect to install, calibrate, maintain, and operate a CEMS for monitoring PM emissions discharged to the atmosphere and record the output of the system. The owner or operator of an affected facility who elects to continuously monitor PM emissions instead of conducting performance testing using Method 5 or 5B of appendix A–3 of this part or Method 17 of appendix A–6 of this part shall install, calibrate, maintain, and operate a CEMS and shall comply with the requirements specified in paragraphs (c)(1) through (c)(14) of this section.

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

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

(3) The monitor shall be installed, evaluated, and operated in accordance with §60.13 of subpart A of this part.

(4) The initial performance evaluation shall be completed no later than 180 days after the date of initial startup of the affected facility, as specified under §60.8 of subpart A of this part or within 180 days of notification to the Administrator of use of CEMS if the owner or operator was previously determining compliance by Method 5, 5B, or 17 of appendix A of this part performance tests, whichever is later.

(5) The owner or operator of an affected facility shall conduct an initial performance test for PM emissions as required under §60.8 of subpart A of this part. Compliance with the PM emission limit shall be determined by using the CEMS

specified in paragraph (d) of this section to measure PM and calculating a 24-hour block arithmetic average emission concentration using EPA Reference Method 19 of appendix A of this part, section 4.1.

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

(7) At a minimum, valid CEMS hourly averages shall be obtained as specified in paragraph (c)(7)(i) of this section for 75 percent of the total operating hours per 30-day rolling average.

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

(ii) [Reserved]

(8) The 1-hour arithmetic averages required under paragraph (c)(7) of this section shall be expressed in ng/J or lb/MMBtu heat input and shall be used to calculate the boiler operating day daily arithmetic average emission concentrations. The 1-hour arithmetic averages shall be calculated using the data points required under §60.13(e)(2) of subpart A of this part.

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

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

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

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

(ii) For O<sub>2</sub> (or CO<sub>2</sub>), Method 3A or 3B of appendix A-2 of this part, as applicable shall be used.

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

(13) When PM emissions data are not obtained because of CEMS breakdowns, repairs, calibration checks, and zero and span adjustments, emissions data shall be obtained by using other monitoring systems as approved by the Administrator or EPA Reference Method 19 of appendix A of this part to provide, as necessary, valid emissions data for a minimum of 75 percent of total operating hours on a 30-day rolling average.

(14) After July 1, 2011, within 90 days after the date of completing each performance evaluation required by paragraph (c)(11) of this section, the owner or operator of the affected facility must either submit the test data to EPA by successfully entering the data electronically into EPA's WebFIRE data base available at <http://cfpub.epa.gov/oarweb/index.cfm?action=fire.main> or mail a copy to: United States Environmental Protection Agency; Energy Strategies Group; 109 TW Alexander DR; Mail Code: D243-01; RTP, NC 27711.

(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/hr).

[72 FR 32759, June 13, 2007, as amended at 74 FR 5091, Jan. 28, 2009; 76 FR 3523, Jan. 20, 2011]

**§ 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), (f), and (g) 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 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;

(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;

(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

(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 30 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) Owners and operators of an affected facility that is subject to an opacity standard in §60.43c(c) and that uses a bag leak detection system to monitor the performance of a fabric filter (baghouse) according to the most recent requirements in section §60.48Da of this part is not required to operate a COMS.

(g) Owners and operators of an affected facility that is subject to an opacity standard in §60.43c(c) and that burns only gaseous fuels or fuel oils that contain less than or equal to 0.5 weight percent sulfur and operates according to a written site-specific monitoring plan approved by the permitting authority is not required to operate a COMS. 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.

[72 FR 32759, June 13, 2007, as amended at 74 FR 5091, Jan. 28, 2009; 76 FR 3523, Jan. 20, 2011]

#### **§ 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]

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

**Attachment C  
to a Part 70 Operating Permit**

**Source Background and Description**

<b>Source Name:</b>	Bunge North America (East), LLC
<b>Source Location:</b>	1200 N. 2nd Street, Decatur, Indiana 46733
<b>County:</b>	Adams
<b>SIC Code:</b>	2075, 2079, 5153, 2048
<b>Permit Renewal No.:</b>	T001-23640-00005

**Subpart GGGG—National Emission Standards for Hazardous Air Pollutants: Solvent Extraction for Vegetable Oil Production**

**Source:** 66 FR 19011, Apr. 12, 2001, unless otherwise noted.

**What This Subpart Covers**

**§ 63.2830 What is the purpose of this subpart?**

This subpart establishes national emission standards for hazardous air pollutants (NESHAP) for emissions during vegetable oil production. This subpart limits hazardous air pollutant (HAP) emissions from specified vegetable oil production processes. This subpart also establishes requirements to demonstrate initial and continuous compliance with the emission standards.

**§ 63.2831 Where can I find definitions of key words used in this subpart?**

You can find definitions of key words used in this subpart in §63.2872.

**§ 63.2832 Am I subject to this subpart?**

(a) You are an affected source subject to this subpart if you meet all of the criteria listed in paragraphs (a)(1) and (2) of this section:

(1) You own or operate a vegetable oil production process that is a major source of HAP emissions or is collocated within a plant site with other sources that are individually or collectively a major source of HAP emissions.

(i) A *vegetable oil production process* is defined in §63.2872. In general, it is the collection of continuous process equipment and activities that produce crude vegetable oil and meal products by removing oil from oilseeds listed in Table 1 to §63.2840 through direct contact with an organic solvent, such as a hexane isomer blend.

(ii) A major source of HAP emissions is a plant site that emits or has the potential to emit any single HAP at a rate of 10 tons (9.07 megagrams) or more per year or any combination of HAP at a rate of 25 tons (22.68 megagrams) or more per year.

(2) Your vegetable oil production process processes any combination of eight types of oilseeds listed in paragraphs (a)(2)(i) through (viii) of this section:

(i) Corn germ;

- (ii) Cottonseed;
- (iii) Flax;
- (iv) Peanut;
- (v) Rapeseed (for example, canola);
- (vi) Safflower;
- (vii) Soybean; and
- (viii) Sunflower.

(b) You are not subject to this subpart if your vegetable oil production process meets any of the criteria listed in paragraphs (b)(1) through (4) of this section:

- (1) It uses only mechanical extraction techniques that use no organic solvent to remove oil from a listed oilseed.
- (2) It uses only batch solvent extraction and batch desolventizing equipment.
- (3) It processes only agricultural products that are not listed oilseeds as defined in §63.2872.
- (4) It functions only as a research and development facility and is not a major source.

(c) As listed in §63.1(c)(5) of the General Provisions, if your HAP emissions increase such that you become a major source, then you are subject to all of the requirements of this subpart.

**§ 63.2833 Is my source categorized as existing or new?**

(a) This subpart applies to each existing and new affected source. You must categorize your vegetable oil production process as either an existing or a new source in accordance with the criteria in Table 1 of this section, as follows:

**Table 1 to §63.2833—Categorizing Your Source as Existing or New**

If your affected source...	And if...	Then your affected source...
(1) was constructed or began construction before May 26, 2000	reconstruction has not occurred	is an existing source.
(2) began reconstruction, as defined in §63.2, on or after May 26, 2000	(i) reconstruction was part of a scheduled plan to comply with the existing source requirements of this subpart; and (ii) reconstruction was completed no later than 3 years after the effective date of this subpart	remains an existing source.
(3) began a significant modification, as defined in §63.2872, at any time on an existing source	the modification does not constitute reconstruction	remains an existing source.

If your affected source...	And if...	Then your affected source...
(4) began a significant modification, as defined in §63.2872, at any time on a new source	the modification does not constitute reconstruction	remains a new source.
(5) began reconstruction on or after May 26, 2000	reconstruction was completed later than 3 years after the effective date of this subpart	is a new source
(6) began construction on or after May 26, 2000		is a new source.

(b) *Reconstruction of a source.* Any affected source is reconstructed if components are replaced so that the criteria in the definition of *reconstruction* in §63.2 are satisfied. In general, a vegetable oil production process is reconstructed if the fixed capital cost of the new components exceeds 50 percent of the fixed capital cost for constructing a new vegetable oil production process, and it is technically and economically feasible for the reconstructed source to meet the relevant new source requirements of this subpart. The effect of reconstruction on the categorization of your existing and new affected source is described in paragraphs (b)(1) and (2) of this section:

(1) After reconstruction of an existing source, the affected source is recategorized as a new source and becomes subject to the new source requirements of this subpart.

(2) After reconstruction of a new source, the affected source remains categorized as a new source and remains subject to the new source requirements of this subpart.

(c) *Significant modification of a source.* A significant modification to an affected source is a term specific to this subpart and is defined in §63.2872.

(1) In general, a significant modification to your source consists of adding new equipment or the modification of existing equipment within the affected source that significantly affects solvent losses from the affected source. Examples include adding or replacing extractors, desolventizer-toasters (conventional and specialty), and meal dryer-coolers. All other significant modifications must meet the criteria listed in paragraphs (c)(1)(i) and (ii) of this section:

(i) The fixed capital cost of the modification represents a significant percentage of the fixed capital cost of building a comparable new vegetable oil production process.

(ii) It does not constitute reconstruction as defined in §63.2.

(2) A significant modification has no effect on the categorization of your source as existing and new. An existing source remains categorized as an existing source and subject to the existing source requirements of this subpart. A new source remains categorized as a new source and subject to the new source requirements of this subpart.

(d) Changes in the type of oilseed processed by your affected source does not affect the categorization of your source as new or existing. Recategorizing an affected source from existing to new occurs only when you add or modify process equipment within the source which meets the definition of *reconstruction*.

**§ 63.2834 When do I have to comply with the standards in this subpart?**

You must comply with this subpart in accordance with one of the schedules in Table 1 of this section, as follows:

**Table 1 of §63.2834—Compliance Dates for Existing and New Sources**

If your affected source is	And if...	Then your compliance date
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<b>categorized as...</b>		<b>is...</b>
(a) an existing source		3 years after the effective date of this subpart.
(b) a new source	you startup your affected source before the effective date of this subpart	the effective date of this subpart.
(c) a new source	you startup your affected source on or after the effective date of this subpart	your startup date.

**Standards**

**§ 63.2840 What emission requirements must I meet?**

For each facility meeting the applicability criteria in §63.2832, you must comply with either the requirements specified in paragraphs (a) through (d), or the requirements in paragraph (e) of this section.

(a)(1) The emission requirements limit the number of gallons of HAP lost per ton of listed oilseeds processed. For each operating month, you must calculate a compliance ratio which compares your actual HAP loss to your allowable HAP loss for the previous 12 operating months as shown in Equation 1 of this section. An operating month, as defined in §63.2872, is any calendar month in which a source processes a listed oilseed, excluding any entire calendar month in which the source operated under an initial startup period subject to §63.2850(c)(2) or (d)(2) or a malfunction period subject to §63.2850(e)(2). Equation 1 of this section follows:

$$\text{Compliance Ratio} = \frac{\text{Actual Hap Loss}}{\text{Allowable Hap Loss}} \quad (\text{Eq. 1})$$

(2) Equation 1 of this section can also be expressed as a function of total solvent loss as shown in Equation 2 of this section. Equation 2 of this section follows:

$$\text{Compliance Ratio} = \frac{f * \text{Actual Solvent Loss}}{0.64 * \sum_{i=1}^n ((\text{Oilseed})_i * (\text{SLF})_i)} \quad (\text{Eq. 2})$$

Where:

f = The weighted average volume fraction of HAP in solvent received during the previous 12 operating months, as determined in §63.2854, dimensionless.

0.64 = The average volume fraction of HAP in solvent in the baseline performance data, dimensionless.

Actual Solvent Loss = Gallons of actual solvent loss during previous 12 operating months, as determined in §63.2853.

Oilseed = Tons of each oilseed type “i” processed during the previous 12 operating months, as shown in §63.2855.

SLF = The corresponding solvent loss factor (gal/ton) for oilseed “i” listed in Table 1 of this section, as follows:

**Table 1 of §63.2840—Oilseed Solvent Loss Factors for Determining Allowable HAP Loss**

Type of oilseed process	A source that...	Oilseed solvent loss factor (gal/ton)	
		Existing sources	New sources
(i) Corn Germ, Wet Milling	processes corn germ that has been separated from other corn components using a "wet" process of centrifuging a slurry steeped in a dilute sulfurous acid solution	0.4	0.3
(ii) Corn Germ, Dry Milling	processes corn germ that has been separated from the other corn components using a "dry" process of mechanical chafing and air sifting	0.7	0.7
(iii) Cottonseed, Large	processes 120,000 tons or more of a combination of cottonseed and other listed oilseeds during all normal operating periods in a 12 operating month period	0.5	0.4
(iv) Cottonseed, Small	processes less than 120,000 tons of a combination of cottonseed and other listed oilseeds during all normal operating periods in a 12 operating month period	0.7	0.4
(v) Flax	processes flax	0.6	0.6
(vi) Peanuts	processes peanuts	1.2	0.7
(vii) Rapeseed	processes rapeseed	0.7	0.3
(viii) Safflower	processes safflower	0.7	0.7
(ix) Soybean, Conventional	uses a conventional style desolventizer to produce crude soybean oil products and soybean animal feed products	0.2	0.2
(x) Soybean, Specialty	uses a special style desolventizer to produce soybean meal products for human and animal consumption	1.7	1.5
(xi) Soybean, Combination Plant with Low Specialty Production	processes soybeans in both specialty and conventional desolventizers and the quantity of soybeans processed in specialty desolventizers during normal operating periods is less than 3.3 percent of total soybeans processed during all normal operating periods in a 12 operating month period. The corresponding solvent loss factor is an overall value and applies to the total quantity of soybeans processed.	0.25	0.25
(xii) Sunflower	processes sunflower	0.4	0.3

(b) When your source has processed listed oilseed for 12 operating months, calculate the compliance ratio by the end of each calendar month following an operating month using Equation 2 of this section. When calculating your compliance ratio, consider the conditions and exclusions in paragraphs (b)(1) through (6) of this section:

(1) If your source processes any quantity of listed oilseeds in a calendar month and the source is not operating under an initial startup period or malfunction period subject to §63.2850, then you must categorize the month as an operating month, as defined in §63.2872.

(2) The 12-month compliance ratio may include operating months occurring prior to a source shutdown and operating months that follow after the source resumes operation.

(3) If your source shuts down and processes no listed oilseed for an entire calendar month, then you must categorize the month as a nonoperating month, as defined in §63.2872. Exclude any nonoperating months from the compliance ratio determination.

(4) If your source is subject to an initial startup period as defined in §63.2872, exclude from the compliance ratio determination any solvent and oilseed information recorded for the initial startup period.

(5) If your source is subject to a malfunction period as defined in §63.2872, exclude from the compliance ratio determination any solvent and oilseed information recorded for the malfunction period.

(6) For sources processing cottonseed or specialty soybean, the solvent loss factor you use to determine the compliance ratio may change each operating month depending on the tons of oilseed processed during all normal operating periods in a 12 operating month period.

(c) If the compliance ratio is less than or equal to 1.00, your source was in compliance with the HAP emission requirements for the previous operating month.

(d) To determine the compliance ratio in Equation 2 of this section, you must select the appropriate oilseed solvent loss factor from Table 1 of this section. First, determine whether your source is new or existing using Table 1 of §63.2833. Then, under the appropriate existing or new source column, select the oilseed solvent loss factor that corresponds to each type oilseed or process operation for each operating month.

(e) *Low-HAP solvent option.* For all vegetable oil production processes subject to this subpart, you must exclusively use solvent where the volume fraction of each HAP comprises 1 percent or less by volume of the solvent (low-HAP solvent) in each delivery, and you must meet the requirements in paragraphs (e)(1) through (5) of this section. Your vegetable oil production process is not subject to the requirements in §§63.2850 through 63.2870 unless specifically referenced in paragraphs (e)(1) through (5) of this section.

(1) You shall determine the HAP content of your solvent in accordance with the specifications in §63.2854(b)(1).

(2) You shall maintain documentation of the HAP content determination for each delivery of the solvent at the facility at all times.

(3) You must submit an initial notification for existing sources in accordance with §63.2860(a).

(4) You must submit an initial notification for new and reconstructed sources in accordance with §63.2860(b).

(5) You must submit an annual compliance certification in accordance with §63.2861(a). The certification should only include the information required under §63.2861(a)(1) and (2), and a certification indicating whether the source complied with all of the requirements in paragraph (e) of this section.

(f) You may change compliance options for your source if you submit a notice to the Administrator at least 60 days prior to changing compliance options. If your source changes from the low-HAP solvent option to the compliance ratio determination option, you must determine the compliance ratio for the most recent 12 operating months beginning with the first month after changing compliance options.

[66 FR 19011, Apr. 12, 2001, as amended at 69 FR 53341, Sept. 1, 2004]

## Compliance Requirements

### § 63.2850 How do I comply with the hazardous air pollutant emission standards?

(a) *General requirements.* The requirements in paragraphs (a)(1)(i) through (iv) of this section apply to all affected sources:

(1) Submit the necessary notifications in accordance with §63.2860, which include:

(i) Initial notifications for existing sources.

(ii) Initial notifications for new and reconstructed sources.

(iii) Initial notifications for significant modifications to existing or new sources.

(iv) Notification of compliance status.

(2) Develop and implement a plan for demonstrating compliance in accordance with §63.2851.

(3) Develop a written startup, shutdown and malfunction (SSM) plan in accordance with the provisions in §63.2852.

(4) Maintain all the necessary records you have used to demonstrate compliance with this subpart in accordance with §63.2862.

(5) Submit the reports in paragraphs (a)(5)(i) through (iii) of this section:

(i) Annual compliance certifications in accordance with §63.2861(a).

(ii) Periodic SSM reports in accordance with §63.2861(c).

(iii) Immediate SSM reports in accordance with §63.2861(d).

(6) Submit all notifications and reports and maintain all records required by the General Provisions for performance testing if you add a control device that destroys solvent.

(b) *Existing sources under normal operation.* You must meet all of the requirements listed in paragraph (a) of this section and table 1 of this section for sources under normal operation, and the schedules for demonstrating compliance for existing sources under normal operation in table 2 of this section.

(c) *New sources.* Your new source, including a source that is categorized as new due to reconstruction, must meet the requirements associated with one of two compliance options. Within 15 days of the startup date, you must choose to comply with one of the options listed in paragraph (c)(1) or (2) of this section:

(1) *Normal operation.* Upon startup of your new source, you must meet all of the requirements listed in §63.2850(a) and table 1 of this section for sources under normal operation, and the schedules for demonstrating compliance for new sources under normal operation in table 2 of this section.

(2) *Initial startup period.* For up to 6 calendar months after the startup date of your new source, you must meet all of the requirements listed in paragraph (a) of this section and table 1 of this section for sources operating under an initial startup period, and the schedules for demonstrating compliance for new sources operating under an initial startup period in Table 2 of this section. After a maximum of 6 calendar months, your new source must then meet all of the requirements listed in table 1 of this section for sources under normal operation.

(d) *Existing or new sources that have been significantly modified.* Your existing or new source that has been significantly modified must meet the requirements associated with one of two compliance options. Within 15 days of the modified source startup date, you must choose to comply with one of the options listed in paragraph (d)(1) or (2) of this section:

(1) *Normal operation.* Upon startup of your significantly modified existing or new source, you must meet all of the requirements listed in paragraph (a) of this section and table 1 of this section for sources under normal operation, and the schedules for demonstrating compliance for an existing or new source that has been significantly modified in table 2 of this section.

(2) *Initial startup period.* For up to 3 calendar months after the startup date of your significantly modified existing or new source, you must meet all of the requirements listed in paragraph (a) of this section and table 1 of this section for sources operating under an initial startup period, and the schedules for demonstrating compliance for a significantly modified existing or new source operating under an initial startup period in table 2 of this section. After a maximum of 3 calendar months, your new or existing source must meet all of the requirements listed in Table 1 of this section for sources under normal operation.

(e) *Existing or new sources experiencing a malfunction.* A *malfunction* is defined in §63.2. In general, it means any sudden, infrequent, and not reasonably preventable failure of air pollution control equipment or process equipment to function in a usual manner. If your existing or new source experiences an unscheduled shutdown as a result of a malfunction, continues to operate during a malfunction (including the period reasonably necessary to correct the malfunction), or starts up after a shutdown resulting from a malfunction, then you must meet the requirements associated with one of two compliance options. Routine or scheduled process startups and shutdowns resulting from, but not limited to, market demands, maintenance activities, and switching types of oilseed processed, are not startups or shutdowns resulting from a malfunction and, therefore, do not qualify for this provision. Within 15 days of the beginning date of the malfunction, you must choose to comply with one of the options listed in paragraphs (e)(1) through (2) of this section:

(1) *Normal operation.* Your source must meet all of the requirements listed in paragraph (a) of this section and one of the options listed in paragraphs (e)(1)(i) through (iii) of this section:

(i) Existing source normal operation requirements in paragraph (b) of this section.

(ii) New source normal operation requirements in paragraph (c)(1) of this section.

(iii) Normal operation requirements for sources that have been significantly modified in paragraph (d)(1) of this section.

(2) *Malfunction period.* Throughout the malfunction period, you must meet all of the requirements listed in paragraph (a) of this section and Table 1 of this section for sources operating during a malfunction period. At the end of the malfunction period, your source must then meet all of the requirements listed in table 1 of this section for sources under normal operation. Table 1 of this section follows:

**Table 1 of §63.2850—Requirements for Compliance with HAP Emission Standards**

Are you required to . . .	For periods of normal operation?	For initial startup periods subject to §63.2850(c)(2) or (d)(2)?	For malfunction periods subject to §63.2850(e)(2)?
(a) Operate and maintain your source in accordance with general duty provisions of §63.6(e)?	Yes. Additionally, the HAP emission limits will apply.	Yes, you are required to minimize emissions to the extent practicable throughout the initial startup period. Such measures should be described in the SSM plan.	Yes, you are required to minimize emissions to the extent practicable throughout the initial startup period. Such measures should be described in the SSM plan.
(b) Determine and record the extraction solvent loss in gallons from your source?	Yes, as described in §63.2853	Yes, as described in §63.2862(e)	Yes, as described in §63.2862(e).
(c) Record the volume fraction of HAP present at greater than 1 percent by volume and gallons of extraction solvent in shipment received?	Yes	Yes	Yes.
(d) Determine and record the tons of each oilseed type processed by your source?	Yes, as described in §63.2855	No	No.
(e) Determine the weighted average volume fraction of HAP in extraction solvent received as described in §63.2854 by the end of the following calendar month?	Yes	No. Except for solvent received by a new or reconstructed source commencing operation under an initial startup period, the HAP volume fraction in any solvent received during an initial startup period is included in the weighted average HAP determination for the next operating month	No, the HAP volume fraction in any solvent received during a malfunction period is included in the weighted average HAP determination for the next operating month.
(f) Determine and record the actual solvent loss, weighted average volume fraction HAP, oilseed processed and compliance ratio for each 12 operating month period as described in §63.2840 by the end of the following calendar month?	Yes,	No, these requirements are not applicable because your source is not required to determine the compliance ratio with data recorded for an initial startup period	No, these requirements are not applicable because your source is not required to determine the compliance ratio with data recorded for a malfunction period.

Are you required to . . .	For periods of normal operation?	For initial startup periods subject to §63.2850(c)(2) or (d)(2)?	For malfunction periods subject to §63.2850(e)(2)?
(g) Submit a Notification of Compliance Status or Annual Compliance Certification as appropriate?	Yes, as described in §§63.2860(d) and 63.2861(a)	No. However, you may be required to submit an annual compliance certification for previous operating months, if the deadline for the annual compliance certification happens to occur during the initial startup period	No. However, you may be required to submit an annual compliance certification for previous operating months, if the deadline for the annual compliance certification happens to occur during the malfunction period.
(h) Submit a Deviation Notification Report by the end of the calendar month following the month in which you determined that the compliance ratio exceeds 1.00 as described in §63.2861(b)?	Yes	No, these requirements are not applicable because your source is not required to determine the compliance ratio with data recorded for an initial startup period	No, these requirements are not applicable because your source is not required to determine the compliance ratio with data recorded for a malfunction period.
(i) Submit a Periodic SSM Report as described in §63.2861(c)?	No, a SSM activity is not categorized as normal operation	Yes	Yes.
(j) Submit an Immediate SSM Report as described in §63.2861(d)?	No, a SSM activity is not categorized as normal operation	Yes, only if your source does not follow the SSM plan	Yes, only if your source does not follow the SSM plan.

**Table 2 of §63.2850—Schedules for Demonstrating Compliance Under Various Source Operating Modes**

<b>If your source is . . .</b>	<b>and is operating under. . .</b>	<b>then your recordkeeping schedule. . .</b>	<b>You must determine your first compliance ratio by the end of the calendar month following. . .</b>	<b>Base your first compliance ratio on information recorded. . .</b>
(a) Existing	Normal operation	Begins on the compliance date	The first 12 operating months after the compliance date	During the first 12 operating months after the compliance date.
(b) New	(1) Normal operation	Begins on the startup date of your new source	The first 12 operating months after the startup date of the new source	During the first 12 operating months after the startup date of the new source.
	(2) An initial startup period	Begins on the startup date of your new source	The first 12 operating months after termination of the initial startup period, which can last for up to 6 months	During the first 12 operating months after the initial startup period, which can last for up to 6 months.
(c) Existing or new that has been significantly modified	(1) Normal operation	Resumes on the startup date of the modified source	The first operating month after the startup date of the modified source	During the previous 11 operating months prior to the significant modification and the first operating month following the initial startup date of the source.
	(2) An initial startup period	Resumes on the startup date of the modified source	The first operating month after termination of the initial startup period, which can last up to 3 months	During the 11 operating months before the significant modification and the first operating month after the initial startup period.

[66 FR 19011, Apr. 12, 2001, as amended at 71 FR 20463, Apr. 20, 2006]

**§ 63.2851 What is a plan for demonstrating compliance?**

(a) You must develop and implement a written plan for demonstrating compliance that provides the detailed procedures you will follow to monitor and record data necessary for demonstrating compliance with this subpart. Procedures followed for quantifying solvent loss from the source and amount of oilseed processed vary from source to source because of site-specific factors such as equipment design characteristics and operating conditions. Typical procedures include one or more accurate measurement methods such as weigh scales, volumetric displacement, and material mass balances. Because the industry does not have a uniform set of procedures, you must develop and implement your own site-specific plan for demonstrating compliance before the compliance date for your source. You must also incorporate the plan for demonstrating compliance by reference in the source's title V permit and keep the plan on-site and readily available as long as the source is operational. If you make any changes to the plan for demonstrating compliance, then you must keep all previous versions of the plan and make them readily available for inspection for at least 5 years after each revision. The plan for demonstrating compliance must include the items in paragraphs (a)(1) through (7) of this section:

- (1) The name and address of the owner or operator.

- (2) The physical address of the vegetable oil production process.
  - (3) A detailed description of all methods of measurement your source will use to determine your solvent losses, HAP content of solvent, and the tons of each type of oilseed processed.
  - (4) When each measurement will be made.
  - (5) Examples of each calculation you will use to determine your compliance status. Include examples of how you will convert data measured with one parameter to other terms for use in compliance determination.
  - (6) Example logs of how data will be recorded.
  - (7) A plan to ensure that the data continue to meet compliance demonstration needs.
- (b) The responsible agency of these NESHAP may require you to revise your plan for demonstrating compliance. The responsible agency may require reasonable revisions if the procedures lack detail, are inconsistent or do not accurately determine solvent loss, HAP content of the solvent, or the tons of oilseed processed.

### **§ 63.2852 What is a startup, shutdown, and malfunction plan?**

You must develop a written SSM plan in accordance with §63.6(e)(3). You must complete the SSM plan before the compliance date for your source. You must also keep the SSM plan on-site and readily available as long as the source is operational. The SSM plan provides detailed procedures for operating and maintaining your source to minimize emissions during a qualifying SSM event for which the source chooses the §63.2850(e)(2) malfunction period, or the §63.2850(c)(2) or (d)(2) initial startup period. The SSM plan must specify a program of corrective action for malfunctioning process and air pollution control equipment and reflect the best practices now in use by the industry to minimize emissions. Some or all of the procedures may come from plans you developed for other purposes such as a Standard Operating Procedure manual or an Occupational Safety and Health Administration Process Safety Management plan. To qualify as a SSM plan, other such plans must meet all the applicable requirements of these NESHAP.

[66 FR 19011, Apr. 12, 2001, as amended at 67 FR 16321, Apr. 5, 2002; 71 FR 20463, Apr. 20, 2006]

### **§ 63.2853 How do I determine the actual solvent loss?**

By the end of each calendar month following an operating month, you must determine the total solvent loss in gallons for the previous operating month. The total solvent loss for an operating month includes all solvent losses that occur during normal operating periods within the operating month. If you have determined solvent losses for 12 or more operating months, then you must also determine the 12 operating months rolling sum of actual solvent loss in gallons by summing the monthly actual solvent loss for the previous 12 operating months. The 12 operating months rolling sum of solvent loss is the "actual solvent loss," which is used to calculate your compliance ratio as described in §63.2840.

(a) To determine the actual solvent loss from your source, follow the procedures in your plan for demonstrating compliance to determine the items in paragraphs (a)(1) through (7) of this section:

(1) *The dates that define each operating status period during a calendar month.* The dates that define each operating status period include the beginning date of each calendar month and the date of any change in the source operating status. If the source maintains the same operating status during an entire calendar month, these dates are the beginning and ending dates of the calendar month. If, prior to the effective date of this rule, your source determines the solvent loss on an *accounting month*, as defined in §63.2872, rather than a calendar month basis, and you have 12 complete accounting months of approximately equal duration in a calendar year, you may substitute the accounting month time interval for the calendar month time interval. If you choose to use an accounting month rather than a calendar month, you must document this measurement frequency selection in your plan for demonstrating compliance, and you must remain on this schedule unless you request and receive written approval from the agency responsible for these NESHAP.

(2) *Source operating status.* You must categorize the operating status of your source for each recorded time interval in accordance with criteria in Table 1 of this section, as follows:

**Table 1 of §63.2853—Categorizing Your Source Operating Status**

If during a recorded time interval . . .	then your source operating status is . . .
(i) Your source processes any amount of listed oilseed and source is not operating under an initial startup operating period or a malfunction period subject to §63.2850(c)(2), (d)(2), or (e)(2)	A normal operating period.
(ii) Your source processes no agricultural product and your source is not operating under an initial startup period or malfunction period subject to §63.2850(c)(2), (d)(2), or (e)(2)	A nonoperating period.
(iii) You choose to operate your source under an initial startup period subject to §63.2850(c)(2) or (d)(2)	An initial startup period.
(iv) You choose to operate your source under a malfunction period subject to §63.2850(e)(2)	A malfunction period.
(v) Your source processes agricultural products not defined as listed oilseed	An exempt period.

(3) *Measuring the beginning and ending solvent inventory.* You are required to measure and record the solvent inventory on the beginning and ending dates of each normal operating period that occurs during an operating month. An operating month is any calendar month with at least one normal operating period. You must consistently follow the procedures described in your plan for demonstrating compliance, as specified in §63.2851, to determine the extraction solvent inventory, and maintain readily available records of the actual solvent loss inventory, as described in §63.2862(c)(1). In general, you must measure and record the solvent inventory only when the source is actively processing any type of agricultural product. When the source is not active, some or all of the solvent working capacity is transferred to solvent storage tanks which can artificially inflate the solvent inventory.

(4) *Gallons of extraction solvent received.* Record the total gallons of extraction solvent received in each shipment. For most processes, the gallons of solvent received represents purchases of delivered solvent added to the solvent storage inventory. However, if your process refines additional vegetable oil from off-site sources, recovers solvent from the off-site oil, and adds it to the on-site solvent inventory, then you must determine the quantity of recovered solvent and include it in the gallons of extraction solvent received.

(5) *Solvent inventory adjustments.* In some situations, solvent losses determined directly from the measured solvent inventory and quantity of solvent received is not an accurate estimate of the “actual solvent loss” for use in determining compliance ratios. In such cases, you may adjust the total solvent loss for each normal operating period as long as you provide a reasonable justification for the adjustment. Situations that may require adjustments of the total solvent loss include, but are not limited to, situations in paragraphs (a)(5)(i) and (ii) of this section:

(i) *Solvent destroyed in a control device.* You may use a control device to reduce solvent emissions to meet the emission standard. The use of a control device does not alter the emission limit for the source. If you use a control device that reduces solvent emissions through destruction of the solvent instead of recovery, then determine the gallons of solvent that enter the control device and are destroyed there during each normal operating period. All solvent destroyed in a control device during a normal operating period can be subtracted from the total solvent loss. Examples of destructive emission control devices include catalytic incinerators, boilers, or flares. Identify and describe, in your plan for demonstrating compliance, each type of reasonable and sound measurement method that you use to quantify the gallons of solvent entering and exiting the control device and to determine the destruction efficiency of the control device. You may use design evaluations to document the gallons of solvent destroyed or removed by the control device instead of performance testing under §63.7. The design evaluations must be based on the procedures and options described in §63.985(b)(1)(i)(A) through (C) or §63.11, as appropriate. All data, assumptions, and procedures used in such evaluations must be documented and available for inspection. If you use performance testing to determine solvent flow rate to the control device or destruction efficiency of the device, follow the procedures as outlined in §63.997(e)(1) and (2). Instead of periodic performance testing to demonstrate

continued good operation of the control device, you may develop a monitoring plan, following the procedures outlined in §63.988(c) and using operational parametric measurement devices such as fan parameters, percent measurements of lower explosive limits, and combustion temperature.

(ii) Changes in solvent working capacity. In records you keep on-site, document any process modifications resulting in changes to the solvent working capacity in your vegetable oil production process. *Solvent working capacity* is defined in §63.2872. In general, solvent working capacity is the volume of solvent normally retained in solvent recovery equipment such as the extractor, desolventizer-toaster, solvent storage, working tanks, mineral oil absorber, condensers, and oil/solvent distillation system. If the change occurs during a normal operating period, you must determine the difference in working solvent volume and make a one-time documented adjustment to the solvent inventory.

(b) Use Equation 1 of this section to determine the actual solvent loss occurring from your affected source for all normal operating periods recorded within a calendar month. Equation 1 of this section follows:

Monthly Actual

$$\text{Solvent (gal)} = \sum_{i=1}^n (SOLV_B - SOLV_E + SOLV_R \pm SOLV_A)_i \quad (Eq. 1)$$

Where:

SOLV<sub>B</sub>= Gallons of solvent in the inventory at the beginning of normal operating period “i” as determined in paragraph (a)(3) of this section.

SOLV<sub>E</sub>= Gallons of solvent in the inventory at the end of normal operating period “i” as determined in paragraph (a)(3) of this section.

SOLV<sub>R</sub>= Gallons of solvent received between the beginning and ending inventory dates of normal operating period “i” as determined in paragraph (a)(4) of this section.

SOLV<sub>A</sub>= Gallons of solvent added or removed from the extraction solvent inventory during normal operating period “i” as determined in paragraph (a)(5) of this section.

n = Number of normal operating periods in a calendar month.

(c) The actual solvent loss is the total solvent losses during normal operating periods for the previous 12 operating months. You determine your actual solvent loss by summing the monthly actual solvent losses for the previous 12 operating months. You must record the actual solvent loss by the end of each calendar month following an operating month. Use the actual solvent loss in Equation 2 of §63.2840 to determine the compliance ratio. Actual solvent loss does not include losses that occur during operating status periods listed in paragraphs (c)(1) through (4) of this section. If any one of these four operating status periods span an entire month, then the month is treated as nonoperating and there is no compliance ratio determination.

(1) Nonoperating periods as described in paragraph (a)(2)(ii) of this section.

(2) Initial startup periods as described in §63.2850(c)(2) or (d)(2).

(3) Malfunction periods as described in §63.2850(e)(2).

(4) Exempt operation periods as described in paragraph (a)(2)(v) of this section.

**§ 63.2854 How do I determine the weighted average volume fraction of HAP in the actual solvent loss?**

(a) This section describes the information and procedures you must use to determine the weighted average volume fraction of HAP in extraction solvent received for use in your vegetable oil production process. By the end of each calendar month following an operating month, determine the weighted average volume fraction of HAP in extraction solvent received since the end of the previous operating month. If you have determined the monthly weighted average volume fraction of HAP in solvent received for 12 or more operating months, then also determine an overall weighted average volume fraction of HAP in solvent received for the previous 12 operating months. Use the volume fraction of HAP determined as a 12 operating months weighted average in Equation 2 of §63.2840 to determine the compliance ratio.

(b) To determine the volume fraction of HAP in the extraction solvent determined as a 12 operating months weighted average, you must comply with paragraphs (b)(1) through (3) of this section:

(1) Record the volume fraction of each HAP comprising more than 1 percent by volume of the solvent in each delivery of solvent, including solvent recovered from off-site oil. To determine the HAP content of the material in each delivery of solvent, the reference method is EPA Method 311 of appendix A of this part. You may use EPA Method 311, an approved alternative method, or any other reasonable means for determining the HAP content. Other reasonable means of determining HAP content include, but are not limited to, a material safety data sheet or a manufacturer's certificate of analysis. A certificate of analysis is a legal and binding document provided by a solvent manufacturer. The purpose of a certificate of analysis is to list the test methods and analytical results that determine chemical properties of the solvent and the volume percentage of all HAP components present in the solvent at quantities greater than 1 percent by volume. You are not required to test the materials that you use, but the Administrator may require a test using EPA Method 311 (or an approved alternative method) to confirm the reported HAP content. However, if the results of an analysis by EPA Method 311 are different from the HAP content determined by another means, the EPA Method 311 results will govern compliance determinations.

(2) Determine the weighted average volume fraction of HAP in the extraction solvent each operating month. The weighted average volume fraction of HAP for an operating month includes all solvent received since the end of the last operating month, regardless of the operating status at the time of the delivery. Determine the monthly weighted average volume fraction of HAP by summing the products of the HAP volume fraction of each delivery and the volume of each delivery and dividing the sum by the total volume of all deliveries as expressed in Equation 1 of this section. Record the result by the end of each calendar month following an operating month. Equation 1 of this section follows:

$$\begin{array}{l} \text{Monthly Weighted} \\ \text{Average HAP Content} \\ \text{of Extraction Solvent} \\ \text{(volume fraction)} \end{array} = \frac{\sum_{i=1}^n (\text{Received}_i * \text{Content}_i)}{\text{Total Received}} \quad (\text{Eq. 1})$$

Where:

Received<sub>i</sub> = Gallons of extraction solvent received in delivery "i."

Content<sub>i</sub> = The volume fraction of HAP in extraction solvent delivery "i."

Total Received = Total gallons of extraction solvent received since the end of the previous operating month.

n = Number of extraction solvent deliveries since the end of the previous operating month.

(3) Determine the volume fraction of HAP in your extraction solvent as a 12 operating months weighted average. When your source has processed oilseed for 12 operating months, sum the products of the monthly weighted average HAP volume fraction and corresponding volume of solvent received, and divide the sum by the total volume of solvent received for the 12 operating months, as expressed by Equation 2 of this section. Record the result by the end of each calendar month following an operating month and use it in Equation 2 of §63.2840 to determine the compliance ratio. Equation 2 of this section follows:

$$\begin{array}{l} \text{12-Month Weighted} \\ \text{Average of HAP Content} \\ \text{in Solvent Received} \\ \text{(volume fraction)} \end{array} = \frac{\sum_{i=1}^{12} (\text{Received}_i * \text{Content}_i)}{\text{Total Received}} \quad (\text{Eq. 2})$$

Where:

Received<sub>i</sub>= Gallons of extraction solvent received in operating month “i” as determined in accordance with §63.2853(a)(4).

Content<sub>i</sub>= Average volume fraction of HAP in extraction solvent received in operating month “i” as determined in accordance with paragraph (b)(1) of this section.

Total Received = Total gallons of extraction solvent received during the previous 12 operating months.

### § 63.2855 How do I determine the quantity of oilseed processed?

All oilseed measurements must be determined on an *as received* basis, as defined in §63.2872. The *as received* basis refers to the oilseed chemical and physical characteristics as initially received by the source and prior to any oilseed handling and processing. By the end of each calendar month following an operating month, you must determine the tons as received of each listed oilseed processed for the operating month. The total oilseed processed for an operating month includes the total of each oilseed processed during all normal operating periods that occur within the operating month. If you have determined the tons of oilseed processed for 12 or more operating months, then you must also determine the 12 operating months rolling sum of each type oilseed processed by summing the tons of each type of oilseed processed for the previous 12 operating months. The 12 operating months rolling sum of each type of oilseed processed is used to calculate the compliance ratio as described in §63.2840.

(a) To determine the tons as received of each type of oilseed processed at your source, follow the procedures in your plan for demonstrating compliance to determine the items in paragraphs (a)(1) through (5) of this section:

(1) *The dates that define each operating status period.* The dates that define each operating status period include the beginning date of each calendar month and the date of any change in the source operating status. If, prior to the effective date of this rule, your source determines the oilseed inventory on an accounting month rather than a calendar month basis, and you have 12 complete accounting months of approximately equal duration in a calendar year, you may substitute the accounting month time interval for the calendar month time interval. If you choose to use an accounting month rather than a calendar month, you must document this measurement frequency selection in your plan for demonstrating compliance, and you must remain on this schedule unless you request and receive written approval from the agency responsible for these NESHAP. The dates on each oilseed inventory log must be consistent with the dates recorded for the solvent inventory.

(2) *Source operating status.* You must categorize the source operation for each recorded time interval. The source operating status for each time interval recorded on the oilseed inventory for each type of oilseed must be consistent with the operating status recorded on the solvent inventory logs as described in §63.2853(a)(2).

(3) *Measuring the beginning and ending inventory for each oilseed.* You are required to measure and record the oilseed inventory on the beginning and ending dates of each normal operating period that occurs during an operating month. An operating month is any calendar month with at least one normal operating period. You must consistently follow the procedures described in your plan for demonstrating compliance, as specified in §63.2851, to determine the oilseed inventory on an *as received* basis and maintain readily available records of the oilseed inventory as described by §63.2862(c)(3).

(4) *Tons of each oilseed received.* Record the type of oilseed and tons of each shipment of oilseed received and added to your on-site storage.

(5) *Oilseed inventory adjustments.* In some situations, determining the quantity of oilseed processed directly from the measured oilseed inventory and quantity of oilseed received is not an accurate estimate of the tons of oilseed processed for use in determining compliance ratios. For example, spoiled and molded oilseed removed from storage but not processed by your source will result in an overestimate of the quantity of oilseed processed. In such cases, you must adjust the oilseed inventory and provide a justification for the adjustment. Situations that may require oilseed inventory adjustments include, but are not limited to, the situations listed in paragraphs (a)(5)(i) through (v) of this section:

(i) Oilseed that mold or otherwise become unsuitable for processing.

(ii) Oilseed you sell before it enters the processing operation.

(iii) Oilseed destroyed by an event such as a process malfunction, fire, or natural disaster.

(iv) Oilseed processed through operations prior to solvent extraction such as screening, dehulling, cracking, drying, and conditioning; but that are not routed to the solvent extractor for further processing.

(v) Periodic physical measurements of inventory. For example, some sources periodically empty oilseed storage silos to physically measure the current oilseed inventory. This periodic measurement procedure typically results in a small inventory correction. The correction factor, usually less than 1 percent, may be used to make an adjustment to the source's oilseed inventory that was estimated previously with indirect measurement techniques. To make this adjustment, your plan for demonstrating compliance must provide for such an adjustment.

(b) Use Equation 1 of this section to determine the quantity of each oilseed type processed at your affected source during normal operating periods recorded within a calendar month. Equation 1 of this section follows:

Monthly Quantity  
of Each Oilseed  
Processed (tons) =  $\sum_{n=1}^n (SEED_B - SEED_E + SEED_R \pm SEED_A)$  (Eq. 1)

Where:

SEED<sub>B</sub>= Tons of oilseed in the inventory at the beginning of normal operating period "i" as determined in accordance with paragraph (a)(3) of this section.

SEED<sub>E</sub>= Tons of oilseed in the inventory at the end of normal operating period "i" as determined in accordance with paragraph (a)(3) of this section.

SEED<sub>R</sub>= Tons of oilseed received during normal operating period "i" as determined in accordance with paragraph (a)(4) of this section.

SEED<sub>A</sub>= Tons of oilseed added or removed from the oilseed inventory during normal operating period "i" as determined in accordance with paragraph (a)(5) of this section.

n = Number of normal operating periods in the calendar month during which this type oilseed was processed.

(c) The quantity of each oilseed processed is the total tons of each type of listed oilseed processed during normal operating periods in the previous 12 operating months. You determine the tons of each oilseed processed by summing the monthly quantity of each oilseed processed for the previous 12 operating months. You must record the 12 operating months quantity of each type of oilseed processed by the end of each calendar month following an operating month. Use the 12 operating months quantity of each type of oilseed processed to determine the

compliance ratio as described in §63.2840. The quantity of oilseed processed does not include oilseed processed during the operating status periods in paragraphs (c)(1) through (4) of this section:

- (1) Nonoperating periods as described in §63.2853 (a)(2)(ii).
- (2) Initial startup periods as described in §63.2850(c)(2) or (d)(2).
- (3) Malfunction periods as described in §63.2850(e)(2).
- (4) Exempt operation periods as described in §63.2853 (a)(2)(v).
- (5) If any one of these four operating status periods span an entire calendar month, then the calendar month is treated as a nonoperating month and there is no compliance ratio determination.

## **Notifications, Reports, and Records**

### **§ 63.2860 What notifications must I submit and when?**

You must submit the one-time notifications listed in paragraphs (a) through (d) of this section to the responsible agency:

(a) *Initial notification for existing sources.* For an existing source, submit an initial notification to the agency responsible for these NESHAP no later than 120 days after the effective date of this subpart. In the notification, include the items in paragraphs (a)(1) through (5) of this section:

- (1) The name and address of the owner or operator.
- (2) The physical address of the vegetable oil production process.
- (3) Identification of the relevant standard, such as the vegetable oil production NESHAP, and compliance date.
- (4) A brief description of the source including the types of listed oilseeds processed, nominal operating capacity, and type of desolventizer(s) used.
- (5) A statement designating the source as a major source of HAP or a demonstration that the source meets the definition of an area source. An area source is a source that is not a major source and is not collocated within a plant site with other sources that are individually or collectively a major source.

(b) *Initial notifications for new and reconstructed sources.* New or reconstructed sources must submit a series of notifications before, during, and after source construction per the schedule listed in §63.9. The information requirements for the notifications are the same as those listed in the General Provisions with the exceptions listed in paragraphs (b)(1) and (2) of this section:

- (1) The application for approval of construction does not require the specific HAP emission data required in §63.5(d)(1)(ii)(H) and (iii), (d)(2) and (d)(3)(ii). The application for approval of construction would include, instead, a brief description of the source including the types of listed oilseeds processed, nominal operating capacity, and type of desolventizer(s) used.
- (2) The notification of actual startup date must also include whether you have elected to operate under an initial startup period subject to §63.2850(c)(2) and provide an estimate and justification for the anticipated duration of the initial startup period.

(c) *Significant modification notifications.* Any existing or new source that plans to undergo a significant modification as defined in §63.2872 must submit two reports as described in paragraphs (c)(1) and (2) of this section:

(1) Initial notification. You must submit an initial notification to the agency responsible for these NESHAP 30 days prior to initial startup of the significantly modified source. The initial notification must demonstrate that the proposed changes qualify as a significant modification. The initial notification must include the items in paragraphs (c)(1)(i) and (ii) of this section:

(i) The expected startup date of the modified source.

(ii) A description of the significant modification including a list of the equipment that will be replaced or modified. If the significant modification involves changes other than adding or replacing extractors, desolventizer-toasters (conventional and specialty), and meal dryer-coolers, then you must also include the fixed capital cost of the new components, expressed as a percentage of the fixed capital cost to build a comparable new vegetable oil production process; supporting documentation for the cost estimate; and documentation that the proposed changes will significantly affect solvent losses.

(2) Notification of actual startup. You must submit a notification of actual startup date within 15 days after initial startup of the modified source. The notification must include the items in paragraphs (c)(2)(i) through (iv) of this section:

(i) The initial startup date of the modified source.

(ii) An indication whether you have elected to operate under an initial startup period subject to §63.2850(d)(2).

(iii) The anticipated duration of any initial startup period.

(iv) A justification for the anticipated duration of any initial startup period.

(d) *Notification of compliance status.* As an existing, new, or reconstructed source, you must submit a notification of compliance status report to the responsible agency no later than 60 days after determining your initial 12 operating months compliance ratio. If you are an existing source, you generally must submit this notification no later than 50 calendar months after the effective date of these NESHAP (36 calendar months for compliance, 12 operating months to record data, and 2 calendar months to complete the report). If you are a new or reconstructed source, the notification of compliance status is generally due no later than 20 calendar months after initial startup (6 calendar months for the initial startup period, 12 operating months to record data, and 2 calendar months to complete the report). The notification of compliance status must contain the items in paragraphs (d)(1) through (6) of this section:

(1) The name and address of the owner or operator.

(2) The physical address of the vegetable oil production process.

(3) Each listed oilseed type processed during the previous 12 operating months.

(4) Each HAP identified under §63.2854(a) as being present in concentrations greater than 1 percent by volume in each delivery of solvent received during the 12 operating months period used for the initial compliance determination.

(5) A statement designating the source as a major source of HAP or a demonstration that the source qualifies as an area source. An area source is a source that is not a major source and is not collocated within a plant site with other sources that are individually or collectively a major source.

(6) A compliance certification indicating whether the source complied with all of the requirements of this subpart throughout the 12 operating months used for the initial source compliance determination. This certification must include a certification of the items in paragraphs (d)(6)(i) through (iii) of this section:

(i) The plan for demonstrating compliance (as described in §63.2851) and SSM plan (as described in §63.2852) are complete and available on-site for inspection.

(ii) You are following the procedures described in the plan for demonstrating compliance.

(iii) The compliance ratio is less than or equal to 1.00.

### **§ 63.2861 What reports must I submit and when?**

After the initial notifications, you must submit the reports in paragraphs (a) through (d) of this section to the agency responsible for these NESHAP at the appropriate time intervals:

(a) *Annual compliance certifications.* The first annual compliance certification is due 12 calendar months after you submit the notification of compliance status. Each subsequent annual compliance certification is due 12 calendar months after the previous annual compliance certification. The annual compliance certification provides the compliance status for each operating month during the 12 calendar months period ending 60 days prior to the date on which the report is due. Include the information in paragraphs (a)(1) through (6) of this section in the annual certification:

(1) The name and address of the owner or operator.

(2) The physical address of the vegetable oil production process.

(3) Each listed oilseed type processed during the 12 calendar months period covered by the report.

(4) Each HAP identified under §63.2854(a) as being present in concentrations greater than 1 percent by volume in each delivery of solvent received during the 12 calendar months period covered by the report.

(5) A statement designating the source as a major source of HAP or a demonstration that the source qualifies as an area source. An area source is a source that is not a major source and is not collocated within a plant site with other sources that are individually or collectively a major source.

(6) A compliance certification to indicate whether the source was in compliance for each compliance determination made during the 12 calendar months period covered by the report. For each such compliance determination, you must include a certification of the items in paragraphs (a)(6)(i) through (ii) of this section:

(i) You are following the procedures described in the plan for demonstrating compliance.

(ii) The compliance ratio is less than or equal to 1.00.

(b) *Deviation notification report.* Submit a deviation report for each compliance determination you make in which the compliance ratio exceeds 1.00 as determined under §63.2840(c). Submit the deviation report by the end of the month following the calendar month in which you determined the deviation. The deviation notification report must include the items in paragraphs (b)(1) through (4) of this section:

(1) The name and address of the owner or operator.

(2) The physical address of the vegetable oil production process.

(3) Each listed oilseed type processed during the 12 operating months period for which you determined the deviation.

(4) The compliance ratio comprising the deviation. You may reduce the frequency of submittal of the deviation notification report if the agency responsible for these NESHAP does not object as provided in §63.10(e)(3)(iii).

(c) *Periodic startup, shutdown, and malfunction report.* If you choose to operate your source under an initial startup period subject to §63.2850(c)(2) or (d)(2) or a malfunction period subject to §63.2850(e)(2), you must submit a periodic SSM report by the end of the calendar month following each month in which the initial startup period or malfunction period occurred. The periodic SSM report must include the items in paragraphs (c)(1) through (3) of this section:

(1) The name, title, and signature of a source's responsible official who is certifying that the report accurately states that all actions taken during the initial startup or malfunction period were consistent with the SSM plan.

(2) A description of events occurring during the time period, the date and duration of the events, and reason the time interval qualifies as an initial startup period or malfunction period.

(3) An estimate of the solvent loss during the initial startup or malfunction period with supporting documentation.

(d) *Immediate SSM reports.* If you handle a SSM during an initial startup period subject to §63.2850(c)(2) or (d)(2) or a malfunction period subject to §63.2850(e)(2) differently from procedures in the SSM plan and the relevant emission requirements in §63.2840 are exceeded, then you must submit an immediate SSM report. Immediate SSM reports consist of a telephone call or facsimile transmission to the responsible agency within 2 working days after starting actions inconsistent with the SSM plan, followed by a letter within 7 working days after the end of the event. The letter must include the items in paragraphs (d)(1) through (3) of this section:

(1) The name, title, and signature of a source's responsible official who is certifying the accuracy of the report, an explanation of the event, and the reasons for not following the SSM plan.

(2) A description and date of the SSM event, its duration, and reason it qualifies as a SSM.

(3) An estimate of the solvent loss for the duration of the SSM event with supporting documentation.

[66 FR 19011, Apr. 12, 2001, as amended at 67 FR 16321, Apr. 5, 2002]

### **§ 63.2862 What records must I keep?**

(a) You must satisfy the recordkeeping requirements of this section by the compliance date for your source specified in Table 1 of §63.2834.

(b) Prepare a plan for demonstrating compliance (as described in §63.2851) and a SSM plan (as described in §63.2852). In these two plans, describe the procedures you will follow in obtaining and recording data, and determining compliance under normal operations or a SSM subject to the §63.2850(c)(2) or (d)(2) initial startup period or the §63.2850(e)(2) malfunction period. Complete both plans before the compliance date for your source and keep them on-site and readily available as long as the source is operational.

(c) If your source processes any listed oilseed, record the items in paragraphs (c)(1) through (5) of this section:

(1) For the solvent inventory, record the information in paragraphs (c)(1)(i) through (vii) of this section in accordance with your plan for demonstrating compliance:

(i) Dates that define each operating status period during a calendar month.

(ii) The operating status of your source such as normal operation, nonoperating, initial startup period, malfunction period, or exempt operation for each recorded time interval.

(iii) Record the gallons of extraction solvent in the inventory on the beginning and ending dates of each normal operating period.

(iv) The gallons of all extraction solvent received, purchased, and recovered during each calendar month.

(v) All extraction solvent inventory adjustments, additions or subtractions. You must document the reason for the adjustment and justify the quantity of the adjustment.

(vi) The total solvent loss for each calendar month, regardless of the source operating status.

(vii) The actual solvent loss in gallons for each operating month.

(2) For the weighted average volume fraction of HAP in the extraction solvent, you must record the items in paragraphs (c)(2)(i) through (iii) of this section:

(i) The gallons of extraction solvent received in each delivery.

(ii) The volume fraction of each HAP exceeding 1 percent by volume in each delivery of extraction solvent.

(iii) The weighted average volume fraction of HAP in extraction solvent received since the end of the last operating month as determined in accordance with §63.2854(b)(2).

(3) For each type of listed oilseed processed, record the items in paragraphs (c)(3)(i) through (vi) of this section, in accordance with your plan for demonstrating compliance:

(i) The dates that define each operating status period. These dates must be the same as the dates entered for the extraction solvent inventory.

(ii) The operating status of your source such as normal operation, nonoperating, initial startup period, malfunction period, or exempt operation for each recorded time interval. On the log for each type of listed oilseed that is not being processed during a normal operating period, you must record which type of listed oilseed is being processed in addition to the source operating status.

(iii) The oilseed inventory for the type of listed oilseed being processed on the beginning and ending dates of each normal operating period.

(iv) The tons of each type of listed oilseed received at the affected source each normal operating period.

(v) All listed oilseed inventory adjustments, additions or subtractions for normal operating periods. You must document the reason for the adjustment and justify the quantity of the adjustment.

(vi) The tons of each type of listed oilseed processed during each operating month.

(d) After your source has processed listed oilseed for 12 operating months, and you are not operating during an initial startup period as described in §63.2850(c)(2) or (d)(2), or a malfunction period as described in §63.2850(e)(2), record the items in paragraphs (d)(1) through (5) of this section by the end of the calendar month following each operating month:

(1) The 12 operating months rolling sum of the actual solvent loss in gallons as described in §63.2853(c).

(2) The weighted average volume fraction of HAP in extraction solvent received for the previous 12 operating months as described in §63.2854(b)(3).

(3) The 12 operating months rolling sum of each type of listed oilseed processed at the affected source in tons as described in §63.2855(c).

(4) A determination of the compliance ratio. Using the values from §§63.2853, 63.2854, 63.2855, and Table 1 of §63.2840, calculate the compliance ratio using Equation 2 of §63.2840.

(5) A statement of whether the source is in compliance with all of the requirements of this subpart. This includes a determination of whether you have met all of the applicable requirements in §63.2850.

(e) For each SSM event subject to an initial startup period as described in §63.2850(c)(2) or (d)(2), or a malfunction period as described in §63.2850(e)(2), record the items in paragraphs (e)(1) through (3) of this section by the end of the calendar month following each month in which the initial startup period or malfunction period occurred:

- (1) A description and date of the SSM event, its duration, and reason it qualifies as an initial startup or malfunction.
- (2) An estimate of the solvent loss in gallons for the duration of the initial startup or malfunction period with supporting documentation.
- (3) A checklist or other mechanism to indicate whether the SSM plan was followed during the initial startup or malfunction period.

**§ 63.2863 In what form and how long must I keep my records?**

- (a) Your records must be in a form suitable and readily available for review in accordance with §63.10(b)(1).
- (b) As specified in §63.10(b)(1), you must keep each record for 5 years following the date of each occurrence, measurement, maintenance, corrective action, report, or record.
- (c) You must keep each record on-site for at least 2 years after the date of each occurrence, measurement, maintenance, corrective action, report, or record, in accordance with §3.10(b)(1). You can keep the records off-site for the remaining 3 years.

**Other Requirements and Information**

**§ 63.2870 What parts of the General Provisions apply to me?**

Table 1 of this section shows which parts of the General Provisions in §§63.1 through 63.15 apply to you. Table 1 of §63.2870 follows:

**Table 1 of §63.2870—Applicability of 40 CFR Part 63, Subpart A, to 40 CFR, Part 63, Subpart GGGG**

General provisions citation	Subject of citation	Brief description of requirement	Applies to subpart	Explanation
§63.1	Applicability	Initial applicability determination; applicability after standard established; permit requirements; extensions; notifications	Yes	
§63.2	Definitions	Definitions for part 63 standards	Yes	Except as specifically provided in this subpart.
§63.3	Units and abbreviations	Units and abbreviations for part 63 standards	Yes	
§63.4	Prohibited activities and circumvention	Prohibited activities; compliance date; circumvention; severability	Yes	
§63.5	Construction/reconstruction	Applicability; applications; approvals	Yes	Except for subsections of §63.5 as listed below.

General provisions citation	Subject of citation	Brief description of requirement	Applies to subpart	Explanation
§63.5(c)	[Reserved]			
§63.5(d)(1)(ii)(H)	Application for approval	Type and quantity of HAP, operating parameters	No	All sources emit HAP. Subpart GGGG does not require control from specific emission points.
§63.5(d)(1)(ii)(I)	[Reserved]			
§63.5(d)(1)(iii), (d)(2), (d)(3)(ii)		Application for approval	No	The requirements of the application for approval for new, reconstructed and significantly modified sources are described in §63.2860(b) and (c) of subpart GGGG. General provision requirements for identification of HAP emission points or estimates of actual emissions are not required. Descriptions of control and methods, and the estimated and actual control efficiency of such do not apply. Requirements for describing control equipment and the estimated and actual control efficiency of such equipment apply only to control equipment to which the subpart GGGG requirements for quantifying.
§63.6	Applicability of General Provisions	Applicability	Yes	Except for subsections of §63.6 as listed below.

General provisions citation	Subject of citation	Brief description of requirement	Applies to subpart	Explanation
§63.6(b)(1)–(3)	Compliance dates, new and reconstructed sources		No	Section 63.2834 of subpart GGGG specifies the compliance dates for new and reconstructed sources.
§63.6(b)(6)	[Reserved]			
§63.6(c)(3)–(4)	[Reserved]			
§63.6(d)	[Reserved]			
§63.6(e)(1) through (e)(3)(ii) and §63.6(e)(3)(v) through (vii)	Operation and maintenance requirements		Yes	Minimize emissions to the extent practical.
§63.6(e)(3)(iii)	Operation and maintenance requirements		No	Minimize emissions to the extent practical
§63.6(e)(3)(iv)	Operation and maintenance requirements		No	Report SSM and in accordance with §63.2861(c) and (d).
§63.6(e)(3)(viii)	Operation and maintenance requirements		Yes	Except, report each revision to your SSM plan in accordance with §63.2861(c) rather than §63.10(d)(5) as required under §63.6(e)(3) (viii).
§63.6(e)(3)(ix)	Title V permit		Yes	
§63.6(f)–(g)	Compliance with nonopacity emission standards except during SSM	Comply with emission standards at all times except during SSM	No	Subpart GGGG does not have nonopacity requirements.
§63.6(h)	Opacity/Visible emission (VE) standards		No	Subpart GGGG has no opacity or VE standards.
§63.6(i)	Compliance extension	Procedures and criteria for responsible agency to grant compliance extension	Yes	

General provisions citation	Subject of citation	Brief description of requirement	Applies to subpart	Explanation
§63.6(j)	Presidential compliance exemption	President may exempt source category from requirement to comply with subpart	Yes	
§63.7	Performance testing requirements	Schedule, conditions, notifications and procedures	Yes	Subpart GGGG requires performance testing only if the source applies additional control that destroys solvent. Section 63.2850(a)(6) requires sources to follow the performance testing guidelines of the General Provisions if a control is added.
§63.8	Monitoring requirements		No	Subpart GGGG does not require monitoring other than as specified therein.
§63.9	Notification requirements	Applicability and state delegation	Yes	Except for subsections of §63.9 as listed below.
§63.9(b)(2)	Notification requirements	Initial notification requirements for existing sources	No	Section 63.2860(a) of subpart GGGG specifies the requirements of the initial notification for existing sources.
§63.9(b)(3)–(5)	Notification requirements	Notification requirement for certain new/reconstructed sources	Yes	Except the information requirements differ as described in §63.2860(b) of subpart GGGG.
§63.9(e)	Notification of performance test	Notify responsible agency 60 days ahead	Yes	Applies only if performance testing is performed.

General provisions citation	Subject of citation	Brief description of requirement	Applies to subpart	Explanation
§63.9(f)	Notification of VE/opacity observations	Notify responsible agency 30 days ahead	No	Subpart GGGG has no opacity or VE standards.
§63.9(g)	Additional notifications when using a continuous monitoring system (CMS)	Notification of performance evaluation; Notification using COMS data; notification that exceeded criterion for relative accuracy	No	Subpart GGGG has no CMS requirements.
§63.9(h)	Notification of compliance status	Contents	No	Section 63.2860(d) of subpart GGGG specifies requirements for the notification of compliance status.
§63.10	Recordkeeping/reporting	Schedule for reporting, record storage	Yes	Except for subsections of §63.10 as listed below.
§63.10(b)(2)(i)	Recordkeeping	Record SSM event	Yes	Applicable to periods when sources must implement their SSM plan as specified in subpart GGGG.
§63.10(b)(2)(ii)–(iii)	Recordkeeping	Malfunction of air pollution equipment	No	Applies only if air pollution control equipment has been added to the process and is necessary for the source to meet the emission limit.
§63.10(b)(2)(vi)	Recordkeeping	CMS recordkeeping	No	Subpart GGGG has no CMS requirements.
§63.10(b)(2)(viii)–(ix)	Recordkeeping	Conditions of performance test	Yes	Applies only if performance tests are performed. Subpart GGGG does not have any CMS opacity or VE observation requirements.

General provisions citation	Subject of citation	Brief description of requirement	Applies to subpart	Explanation
§63.10(b)(2)(x)–(xii)	Recordkeeping	CMS, performance testing, and opacity and VE observations recordkeeping	No	Subpart GGGG does not require CMS.
§63.10(c)	Recordkeeping	Additional CMS recordkeeping	No	Subpart GGGG does not require CMS.
§63.10(d)(2)	Reporting	Reporting performance test results	Yes	Applies only if performance testing is performed.
§63.10(d)(3)	Reporting	Reporting opacity or VE observations	No	Subpart GGGG has no opacity or VE standards.
§63.10(d)(4)	Reporting	Progress reports	Yes	Applies only if a condition of compliance extension exists.
§63.10(d)(5)	Reporting	SSM reporting	No	Section 63.2861(c) and (d) specify SSM reporting requirements.
§63.10(e)	Reporting	Additional CMS reports	No	Subpart GGGG does not require CMS.
§63.11	Control device requirements	Requirements for flares	Yes	Applies only if your source uses a flare to control solvent emissions. Subpart GGGG does not require flares.
§63.12	State authority and delegations	State authority to enforce standards	Yes	
§63.13	State/regional addresses	Addresses where reports, notifications, and requests are sent	Yes	
§63.14	Incorporation by reference	Test methods incorporated by reference	Yes	
§63.15	Availability of information and confidentiality	Public and confidential information	Yes	

[66 FR 19011, Apr. 12, 2001, as amended at 67 FR 16321, Apr. 5, 2002; 71 FR 20463, Apr. 20, 2006]

**§ 63.2871 Who implements and enforces this subpart?**

(a) This subpart can be implemented by us, the U.S. EPA, or a delegated authority such as your State, local, or tribal agency. If the U.S. EPA Administrator has delegated authority to your State, local, or tribal agency, then that agency, as well as the U.S. EPA, has the authority to implement and enforce this subpart. You should contact your U.S. EPA Regional Office to find out if 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 section 40 CFR part 63, subpart E, the authorities contained in paragraph (c) of this section are retained by the Administrator of the U.S. EPA and are not transferred to the State, local, or tribal agency.

(c) The authorities that will not be delegated to State, local, or tribal agencies are as follows:

(1) Approval of alternative nonopacity emissions standards under §63.6(g).

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

(3) Approval of major alternatives to test methods under §63.7(e)(2)(ii) and (f) and as defined in §63.90.

(4) Approval of major alternatives to monitoring under §63.8(f) and as defined in §63.90.

(5) Approval of major alternatives to recordkeeping and reporting under §63.10(f) and as defined in §63.90.

### **§ 63.2872 What definitions apply to this subpart?**

Terms used in this subpart are defined in the sources listed:

(a) The Clean Air Act, section 112(a).

(b) In 40 CFR 63.2, the NESHAP General Provisions.

(c) In this section as follows:

*Accounting month* means a time interval defined by a business firm during which corporate economic and financial factors are determined on a consistent and regular basis. An accounting month will consist of approximately 4 to 5 calendar weeks and each accounting month will be of approximate equal duration. An accounting month may not correspond exactly to a calendar month, but 12 accounting months will correspond exactly to a calendar year.

*Actual solvent loss* means the gallons of solvent lost from a source during 12 operating months as determined in accordance with §63.2853.

*Agricultural product* means any commercially grown plant or plant product.

*Allowable HAP loss* means the gallons of HAP that would have been lost from a source if the source was operating at the solvent loss factor for each listed oilseed type. The allowable HAP loss in gallons is determined by multiplying the tons of each oilseed type processed during the previous 12 operating months, as determined in accordance with §63.2855, by the corresponding oilseed solvent loss factor (gal/ton) listed in Table 1 of §63.2840, and by the dimensionless constant 0.64, and summing the result for all oilseed types processed.

*Area source* means any source that does not meet the major source definition.

*As received* is the basis upon which all oilseed measurements must be determined and refers to the oilseed chemical and physical characteristics as initially received by the source and prior to any oilseed handling and processing.

*Batch operation* means any process that operates in a manner where the addition of raw material and withdrawal of product do not occur simultaneously. Typically, raw material is added to a process, operational steps occur, and a product is removed from the process. More raw material is then added to the process and the cycle repeats.

*Calendar month* means 1 month as specified in a calendar.

*Compliance date* means the date on which monthly compliance recordkeeping begins. For existing sources, recordkeeping typically begins 3 years after the effective date of the subpart. For new and reconstructed sources, recordkeeping typically begins upon initial startup, except as noted in §63.2834.

*Compliance ratio* means a ratio of the actual HAP loss in gallons from the previous 12 operating months to an allowable HAP loss in gallons, which is determined by using oilseed solvent loss factors in Table 1 of §63.2840, the weighted average volume fraction of HAP in solvent received for the previous 12 operating months, and the tons of each type of listed oilseed processed in the previous 12 operating months. Months during which no listed oilseed is processed, or months during which the §63.2850(c)(2) or (d)(2) initial startup period or the §63.2850(e)(2) malfunction period applies, are excluded from this calculation. Equation 2 of §63.2840 is used to calculate this value. If the value is less than or equal to 1.00, the source is in compliance. If the value is greater than 1.00, the source is deviating from compliance.

*Continuous operation* means any process that adds raw material and withdraws product simultaneously. Mass, temperature, concentration and other properties typically approach steady-state conditions.

*Conventional desolventizer* means a desolventizer toaster that operates with indirect and direct-contact steam to remove solvent from the extracted meal. Oilseeds processed in a conventional desolventizer produce crude vegetable oil and crude meal products, such as animal feed.

*Corn germ dry milling* means a source that processes corn germ that has been separated from the other corn components using a "dry" process of mechanical chafing and air sifting.

*Corn germ wet milling* means a source that processes corn germ that has been separated from other corn components using a "wet" process of centrifuging a slurry steeped in a dilute sulfurous acid solution.

*Exempt period* means a period of time during which a source processes agricultural products not defined as listed oilseed.

*Extraction solvent* means an organic chemical medium used to remove oil from an oilseed. Typically, the extraction solvent is a commercial grade of hexane isomers which have an approximate HAP content of 64 percent by volume.

*Hazardous air pollutant (HAP)* means any substance or mixture of substances listed as a hazardous air pollutant under section 112(b) of the Clean Air Act, as of April 12, 2001.

*Initial startup date* means the first calendar day that a new, reconstructed or significantly modified source processes any listed oilseed.

*Initial startup period* means a period of time from the initial startup date of a new, reconstructed or significantly modified source, for which you choose to operate the source under an initial startup period subject to §63.2850(c)(2) or (d)(2). During an initial startup period, a source complies with the standards by minimizing HAP emissions to the extent practical. The initial startup period following initial startup of a new or reconstructed source may not exceed 6 calendar months. The initial startup period following a significant modification may not exceed 3 calendar months. Solvent and oilseed inventory information recorded during the initial startup period is excluded from use in any compliance ratio determinations.

*Large cottonseed plant* means a vegetable oil production process that processes 120,000 tons or more of cottonseed and other listed oilseed during all normal operating periods in a 12 operating months period used to determine compliance.

*Malfunction period* means a period of time between the beginning and end of a process malfunction and the time reasonably necessary for a source to correct the malfunction for which you choose to operate the source under a malfunction period subject to §63.2850(e)(2). This period may include the duration of an unscheduled process shutdown, continued operation during a malfunction, or the subsequent process startup after a shutdown resulting from a malfunction. During a malfunction period, a source complies with the standards by minimizing HAP emissions

to the extent practical. Therefore, solvent and oilseed inventory information recorded during a malfunction period is excluded from use in any compliance ratio determinations.

*Mechanical extraction* means removing vegetable oil from oilseeds using only mechanical devices such as presses or screws that physically force the oil from the oilseed. Mechanical extraction techniques use no organic solvents to remove oil from an oilseed.

*Nonoperating period* means any period of time in which a source processes no agricultural product. This operating status does not apply during any period in which the source operates under an initial startup period as described in §63.2850(c)(2) or (d)(2), or a malfunction period, as described in §63.2850(e)(2).

*Normal operating period* means any period of time in which a source processes a listed oilseed that is not categorized as an initial startup period as described in §63.2850(c)(2) or (d)(2), or a malfunction period, as described in §63.2850(e)(2). At the beginning and ending dates of a normal operating period, solvent and oilseed inventory information is recorded and included in the compliance ratio determination.

*Oilseed or listed oilseed* means the following agricultural products: corn germ, cottonseed, flax, peanut, rapeseed (for example, canola), safflower, soybean, and sunflower.

*Oilseed solvent loss factor* means a ratio expressed as gallons of solvent loss per ton of oilseed processed. The solvent loss factors are presented in Table 1 of §63.2840 and are used to determine the allowable HAP loss.

*Operating month* means any calendar or accounting month in which a source processes any quantity of listed oilseed, excluding any entire calendar or accounting month in which the source operated under an initial startup period as described in §63.2850(c)(2) or (d)(2), or a malfunction period as described in §63.2850(e)(2). An operating month may include time intervals characterized by several types of operating status. However, an operating month must have at least one normal operating period.

*Significant modification* means the addition of new equipment or the modification of existing equipment that:

- (1) Significantly affects solvent losses from your vegetable oil production process;
- (2) The fixed capital cost of the new components represents a significant percentage of the fixed capital cost of building a comparable new vegetable oil production process;
- (3) The fixed capital cost of the new equipment does not constitute reconstruction as defined in §63.2; and
- (4) Examples of significant modifications include replacement of or major changes to solvent recovery equipment such as extractors, desolventizer-toasters/dryer-coolers, flash desolventizers, and distillation equipment associated with the mineral oil system, and equipment affecting desolventizing efficiency and steady-state operation of your vegetable oil production process such as flaking mills, oilseed heating and conditioning equipment, and cracking mills.

*Small cottonseed plant* means a vegetable oil production process that processes less than 120,000 tons of cottonseed and other listed oilseed during all normal operating periods in a 12 operating months period used to determine compliance.

*Solvent extraction* means removing vegetable oil from listed oilseed using an organic solvent in a direct-contact system.

*Solvent working capacity* means the volume of extraction solvent normally retained in solvent recovery equipment. Examples include components such as the solvent extractor, desolventizer-toaster, solvent storage and working tanks, mineral oil absorption system, condensers, and oil/solvent distillation system.

*Specialty desolventizer* means a desolventizer that removes excess solvent from soybean meal using vacuum conditions, energy from superheated solvent vapors, or reduced operating conditions (e.g., temperature) as

compared to the typical operation of a conventional desolventizer. Soybeans processed in a specialty desolventizer result in high-protein vegetable meal products for human and animal consumption, such as calf milk replacement products and meat extender products.

*Vegetable oil production process* means the equipment comprising a continuous process for producing crude vegetable oil and meal products, including specialty soybean products, in which oil is removed from listed oilseeds through direct contact with an organic solvent. Process equipment typically includes the following components: oilseed preparation operations (including conditioning, drying, dehulling, and cracking), solvent extractors, desolventizer-toasters, meal dryers, meal coolers, meal conveyor systems, oil distillation units, solvent evaporators and condensers, solvent recovery system (also referred to as a mineral oil absorption system), vessels storing solvent-laden materials, and crude meal packaging and storage vessels. A vegetable oil production process does not include vegetable oil refining operations (including operations such as bleaching, hydrogenation, and deodorizing) and operations that engage in additional chemical treatment of crude soybean meals produced in specialty desolventizer units (including operations such as soybean isolate production).

[66 FR 19011, Apr. 12, 2001, as amended at 71 FR 20464, Apr. 20, 2006]

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

**Attachment D  
to a Part 70 Operating Permit**

**Source Background and Description**

<b>Source Name:</b>	Bunge North America (East), LLC
<b>Source Location:</b>	1200 N. 2nd Street, Decatur, Indiana 46733
<b>County:</b>	Adams
<b>SIC Code:</b>	2075, 2079, 5153, and 2048
<b>Permit Renewal No.:</b>	T001-23640-00005

**Subpart DDDDD—National Emission Standards for Hazardous Air Pollutants for Industrial, Commercial, and Institutional Boilers and Process Heaters**

**Source:** 69 FR 55253, Sept. 13, 2004, unless otherwise noted.

**What This Subpart Covers**

**§ 63.7480 What is the purpose of this subpart?**

This subpart establishes national emission limits and work practice standards for hazardous air pollutants (HAP) emitted from industrial, commercial, and institutional boilers and process heaters. This subpart also establishes requirements to demonstrate initial and continuous compliance with the emission limits and work practice standards.

**§ 63.7485 Am I subject to this subpart?**

You are subject to this subpart if you own or operate an industrial, commercial, or institutional boiler or process heater as defined in §63.7575 that is located at, or is part of, a major source of HAP as defined in §63.2 or §63.761 (40 CFR part 63, subpart HH, National Emission Standards for Hazardous Air Pollutants from Oil and Natural Gas Production Facilities), except as specified in §63.7491.

**§ 63.7490 What is the affected source of this subpart?**

(a) This subpart applies to new, reconstructed, or existing affected sources as described 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 and process heaters within a subcategory located at a major source as defined in §63.7575.

(2) The affected source of this subpart is each new or reconstructed industrial, commercial, or institutional boiler or process heater located at a major source as defined in §63.7575.

(b) A boiler or process heater is new if you commence construction of the boiler or process heater after January 13, 2003, and you meet the applicability criteria at the time you commence construction.

(c) A boiler or process heater is reconstructed if you meet the reconstruction criteria as defined in §63.2, you commence reconstruction after January 13, 2003, and you meet the applicability criteria at the time you commence reconstruction.

(d) A boiler or process heater is existing if it is not new or reconstructed.

**§ 63.7491 Are any boilers or process heaters not subject to this subpart?**

The types of boilers and process heaters listed in paragraphs (a) through (o) of this section are not subject to this subpart.

(a) A municipal waste combustor covered by 40 CFR part 60, subpart AAAA, subpart BBBB, subpart Cb or subpart Eb.

(b) A hospital/medical/infectious waste incinerator covered by 40 CFR part 60, subpart Ce or subpart Ec.

(c) An electric utility steam generating unit (including a unit covered by 40 CFR part 60, subpart Da) or a Mercury (Hg) Budget unit covered by 40 CFR part 60, subpart HHHH.

(d) A boiler or process heater required to have a permit under section 3005 of the Solid Waste Disposal Act or covered by 40 CFR part 63, subpart EEE ( e.g. , hazardous waste boilers).

(e) A commercial and industrial solid waste incineration unit covered by 40 CFR part 60, subpart CCCC or subpart DDDD.

(f) A recovery boiler or furnace covered by 40 CFR part 63, subpart MM.

(g) A boiler or process heater that is used specifically for research and development. This does not include units that only provide heat or steam to a process at a research and development facility.

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

(i) A refining kettle covered by 40 CFR part 63, subpart X.

(j) An ethylene cracking furnace covered by 40 CFR part 63, subpart YY.

(k) Blast furnace stoves as described in the EPA document, entitled "National Emission Standards for Hazardous Air Pollutants (NESHAP) for Integrated Iron and Steel Plants—Background Information for Proposed Standards," (EPA-453/R-01-005).

(l) Any boiler and process heater specifically listed as an affected source in another standard(s) under 40 CFR part 63.

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

(n) Temporary boilers as defined in this subpart.

(o) Blast furnace gas fuel-fired boilers and process heaters as defined in this subpart.

[69 FR 55253, Sept. 13, 2004, as amended at 71 FR 70660, Dec. 6, 2006]

**§ 63.7495 When do I have to comply with this subpart?**

(a) If you have a new or reconstructed boiler or process heater, you must comply with this subpart by November 12, 2004 or upon startup of your boiler or process heater, whichever is later.

(b) If you have an existing boiler or process heater, you must comply with this subpart no later than September 13, 2007.

(c) If you have an area source that increases its emissions or its potential to emit such that it becomes a major source of HAP, paragraphs (c)(1) and (2) of this section apply to you.

(1) Any new or reconstructed boiler or process heater at the existing facility must be in compliance with this subpart upon startup.

(2) Any existing boiler or process heater at the existing facility must be in compliance with this subpart within 3 years after the facility becomes a major source.

(d) You must meet the notification requirements in §63.7545 according to the schedule in §63.7545 and in subpart A of this part. Some of the notifications must be submitted before you are required to comply with the emission limits and work practice standards in this subpart.

### **Emission Limits and Work Practice Standards**

#### **§ 63.7499 What are the subcategories of boilers and process heaters?**

The subcategories of boilers and process heaters are large solid fuel, limited use solid fuel, small solid fuel, large liquid fuel, limited use liquid fuel, small liquid fuel, large gaseous fuel, limited use gaseous fuel, and small gaseous fuel. Each subcategory is defined in §63.7575.

#### **§ 63.7500 What emission limits, work practice standards, and operating limits must I meet?**

(a) You must meet the requirements in paragraphs (a)(1) and (2) of this section.

(1) You must meet each emission limit and work practice standard in Table 1 to this subpart that applies to your boiler or process heater, except as provided under §63.7507.

(2) You must meet each operating limit in Tables 2 through 4 to this subpart that applies to your boiler or process heater. If you use a control device or combination of control devices not covered in Tables 2 through 4 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).

(b) As provided in §63.6(g), EPA may approve use of an alternative to the work practice standards in this section.

### **General Compliance Requirements**

#### **§ 63.7505 What are my general requirements for complying with this subpart?**

(a) You must be in compliance with the emission limits (including operating limits) and the work practice standards in this subpart at all times, except during periods of startup, shutdown, and malfunction.

(b) You must always operate and maintain your affected source, including air pollution control and monitoring equipment, according to the provisions in §63.6(e)(1)(i).

(c) You can demonstrate compliance with any applicable emission limit using fuel analysis if the emission rate calculated according to §63.7530(d) is less than the applicable emission limit. Otherwise, you must demonstrate compliance using performance testing.

(d) If you demonstrate compliance with any applicable emission limit through performance testing, you must develop a site-specific monitoring plan according to the requirements in paragraphs (d)(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 continuous monitoring system (CMS) required in this section, you must develop and submit to the EPA Administrator for approval a site-specific monitoring plan that addresses paragraphs (d)(1)(i) through (iii) of this section. You must submit this site-specific monitoring plan 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 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).

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

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

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

(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.

(e) If you have an applicable emission limit or work practice standard, you must develop a written startup, shutdown, and malfunction plan (SSMP) according to the provisions in §63.6(e)(3).

[69 FR 55253, Sept. 13, 2004, as amended at 71 FR 20467, Apr. 20, 2006]

### **§ 63.7506 Do any boilers or process heaters have limited requirements?**

(a) New or reconstructed boilers and process heaters in the large liquid fuel subcategory or the limited use liquid fuel subcategory that burn only fossil fuels and other gases and do not burn any residual oil are subject to the emission limits and applicable work practice standards in Table 1 to this subpart. You are not required to conduct a performance test to demonstrate compliance with the emission limits. You are not required to set and maintain operating limits to demonstrate continuous compliance with the emission

limits. However, you must meet the requirements in paragraphs (a)(1) and (2) of this section and meet the CO work practice standard in Table 1 to this subpart.

(1) To demonstrate initial compliance, you must include a signed statement in the Notification of Compliance Status report required in §63.7545(e) that indicates you burn only liquid fossil fuels other than residual oils, either alone or in combination with gaseous fuels.

(2) To demonstrate continuous compliance with the applicable emission limits, you must also keep records that demonstrate that you burn only liquid fossil fuels other than residual oils, either alone or in combination with gaseous fuels. You must also include a signed statement in each semiannual compliance report required in §63.7550 that indicates you burned only liquid fossil fuels other than residual oils, either alone or in combination with gaseous fuels, during the reporting period.

(b) The affected boilers and process heaters listed in paragraphs (b)(1) through (3) of this section are subject to only the initial notification requirements in §63.9(b) ( *i.e.* , they are not subject to the emission limits, work practice standards, performance testing, monitoring, SSMP, site-specific monitoring plans, recordkeeping and reporting requirements of this subpart or any other requirements in subpart A of this part).

(1) Existing large and limited use gaseous fuel units.

(2) Existing large and limited use liquid fuel units.

(3) New or reconstructed small liquid fuel units that burn only gaseous fuels or distillate oil. New or reconstructed small liquid fuel boilers and process heaters that commence burning of any other type of liquid fuel must comply with all applicable requirements of this subpart and subpart A of this part upon startup of burning the other type of liquid fuel.

(c) The affected boilers and process heaters listed in paragraphs (c)(1) through (4) of this section are not subject to the initial notification requirements in §63.9(b) and are not subject to any requirements in this subpart or in subpart A of this part ( *i.e.* , they are not subject to the emission limits, work practice standards, performance testing, monitoring, SSM plans, site-specific monitoring plans, recordkeeping and reporting requirements of this subpart, or any other requirements in subpart A of this part.

(1) Existing small solid fuel boilers and process heaters.

(2) Existing small liquid fuel boilers and process heaters.

(3) Existing small gaseous fuel boilers and process heaters.

(4) New or reconstructed small gaseous fuel units.

**§ 63.7507 What are the health-based compliance alternatives for the hydrogen chloride (HCl) and total selected metals (TSM) standards?**

(a) As an alternative to the requirement to demonstrate compliance with the HCl emission limit in table 1 to this subpart, you may demonstrate eligibility for the health-based compliance alternative for HCl emissions under the procedures prescribed in appendix A to this subpart.

(b) As an alternative to the requirement to demonstrate compliance with the TSM emission limit in table 1 to this subpart based on the sum of emissions for the eight selected metals, you may demonstrate eligibility for the health-based alternative for manganese emissions under the procedures prescribed in appendix A to this subpart and comply with the TSM emission standards in table 1 based on the sum of

emissions for seven selected metals (by excluding manganese emissions from the summation of TSM emissions).

[70 FR 76933, Dec. 28, 2005]

## **Testing, Fuel Analyses, and Initial Compliance Requirements**

### **§ 63.7510 What are my initial compliance requirements and by what date must I conduct them?**

(a) For affected sources that elect to demonstrate compliance with any of the emission limits of this subpart through performance testing, your initial compliance requirements include conducting performance tests according to §63.7520 and Table 5 to this subpart, conducting a fuel analysis for each type of fuel burned in your boiler or process heater according to §63.7521 and Table 6 to this subpart, establishing operating limits according to §63.7530 and Table 7 to this subpart, and conducting CMS performance evaluations according to §63.7525. For affected sources that burn a single type of fuel, you are exempted from the initial compliance requirements of conducting a fuel analysis for each type of fuel burned in your boiler or process heater according to §63.7521 and Table 6 to this subpart.

(b) For affected sources that elect to demonstrate compliance with the emission limits for HCl, mercury, or TSM through fuel analysis, your initial compliance requirement is to conduct a fuel analysis for each type of fuel burned in your boiler or process heater according to §63.7521 and Table 6 to this subpart and establish operating limits according to §63.7530 and Table 8 to this subpart.

(c) For affected sources that have an applicable work practice standard, your initial compliance requirements depend on the subcategory and rated capacity of your boiler or process heater. If your boiler or process heater is in any of the limited use subcategories or has a heat input capacity less than 100 MMBtu per hour, your initial compliance demonstration is conducting a performance test for carbon monoxide according to Table 5 to this subpart. If your boiler or process heater is in any of the large subcategories and has a heat input capacity of 100 MMBtu per hour or greater, your initial compliance demonstration is conducting a performance evaluation of your continuous emission monitoring system for carbon monoxide according to §63.7525(a).

(d) For existing affected sources, you must demonstrate initial compliance no later than 180 days after the compliance date that is specified for your source in §63.7495 and according to the applicable provisions in §63.7(a)(2) as cited in Table 10 to this subpart.

(e) If your new or reconstructed affected source commenced construction or reconstruction between January 13, 2003 and November 12, 2004, you must demonstrate initial compliance with either the proposed emission limits and work practice standards or the promulgated emission limits and work practice standards no later than 180 days after November 12, 2004 or within 180 days after startup of the source, whichever is later, according to §63.7(a)(2)(ix).

(f) If your new or reconstructed affected source commenced construction or reconstruction between January 13, 2003, and November 12, 2004, and you chose to comply with the proposed emission limits and work practice standards when demonstrating initial compliance, you must conduct a second compliance demonstration for the promulgated emission limits and work practice standards within 3 years after November 12, 2004 or within 3 years after startup of the affected source, whichever is later.

(g) If your new or reconstructed affected source commences construction or reconstruction after November 12, 2004, you must demonstrate initial compliance with the promulgated emission limits and work practice standards no later than 180 days after startup of the source.

[69 FR 55253, Sept. 13, 2004, as amended at 71 FR 70660, Dec. 6, 2006]

**§ 63.7515 When must I conduct subsequent performance tests or fuel analyses?**

(a) You must conduct all applicable performance tests according to §63.7520 on an annual basis, unless you follow the requirements listed in paragraphs (b) through (d) of this section. Annual performance tests must be completed between 10 and 12 months after the previous performance test, unless you follow the requirements listed in paragraphs (b) through (d) of this section.

(b) You can conduct performance tests less often for a given pollutant if your performance tests for the pollutant (particulate matter, HCl, mercury, or TSM) for at least 3 consecutive years show that you comply with the emission limit. In this case, you do not have to conduct a performance test for that pollutant for the next 2 years. You must conduct a performance test during the third year and no more than 36 months after the previous performance test.

(c) If your boiler or process heater continues to meet the emission limit for particulate matter, HCl, mercury, or TSM, you may choose to conduct performance tests for these pollutants every third year, but each such performance test must be conducted no more than 36 months after the previous performance test.

(d) If a performance test shows noncompliance with an emission limit for particulate matter, HCl, mercury, or TSM, you must conduct annual performance tests for that pollutant until all performance tests over a consecutive 3-year period show compliance.

(e) If you have an applicable work practice standard for carbon monoxide and your boiler or process heater is in any of the limited use subcategories or has a heat input capacity less than 100 MMBtu per hour, you must conduct annual performance tests for carbon monoxide according to §63.7520. Each annual performance test must be conducted between 10 and 12 months after the previous performance test.

(f) You must conduct a fuel analysis according to §63.7521 for each type of fuel burned no later than 5 years after the previous fuel analysis for each fuel type. If you burn a new type of fuel, you must conduct a fuel analysis before burning the new type of fuel in your boiler or process heater. You must still meet all applicable continuous compliance requirements in §63.7540.

(g) You must report the results of performance tests and fuel analyses within 60 days after the completion of the performance tests or fuel analyses. This report should also verify that the operating limits for your affected source have not changed or provide documentation of revised operating parameters established according to §63.7530 and Table 7 to this subpart, as applicable. The reports for all subsequent performance tests and fuel analyses should include all applicable information required in §63.7550.

**§ 63.7520 What performance tests and procedures must I use?**

(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) if you elect to demonstrate compliance through performance testing.

(b) You must conduct each performance test according to the requirements in Table 5 to this subpart.

(c) New or reconstructed boilers or process heaters in one of the liquid fuel subcategories that burn only fossil fuels and other gases and do not burn any residual oil must demonstrate compliance according to §63.7506(a).

(d) You must conduct each performance test under the specific conditions listed in Tables 5 and 7 to this subpart. You must conduct performance tests at the maximum normal operating load while burning the type of fuel or mixture of fuels that have the highest content of chlorine, mercury, and total selected metals, and you must demonstrate initial compliance and establish your operating limits based on these tests. These requirements could result in the need to conduct more than one performance test.

(e) You may not conduct performance tests during periods of startup, shutdown, or malfunction.

(f) You must conduct three separate test runs for each performance test required in this section, as specified in §63.7(e)(3). Each test run must last at least 1 hour.

(g) 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 to part 60 of this chapter to convert the measured particulate matter concentrations, the measured HCl concentrations, the measured TSM concentrations, and the measured mercury concentrations that result from the initial performance test to pounds per million Btu heat input emission rates using F-factors.

### **§ 63.7521 What fuel analyses and procedures must I use?**

(a) You must conduct fuel analyses according to the procedures in paragraphs (b) through (e) of this section and Table 6 to this subpart, as applicable.

(b) You must develop and submit a site-specific fuel analysis plan to the EPA Administrator for review and approval according to the following procedures and requirements in paragraphs (b)(1) and (2) of this section.

(1) You must submit the fuel analysis plan no later than 60 days before the date that you intend to demonstrate compliance.

(2) You must include the information contained in paragraphs (b)(2)(i) through (vi) of this section in your fuel analysis plan.

(i) The identification of all fuel types anticipated to be burned in each boiler or process heater.

(ii) For each fuel type, the notification of whether you or a fuel supplier will be conducting the fuel analysis.

(iii) For each fuel type, a detailed description of the sample location and specific procedures to be used for collecting and preparing the composite samples if your procedures are different from paragraph (c) or (d) of this section. Samples should be collected at a location that most accurately represents the fuel type, where possible, at a point prior to mixing with other dissimilar fuel types.

(iv) For each fuel type, the analytical methods, with the expected minimum detection levels, to be used for the measurement of selected total metals, chlorine, or mercury.

(v) If you request to use an alternative analytical method other than those required by Table 6 to this subpart, you must also include a detailed description of the methods and procedures that will be used.

(vi) If you will be using fuel analysis from a fuel supplier in lieu of site-specific sampling and analysis, the fuel supplier must use the analytical methods required by Table 6 to this subpart.

(c) At a minimum, you must obtain three composite fuel samples for each fuel type according to the procedures in paragraph (c)(1) or (2) of this section.

(1) If sampling from a belt (or screw) feeder, collect fuel samples according to paragraphs (c)(1)(i) and (ii) of this section.

(i) Stop the belt and withdraw a 6-inch wide sample from the full cross-section of the stopped belt to obtain a minimum two pounds of sample. Collect all the material (fines and coarse) in the full cross-section. Transfer the sample to a clean plastic bag.

(ii) Each composite sample will consist of a minimum of three samples collected at approximately equal intervals during the testing period.

(2) If sampling from a fuel pile or truck, collect fuel samples according to paragraphs (c)(2)(i) through (iii) of this section.

(i) For each composite sample, select a minimum of five sampling locations uniformly spaced over the surface of the pile.

(ii) At each sampling site, dig into the pile to a depth of 18 inches. Insert a clean flat square shovel into the hole and withdraw a sample, making sure that large pieces do not fall off during sampling.

(iii) Transfer all samples to a clean plastic bag for further processing.

(d) Prepare each composite sample according to the procedures in paragraphs (d)(1) through (7) of this section.

(1) Thoroughly mix and pour the entire composite sample over a clean plastic sheet.

(2) Break sample pieces larger than 3 inches into smaller sizes.

(3) Make a pie shape with the entire composite sample and subdivide it into four equal parts.

(4) Separate one of the quarter samples as the first subset.

(5) If this subset is too large for grinding, repeat the procedure in paragraph (d)(3) of this section with the quarter sample and obtain a one-quarter subset from this sample.

(6) Grind the sample in a mill.

(7) Use the procedure in paragraph (d)(3) of this section to obtain a one-quarter subsample for analysis. If the quarter sample is too large, subdivide it further using the same procedure.

(e) Determine the concentration of pollutants in the fuel (mercury, chlorine, and/or total selected metals) in units of pounds per million Btu of each composite sample for each fuel type according to the procedures in Table 6 to this subpart.

#### **§ 63.7522 Can I use emission averaging to comply with this subpart?**

(a) As an alternative to meeting the requirements of §63.7500, if you have more than one existing large solid fuel boiler located at your facility, you may demonstrate compliance by emission averaging according to the procedures in this section in a State that does not choose to exclude emission averaging.

(b) Separate stack requirements. For a group of two or more existing large solid fuel boilers that each vent to a separate stack, you may average particulate matter or TSM, HCl and mercury emissions to demonstrate compliance with the limits in Table 1 to this subpart if you satisfy the requirements in paragraphs (c), (d), (e), (f), and (g) of this section.

(c) For each existing large solid fuel boiler in the averaging group, the emission rate achieved during the initial compliance test for the HAP being averaged must not exceed the emission level that was being achieved on November 12, 2004 or the control technology employed during the initial compliance test must not be less effective for the HAP being averaged than the control technology employed on November 12, 2004.

(d) The emissions rate from the existing large solid fuel boilers participating in the emissions averaging option must be in compliance with the limits in Table 1 to this subpart at all times following the compliance date specified in §63.7495.

(e) You must demonstrate initial compliance according to paragraph (e)(1) or (2) of this section.

(1) You must use Equation 1 of this section to demonstrate that the particulate matter or TSM, HCl, and mercury emissions from all existing large solid fuel boilers participating in the emissions averaging option do not exceed the emission limits in Table 1 to this subpart.

$$\text{Ave Weighted Emissions} = \sum_{i=1}^n (Er \times Hm) \div \sum_{i=1}^n Hm \quad (\text{Eq 1})$$

Where:

Ave Weighted Emissions = Average weighted emissions for particulate matter or TSM, HCl, or mercury, in units of pounds per million Btu of heat input.

Er = Emission rate (as calculated according to Table 5 to this subpart or by fuel analysis (as calculated by the applicable equation in §63.7530(d))) for boiler, i, for particulate matter or TSM, HCl, or mercury, in units of pounds per million Btu of heat input.

Hm = Maximum rated heat input capacity of boiler, i, in units of million Btu per hour.

n = Number of large solid fuel boilers participating in the emissions averaging option.

(2) If you are not capable of monitoring heat input, you may use Equation 2 of this section as an alternative to using Equation 1 of this section to demonstrate that the particulate matter or TSM, HCl, and mercury emissions from all existing large solid fuel boilers participating in the emissions averaging option do not exceed the emission limits in Table 1 to this subpart.

$$\text{Ave Weighted Emissions} = \sum_{i=1}^n (Er \times Sm \times Cf) \div \sum_{i=1}^n Sm \times Cf \quad (\text{Eq 2})$$

Where:

Ave Weighted Emissions = Average weighted emission level for PM or TSM, HCl, or mercury, in units of pounds per million Btu of heat input.

Er = Emission rate (as calculated according to Table 5 to this subpart or by fuel analysis (as calculated by the applicable equation in §63.7530(d))) for boiler, i, for particulate matter or TSM, HCl, or mercury, in units of pounds per million Btu of heat input.

Sm = Maximum steam generation by boiler, i, in units of pounds.

Cf = Conversion factor, calculated from the most recent compliance test, in units of million Btu of heat input per pounds of steam generated.

(f) You must demonstrate continuous compliance on a monthly basis determined at the end of every month (12 times per year) according to paragraphs (f)(1) through (3) of this section. The first monthly period begins on the compliance date specified in §63.7495.

(1) For each calendar month, you must use Equation 3 of this section to calculate the monthly average weighted emission rate using the actual heat capacity for each existing large solid fuel boiler participating in the emissions averaging option.

$$\text{Ave Weighted Emissions} = \frac{\sum_{i=1}^n (Er \times Hb)}{\sum_{i=1}^n Hb} \quad (\text{Eq. 3})$$

Where:

Ave Weighted Emissions = monthly average weighted emission level for particulate matter or TSM, HCl, or mercury, in units of pounds per million Btu of heat input.

Er = Emission rate, (as calculated during the most recent compliance test, (as calculated according to Table 5 to this subpart) or fuel analysis (as calculated by the applicable equation in §63.7530(d))) for boiler, i, for particulate matter or TSM, HCl, or mercury, in units of pounds per million Btu of heat input.

Hb = The average heat input for each calendar month of boiler, i, in units of million Btu.

n = Number of large solid fuel boilers participating in the emissions averaging option.

(2) If you are not capable of monitoring heat input, you may use Equation 4 of this section as an alternative to using Equation 3 of this section to calculate the monthly weighted emission rate using the actual steam generation from the large solid fuel boilers participating in the emissions averaging option.

$$\text{Ave Weighted Emissions} = \frac{\sum_{i=1}^n (Er \times Sa \times Cf)}{\sum_{i=1}^n Sa \times Cf} \quad (\text{Eq. 4})$$

Where:

Ave Weighted Emissions = monthly average weighted emission level for PM or TSM, HCl, or mercury, in units of pounds per million Btu of heat input.

Er = Emission rate, (as calculated during the most recent compliance test (as calculated according to Table 5 to this subpart) or by fuel analysis (as calculated by the applicable equation in §63.7530(d))) for boiler, i, for particulate matter or TSM, HCl, or mercury, in units of pounds per million Btu of heat input.

Sa = Actual steam generation for each calendar month by boiler, i, in units of pounds.

Cf = Conversion factor, as calculated during the most recent compliance test, in units of million Btu of heat input per pounds of steam generated.

(3) Until 12 monthly weighted average emission rates have been accumulated, calculate and report only the monthly average weighted emission rate determined under paragraph (f)(1) or (2) of this section. After 12 monthly weighted average emission rates have been accumulated, for each subsequent calendar month, use Equation 4A of this section to calculate the 12-month rolling average of the monthly weighted average emission rates for the current month and the previous 11 months.

$$E_{avg} = \frac{\sum_{i=1}^n ER_i}{12} \quad (\text{Eq. 4A})$$

Where:

Eavg = 12-month rolling average emission rate, (pounds per million Btu heat input)

ERi = Monthly weighted average, for month "i", (pounds per million Btu heat input)(as calculated by (f)(1) or (2))

(g) You must develop and submit an implementation plan for emission averaging to the applicable regulatory authority for review and approval according to the following procedures and requirements in paragraphs (g)(1) through (4).

(1) You must submit the implementation plan no later than 180 days before the date that the facility intends to demonstrate compliance using the emission averaging option.

(2) You must include the information contained in paragraphs (g)(2)(i) through (vii) of this section in your implementation plan for all emission sources included in an emissions average:

(i) The identification of all existing large solid fuel boilers in the averaging group, including for each either the applicable HAP emission level or the control technology installed on;

(ii) The process parameter (heat input or steam generated) that will be monitored for each averaging group of large solid fuel boilers;

(iii) The specific control technology or pollution prevention measure to be used for each emission source in the averaging group and the date of its installation or application. If the pollution prevention measure reduces or eliminates emissions from multiple sources, the owner or operator must identify each source;

(iv) The test plan for the measurement of particulate matter (or TSM), HCl, or mercury emissions in accordance with the requirements in §63.7520;

(v) The operating parameters to be monitored for each control system or device and a description of how the operating limits will be determined;

(vi) If you request to monitor an alternative operating parameter pursuant to §63.7525, you must also include:

(A) A description of the parameter(s) to be monitored and an explanation of the criteria used to select the parameter(s); and

(B) A description of the methods and procedures that will be used to demonstrate that the parameter indicates proper operation of the control device; the frequency and content of monitoring, reporting, and recordkeeping requirements; and a demonstration, to the satisfaction of the applicable regulatory authority, that the proposed monitoring frequency is sufficient to represent control device operating conditions; and

(vii) A demonstration that compliance with each of the applicable emission limit(s) will be achieved under representative operating conditions.

(3) Upon receipt, the regulatory authority shall review and approve or disapprove the plan according to the following criteria:

(i) Whether the content of the plan includes all of the information specified in paragraph (g)(2) of this section; and

(ii) Whether the plan presents sufficient information to determine that compliance will be achieved and maintained.

(4) The applicable regulatory authority shall not approve an emission averaging implementation plan containing any of the following provisions:

(i) Any averaging between emissions of differing pollutants or between differing sources; or

(ii) The inclusion of any emission source other than an existing large solid fuel boiler.

(h) Common stack requirements. For a group of two or more existing large solid fuel boilers, each of which vents through a single common stack, you may average particulate matter or TSM, HCl and mercury to demonstrate compliance with the limits in Table 1 to this subpart if you satisfy the requirements in paragraph (i) or (j) of this section.

(i) For a group of two or more existing large solid fuel boilers, each of which vents through a common emissions control system to a common stack, that does not receive emissions from units in other subcategories or categories, you may treat such averaging group as a single existing solid fuel boiler for purposes of this subpart and comply with the requirements of this subpart as if the group were a single boiler.

(j) For all other groups of boilers subject to paragraph (h) of this section, the owner or operator may elect to:

(1) Conduct performance tests according to procedures specified in §63.7520 in the common stack (if affected units from other subcategories ( e.g. , gas-fired units) or nonaffected units vent to the common stack, the units from other subcategories and nonaffected units must be shut down or vented to a different stack during the performance test); and

(2) Meet the applicable operating limit specified in §63.7540 and Table 8 to this subpart for each emissions control system (except that, if each boiler venting to the common stack has an applicable opacity operating limit, then a single continuous opacity monitoring system may be located in the common stack instead of in each duct to the common stack).

(k) *Combination requirements.* The common stack of a group of two or more boilers subject to paragraph (h) of this section may be treated as a separate stack for purposes of paragraph (b) of this section and included in an emissions averaging group subject to paragraph (b) of this section.

[69 FR 55253, Sept. 13, 2004, as amended at 71 FR 70660, Dec. 6, 2006]

**§ 63.7525 What are my monitoring, installation, operation, and maintenance requirements?**

(a) If you have an applicable work practice standard for carbon monoxide, and your boiler or process heater is in any of the large subcategories and has a heat input capacity of 100 MMBtu per hour or greater, you must install, operate, and maintain a continuous emission monitoring system (CEMS) for carbon monoxide and oxygen according to the procedures in paragraphs (a)(1) through (6) of this section by the compliance date specified in §63.7495. The carbon monoxide and oxygen shall be monitored at the same location at the outlet of the boiler or process heater.

(1) Each CEMS must be installed, operated, and maintained according to the applicable procedures under Performance Specification (PS) 3 or 4A of 40 CFR part 60, appendix B, and according to the site-specific monitoring plan developed according to §63.7505(d).

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

(3) Each CEMS must complete a minimum of one cycle of operation (sampling, analyzing, and data recording) for each successive 15-minute period.

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

(5) You must calculate and record a 30-day rolling average emission rate on a daily basis. A new 30-day rolling average emission rate is calculated as the average of all of the hourly CO emission data for the preceding 30 operating days.

(6) For purposes of calculating data averages, you must not use data recorded during periods of monitoring malfunctions, associated repairs, out-of-control periods, required quality assurance or control activities, or when your boiler or process heater is operating at less than 50 percent of its rated capacity. You must use all the data collected during all other periods in assessing compliance. Any period for which the monitoring system is out of control and data are not available for required calculations constitutes a deviation from the monitoring requirements.

(b) If you have an applicable opacity operating limit, you must install, operate, certify and maintain each continuous opacity monitoring system (COMS) according to the procedures in paragraphs (b)(1) through (7) of this section by the compliance date specified in §63.7495.

(1) Each COMS must be installed, operated, and maintained according to PS 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 PS 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). 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 determine and record all the 6-minute averages (and 1-hour block averages as applicable) collected for periods during which the COMS is not out of control.

(c) If you have an operating limit that requires the use of a CMS, you must install, operate, and maintain each continuous parameter monitoring system (CPMS) according to the procedures in paragraphs (c)(1) through (5) of this section by the compliance date specified in §63.7495.

(1) The CPMS must complete a minimum of one cycle of operation for each successive 15-minute period. You must have a minimum of four successive cycles of operation to have a valid hour of data.

(2) Except for monitoring malfunctions, associated repairs, and required quality assurance or control activities (including, as applicable, calibration checks and required zero and span adjustments), you must conduct all monitoring in continuous operation at all times that the unit is operating. A monitoring malfunction is any sudden, infrequent, not reasonably preventable failure of the monitoring to provide valid data. Monitoring failures that are caused in part by poor maintenance or careless operation are not malfunctions.

(3) For purposes of calculating data averages, you must not use data recorded during monitoring malfunctions, associated repairs, out of control periods, or required quality assurance or control activities. You must use all the data collected during all other periods in assessing compliance. Any period for which the monitoring system is out-of-control and data are not available for required calculations constitutes a deviation from the monitoring requirements.

(4) Determine the 3-hour block average of all recorded readings, except as provided in paragraph (c)(3) of this section.

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

(d) If you have an operating limit that requires the use of a flow measurement device, you must meet the requirements in paragraphs (c) and (d)(1) through (4) of this section.

(1) Locate the flow sensor and other necessary equipment in a position that provides a representative flow.

(2) Use a flow sensor with a measurement sensitivity of 2 percent of the flow rate.

(3) Reduce swirling flow or abnormal velocity distributions due to upstream and downstream disturbances.

(4) Conduct a flow sensor calibration check at least semiannually.

(e) If you have an operating limit that requires the use of a pressure measurement device, you must meet the requirements in paragraphs (c) and (e)(1) through (6) of this section.

(1) Locate the pressure sensor(s) in a position that provides a representative measurement of the pressure.

(2) Minimize or eliminate pulsating pressure, vibration, and internal and external corrosion.

(3) Use a gauge with a minimum tolerance of 1.27 centimeters of water or a transducer with a minimum tolerance of 1 percent of the pressure range.

(4) Check pressure tap pluggage daily.

(5) Using a manometer, check gauge calibration quarterly and transducer calibration monthly.

(6) Conduct calibration checks any time the sensor exceeds the manufacturer's specified maximum operating pressure range or install a new pressure sensor.

(f) If you have an operating limit that requires the use of a pH measurement device, you must meet the requirements in paragraphs (c) and (f)(1) through (3) of this section.

(1) Locate the pH sensor in a position that provides a representative measurement of scrubber effluent pH.

(2) Ensure the sample is properly mixed and representative of the fluid to be measured.

(3) Check the pH meter's calibration on at least two points every 8 hours of process operation.

(g) If you have an operating limit that requires the use of equipment to monitor voltage and secondary current (or total power input) of an electrostatic precipitator (ESP), you must use voltage and secondary current monitoring equipment to measure voltage and secondary current to the ESP.

(h) If you have an operating limit that requires the use of equipment to monitor sorbent injection rate ( e.g. , weigh belt, weigh hopper, or hopper flow measurement device), you must meet the requirements in paragraphs (c) and (h)(1) through (3) of this section.

(1) Locate the device in a position(s) that provides a representative measurement of the total sorbent injection rate.

(2) Install and calibrate the device in accordance with manufacturer's procedures and specifications.

(3) At least annually, calibrate the device in accordance with the manufacturer's procedures and specifications.

(i) If you elect to use a fabric filter bag leak detection system to comply with the requirements of this subpart, you must install, calibrate, maintain, and continuously operate a bag leak detection system as specified in paragraphs (i)(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 the guidance provided in EPA-454/R-98-015, September 1997.

- (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 alarm system that will sound automatically when an increase in relative particulate matter emissions over a preset level is detected. The alarm must be located where it is easily heard by plant operating personnel.
- (7) For positive pressure fabric filter systems that do not duct all compartments of cells to a common stack, a bag leak detection system must be installed in each baghouse compartment or cell.
- (8) Where multiple bag leak detectors are required, the system's instrumentation and alarm may be shared among detectors.

[69 FR 55253, Sept. 13, 2004, as amended at 71 FR 70662, Dec. 6, 2006]

**§ 63.7530 How do I demonstrate initial compliance with the emission limits and work practice standards?**

- (a) You must demonstrate initial compliance with each emission limit and work practice standard that applies to you by either conducting initial performance tests and establishing operating limits, as applicable, according to §63.7520, paragraph (c) of this section, and Tables 5 and 7 to this subpart OR conducting initial fuel analyses to determine emission rates and establishing operating limits, as applicable, according to §63.7521, paragraph (d) of this section, and Tables 6 and 8 to this subpart.
- (b) New or reconstructed boilers or process heaters in one of the liquid fuel subcategories that burn only fossil fuels and other gases and do not burn any residual oil must demonstrate compliance according to §63.7506(a).
- (c) If you demonstrate compliance through performance testing, you must establish each site-specific operating limit in Tables 2 through 4 to this subpart that applies to you according to the requirements in §63.7520, Table 7 to this subpart, and paragraph (c)(4) of this section, as applicable. You must also conduct fuel analyses according to §63.7521 and establish maximum fuel pollutant input levels according to paragraphs (c)(1) through (3) of this section, as applicable.
  - (1) You must establish the maximum chlorine fuel input ( $C_{input}$ ) during the initial performance testing according to the procedures in paragraphs (c)(1)(i) through (iii) of this section.
    - (i) You must determine the fuel type or fuel mixture that you could burn in your boiler or process heater that has the highest content of chlorine.
    - (ii) During the performance testing for HCl, you must determine the fraction of the total heat input for each fuel type burned ( $Q_i$ ) based on the fuel mixture that has the highest content of chlorine, and the average chlorine concentration of each fuel type burned ( $C_i$ ).
    - (iii) You must establish a maximum chlorine input level using Equation 5 of this section.

$$Cl_{input} = \sum_{i=1}^n [(C_i)(Q_i)] \quad (Eq. 5)$$

Where:

$Cl_{input}$  = Maximum amount of chlorine entering the boiler or process heater through fuels burned in units of pounds per million Btu.

$C_i$  = Arithmetic average concentration of chlorine in fuel type, i, analyzed according to §63.7521, in units of pounds per million Btu.

$Q_i$  = Fraction of total heat input from fuel type, i, based on the fuel mixture that has the highest content of chlorine. If you do not burn multiple fuel types during the performance testing, it is not necessary to determine the value of this term. Insert a value of "1" for  $Q_i$ .

n = Number of different fuel types burned in your boiler or process heater for the mixture that has the highest content of chlorine.

(2) If you choose to comply with the alternative TSM emission limit instead of the particulate matter emission limit, you must establish the maximum TSM fuel input level ( $TSM_{input}$ ) during the initial performance testing according to the procedures in paragraphs (c)(2)(i) through (iii) of this section.

(i) You must determine the fuel type or fuel mixture that you could burn in your boiler or process heater that has the highest content of TSM.

(ii) During the performance testing for TSM, you must determine the fraction of total heat input from each fuel burned ( $Q_i$ ) based on the fuel mixture that has the highest content of total selected metals, and the average TSM concentration of each fuel type burned ( $M_i$ ).

(iii) You must establish a baseline TSM input level using Equation 6 of this section.

$$TSM_{input} = \sum_{i=1}^n [(M_i)(Q_i)] \quad (Eq. 6)$$

Where:

$TSM_{input}$  = Maximum amount of TSM entering the boiler or process heater through fuels burned in units of pounds per million Btu.

$M_i$  = Arithmetic average concentration of TSM in fuel type, i, analyzed according to §63.7521, in units of pounds per million Btu.

$Q_i$  = Fraction of total heat input from based fuel type, i, based on the fuel mixture that has the highest content of TSM. If you do not burn multiple fuel types during the performance test, it is not necessary to determine the value of this term. Insert a value of "1" for  $Q_i$ .

n = Number of different fuel types burned in your boiler or process heater for the mixture that has the highest content of TSM.

(3) You must establish the maximum mercury fuel input level ( $Mercury_{input}$ ) during the initial performance testing using the procedures in paragraphs (c)(3)(i) through (iii) of this section.

(i) You must determine the fuel type or fuel mixture that you could burn in your boiler or process heater that has the highest content of mercury.

(ii) During the compliance demonstration for mercury, you must determine the fraction of total heat input for each fuel burned ( $Q_i$ ) based on the fuel mixture that has the highest content of mercury, and the average mercury concentration of each fuel type burned ( $HG_i$ ).

(iii) You must establish a maximum mercury input level using Equation 7 of this section.

$$\text{Mercury}_{\text{input}} = \sum_{i=1}^n [(HG_i)(Q_i)] \quad (\text{Eq. 7})$$

Where:

$\text{Mercury}_{\text{input}}$  = Maximum amount of mercury entering the boiler or process heater through fuels burned in units of pounds per million Btu.

$HG_i$  = Arithmetic average concentration of mercury in fuel type,  $i$ , analyzed according to §63.7521, in units of pounds per million Btu.

$Q_i$  = Fraction of total heat input from fuel type,  $i$ , based on the fuel mixture that has the highest mercury content. If you do not burn multiple fuel types during the performance test, it is not necessary to determine the value of this term. Insert a value of "1" for  $Q_i$ .

$n$  = Number of different fuel types burned in your boiler or process heater for the mixture that has the highest content of mercury.

(4) You must establish parameter operating limits according to paragraphs (c)(4)(i) through (iv) of this section.

(i) For a wet scrubber, you must establish the minimum scrubber effluent pH, liquid flowrate, and pressure drop as defined in §63.7575, as your operating limits during the three-run performance test. If you use a wet scrubber and you conduct separate performance tests for particulate matter, HCl, and mercury emissions, you must establish one set of minimum scrubber effluent pH, liquid flowrate, and pressure drop operating limits. The minimum scrubber effluent pH operating limit must be established during the HCl performance test. If you conduct multiple performance tests, you must set the minimum liquid flowrate and pressure drop operating limits at the highest minimum values established during the performance tests.

(ii) For an electrostatic precipitator, you must establish the minimum voltage and secondary current (or total power input), as defined in §63.7575, as your operating limits during the three-run performance test.

(iii) For a dry scrubber, you must establish the minimum sorbent injection rate, as defined in §63.7575, as your operating limit during the three-run performance test.

(iv) The operating limit for boilers or process heaters with fabric filters that choose to demonstrate continuous compliance through bag leak detection systems is that a bag leak detection system be installed according to the requirements in §63.7525, 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.

(d) If you elect to demonstrate compliance with an applicable emission limit through fuel analysis, you must conduct fuel analyses according to §63.7521 and follow the procedures in paragraphs (d)(1) through (5) of this section.

(1) If you burn more than one fuel type, you must determine the fuel mixture you could burn in your boiler or process heater that would result in the maximum emission rates of the pollutants that you elect to demonstrate compliance through fuel analysis.

(2) You must determine the 90th percentile confidence level fuel pollutant concentration of the composite samples analyzed for each fuel type using the one-sided z-statistic test described in Equation 8 of this section.

$$P_{90} = \text{mean} + (\text{SD} \times t) \quad (\text{Eq. 8})$$

Where:

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

mean = Arithmetic average of the fuel pollutant concentration in the fuel samples analyzed according to §63.7521, in units of pounds per million Btu.

SD = Standard deviation of the pollutant concentration in the fuel samples analyzed according to §63.7521, 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 emission limit for HCl, the HCl emission rate that you calculate for your boiler or process heater using Equation 9 of this section must be less than the applicable emission limit for HCl.

$$HCl = \sum_{i=1}^n [(C_{i90})(Q_i)(1.028)] \quad (\text{Eq. 9})$$

Where:

HCl = HCl emission rate from the boiler or process heater in units of pounds per million Btu.

$C_{i90}$  = 90th percentile confidence level concentration of chlorine in fuel type, i, in units of pounds per million Btu as calculated according to Equation 8 of this section.

$Q_i$  = Fraction of total heat input from fuel type, i, based on the fuel mixture that has the highest content of chlorine. If you do not burn multiple fuel types, it is not necessary to determine the value of this term. Insert a value of "1" for  $Q_i$ .

n = Number of different fuel types burned in your boiler or process heater for the mixture that has the highest content of chlorine.

1.028 = Molecular weight ratio of HCl to chlorine.

(4) To demonstrate compliance with the applicable emission limit for TSM, the TSM emission rate that you calculate for your boiler or process heater using Equation 10 of this section must be less than the applicable emission limit for TSM.

$$TSM = \sum_{i=1}^n [(M_{i90})(Q_i)] \quad (Eq. 10)$$

Where:

TSM = TSM emission rate from the boiler or process heater in units of pounds per million Btu.

$M_{i90}$  = 90th percentile confidence level concentration of TSM in fuel, i, in units of pounds per million Btu as calculated according to Equation 8 of this section.

$Q_i$  = Fraction of total heat input from fuel type, i, based on the fuel mixture that has the highest content of total selected metals. If you do not burn multiple fuel types, it is not necessary to determine the value of this term. Insert a value of "1" for  $Q_i$ .

n = Number of different fuel types burned in your boiler or process heater for the mixture that has the highest content of TSM.

(5) To demonstrate compliance with the applicable emission limit for mercury, the mercury emission rate that you calculate for your boiler or process heater using Equation 11 of this section must be less than the applicable emission limit for mercury.

$$Mercury = \sum_{i=1}^n [(HG_{i90})(Q_i)] \quad (Eq. 11)$$

Where:

Mercury = Mercury emission rate from the boiler or process heater in units of pounds per million Btu.

$HG_{i90}$  = 90th percentile confidence level concentration of mercury in fuel, i, in units of pounds per million Btu as calculated according to Equation 8 of this section.

$Q_i$  = Fraction of total heat input from fuel type, i, based on the fuel mixture that has the highest mercury content. If you do not burn multiple fuel types, it is not necessary to determine the value of this term. Insert a value of "1" for  $Q_i$ .

n = Number of different fuel types burned in your boiler or process heater for the mixture that has the highest mercury content.

(e) You must submit the Notification of Compliance Status containing the results of the initial compliance demonstration according to the requirements in §63.7545(e).

### Continuous Compliance Requirements

#### § 63.7535 How do I monitor and collect data to demonstrate continuous compliance?

(a) You must monitor and collect data according to this section and the site-specific monitoring plan required by §63.7505(d).

(b) Except for monitor malfunctions, associated repairs, and required quality assurance or control activities (including, as applicable, calibration checks and required zero and span adjustments), you must monitor continuously (or collect data at all required intervals) at all times that the affected source is operating.

(c) You may not use data recorded during monitoring malfunctions, associated repairs, or required quality assurance or control activities in data averages and calculations used to report emission or operating levels. You must use all the data collected during all other periods in assessing the operation of the control device and associated control system. Boilers and process heaters that have an applicable carbon monoxide work practice standard and are required to install and operate a CEMS, may not use data recorded during periods when the boiler or process heater is operating at less than 50 percent of its rated capacity.

**§ 63.7540 How do I demonstrate continuous compliance with the emission limits and work practice standards?**

(a) You must demonstrate continuous compliance with each emission limit, operating limit, and work practice standard in Tables 1 through 4 to this subpart that applies to you according to the methods specified in Table 8 to this subpart and paragraphs (a)(1) through (10) of this section.

(1) Following the date on which the initial performance test is completed or is required to be completed under §§63.7 and 63.7510, whichever date comes first, you must not operate above any of the applicable maximum operating limits or below any of the applicable minimum operating limits listed in Tables 2 through 4 to this subpart at all times except during periods of startup, shutdown and malfunction. Operating limits do not apply during performance tests. Operation above the established maximum or below the established minimum operating limits shall constitute a deviation of established operating limits.

(2) You must keep records of the type and amount of all fuels burned in each boiler or process heater during the reporting period to demonstrate that all fuel types and mixtures of fuels burned would either result in lower emissions of TSM, HCl, and mercury, than the applicable emission limit for each pollutant (if you demonstrate compliance through fuel analysis), or result in lower fuel input of TSM, chlorine, and mercury than the maximum values calculated during the last performance tests (if you demonstrate compliance through performance testing).

(3) If you demonstrate compliance with an applicable HCl emission limit through fuel analysis and you plan to burn a new type of fuel, you must recalculate the HCl emission rate using Equation 9 of §63.7530 according to paragraphs (a)(3)(i) through (iii) of this section.

(i) You must determine the chlorine concentration for any new fuel type in units of pounds per million Btu, based on supplier data or your own fuel analysis, according to the provisions in your site-specific fuel analysis plan developed according to §63.7521(b).

(ii) You must determine the new mixture of fuels that will have the highest content of chlorine.

(iii) Recalculate the HCl emission rate from your boiler or process heater under these new conditions using Equation 9 of §63.7530. The recalculated HCl emission rate must be less than the applicable emission limit.

(4) If you demonstrate compliance with an applicable HCl emission limit through performance testing and you plan to burn a new type of fuel or a new mixture of fuels, you must recalculate the maximum chlorine

input using Equation 5 of §63.7530. If the results of recalculating the maximum chlorine input using Equation 5 of §63.7530 are higher than the maximum chlorine input level established 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 §63.7520 to demonstrate that the HCl emissions do not exceed the emission limit. You must also establish new operating limits based on this performance test according to the procedures in §63.7530(c).

(5) If you demonstrate compliance with an applicable TSM emission limit through fuel analysis, and you plan to burn a new type of fuel, you must recalculate the TSM emission rate using Equation 10 of §63.7530 according to the procedures specified in paragraphs (a)(5)(i) through (iii) of this section.

(i) You must determine the TSM concentration for any new fuel type in units of pounds per million Btu, based on supplier data or your own fuel analysis, according to the provisions in your site-specific fuel analysis plan developed according to §63.7521(b).

(ii) You must determine the new mixture of fuels that will have the highest content of TSM.

(iii) Recalculate the TSM emission rate from your boiler or process heater under these new conditions using Equation 10 of §63.7530. The recalculated TSM emission rate must be less than the applicable emission limit.

(6) If you demonstrate compliance with an applicable TSM emission limit through performance testing, and you plan to burn a new type of fuel or a new mixture of fuels, you must recalculate the maximum TSM input using Equation 6 of §63.7530. If the results of recalculating the maximum total selected metals input using Equation 6 of §63.7530 are higher than the maximum TSM input level established 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 §63.7520 to demonstrate that the TSM emissions do not exceed the emission limit. You must also establish new operating limits based on this performance test according to the procedures in §63.7530(c).

(7) If you demonstrate compliance with an applicable mercury emission limit through fuel analysis, and you plan to burn a new type of fuel, you must recalculate the mercury emission rate using Equation 11 of §63.7530 according to the procedures specified in paragraphs (a)(7)(i) through (iii) of this section.

(i) You must determine the mercury concentration for any new fuel type in units of pounds per million Btu, based on supplier data or your own fuel analysis, according to the provisions in your site-specific fuel analysis plan developed according to §63.7521(b).

(ii) You must determine the new mixture of fuels that will have the highest content of mercury.

(iii) Recalculate the mercury emission rate from your boiler or process heater under these new conditions using Equation 11 of §63.7530. The recalculated mercury emission rate must be less than the applicable emission limit.

(8) If you demonstrate compliance with an applicable mercury emission limit through performance testing, and you plan to burn a new type of fuel or a new mixture of fuels, you must recalculate the maximum mercury input using Equation 7 of §63.7530. If the results of recalculating the maximum mercury input using Equation 7 of §63.7530 are higher than the maximum mercury input level established 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 §63.7520 to demonstrate that the mercury emissions do not exceed the emission limit. You must also establish new operating limits based on this performance test according to the procedures in §63.7530(c).

(9) 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 complete corrective actions as soon as practical, 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 shall be counted as a minimum of 1 hour. If you take longer than 1 hour to initiate corrective action, the alarm time shall be counted as the actual amount of time taken to initiate corrective action.

(10) If you have an applicable work practice standard for carbon monoxide, and you are required to install a CEMS according to §63.7525(a), then you must meet the requirements in paragraphs (a)(10)(i) through (iii) of this section.

(i) You must continuously monitor carbon monoxide according to §§63.7525(a) and 63.7535.

(ii) Maintain a carbon monoxide emission level below your applicable carbon monoxide work practice standard in Table 1 to this subpart at all times except during periods of startup, shutdown, malfunction, and when your boiler or process heater is operating at less than 50 percent of rated capacity.

(iii) Keep records of carbon monoxide levels according to §63.7555(b).

(b) You must report each instance in which you did not meet each emission limit, operating limit, and work practice standard in Tables 1 through 4 to this subpart that apply to you. You must also report each instance during a startup, shutdown, or malfunction when you did not meet each applicable emission limit, operating limit, and work practice standard. These instances are deviations from the emission limits and work practice standards in this subpart. These deviations must be reported according to the requirements in §63.7550.

(c) [Reserved]

(d) Consistent with §§63.6(e) and 63.7(e)(1), deviations that occur during a period of startup, shutdown, or malfunction are not violations if you demonstrate to the EPA Administrator's satisfaction that you were operating in accordance with §63.6(e)(1). The EPA Administrator will determine whether deviations that occur during a period of startup, shutdown, or malfunction are violations, according to the provisions in §63.6(e).

[69 FR 55253, Sept. 13, 2004, as amended at 71 FR 20467, Apr. 20, 2006; 71 FR 70662, Dec. 6, 2006]

**§ 63.7541 How do I demonstrate continuous compliance under the emission averaging provision?**

(a) Following the compliance date, the owner or operator must demonstrate compliance with this subpart on a continuous basis by meeting the requirements of paragraphs (a)(1) through (5) of this section.

(1) For each calendar month, demonstrate compliance with the average weighted emissions limit for the existing large solid fuel boilers participating in the emissions averaging option as determined in §63.7522(f) and (g);

(2) You must maintain the applicable opacity limit according to paragraphs (a)(2)(i) through (ii) of this section.

(i) For each existing solid fuel boiler participating in the emissions averaging option that is equipped with a dry control system and not vented to a common stack, maintain opacity at or below the applicable limit.

(ii) For each group of boilers participating in the emissions averaging option where each boiler in the group is an existing solid fuel boiler equipped with a dry control system and vented to a common stack that does not receive emissions from affected units from other subcategories or nonaffected units, maintain opacity at or below the applicable limit at the common stack;

(3) For each existing solid fuel boiler participating in the emissions averaging option that is equipped with a wet scrubber, maintain the 3-hour average parameter values at or below the operating limits established during the most recent performance test; and

(4) For each existing solid fuel boiler participating in the emissions averaging option that has an approved alternative operating plan, maintain the 3-hour average parameter values at or below the operating limits established in the most recent performance test.

(5) For each existing large solid fuel boiler participating in the emissions averaging option venting to a common stack configuration containing affected units from other subcategories and/or nonaffected units, maintain the appropriate operating limit for each unit as specified in Tables 2 through 4 to this subpart that applies.

(b) Any instance where the owner or operator fails to comply with the continuous monitoring requirements in paragraphs (a)(1) through (5) of this section, except during periods of startup, shutdown, and malfunction, is a deviation.

[69 FR 55253, Sept. 13, 2004, as amended at 71 FR 70662, Dec. 6, 2006]

## **Notification, Reports, and Records**

### **§ 63.7545 What notifications must I submit and when?**

(a) You must submit all of the notifications in §§63.7(b) and (c), 63.8 (e), (f)(4) and (6), and 63.9 (b) through (h) that apply to you by the dates specified.

(b) As specified in §63.9(b)(2), if you startup your affected source before November 12, 2004, you must submit an Initial Notification not later than 120 days after November 12, 2004. The Initial Notification must include the information required in paragraphs (b)(1) and (2) of this section, as applicable.

(1) If your affected source has an annual capacity factor of greater than 10 percent, your Initial Notification must include the information required by §63.9(b)(2).

(2) If your affected source has a federally enforceable permit that limits the annual capacity factor to less than or equal to 10 percent such that the unit is in one of the limited use subcategories (the limited use solid fuel subcategory, the limited use liquid fuel subcategory, or the limited use gaseous fuel subcategory), your Initial Notification must include the information required by §63.9(b)(2) and also a signed statement indicating your affected source has a federally enforceable permit that limits the annual capacity factor to less than or equal to 10 percent.

(c) As specified in §63.9(b)(4) and (b)(5), if you startup your new or reconstructed affected source on or after November 12, 2004, you must submit an Initial Notification not later than 15 days after the actual date of startup of the affected source.

(d) If you are required to conduct a performance test you must submit a Notification of Intent to conduct a performance test at least 30 days before the performance test is scheduled to begin.

(e) If you are required to conduct an initial compliance demonstration as specified in §63.7530(a), you must submit a Notification of Compliance Status according to §63.9(h)(2)(ii). For each initial compliance demonstration, you must submit the Notification of Compliance Status, including all performance test results and fuel analyses, before the close of business on the 60th day following the completion of the performance test and/or other initial compliance demonstrations according to §63.10(d)(2). The Notification of Compliance Status report must contain all the information specified in paragraphs (e)(1) through (9), as applicable.

(1) A description of the affected source(s) including identification of which subcategory the source is in, the capacity of the source, a description of the add-on controls used on the source description of the fuel(s) burned, and justification for the fuel(s) burned during the performance test.

(2) Summary of the results of all performance tests, fuel analyses, and calculations conducted to demonstrate initial compliance including all established operating limits.

(3) Identification of whether you are complying with the particulate matter emission limit or the alternative total selected metals emission limit.

(4) Identification of whether you plan to demonstrate compliance with each applicable emission limit through performance testing or fuel analysis.

(5) Identification of whether you plan to demonstrate compliance by emissions averaging.

(6) A signed certification that you have met all applicable emission limits and work practice standards.

(7) A summary of the carbon monoxide emissions monitoring data and the maximum carbon monoxide emission levels recorded during the performance test to show that you have met any applicable work practice standard in Table 1 to this subpart.

(8) If your new or reconstructed boiler or process heater is in one of the liquid fuel subcategories and burns only liquid fossil fuels other than residual oil either alone or in combination with gaseous fuels, you must submit a signed statement certifying this in your Notification of Compliance Status report.

(9) If you had a deviation from any emission limit or work practice standard, you must also submit a description of the deviation, the duration of the deviation, and the corrective action taken in the Notification of Compliance Status report.

### **§ 63.7550 What reports must I submit and when?**

(a) You must submit each report in Table 9 to this subpart that applies to you.

(b) Unless the EPA Administrator has approved a different schedule for submission of reports under §63.10(a), you must submit each report by the date in Table 9 to this subpart and according to the requirements in paragraphs (b)(1) through (5) of this section.

(1) The first compliance report must cover the period beginning on the compliance date that is specified for your affected source in §63.7495 and ending on June 30 or December 31, whichever date is the first date that occurs at least 180 days after the compliance date that is specified for your source in §63.7495.

- (2) The first compliance report must be postmarked or delivered no later than July 31 or January 31, whichever date is the first date following the end of the first calendar half after the compliance date that is specified for your source in §63.7495.
- (3) Each subsequent compliance report must cover the semiannual reporting period from January 1 through June 30 or the semiannual reporting period from July 1 through December 31.
- (4) Each subsequent compliance report must be postmarked or delivered no later than July 31 or January 31, whichever date is the first date following the end of the semiannual reporting period.
- (5) For each affected source that is subject to permitting regulations pursuant to 40 CFR part 70 or 40 CFR part 71, and if the permitting authority has established dates for submitting semiannual reports pursuant to 40 CFR 70.6(a)(3)(iii)(A) or 40 CFR 71.6(a)(3)(iii)(A), you may submit the first and subsequent compliance reports according to the dates the permitting authority has established instead of according to the dates in paragraphs (b)(1) through (4) of this section.
- (c) The compliance report must contain the information required in paragraphs (c)(1) through (11) of this section.
- (1) Company name and address.
- (2) Statement by a responsible official with that official's name, title, and signature, certifying the truth, accuracy, and completeness of the content of the report.
- (3) Date of report and beginning and ending dates of the reporting period.
- (4) The total fuel use by each affected source subject to an emission limit, for each calendar month within the semiannual reporting period, including, but not limited to, a description of the fuel and the total fuel usage amount with units of measure.
- (5) A summary of the results of the annual performance tests and documentation of any operating limits that were reestablished during this test, if applicable.
- (6) A signed statement indicating that you burned no new types of fuel. Or, if you did burn a new type of fuel, you must submit the calculation of chlorine input, using Equation 5 of §63.7530, that demonstrates that your source is still within its maximum chlorine input level established during the previous performance testing (for sources that demonstrate compliance through performance testing) or you must submit the calculation of HCl emission rate using Equation 9 of §63.7530 that demonstrates that your source is still meeting the emission limit for HCl emissions (for boilers or process heaters that demonstrate compliance through fuel analysis). If you burned a new type of fuel, you must submit the calculation of TSM input, using Equation 6 of §63.7530, that demonstrates that your source is still within its maximum TSM input level established during the previous performance testing (for sources that demonstrate compliance through performance testing), or you must submit the calculation of TSM emission rate using Equation 10 of §63.7530 that demonstrates that your source is still meeting the emission limit for TSM emissions (for boilers or process heaters that demonstrate compliance through fuel analysis). If you burned a new type of fuel, you must submit the calculation of mercury input, using Equation 7 of §63.7530, that demonstrates that your source is still within its maximum mercury input level established during the previous performance testing (for sources that demonstrate compliance through performance testing), or you must submit the calculation of mercury emission rate using Equation 11 of §63.7530 that demonstrates that your source is still meeting the emission limit for mercury emissions (for boilers or process heaters that demonstrate compliance through fuel analysis).

(7) If you wish to burn a new type of fuel and you can not demonstrate compliance with the maximum chlorine input operating limit using Equation 5 of §63.7530, the maximum TSM input operating limit using Equation 6 of §63.7530, or the maximum mercury input operating limit using Equation 7 of §63.7530, you must include in the compliance report a statement indicating the intent to conduct a new performance test within 60 days of starting to burn the new fuel.

(8) The hours of operation for each boiler and process heater that is subject to an emission limit for each calendar month within the semiannual reporting period. This requirement applies only to limited use boilers and process heaters.

(9) If you had a startup, shutdown, or malfunction during the reporting period and you took actions consistent with your SSMP, the compliance report must include the information in §63.10(d)(5)(i).

(10) If there are no deviations from any emission limits or operating limits in this subpart that apply to you, and there are no deviations from the requirements for work practice standards in this subpart, a statement that there were no deviations from the emission limits, operating limits, or work practice standards during the reporting period.

(11) If there were no periods during which the CMSs, including CEMS, COMS, and CPMS, were out of control as specified in §63.8(c)(7), a statement that there were no periods during which the CMSs were out of control during the reporting period.

(d) For each deviation from an emission limit or operating limit in this subpart and for each deviation from the requirements for work practice standards in this subpart that occurs at an affected source where you are not using a CMSs to comply with that emission limit, operating limit, or work practice standard, the compliance report must contain the information in paragraphs (c)(1) through (10) of this section and the information required in paragraphs (d)(1) through (4) of this section. This includes periods of startup, shutdown, and malfunction.

(1) The total operating time of each affected source during the reporting period.

(2) A description of the deviation and which emission limit, operating limit, or work practice standard from which you deviated.

(3) Information on the number, duration, and cause of deviations (including unknown cause), as applicable, and the corrective action taken.

(4) A copy of the test report if the annual performance test showed a deviation from the emission limit for particulate matter or the alternative TSM limit, a deviation from the HCl emission limit, or a deviation from the mercury emission limit.

(e) For each deviation from an emission limitation and operating limit or work practice standard in this subpart occurring at an affected source where you are using a CMS to comply with that emission limit, operating limit, or work practice standard, you must include the information in paragraphs (c) (1) through (10) of this section and the information required in paragraphs (e) (1) through (12) of this section. This includes periods of startup, shutdown, and malfunction and any deviations from your site-specific monitoring plan as required in §63.7505(d).

(1) The date and time that each malfunction started and stopped and description of the nature of the deviation ( *i.e.* , what you deviated from).

(2) The date and time that each CMS was inoperative, except for zero (low-level) and high-level checks.

- (3) The date, time, and duration that each CMS was out of control, including the information in §63.8(c)(8).
- (4) The date and time that each deviation started and stopped, and whether each deviation occurred during a period of startup, shutdown, or malfunction or during another period.
- (5) A summary of the total duration of the deviation during the reporting period and the total duration as a percent of the total source operating time during that reporting period.
- (6) A breakdown of the total duration of the deviations during the reporting period into those that are due to startup, shutdown, control equipment problems, process problems, other known causes, and other unknown causes.
- (7) A summary of the total duration of CMSs downtime during the reporting period and the total duration of CMS downtime as a percent of the total source operating time during that reporting period.
- (8) An identification of each parameter that was monitored at the affected source for which there was a deviation, including opacity, carbon monoxide, and operating parameters for wet scrubbers and other control devices.
- (9) A brief description of the source for which there was a deviation.
- (10) A brief description of each CMS for which there was a deviation.
- (11) The date of the latest CMS certification or audit for the system for which there was a deviation.
- (12) A description of any changes in CMSs, processes, or controls since the last reporting period for the source for which there was a deviation.
- (f) Each affected source that has obtained a title V operating permit pursuant to 40 CFR part 70 or 40 CFR part 71 must report all deviations as defined in this subpart in the semiannual monitoring report required by 40 CFR 70.6(a)(3)(iii)(A) or 40 CFR 71.6(a)(3)(iii)(A). If an affected source submits a compliance report pursuant to Table 9 to this subpart along with, or as part of, the semiannual monitoring report required by 40 CFR 70.6(a)(3)(iii)(A) or 40 CFR 71.6(a)(3)(iii)(A), and the compliance report includes all required information concerning deviations from any emission limit, operating limit, or work practice requirement in this subpart, submission of the compliance report satisfies any obligation to report the same deviations in the semiannual monitoring report. However, submission of a compliance report does not otherwise affect any obligation the affected source may have to report deviations from permit requirements to the permit authority.
- (g) If you operate a new gaseous fuel unit that is subject to the work practice standard specified in Table 1 to this subpart, and you intend to use a fuel other than natural gas or equivalent to fire the affected unit, you must submit a notification of alternative fuel use within 48 hours of the declaration of a period of natural gas curtailment or supply interruption, as defined in §63.7575. The notification must include the information specified in paragraphs (g)(1) through (5) of this section.
- (1) Company name and address.
- (2) Identification of the affected unit.
- (3) Reason you are unable to use natural gas or equivalent fuel, including the date when the natural gas curtailment was declared or the natural gas supply interruption began.

(4) Type of alternative fuel that you intend to use.

(5) Dates when the alternative fuel use is expected to begin and end.

### **§ 63.7555 What records must I keep?**

(a) You must keep records according to paragraphs (a)(1) through (3) of this section.

(1) A copy of each notification and report that you submitted to comply with this subpart, including all documentation supporting any Initial Notification or Notification of Compliance Status or semiannual compliance report that you submitted, according to the requirements in §63.10(b)(2)(xiv).

(2) The records in §63.6(e)(3)(iii) through (v) related to startup, shutdown, and malfunction.

(3) Records of performance tests, fuel analyses, or other compliance demonstrations, performance evaluations, and opacity observations as required in §63.10(b)(2)(viii).

(b) For each CEMS, CPMS, and COMS, you must keep records according to paragraphs (b)(1) through (5) of this section.

(1) Records described in §63.10(b)(2) (vi) through (xi).

(2) Monitoring data for continuous opacity monitoring system during a performance evaluation as required in §63.6(h)(7)(i) and (ii).

(3) Previous ( *i.e.*, superseded) versions of the performance evaluation plan as required in §63.8(d)(3).

(4) Request for alternatives to relative accuracy test for CEMS as required in §63.8(f)(6)(i).

(5) Records of the date and time that each deviation started and stopped, and whether the deviation occurred during a period of startup, shutdown, or malfunction or during another period.

(c) You must keep the records required in Table 8 to this subpart including records of all monitoring data and calculated averages for applicable operating limits such as opacity, pressure drop, carbon monoxide, and pH to show continuous compliance with each emission limit, operating limit, and work practice standard that applies to you.

(d) For each boiler or process heater subject to an emission limit, you must also keep the records in paragraphs (d)(1) through (5) of this section.

(1) You must keep records of monthly fuel use by each boiler or process heater, including the type(s) of fuel and amount(s) used.

(2) You must keep records of monthly hours of operation by each boiler or process heater. This requirement applies only to limited-use boilers and process heaters.

(3) A copy of all calculations and supporting documentation of maximum chlorine fuel input, using Equation 5 of §63.7530, that were done to demonstrate continuous compliance with the HCl emission limit, for sources that demonstrate compliance through performance testing. For sources that demonstrate compliance through fuel analysis, a copy of all calculations and supporting documentation of HCl

emission rates, using Equation 9 of §63.7530, that were done to demonstrate compliance with the HCl emission limit. Supporting documentation should include results of any fuel analyses and basis for the estimates of maximum chlorine fuel input or HCl emission rates. You can use the results from one fuel analysis for multiple boilers and process heaters provided they are all burning the same fuel type. However, you must calculate chlorine fuel input, or HCl emission rate, for each boiler and process heater.

(4) A copy of all calculations and supporting documentation of maximum TSM fuel input, using Equation 6 of §63.7530, that were done to demonstrate continuous compliance with the TSM emission limit for sources that demonstrate compliance through performance testing. For sources that demonstrate compliance through fuel analysis, a copy of all calculations and supporting documentation of TSM emission rates, using Equation 10 of §63.7530, that were done to demonstrate compliance with the TSM emission limit. Supporting documentation should include results of any fuel analyses and basis for the estimates of maximum TSM fuel input or TSM emission rates. You can use the results from one fuel analysis for multiple boilers and process heaters provided they are all burning the same fuel type. However, you must calculate TSM fuel input, or TSM emission rates, for each boiler and process heater.

(5) A copy of all calculations and supporting documentation of maximum mercury fuel input, using Equation 7 of §63.7530, that were done to demonstrate continuous compliance with the mercury emission limit for sources that demonstrate compliance through performance testing. For sources that demonstrate compliance through fuel analysis, a copy of all calculations and supporting documentation of mercury emission rates, using Equation 11 of §63.7530, that were done to demonstrate compliance with the mercury emission limit. Supporting documentation should include results of any fuel analyses and basis for the estimates of maximum mercury fuel input or mercury emission rates. You can use the results from one fuel analysis for multiple boilers and process heaters provided they are all burning the same fuel type. However, you must calculate mercury fuel input, or mercury emission rates, for each boiler and process heater.

(e) If your boiler or process heater is subject to an emission limit or work practice standard in Table 1 to this subpart and has a federally enforceable permit that limits the annual capacity factor to less than or equal to 10 percent such that the unit is in one of the limited use subcategories, you must keep the records in paragraphs (e)(1) and (2) of this section.

(1) A copy of the federally enforceable permit that limits the annual capacity factor of the source to less than or equal to 10 percent.

(2) Fuel use records for the days the boiler or process heater was operating.

### **§ 63.7560 In what form and how long must I keep my records?**

(a) Your records must be in a form suitable and readily available for expeditious review, according to §63.10(b)(1).

(b) As specified in §63.10(b)(1), you must keep each record for 5 years following the date of each occurrence, measurement, maintenance, corrective action, report, or record.

(c) You must keep each record on site for at least 2 years after the date of each occurrence, measurement, maintenance, corrective action, report, or record, according to §63.10(b)(1). You can keep the records off site for the remaining 3 years.

### **Other Requirements and Information**

### **§ 63.7565 What parts of the General Provisions apply to me?**

Table 10 to this subpart shows which parts of the General Provisions in §§63.1 through 63.15 apply to you.

### **§ 63.7570 Who implements and enforces this subpart?**

(a) This subpart can be implemented and enforced by U.S. EPA, or a delegated authority 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 (as well as the U.S. EPA) has the authority to implement and enforce this subpart. You should contact your EPA Regional Office to find out if 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 listed in paragraphs (b)(1) through (5) of this section are retained by the EPA Administrator and are not transferred to the State, local, or tribal agency, however, the U.S. EPA retains oversight of this subpart and can take enforcement actions, as appropriate.

(1) Approval of alternatives to the non-opacity emission limits and work practice standards in §63.7500(a) and (b) under §63.6(g).

(2) Approval of alternative opacity emission limits in §63.7500(a) under §63.6(h)(9).

(3) Approval of major change to test methods in Table 5 to this subpart under §63.7(e)(2)(ii) and (f) and as defined in §63.90.

(4) Approval of major change to monitoring under §63.8(f) and as defined in §63.90.

(5) Approval of major change to recordkeeping and reporting under §63.10(f) and as defined in §63.90.

### **§ 63.7575 What definitions apply to this subpart?**

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

*Annual capacity factor* means the ratio between the actual heat input to a boiler or process heater from the fuels burned during a calendar year, and the potential heat input to the boiler or process heater had it been operated for 8,760 hours during a year at the maximum steady state design heat input capacity.

*Bag leak detection system* means an instrument that is 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.

*Biomass fuel* means unadulterated wood as defined in this subpart, wood residue, and wood products ( *e.g.* , trees, tree stumps, tree limbs, bark, lumber, sawdust, sanderdust, chips, scraps, slabs, millings, and shavings); animal litter; 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.

*Blast furnace gas fuel-fired boiler or process heater* means an industrial/commercial/institutional boiler or process heater that receives 90 percent or more of its total heat input (based on an annual average) from blast furnace gas.

*Boiler* means an enclosed device using controlled flame combustion and having the primary purpose of recovering thermal energy in the form of steam or hot water. Waste heat boilers are excluded from this definition.

*Coal* means all solid fuels classifiable as anthracite, bituminous, sub-bituminous, or lignite by the American Society for Testing and Materials in ASTM D388–991e1., “Standard Specification for Classification of Coals by Rank<sup>1</sup>” (incorporated by reference, see §63.14(b)), coal refuse, and petroleum coke. Synthetic fuels derived from coal for the purpose of creating useful heat including but not limited to, solvent-refined coal, coal-oil mixtures, and coal-water mixtures, for the purposes of this subpart. Coal derived gases are excluded from this definition.

*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 (6,000 Btu per pound) on a dry basis.

*Commercial/institutional boiler* means a boiler used in commercial establishments or institutional establishments such as medical centers, research centers, institutions of higher education, hotels, 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.

*Construction/demolition material* means waste building material that result from the construction or demolition operations on houses and commercial and industrial buildings.

*Deviation.* (1) Deviation 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 requirement or obligation established by this subpart including, but not limited to, any emission limit, operating limit, or work practice standard;

(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; or

(iii) Fails to meet any emission limit, operating limit, or work practice standard in this subpart during startup, shutdown, or malfunction, regardless of whether or not such failure is permitted by this subpart.

(2) A deviation is not always a violation. The determination of whether a deviation constitutes a violation of the standard is up to the discretion of the entity responsible for enforcement of the standards.

*Distillate oil* means fuel oils, including recycled oils, that comply with the specifications for fuel oil numbers 1 and 2, as defined by the American Society for Testing and Materials in ASTM D396–02a, “Standard Specifications for Fuel Oils<sup>1</sup>” (incorporated by reference, see §63.14(b)).

*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 in fluidized bed boilers and process heaters are included in this definition.

*Electric utility steam generating unit* 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.

*Electrostatic precipitator* 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.

*Equivalent* means the following only as this term is used in Table 6 to subpart DDDDD:

- (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 metals (especially the mercury, selenium, or arsenic) using an aliquot of the dried sample, then the drying temperature must be modified to prevent vaporizing these metals. 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 metals concentration mathematically adjusted to a dry basis.
- (6) An equivalent pollutant (mercury, TSM, or total chlorine) determinative or analytical 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 and has a published detection limit equal or lower than the methods listed in Table 6 to subpart DDDDD 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.

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

*Firetube boiler* means a boiler that utilizes a containment shell that encloses firetubes (tubes in a boiler having water on the outside and carrying the hot gases of combustion inside), and allows the water to vaporize and steam to separate. Hybrid boilers that have been registered/certified by the National Board of Boiler and Pressure Vessel Inspectors and/or the State as firetube boilers as indicated by "Form P-2" (Manufacturers' Data Report for All Types of Boilers Except Watertube and Electric, As Required by the

Provisions of the ASME Code Rules, Section I), are considered to be firetube boilers for the purpose of this subpart.

*Fuel type* means each category of fuels that share a common name or classification. Examples include, but are not limited to, bituminous coal, subbituminous coal, lignite, anthracite, biomass, construction/demolition material, salt water laden wood, creosote treated wood, tires, residual oil. Individual fuel types received from different suppliers are not considered new fuel types except for construction/demolition material. Contraband, prohibited goods, or retired U.S. flags, burned at the request of a government agency, are not considered a fuel type for the purpose of this subpart.

*Gaseous fuel* includes, but is not limited to, natural gas, process gas, landfill gas, coal derived gas, refinery gas, and biogas. Blast furnace gas is exempted from this definition.

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

*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 or liquid fuel and is withdrawn for use external to the vessel at pressures not exceeding 160 psig, including the apparatus by which the heat is generated and all controls and devices necessary to prevent water temperatures from exceeding 210 °F (99 °C).

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

*Large gaseous fuel subcategory* includes any watertube boiler or process heater that burns gaseous fuels not combined with any solid fuels, burns liquid fuel only during periods of gas curtailment, gas supply emergencies, or for periodic testing of liquid fuel, has a rated capacity of greater than 10 MMBtu per hour heat input, and does not have a federally enforceable annual average capacity factor of equal to or less than 10 percent. Periodic testing of liquid fuel is not to exceed a combined total of 48 hours during any calendar year.

*Large liquid fuel subcategory* includes any watertube boiler or process heater that does not burn any solid fuel and burns any liquid fuel either alone or in combination with gaseous fuels, has a rated capacity of greater than 10 MMBtu per hour heat input, and does not have a federally enforceable annual average capacity factor of equal to or less than 10 percent. Large gaseous fuel boilers and process heaters that burn liquid fuel during periods of gas curtailment, gas supply emergencies or for periodic testing of liquid fuel not to exceed a combined total of 48 hours during any calendar year are not included in this definition.

*Large solid fuel subcategory* includes any watertube boiler or process heater that burns any amount of solid fuel either alone or in combination with liquid or gaseous fuels, has a rated capacity of greater than 10 MMBtu per hour heat input, and does not have a federally enforceable annual average capacity factor of equal to or less than 10 percent.

*Limited use gaseous fuel subcategory* includes any watertube boiler or process heater that burns gaseous fuels not combined with any liquid or solid fuels, burns liquid fuel only during periods of gas curtailment or gas supply emergencies, has a rated capacity of greater than 10 MMBtu per hour heat input, and has a federally enforceable annual average capacity factor of equal to or less than 10 percent.

*Limited use liquid fuel subcategory* includes any watertube boiler or process heater that does not burn any solid fuel and burns any liquid fuel either alone or in combination with gaseous fuels, has a rated capacity of greater than 10 MMBtu per hour heat input, and has a federally enforceable annual average capacity factor of equal to or less than 10 percent. Limited use gaseous fuel boilers and process heaters

that burn liquid fuel during periods of gas curtailment or gas supply emergencies are not included in this definition.

*Limited use solid fuel subcategory* includes any watertube boiler or process heater that burns any amount of solid fuel either alone or in combination with liquid or gaseous fuels, has a rated capacity of greater than 10 MMBtu per hour heat input, and has a federally enforceable annual average capacity factor of equal to or less than 10 percent.

*Liquid fossil fuel* means petroleum, distillate oil, residual oil and any form of liquid fuel derived from such material.

*Liquid fuel* includes, but is not limited to, distillate oil, residual oil, waste oil, and process liquids.

*Minimum pressure drop* means 90 percent of the lowest test-run average pressure drop measured according to Table 7 to this subpart during the most recent performance test demonstrating compliance with the applicable emission limit.

*Minimum scrubber effluent pH* means 90 percent of the lowest test-run average effluent pH measured at the outlet of the wet scrubber according to Table 7 to this subpart during the most recent performance test demonstrating compliance with the applicable hydrogen chloride emission limit.

*Minimum scrubber flow rate* means 90 percent of the lowest test-run average flow rate measured according to Table 7 to this subpart during the most recent performance test demonstrating compliance with the applicable emission limit.

*Minimum sorbent flow rate* means 90 percent of the lowest test-run average sorbent (or activated carbon) flow rate measured according to Table 7 to this subpart during the most recent performance test demonstrating compliance with the applicable emission limits.

*Minimum voltage or amperage* means 90 percent of the lowest test-run average voltage or amperage to the electrostatic precipitator measured according to Table 7 to this subpart during the most recent performance 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) Liquid petroleum gas, as defined by the American Society for Testing and Materials in ASTM D1835–03a, “Standard Specification for Liquid Petroleum Gases” (incorporated by reference, see §63.14(b)).

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

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

*Period of natural gas curtailment or supply interruption* means a period of time during which the supply of natural gas to an affected facility is halted for reasons beyond the control of the facility. An increase in the cost or unit price of natural gas does not constitute a period of natural gas curtailment or supply interruption.

*Process heater* means an enclosed device using controlled flame, that is not a boiler, 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 for use in a process unit, instead of generating steam. Process heaters are devices in which the combustion gases do not directly come into contact with process materials. Process heaters do not include units used for comfort heat or space heat, food preparation for on-site consumption, or autoclaves.

*Residual oil* means crude oil, and all fuel oil numbers 4, 5 and 6, as defined by the American Society for Testing and Materials in ASTM D396–02a, "Standard Specifications for Fuel Oils<sup>1</sup>" (incorporated by reference, see §63.14(b)).

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

*Small gaseous fuel subcategory* includes any size of firetube boiler and any other boiler or process heater with a rated capacity of less than or equal to 10 MMBtu per hour heat input that burn gaseous fuels not combined with any solid fuels and burns liquid fuel only during periods of gas curtailment, gas supply emergencies, or for periodic testing of liquid fuel. Periodic testing is not to exceed a combined total of 48 hours during any calendar year.

*Small liquid fuel subcategory* includes any size of firetube boiler and any other boiler or process with a rated capacity of less than or equal to 10 MMBtu per hour heat input that do not burn any solid fuel and burn any liquid fuel either alone or in combination with gaseous fuels. Small gaseous fuel boilers and process heaters that burn liquid fuel during periods of gas curtailment, gas supply emergencies or for periodic testing of liquid fuel not to exceed a combined total of 48 hours during any calendar year are not included in this definition.

*Small solid fuel subcategory* includes any firetube boiler that burns any amount of solid fuel either alone or in combination with liquid or gaseous fuels, and any other boiler or process heater that burns any amount of solid fuel either alone or in combination with liquid or gaseous fuels and has a rated capacity of less than or equal to 10 MMBtu per hour heat input.

*Solid fuel* includes, but is not limited to, coal, wood, biomass, tires, plastics, and other nonfossil solid materials.

*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. A temporary boiler that remains at a location for more than 180 consecutive days is no longer considered to be a temporary boiler. Any temporary boiler that replaces a temporary boiler at a location and is intended to perform the same or similar function will be included in calculating the consecutive time period.

*Total selected metals* means the combination of the following metallic HAP: arsenic, beryllium, cadmium, chromium, lead, manganese, nickel and selenium.

*Unadulterated wood* means wood or wood products that have not been painted, pigment-stained, or pressure treated with compounds such as chromate copper arsenate, pentachlorophenol, and creosote. Plywood, particle board, oriented strand board, and other types of wood products bound by glues and resins are included in this definition.

*Voluntary Consensus Standards or 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/OAQPS has by precedent only used VCS that are written in English. Examples of VCS bodies are: American Society of Testing and Materials (ASTM), American Society of Mechanical Engineers (ASME), International Standards Organization (ISO), Standards Australia (AS), British Standards (BS), Canadian Standards (CSA), European Standard (EN or CEN) and German Engineering

Standards (VDI). The types of standards that are not considered VCS are standards developed by: the U.S. 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 and converts it to usable heat. Waste heat boilers incorporating duct or supplemental burners that are designed to supply 50 percent or more of the total rated heat input capacity of the waste heat boiler are not considered waste heat boilers, but are considered boilers. Waste heat boilers are also referred to as heat recovery steam generators.

*Watertube boiler* means a boiler that incorporates a steam drum with tubes connected to the drum to separate steam from water.

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

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

[69 FR 55253, Sept. 13, 2004, as amended at 71 FR 70662, Dec. 6, 2006]

**Table 1 to Subpart DDDDD of Part 63—Emission Limits and Work Practice Standards**

As stated in §63.7500, you must comply with the following applicable emission limits and work practice standards:

<b>If your boiler or process heater is in this subcategory . . .</b>	<b>For the following pollutants . . .</b>	<b>You must meet the following emission limits and work practice standards . . .</b>
1. New or reconstructed large solid fuel	a. Particulate Matter (or Total Selected Metals)	0.025 lb per MMBtu of heat input; or (0.0003 lb per MMBtu of heat input).
	b. Hydrogen Chloride	0.02 lb per MMBtu of heat input.
	c. Mercury	0.000003 lb per MMBtu of heat input.
	d. Carbon Monoxide	400 ppm by volume on a dry basis corrected to 7 percent oxygen (30-day rolling average for units 100 MMBtu/hr or greater, 3-run average for units less than 100 MMBtu/hr).
2. New or reconstructed limited use solid fuel	a. Particulate Matter (or Total Selected Metals)	0.025 lb per MMBtu of heat input; or (0.0003 lb per MMBtu of heat input).
	b. Hydrogen Chloride	0.02 lb per MMBtu of heat input.
	c. Mercury	0.000003 lb per MMBtu of heat input.

<b>If your boiler or process heater is in this subcategory . . .</b>	<b>For the following pollutants . . .</b>	<b>You must meet the following emission limits and work practice standards . . .</b>
	d. Carbon Monoxide	400 ppm by volume on a dry basis corrected to 7 percent oxygen (3-run average).
3. New or reconstructed small solid fuel	a. Particulate Matter (or Total Selected Metals)	0.025 lb per MMBtu of heat input; or (0.0003 lb per MMBtu of heat input).
	b. Hydrogen Chloride	0.02 lb per MMBtu of heat input.
	c. Mercury	0.000003 lb per MMBtu of heat input.
4. New reconstructed large liquid fuel	a. Particulate Matter	0.03 lb per MMBtu of heat input.
	b. Hydrogen Chloride	0.0005 lb per MMBtu of heat input.
	c. Carbon Monoxide	400 ppm by volume on a dry basis corrected to 3 percent oxygen (30-day rolling average for units 100 MMBtu/hr or greater, 3-run average for units less than 100 MMBtu/hr).
5. New or reconstructed limited use liquid fuel	a. Particulate Matter	0.03 lb per MMBtu of heat input.
	b. Hydrogen Chloride	0.0009 lb per MMBtu of heat input.
	c. Carbon Monoxide	400 ppm by volume on a dry basis liquid corrected to 3 percent oxygen (3-run average).
6. New or reconstructed small liquid fuel	a. Particulate Matter	0.03 lb per MMBtu of heat input.
	b. Hydrogen Chloride	0.0009 lb per MMBtu of heat input.
7. New reconstructed large gaseous fuel	Carbon Monoxide	400 ppm by volume on a dry basis corrected to 3 percent oxygen (30-day rolling average for units 100 MMBtu/hr or greater, 3-run average for units less than 100 MMBtu/hr).
8. New or reconstructed limited use gaseous fuel	Carbon Monoxide	400 ppm by volume on a dry basis corrected to 3 percent oxygen (3-run average).
9. Existing large solid fuel	a. Particulate Matter (or Total Selected Metals)	0.07 lb per MMBtu of heat input; or (0.001 lb per MMBtu of heat input).
	b. Hydrogen Chloride	0.09 lb per MMBtu of heat input.
	c. Mercury	0.000009 lb per MMBtu of heat input.

<b>If your boiler or process heater is in this subcategory . . .</b>	<b>For the following pollutants . . .</b>	<b>You must meet the following emission limits and work practice standards . . .</b>
10. Existing limited use solid fuel	Particulate Matter (or Total Selected Metals)	0.21 lb per MMBtu of heat input; or (0.004 lb per MMBtu of heat input).

**Table 2 to Subpart DDDDD of Part 63—Operating Limits for Boilers and Process Heaters With Particulate Matter Emission Limits**

As stated in §63.7500, you must comply with the applicable operating limits:

If you demonstrate compliance with applicable particulate matter emission limits using . . .	You must meet these operating limits . . .
1. Wet scrubber control	a. Maintain the minimum pressure drop and liquid flow-rate at or above the operating levels established during the performance test according to §63.7530(c) and Table 7 to this subpart that demonstrated compliance with the applicable emission limit for particulate matter.
2. Fabric filter control	a. Install and operate a bag leak detection system according to §63.7525 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; or
	b. This option is for boilers and process heaters that operate dry control systems. Existing boilers and process heaters must maintain opacity to less than or equal to 20 percent (6-minute average) except for one 6-minute period per hour of not more than 27 percent. New boilers and process heaters must maintain opacity to less than or equal to 10 percent opacity (1-hour block average).
3. Electrostatic precipitator control	a. This option is for boilers and process heaters that operate dry control systems. Existing boilers and process heaters must maintain opacity to less than or equal to 20 percent (6-minute average) except for one 6-minute period per hour of not more than 27 percent. New boilers and process heaters must maintain opacity to less than or equal to 10 percent opacity (1-hour block average); or
	b. This option is only for boilers and process heaters that operate additional wet control systems. Maintain the minimum voltage and secondary current or total power input of the electrostatic precipitator at or above the operating limits established during the performance test according to §63.7530(c) and Table 7 to this subpart that demonstrated compliance with the applicable emission limit for particulate matter.
4. Any other control type	This option is for boilers and process heaters that operate dry control systems. Existing boilers and process heaters must maintain opacity to less than or equal to 20 percent (6-minute average) except for one 6-minute period per hour of not more than 27 percent. New boilers and process heaters must maintain opacity to less than or equal to 10 percent opacity (1-hour block average).

**Table 3 to Subpart DDDDD of Part 63—Operating Limits for Boilers and Process Heaters With Mercury Emission Limits and Boilers and Process Heaters That Choose To Comply With the Alternative Total Selected Metals Emission Limits**

As stated in §63.7500, you must comply with the applicable operating limits:

If you demonstrate compliance with applicable mercury and/or total selected metals emission limits using . . .	You must meet these operating limits . . .
1. Wet scrubber control	Maintain the minimum pressure drop and liquid flow-rate at or above the operating levels established during the performance test according to §63.7530(c) and Table 7 to this subpart that demonstrated compliance with the applicable emission limits for mercury and/or total selected metals.
2. Fabric filter control	a. Install and operate a bag leak detection system according to §63.7525 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 a 6-month period; or
	b. This option is for boilers and process heaters that operate dry control systems. Existing sources must maintain opacity to less than or equal to 20 percent (6-minute average) except for one 6-minute period per hour of not more than 27 percent. New sources must maintain opacity to less than or equal to 10 percent opacity (1-hour block average).
3. Electrostatic precipitator control	a. This option is for boilers and process heaters that operate dry control systems. Existing sources must maintain opacity to less than or equal to 20 percent (6-minute average) except for one 6-minute period per hour of not more than 27 percent. New sources must maintain opacity to less than or equal to 10 percent opacity (1-hour block average); or
	b. This option is only for boilers and process heaters that operate additional wet control systems. Maintain the minimum voltage and secondary current or total power input of the electrostatic precipitator at or above the operating limits established during the performance test according to §63.7530(c) and Table 7 to this subpart that demonstrated compliance with the applicable emission limits for mercury and/or total selected metals.
4. Dry scrubber or carbon injection control	Maintain the minimum sorbent or carbon injection rate at or above the operating levels established during the performance test according to §63.7530(c) and Table 7 to this subpart that demonstrated compliance with the applicable emission limit for mercury.
5. Any other control type	This option is only for boilers and process heaters that operate dry control systems. Existing sources must maintain opacity to less than or equal to 20 percent (6-minute average) except for one 6-minute period per hour of not more than 27 percent. New sources must maintain opacity to less than or equal to 10 percent opacity (1-hour block average).

If you demonstrate compliance with applicable mercury and/or total selected metals emission limits using . . .	You must meet these operating limits . . .
6. Fuel analysis	Maintain the fuel type or fuel mixture such that the mercury and/or total selected metals emission rates calculated according to §63.7530(d)(4) and/or (5) is less than the applicable emission limits for mercury and/or total selected metals.

**Table 4 to Subpart DDDDD of Part 63—Operating Limits for Boilers and Process Heaters With Hydrogen Chloride Emission Limits**

As stated in §63.7500, you must comply with the following applicable operating limits:

If you demonstrate compliance with applicable hydrogen chloride emission limits using . . .	You must meet these operating limits . . .
1. Wet scrubber control	Maintain the minimum scrubber effluent pH, pressure drop, and liquid flow-rate at or above the operating levels established during the performance test according to §63.7530(c) and Table 7 to this subpart that demonstrated compliance with the applicable emission limit for hydrogen chloride.
2. Dry scrubber control	Maintain the minimum sorbent injection rate at or above the operating levels established during the performance test according to §63.7530(c) and Table 7 to this subpart that demonstrated compliance with the applicable emission limit for hydrogen chloride.
3. Fuel analysis	Maintain the fuel type or fuel mixture such that the hydrogen chloride emission rate calculated according to §63.7530(d)(3) is less than the applicable emission limit for hydrogen chloride.

**Table 5 to Subpart DDDDD of Part 63—Performance Testing Requirements**

As stated in §63.7520, you must comply with the following requirements for performance test for existing, new or reconstructed affected sources:

To conduct a performance test for the following pollutant . . .	You must . . .	Using . . .
1. Particulate Matter	a. Select sampling ports location and the number of traverse points	Method 1 in appendix A 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 to part 60 of this chapter.

<b>To conduct a performance test for the following pollutant . . .</b>	<b>You must . . .</b>	<b>Using . . .</b>
	c. Determine oxygen and carbon dioxide concentrations of the stack gas	Method 3A or 3B in appendix A to part 60 of this chapter, or ASME PTC 19, Part 10 (1981) (IBR, see §63.14(i)).
	d. Measure the moisture content of the stack gas	Method 4 in appendix A 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 to part 60 of this chapter.
	f. Convert emissions concentration to lb per MMBtu emission rates	Method 19 F-factor methodology in appendix A to part 60 of this chapter.
2. Total selected metals	a. Select sampling ports location and the number of traverse points	Method 1 in appendix A 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 to part 60 of this chapter.
	c. Determine oxygen and carbon dioxide concentrations of the stack gas	Method 3A or 3B in appendix A to part 60 of this chapter, or ASME PTC 19, Part 10 (1981) (IBR, see §63.14(i)).
	d. Measure the moisture content of the stack gas	Method 4 in appendix A to part 60 of this chapter.
	e. Measure the total selected metals emission concentration	Method 29 in appendix A to part 60 of this chapter.
	f. Convert emissions concentration to lb per MMBtu emission rates	Method 19 F-factor methodology in appendix A to part 60 of this chapter.
3. Hydrogen chloride	a. Select sampling ports location and the number of traverse points	Method 1 in appendix A 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 to part 60 of this chapter.
	c. Determine oxygen and carbon dioxide concentrations of the stack gas	Method 3A or 3B in appendix A to part 60 of this chapter, or ASME PTC 19, Part 10 (1981) (IBR, see §63.14(i)).
	d. Measure the moisture content of the stack gas	Method 4 in appendix A to part 60 of this chapter.

<b>To conduct a performance test for the following pollutant . . .</b>	<b>You must . . .</b>	<b>Using . . .</b>
	e. Measure the hydrogen chloride emission concentration	Method 26 or 26A in appendix A to part 60 of this chapter.
	f. Convert emissions concentration to lb per MMBtu emission rates	Method 19 F-factor methodology in appendix A to part 60 of this chapter.
4. Mercury	a. Select sampling ports location and the number of traverse points	Method 1 in appendix A 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 to part 60 of this chapter.
	c. Determine oxygen and carbon dioxide concentrations of the stack gas	Method 3A or 3B in appendix A to part 60 of this chapter, or ASME PTC 19, Part 10 (1981) (IBR, see §62.14(i)).
	d. Measure the moisture content of the stack gas	Method 4 in appendix A to part 60 of this chapter.
	e. Measure the mercury emission concentration	Method 29 in appendix A to part 60 of this chapter or Method 101A in appendix B to part 61 of this chapter or ASTM Method D6784–02 (IBR, see §63.14(b)).
	f. Convert emissions concentration to lb per MMBtu emission rates	Method 19 F-factor methodology in appendix A to part 60 of this chapter.
5. Carbon Monoxide	a. Select the sampling ports location and the number of traverse points	Method 1 in appendix A to part 60 of this chapter.
	b. Determine oxygen and carbon dioxide concentrations of the stack gas	Method 3A or 3B in appendix A to part 60 of this chapter, or ASTM D6522–00 (IBR, see §63.14(b)), or ASME PTC 19, Part 10 (1981) (IBR, see §63.14(i)).
	c. Measure the moisture content of the stack gas	Method 4 in appendix A to part 60 of this chapter.
	d. Measure the carbon monoxide emission concentration	Method 10, 10A, or 10B in appendix A to part 60 of this chapter, or ASTM D6522–00 (IBR, see §63.14(b)) when the fuel is natural gas.

**Table 6 to Subpart DDDDD of Part 63—Fuel Analysis Requirements**

As stated in §63.7521, you must comply with the following requirements for fuel analysis testing for existing, new or reconstructed affected sources. However, equivalent methods may be used in lieu of the prescribed methods at the discretion of the source owner or operator:

<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 §63.7521(c) or ASTM D2234–D2234M–03(for coal) (IBR, see §63.14(b)) or ASTM D6323–98 (2003) (for biomass) (IBR, See §63.14(b)) or equivalent.
	b. Composite fuel samples * * *	Procedure in §63.7521(d) or equivalent.
	c. Prepare composited fuel samples * * *	SW–846–3050B (for solid samples) or SW–846–3020A (for liquid samples) or ASTM D2013–04 (for coal) (IBR, see §63.14(b)) or ASTM D5198–92 (2003) (for biomass) (IBR, see §63.14(b)) or equivalent.
	d. Determine heat content of the fuel type * * *	ASTM D5865–04 (for coal) (IBR, see §63.24(b)) or ASTM E711–87 (for biomass) (IBR, see §63.14(b)) or equivalent.
	e. Determine moisture content of the fuel type * * *	ASTM D3173–03 (IBR, see §63.14(b)) or ASTM E871–82 (1998) (IBR, see §63.14(b)) or equivalent.
	f. Measure mercury concentration in fuel sample * * *	ASTM D6722–01 (for coal) (IBR, see §63.14(b)) or SW–846–7471A (for solid samples) or SW–846–7470A (for liquid samples) or equivalent.
	g. Convert concentration into units of pounds of pollutant per MMBtu of heat content.	
2. Total Selected metals * * *	a. Collect fuel samples * * *	Procedure in §63.7521(c) or ASTM D2234–D2234M–03(for coal) (IBR, see §63.14(b)) or ASTM D6323–98 (2003) (for biomass) (IBR, see §63.14(b)) or equivalent.
	b. Composite fuel samples * * *	Procedure in §63.7521(d) or equivalent.
	c. Prepare composited fuel samples * * *	SW–846–3050B (for solid samples) or SW–846–3020A (for liquid samples) or ASTM D2013–04 (for coal) (IBR, see §63.14(b)) or ASTM D5198–92 (2003) (for biomass) (IBR, see §63.14(b)) or equivalent.
	d. Determine heat content of the fuel type * * *	ASTM D5865–04 (for coal) (IBR, see §63.14(b)) or ASTM E711–87 (for biomass) (IBR, see §63.14(b)) or equivalent.
	e. Determine moisture content of the fuel type * * *	ASTM D3173–03 (IBR, see §63.14(b)) or ASTM E871–82 (IBR, see §63.14(b)) or equivalent.

<b>To conduct a fuel analysis for the following pollutant</b> * * *	<b>You must</b> * * *	<b>Using</b> * * *
	f. Measure total selected metals concentration in fuel sample * * *	SW-846-6010B or ASTM D6357-04 (for arsenic, beryllium, cadmium, chromium, lead, manganese, and nickel for all solid fuels) and ASTM D4606-03 (for selenium in coal) (IBR, see §63.14(b)) or ASTM E885-88 (1996) for biomass) (IBR, see §63.14(b)) or equivalent.
	g. Convert concentrations into units of pounds of pollutant per MMBtu of heat content.	
3. Hydrogen Chloride * * *	a. Collect fuel samples * * *	Procedure in §63.7521(c) or ASTM D2234-D2234M-03(for coal) (IBR, see §63.14(b)) or ASTM D6323-98 (2003) (for biomass) (IBR, see §63.14(b)) or equivalent.
	b. Composite fuel samples * * *	Procedure in §63.7521(d) or equivalent.
	c. Prepare composited fuel samples * * *	SW-846-3050B (for solid samples) or SW-846-3020A (for liquid samples) or ASTM D2013-04 (for coal) (IBR, see §63.14(b)) or ASTM D5198-92 (2003) (for biomass) (IBR, see §63.14(b)) or equivalent.
	d. Determine heat content of the fuel type * * *	ASTM D5865-04 (for coal) (IBR, see §63.14(b)) or ASTM E711-87 (1996) (for biomass) (IBR, see §63.14(b)) or equivalent.
	e. Determine moisture content of the fuel type * * *	ASTM D3173-03 (IBR, see §63.14(b)) or ASTM E871-82 (1998) or equivalent.
	f. Measure chlorine concentration in fuel sample * * *	SW-846-9250 or ASTM D6721-01 (for coal) or ASTM E776-87 (1996) (for biomass) (IBR, see §63.14(b)) or equivalent.
	g. Convert concentrations into units of pounds of pollutant per MMBtu of heat content.	

[71 FR 70663, Dec. 6, 2006]

**Table 7 to Subpart DDDDD of Part 63—Establishing Operating Limits**

As stated in §63.7520, 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. Particulate matter, mercury, or total selected metals	a. Wet scrubber operating parameters	i. Establish a site-specific minimum pressure drop and minimum flow rate operating limit according to §63.7530(c)	(1) Data from the pressure drop and liquid flow rate monitors and the particulate matter, mercury, or total selected metals performance test	(a) You must collect pressure drop and liquid flow-rate data every 15 minutes during the entire period of the performance tests;
				(b) Determine the average pressure drop and liquid flow-rate for each individual test run in the three-run performance test by computing the average of all the 15-minute readings taken during each test run.
	b. Electrostatic precipitator operating parameters (option only for units with additional wet scrubber control)	i. Establish a site-specific minimum voltage and secondary current or total power input according to §63.7530(c)	(1) Data from the pressure drop and liquid flow rate monitors and the particulate matter, mercury, or total selected metals performance test	(a) You must collect voltage and secondary current or total power input data every 15 minutes during the entire period of the performance tests;
				(b) Determine the average voltage and secondary current or total power input for each individual test run in the three-run performance test by computing the average of all the 15-minute readings taken during each test run.
2. Hydrogen Chloride	a. Wet scrubber operating parameters	i. Establish a site-specific minimum pressure drop and minimum flow rate operating limit according to §63.7530(c)	(1) Data from the pH, pressure drop, and liquid flow-rate monitors and the hydrogen chloride performance test	(a) You must collect pH, pressure drop, and liquid flow-rate data every 15 minutes during the entire period of the performance tests;

If you have an applicable emission limit for . . .	And your operating limits are based on . . .	You must . . .	Using . . .	According to the following requirements
				(b) Determine the average pH, pressure drop, and liquid flow-rate for each individual test run in the three-run performance test by computing the average of all the 15-minute readings taken during each test run.
	b. Dry scrubber operating parameters	i. Establish a site-specific minimum sorbent injection rate operating limit according to §63.7530(c)	(1) Data from the sorbent injection rate monitors and hydrogen chloride performance test	(a) You must collect sorbent injection rate data every 15 minutes during the entire period of the performance tests;
				(b) Determine the average sorbent injection rate for each individual test run in the three-run performance test by computing the average of all the 15-minute readings taken during each test run.

**Table 8 to Subpart DDDDD of Part 63—Demonstrating Continuous Compliance**

As stated in §63.7540, you must show continuous compliance with the emission limitations for affected sources according to the following:

If you must meet the following operating limits or work practice standards . . .	You must demonstrate continuous compliance by . . .
1. Opacity	a. Collecting the opacity monitoring system data according to §§63.7525(b) and 63.7535; and
	b. Reducing the opacity monitoring data to 6-minute averages; and
	c. Maintaining opacity to less than or equal to 20 percent (6-minute average) except for one 6-minute period per hour of not more than 27 percent for existing sources; or maintaining opacity to less than or equal to 10 percent (1-hour block average) for new sources.
2. Fabric Filter Bag Leak Detection Operation	Installing and operating a bag leak detection system according to §63.7525 and operating the fabric filter such that the requirements in §63.7540(a)(9) 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 §§63.7525 and 63.7535; and

<p><b>If you must meet the following operating limits or work practice standards . . .</b></p>	<p><b>You must demonstrate continuous compliance by . . .</b></p>
	<p>b. Reducing the data to 3-hour block averages; and</p>
	<p>c. Maintaining the 3-hour average pressure drop and liquid flow-rate at or above the operating limits established during the performance test according to §63.7530(c).</p>
<p>4. Wet Scrubber pH</p>	<p>a. Collecting the pH monitoring system data according to §§63.7525 and 63.7535; and</p>
	<p>b. Reducing the data to 3-hour block averages; and</p>
	<p>c. Maintaining the 3-hour average pH at or above the operating limit established during the performance test according to §63.7530(c).</p>
<p>5. Dry Scrubber Sorbent or Carbon Injection Rate</p>	<p>a. Collecting the sorbent or carbon injection rate monitoring system data for the dry scrubber according to §§63.7525 and 63.7535; and</p>
	<p>b. Reducing the data to 3-hour block averages; and</p>
	<p>c. Maintaining the 3-hour average sorbent or carbon injection rate at or above the operating limit established during the performance test according to §§63.7530(c).</p>
<p>6. Electrostatic Precipitator Secondary Current and Voltage or Total Power Input</p>	<p>a. Collecting the secondary current and voltage or total power input monitoring system data for the electrostatic precipitator according to §§63.7525 and 63.7535; and</p>
	<p>b. Reducing the data to 3-hour block averages; and</p>
	<p>c. Maintaining the 3-hour average secondary current and voltage or total power input at or above the operating limits established during the performance test according to §§63.7530(c).</p>
<p>7. Fuel Pollutant Content</p>	<p>a. Only burning the fuel types and fuel mixtures used to demonstrate compliance with the applicable emission limit according to §63.7530(c) or (d) as applicable; and</p>
	<p>b. Keeping monthly records of fuel use according to §63.7540(a).</p>

**Table 9 to Subpart DDDDD of Part 63—Reporting Requirements**

As stated in §63.7550, you must comply with the following requirements for reports:

<b>You must submit a(n)</b>	<b>The report must contain . . .</b>	<b>You must submit the report . . .</b>
1. Compliance report	a. Information required in §63.7550(c)(1) through (11); and	Semiannually according to the requirements in §63.7550(b).
	b. If there are no deviations from any emission limitation (emission limit and operating limit) that applies to you and there are no deviations from the requirements for work practice standards in Table 8 to this subpart that apply to you, a statement that there were no deviations from the emission limitations and work practice standards during the reporting period. If there were no periods during which the CMSs, including continuous emissions monitoring system, continuous opacity monitoring system, and operating parameter monitoring systems, were out-of-control as specified in §63.8(c)(7), a statement that there were no periods during which the CMSs were out-of-control during the reporting period; and	
	c. If you have a deviation from any emission limitation (emission limit and operating limit) or work practice standard during the reporting period, the report must contain the information in §63.7550(d). If there were periods during which the CMSs, including continuous emissions monitoring system, continuous opacity monitoring system, and operating parameter monitoring systems, were out-of-control, as specified in §63.8(c)(7), the report must contain the information in §63.7550(e); and	
	d. If you had a startup, shutdown, or malfunction during the reporting period and you took actions consistent with your startup, shutdown, and malfunction plan, the compliance report must include the information in §63.10(d)(5)(i)	

You must submit a(n)	The report must contain . . .	You must submit the report . . .
2. An immediate startup, shutdown, and malfunction report if you had a startup, shutdown, or malfunction during the reporting period that is not consistent with your startup, shutdown, and malfunction plan, and the source exceeds any applicable emission limitation in the relevant emission standard	a. Actions taken for the event; and	i. By fax or telephone within 2 working days after starting actions inconsistent with the plan; and
	b. The information in §63.10(d)(5)(ii)	ii. By letter within 7 working days after the end of the event unless you have made alternative arrangements with the permitting authority.

**Table 10 to Subpart DDDDD of Part 63—Applicability of General Provisions to Subpart DDDDD**

As stated in §63.7565, you must comply with the applicable General Provisions according to the following:

Citation	Subject	Brief description	Applicable
§63.1	Applicability	Initial Applicability Determination; Applicability After Standard Established; Permit Requirements; Extensions, Notifications	Yes.
§63.2	Definitions	Definitions for part 63 standards	Yes.
§63.3	Units and Abbreviations	Units and abbreviations for part 63 standards	Yes.
§63.4	Prohibited Activities	Prohibited Activities; Compliance date; Circumvention, Severability	Yes.
§63.5	Construction/Reconstruction	Applicability; applications; approvals	Yes.
§63.6(a)	Applicability	GP apply unless compliance extension; and GP apply to area sources that become major	Yes.
§63.6(b)(1)–(4)	Compliance Dates for New and Reconstructed sources	Standards apply at effective date; 3 years after effective date; upon startup; 10 years after construction or reconstruction commences for 112(f)	Yes.
§63.6(b)(5)	Notification	Must notify if commenced construction or reconstruction after proposal	Yes.
§63.6(b)(6)	[Reserved]		

Citation	Subject	Brief description	Applicable
§63.6(b)(7)	Compliance Dates for New and Reconstructed Area Sources That Become Major	Area sources that become major must comply with major source standards immediately upon becoming major, regardless of whether required to comply when they were an area source	Yes.
§63.6(c)(1)–(2)	Compliance Dates for Existing Sources	Comply according to date in subpart, which must be no later than 3 years after effective date; and for 112(f) standards, comply within 90 days of effective date unless compliance extension	Yes.
§63.6(c)(3)–(4)	[Reserved]		
§63.6(c)(5)	Compliance Dates for Existing Area Sources That Become Major	Area sources that become major must comply with major source standards by date indicated in subpart or by equivalent time period (for example, 3 years)	Yes.
§63.6(d)	[Reserved]		
§63.6(e)(1)–(2)	Operation & Maintenance	Operate to minimize emissions at all times; and Correct malfunctions as soon as practicable; and Operation and maintenance requirements independently enforceable; information Administrator will use to determine if operation and maintenance requirements were met	Yes.
§63.6(e)(3)	Startup, Shutdown, and Malfunction Plan (SSMP)	Requirement for SSM and startup, shutdown, malfunction plan; and content of SSMP	Yes.
§63.6(f)(1)	Compliance Except During SSM	Comply with emission standards at all times except during SSM	Yes.
§63.6(f)(2)–(3)	Methods for Determining Compliance	Compliance based on performance test, operation and maintenance plans, records, inspection	Yes.
§63.6(g)(1)–(3)	Alternative Standard	Procedures for getting an alternative standard	Yes.
§63.6(h)(1)	Compliance with Opacity/VE Standards	Comply with opacity/VE emission limitations at all times except during SSM	Yes.
§63.6(h)(2)(i)	Determining Compliance with Opacity/Visible Emission (VE) Standards	If standard does not state test method, use Method 9 for opacity and Method 22 for VE	No.
§63.6(h)(2)(ii)	[Reserved]		
§63.6(h)(2)(iii)	Using Previous Tests to Demonstrate Compliance with Opacity/VE Standards	Criteria for when previous opacity/VE testing can be used to show compliance with this subpart	Yes.
§63.6(h)(3)	[Reserved]		

Citation	Subject	Brief description	Applicable
§63.6(h)(4)	Notification of Opacity/VE Observation Date	Notify Administrator of anticipated date of observation	No.
§63.6(h)(5)(i),(iii)–(v)	Conducting Opacity/VE Observations	Dates and Schedule for conducting opacity/VE observations	No.
§63.6(h)(5)(ii)	Opacity Test Duration and Averaging Times	Must have at least 3 hours of observation with thirty, 6-minute averages	No.
§63.6(h)(6)	Records of Conditions During Opacity/VE observations	Keep records available and allow Administrator to inspect	No.
§63.6(h)(7)(i)	Report continuous opacity monitoring system Monitoring Data from Performance Test	Submit continuous opacity monitoring system data with other performance test data	Yes.
§63.6(h)(7)(ii)	Using continuous opacity monitoring system instead of Method 9	Can submit continuous opacity monitoring system data instead of Method 9 results even if subpart requires Method 9, but must notify Administrator before performance test	No.
§63.6(h)(7)(iii)	Averaging time for continuous opacity monitoring system during performance test	To determine compliance, must reduce continuous opacity monitoring system data to 6-minute averages	Yes.
§63.6(h)(7)(iv)	Continuous opacity monitoring system requirements	Demonstrate that continuous opacity monitoring system performance evaluations are conducted according to §§63.8(e), continuous opacity monitoring systems are properly maintained and operated according to §63.8(c) and data quality as §63.8(d)	Yes.
§63.6(h)(7)(v)	Determining Compliance with Opacity/VE Standards	Continuous opacity monitoring system is probative but not conclusive evidence of compliance with opacity standard, even if Method 9 observation shows otherwise. Requirements for continuous opacity monitoring system to be probative evidence-proper maintenance, meeting PS 1, and data have not been altered	Yes.
§63.6(h)(8)	Determining Compliance with Opacity/VE Standards	Administrator will use all continuous opacity monitoring system, Method 9, and Method 22 results, as well as information about operation and maintenance to determine compliance	Yes.
§63.6(h)(9)	Adjusted Opacity Standard	Procedures for Administrator to adjust an opacity standard	Yes.
§63.6(i)(1)–(14)	Compliance Extension	Procedures and criteria for Administrator to grant compliance extension	Yes.
§63.6(j)	Presidential Compliance Exemption	President may exempt source category from requirement to comply with rule	Yes.

Citation	Subject	Brief description	Applicable
§63.7(a)(1)	Performance Test Dates	Dates for Conducting Initial Performance Testing and Other Compliance Demonstrations	Yes.
§63.7(a)(2)	Performance Test Dates	New source with initial startup date before effective date has 180 days after effective date to demonstrate compliance	Yes.
§63.7(a)(2)(ii-viii)	[Reserved]		
§63.7(a)(2)(ix)	Performance Test Dates	1. New source that commenced construction between proposal and promulgation dates, when promulgated standard is more stringent than proposed standard, has 180 days after effective date or 180 days after startup of source, whichever is later, to demonstrate compliance; and	Yes.
		2. If source initially demonstrates compliance with less stringent proposed standard, it has 3 years and 180 days after the effective date of the standard or 180 days after startup of source, whichever is later, to demonstrate compliance with promulgated standard	No.
§63.7(a)(3)	Section 114 Authority	Administrator may require a performance test under CAA Section 114 at any time	Yes.
§63.7(b)(1)	Notification of Performance Test	Must notify Administrator 60 days before the test	No.
§63.7(b)(2)	Notification of Rescheduling	If rescheduling a performance test is necessary, must notify Administrator 5 days before scheduled date of rescheduled date	Yes.
§63.7(c)	Quality Assurance/Test Plan	Requirement to submit site-specific test plan 60 days before the test or on date Administrator agrees with: test plan approval procedures; and performance audit requirements; and internal and external QA procedures for testing	Yes.
§63.7(d)	Testing Facilities	Requirements for testing facilities	Yes.
§63.7(e)(1)	Conditions for Conducting Performance Tests	1. Performance tests must be conducted under representative conditions; and	No.
		2. Cannot conduct performance tests during SSM; and	Yes.
		3. Not a deviation to exceed standard during SSM; and	Yes.

Citation	Subject	Brief description	Applicable
		4. Upon request of Administrator, make available records necessary to determine conditions of performance tests	Yes.
§63.7(e)(2)	Conditions for Conducting Performance Tests	Must conduct according to rule and EPA test methods unless Administrator approves alternative	Yes.
§63.7(e)(3)	Test Run Duration	Must have three separate test runs; and Compliance is based on arithmetic mean of three runs; and conditions when data from an additional test run can be used	Yes.
§63.7(e)(4)	Interaction with other sections of the Act	Nothing in §63.7(e)(1) through (4) can abrogate the Administrator's authority to require testing under Section 114 of the Act	Yes.
§63.7(f)	Alternative Test Method	Procedures by which Administrator can grant approval to use an alternative test method	Yes.
§63.7(g)	Performance Test Data Analysis	Must include raw data in performance test report; and must submit performance test data 60 days after end of test with the Notification of Compliance Status; and keep data for 5 years	Yes.
§63.7(h)	Waiver of Tests	Procedures for Administrator to waive performance test	Yes.
§63.8(a)(1)	Applicability of Monitoring Requirements	Subject to all monitoring requirements in standard	Yes.
§63.8(a)(2)	Performance Specifications	Performance Specifications in appendix B of part 60 apply	Yes.
§63.8(a)(3)	[Reserved]		
§63.8(a)(4)	Monitoring with Flares	Unless your rule says otherwise, the requirements for flares in §63.11 apply	No.
§63.8(b)(1)(i)–(ii)	Monitoring	Must conduct monitoring according to standard unless Administrator approves alternative	Yes.
§63.8(b)(1)(iii)	Monitoring	Flares not subject to this section unless otherwise specified in relevant standard	No.
§63.8(b)(2)–(3)	Multiple Effluents and Multiple Monitoring Systems	Specific requirements for installing monitoring systems; and must install on each effluent before it is combined and before it is released to the atmosphere unless Administrator approves otherwise; and if more than one monitoring system on an emission point, must report all monitoring system results, unless one monitoring system is a backup	Yes.

Citation	Subject	Brief description	Applicable
§63.8(c)(1)	Monitoring System Operation and Maintenance	Maintain monitoring system in a manner consistent with good air pollution control practices	Yes.
§63.8(c)(1)(i)	Routine and Predictable SSM	Maintain and operate CMS according to §63.6(e)(1)	Yes.
§63.8(c)(1)(ii)	SSM not in SSMP	Must keep necessary parts available for routine repairs of CMSs	Yes.
§63.8(c)(1)(iii)	Compliance with Operation and Maintenance	Must develop an SSMP for CMS	Yes.
§63.8(c)(2)–(3)	Monitoring System Installation	Must install to get representative emission and parameter measurements; and must verify operational status before or at performance test	Yes.
§63.8(c)(4)	Continuous Monitoring System (CMS) Requirements	CMSs must be operating except during breakdown, out-of-control, repair, maintenance, and high-level calibration drifts	No.
§63.8(c)(4)(i)	Continuous Monitoring System (CMS) Requirements	Continuous opacity monitoring system must have a minimum of one cycle of sampling and analysis for each successive 10-second period and one cycle of data recording for each successive 6-minute period	Yes.
§63.8(c)(4)(ii)	Continuous Monitoring System (CMS) Requirements	Continuous emissions monitoring system must have a minimum of one cycle of operation for each successive 15-minute period	No.
§63.8(c)(5)	Continuous Opacity Monitoring system (COMS) Requirements	Must do daily zero and high level calibrations	Yes.
§63.8(c)(6)	Continuous Monitoring System (CMS) Requirements	Must do daily zero and high level calibrations	No.
§63.8(c)(7)–(8)	Continuous Monitoring Systems Requirements	Out-of-control periods, including reporting	Yes.
§63.8(d)	Continuous Monitoring Systems Quality Control	Requirements for continuous monitoring systems quality control, including calibration, etc.; and must keep quality control plan on record for the life of the affected source. Keep old versions for 5 years after revisions	Yes.
§63.8(e)	Continuous monitoring systems Performance Evaluation	Notification, performance evaluation test plan, reports	Yes.
§63.8(f)(1)–(5)	Alternative Monitoring Method	Procedures for Administrator to approve alternative monitoring	Yes.

Citation	Subject	Brief description	Applicable
§63.8(f)(6)	Alternative to Relative Accuracy Test	Procedures for Administrator to approve alternative relative accuracy tests for continuous emissions monitoring system	No.
§63.8(g)(1)–(4)	Data Reduction	Continuous opacity monitoring system 6-minute averages calculated over at least 36 evenly spaced data points; and continuous emissions monitoring system 1-hour averages computed over at least 4 equally spaced data points	Yes.
§63.8(g)(5)	Data Reduction	Data that cannot be used in computing averages for continuous emissions monitoring system and continuous opacity monitoring system	No.
§63.9(a)	Notification Requirements	Applicability and State Delegation	Yes.
§63.9(b)(1)–(5)	Initial Notifications	Submit notification 120 days after effective date; and Notification of intent to construct/reconstruct; and Notification of commencement of construct/reconstruct; Notification of startup; and Contents of each	Yes.
§63.9(c)	Request for Compliance Extension	Can request if cannot comply by date or if installed BACT/LAER	Yes.
§63.9(d)	Notification of Special Compliance Requirements for New Source	For sources that commence construction between proposal and promulgation and want to comply 3 years after effective date	Yes.
§63.9(e)	Notification of Performance Test	Notify Administrator 60 days prior	No.
§63.9(f)	Notification of VE/Opacity Test	Notify Administrator 30 days prior	No.
§63.9(g)	Additional Notifications When Using Continuous Monitoring Systems	Notification of performance evaluation; and notification using continuous opacity monitoring system data; and notification that exceeded criterion for relative accuracy	Yes.
§63.9(h)(1)–(6)	Notification of Compliance Status	Contents; and due 60 days after end of performance test or other compliance demonstration, and when to submit to Federal vs. State authority	Yes.
§63.9(i)	Adjustment of Submittal Deadlines	Procedures for Administrator to approve change in when notifications must be submitted	Yes.
§63.9(j)	Change in Previous Information	Must submit within 15 days after the change	Yes.

Citation	Subject	Brief description	Applicable
§63.10(a)	Recordkeeping/Reporting	Applies to all, unless compliance extension; and when to submit to Federal vs. State authority; and procedures for owners of more than 1 source	Yes.
§63.10(b)(1)	Recordkeeping/Reporting	General Requirements; and keep all records readily available and keep for 5 years	Yes.
§63.10(b)(2)(i)–(v)	Records related to Startup, Shutdown, and Malfunction	Occurrence of each of operation (process, equipment); and occurrence of each malfunction of air pollution equipment; and maintenance of air pollution control equipment; and actions during startup, shutdown, and malfunction	Yes.
§63.10(b)(2)(vi) and (x-xi)	Continuous monitoring systems Records	Malfunctions, inoperative, out-of-control; and calibration checks; and adjustments, maintenance	Yes.
§63.10(b)(2)(vii)–(ix)	Records	Measurements to demonstrate compliance with emission limitations; and performance test, performance evaluation, and visible emission observation results; and measurements to determine conditions of performance tests and performance evaluations.	Yes.
§63.10(b)(2)(xii)	Records	Records when under waiver	Yes.
§63.10(b)(2)(xiii)	Records	Records when using alternative to relative accuracy test	No.
§63.10(b)(2)(xiv)	Records	All documentation supporting Initial Notification and Notification of Compliance Status	Yes.
§63.10(b)(3)	Records	Applicability Determinations	Yes.
§63.10(c)(1),(5)–(8),(10)–(15)	Records	Additional Records for continuous monitoring systems	Yes.
§63.10(c)(7)–(8)	Records	Records of excess emissions and parameter monitoring exceedances for continuous monitoring systems	No.
§63.10(d)(1)	General Reporting Requirements	Requirement to report	Yes.
§63.10(d)(2)	Report of Performance Test Results	When to submit to Federal or State authority	Yes.
§63.10(d)(3)	Reporting Opacity or VE Observations	What to report and when	Yes.
§63.10(d)(4)	Progress Reports	Must submit progress reports on schedule if under compliance extension	Yes.

<b>Citation</b>	<b>Subject</b>	<b>Brief description</b>	<b>Applicable</b>
§63.10(d)(5)	Startup, Shutdown, and Malfunction Reports	Contents and submission	Yes.
§63.10(e)(1)(2)	Additional continuous monitoring systems Reports	Must report results for each CEM on a unit; and written copy of performance evaluation; and 3 copies of continuous opacity monitoring system performance evaluation	Yes.
§63.10(e)(3)	Reports	Excess Emission Reports	No.
§63.10(e)(3)(i-iii)	Reports	Schedule for reporting excess emissions and parameter monitor exceedance (now defined as deviations)	No.
§63.10(e)(3)(iv-v)	Excess Emissions Reports	Requirement to revert to quarterly submission if there is an excess emissions and parameter monitor exceedance (now defined as deviations); and provision to request semiannual reporting after compliance for one year; and submit report by 30th day following end of quarter or calendar half; and if there has not been an exceedance or excess emission (now defined as deviations), report contents is a statement that there have been no deviations	No.
§63.10(e)(3)(iv-v)	Excess Emissions Reports	Must submit report containing all of the information in §63.10(c)(5–13), §63.8(c)(7–8)	No.
§63.10(e)(3)(vi-viii)	Excess Emissions Report and Summary Report	Requirements for reporting excess emissions for continuous monitoring systems (now called deviations); Requires all of the information in §63.10(c)(5–13), §63.8(c)(7–8)	No.
§63.10(e)(4)	Reporting continuous opacity monitoring system data	Must submit continuous opacity monitoring system data with performance test data	Yes.
§63.10(f)	Waiver for Recordkeeping/Reporting	Procedures for Administrator to waive	Yes.
§63.11	Flares	Requirements for flares	No.
§63.12	Delegation	State authority to enforce standards	Yes.
§63.13	Addresses	Addresses where reports, notifications, and requests are sent	Yes.
§63.14	Incorporation by Reference	Test methods incorporated by reference	Yes.
§63.15	Availability of Information	Public and confidential Information	Yes.

[69 FR 55253, Sept. 13, 2004, as amended at 71 FR 20468, Apr. 20, 2006]

## **Appendix A to Subpart DDDDD of Part 63—Methodology and Criteria for Demonstrating Eligibility for the Health-Based Compliance Alternatives**

### 1. Purpose/Introduction

This appendix provides the methodology and criteria for demonstrating that your affected source is eligible for the compliance alternative for the HCl emission limit and/or the total selected metals (TSM) emission limit. This appendix specifies emissions testing methods that you must use to determine HCl, chlorine, and manganese emissions from the affected units and what parts of the affected source facility must be included in the eligibility demonstration. You must demonstrate that your affected source is eligible for the health-based compliance alternatives using either a look-up table analysis (based on the look-up tables included in this appendix) or a site-specific compliance demonstration performed according to the criteria specified in this appendix. This appendix also specifies how and when you file any eligibility demonstrations for your affected source and how to show that your affected source remains eligible for the health-based compliance alternatives in the future.

### 2. Who Is Eligible To Demonstrate That They Qualify for the Health-Based Compliance Alternatives?

Each new, reconstructed, or existing affected source may demonstrate that they are eligible for the health-based compliance alternatives. Section 63.7490 of subpart DDDDD defines the affected source and explains which affected sources are new, existing, or reconstructed.

### 3. What Parts of My Facility Have To Be Included in the Health-Based Eligibility Demonstration?

If you are attempting to determine your eligibility for the compliance alternative for HCl, you must include every emission point subject to subpart DDDDD that emits either HCl or Cl<sub>2</sub> in the eligibility demonstration.

If you are attempting to determine your eligibility for the compliance alternative for TSM, you must include every emission point subject to subpart DDDDD that emits manganese in the eligibility demonstration.

### 4. How Do I Determine HAP Emissions From My Affected Source?

(a) You must conduct HAP emissions tests or fuel analysis for every emission point covered under subpart DDDDD within the affected source facility according to the requirements in paragraphs (b) through (f) of this section and the methods specified in Table 1 of this appendix.

(1) If you are attempting to determine your eligibility for the compliance alternative for HCl, you must test the subpart DDDDD units at your facility for both HCl and Cl<sub>2</sub>. When conducting fuel analysis, you must assume any chlorine detected will be emitted as Cl<sub>2</sub>.

(2) If you are attempting to determine your eligibility for the compliance alternative for TSM, you must test the subpart DDDDD units at your facility for manganese.

(b) *Periods when emissions tests must be conducted.* (1) You must not conduct emissions tests during periods of startup, shutdown, or malfunction, as specified in §63.7(e)(1).

(2) You must test under worst-case operating conditions as defined in this appendix. You must describe your worst-case operating conditions in your performance test report for the process and control systems (if applicable) and explain why the conditions are worst-case.

(c) *Number of test runs.* You must conduct three separate test runs for each test required in this section, as specified in §63.7(e)(3). Each test run must last at least 1 hour.

(d) *Sampling locations.* Sampling sites must be located at the outlet of the control device and prior to any releases to the atmosphere.

(e) *Collection of monitoring data for HAP control devices.* During the emissions test, you must collect operating parameter monitoring system data at least every 15 minutes during the entire emissions test and establish the site-specific operating requirements in Tables 3 or 4, as appropriate, of subpart DDDDD using data from the monitoring system and the procedures specified in §63.7530 of subpart DDDDD.

(f) *Nondetect data.* You may treat emissions of an individual HAP as zero if all of the test runs result in a nondetect measurement and the condition in paragraph (f)(1) of this section is met for the manganese test method. Otherwise, nondetect data for individual HAP must be treated as one-half of the method detection limit.

(1) For manganese measured using Method 29 in appendix A to 40 CFR part 60, you analyze samples using atomic absorption spectroscopy (AAS).

(g) You must determine the maximum hourly emission rate for each appropriate emission point according to Equation 1 of this appendix. An appropriate emission point is any emission point emitting HCl, Cl<sub>2</sub>, or Manganese from a subpart DDDDD emission unit.

$$E_{i,s} = \sum_{j=1}^t (R_{i,j} \times I_j) \quad (\text{Eq. 1})$$

Where:

$E_{i,s}$  = maximum hourly emission rate for HAP i at each emission point s associated with a subpart DDDDD emission unit j, lbs/hr

i = applicable HAP, where i = (HCl, Cl<sub>2</sub>, or Manganese) s = individual emission point

j = each subpart DDDDD emission unit associated with an emission point, s

t = total number of subpart DDDDD emission units associated with an emission point s

$R_{i,j}$  = emission rate (the 3-run average as determined according to table 1 of this appendix or the pollutant concentration in the fuel samples analyzed according to §63.7521) for HAP i at subpart DDDDD emission unit j associated with emission point s, lb per million Btu.

$I_j$  = Maximum rated heat input capacity of each subpart DDDDD unit j emitting HAP i associated with emission point s, million Btu per hour.

## 5. What Are the Criteria for Determining If My Facility Is Eligible for the Health-Based Compliance Alternatives?

(a) Determine the HAP emissions from each appropriate emission point within the affected source facility using the procedures specified in section 4 of this appendix.

(b) Demonstrate that your facility is eligible for either of the health-based compliance alternatives using either the methods described in section 6 of this appendix (look-up table analysis) or section 7 of this appendix (site-specific compliance demonstration).

(c) Your facility is eligible for the health-based compliance alternative for HCl if one of the following two statements is true:

- (1) The calculated HCl-equivalent emission rate is below the appropriate value in the look-up table;
- (2) Your site-specific compliance demonstration indicates that none of your HI values for HCl and  $Cl_2$  are greater than 1.0 at locations where people live or congregate (e.g., schools, daycare centers, etc.);

(d) Your facility is eligible for the health-based compliance alternative for TSM if one of the following two statements is true:

- (1) The manganese emission rate for all your subpart DDDDD sources is below the appropriate value in the look-up table;
- (2) Your site-specific compliance demonstration indicates that none of your HQ values for manganese are greater than 1.0 at locations where people live or congregate (e.g., schools, daycare centers, etc.).

## 6. How Do I Conduct a Look-Up Table Analysis?

You may use look-up tables to demonstrate that your facility is eligible for either the compliance alternative for HCl emissions limit or the compliance alternative for the TSM emissions limit, unless your permitting authority determines that the look-up table analysis in this section is not applicable to your facility on technical grounds due to site-specific variations that are not accounted for in the look-up table analysis (e.g. presence of complex terrain, rain caps, or building downwash effects).

(a) *HCl compliance alternative.* (1) Using the emission rates for HCl and  $Cl_2$  determined according to section 4 of this appendix, calculate, using equation 2 of this appendix, the toxicity-weighted emission rate (expressed in HCl-equivalents) for each emission point that emits HCl or  $Cl_2$  from any subpart DDDDD sources. Then, calculate the weighted average stack height using equation 3 of this appendix.

$$TW_s = E_{HCl,s} + E_{Cl_2,s} \left( \frac{RV_{HCl}}{RV_{Cl_2}} \right) \quad (\text{Eq. 2})$$

Where:

$TW_s$  = the toxicity-weighted emission rate (in HCl-equivalent) for each emission point s, lb/hr.

s = individual emission points

$E_{HCl,s}$  = the maximum hourly emission rate for HCl at emission point s, lb/hr

$E_{Cl_2,s}$  = the maximum hourly emission rate for  $Cl_2$  at emission point s, lb/hr

$RV_{Cl_2}$  = the reference value for  $Cl_2$

$RV_{HCl}$  = the reference value for HCl

(reference values for HCl and  $Cl_2$  can be found at <http://www.epa.gov/ttn/atw/toxsource/summary.html>).

$$H_{HCl} = \frac{\sum_{s=1}^n (TW_s \times H_s)}{TW_T} \quad (\text{Eq. 3})$$

Where:

$H_{HCl}$  = weighted average stack height for determining the maximum allowable HCl-equivalent emission rate (in Table 2 to this appendix), m.

s = individual emission points

n = total number of emission points

$TW_s$  = toxicity-weighted HCl-equivalent emission rate from each emission point (from equation 2), lb/hr.

$H_s$  = height of each individual stack, m

$TW_T$  = total toxicity-weighted HCl-equivalent emission rate from the source (summed for all emission points), lb/hr.

(2) Calculate the total toxicity-weighted emission rate for your affected source by summing the toxicity-weighted emission rate for each appropriate subpart DDDDD emission point.

(3) Using the weighted average stack height and the minimum distance between any appropriate subpart DDDDD emission point at the source and the property boundary, identify the appropriate maximum allowable toxicity weighted emission rate for your affected source, expressed in HCl-equivalents, from table 2 of this appendix. Appropriate emission points are those that emit HCl or Cl<sub>2</sub>, or both, from subpart DDDDD units. If one or both of these values does not match the exact values in the look-up tables, then use the next lowest table value. (Note: If your weighted average stack height is less than 5 meters (m), you must use the 5 meter row.) Your affected source is eligible to comply with the health-based alternative for HCl emissions if the value calculated in paragraph (a)(2) of this section, determined using the methods specified in this appendix, does not exceed the appropriate value in table 2 of this appendix.

(b) *TSM Compliance Alternative.* Using the emission rates for manganese determined according to section 4 of this appendix, calculate the total manganese emission rate for your affected source by summing the maximum hourly manganese emission rates for all your subpart DDDDD units. Identify the appropriate allowable emission rate in table 3 of this appendix for your affected source using the weighted average stack height value and the minimum distance between any appropriate subpart DDDDD emission point at the facility and the property boundary. Appropriate emission points are those that emit manganese from subpart DDDDD units. If one or both of these values does not match the exact values in the look-up tables, then use the next lowest table value. (Note: If your weighted average stack height is less than 5 meters, you must use the 5 meter row.) Your affected source is eligible to comply with the health-based alternative for manganese emissions and may exclude manganese when demonstrating compliance with the TSM emission limit if the total manganese emission rate, determined using the methods specified in this appendix, does not exceed the appropriate value specified in table 3 of this appendix.

$$H_{Mn} = \frac{\sum_{s=1}^n (E_{Mn,s} \times H_s)}{E_{Mn,T}} \quad (\text{Eq. 4})$$

Where:

$H_{Mn}$  = weighted average stack height for determining the maximum allowable emission rate for manganese (in table 3 to this appendix), m.

s = individual emission points

n = total number of emission points

$E_{Mn,s}$  = maximum hourly manganese emissions from emission point s, lbs/hr.

$H_s$  = height of each individual stack s

$E_{Mn,T}$  = total maximum hourly manganese emissions from affected source (sum emission rates from all emission points), lb/hr

## 7. How Do I Conduct a Site-Specific Compliance Demonstration?

If you fail to demonstrate that your facility is able to comply with one or both of the alternative health-based emission standards using the look-up table approach, you may choose to perform a site-specific compliance demonstration for your facility. You may use any scientifically-accepted peer-reviewed risk assessment methodology for your site-specific compliance demonstration. An example of one approach for performing a site-specific compliance demonstration for air toxics can be found in the EPA's "Air Toxics Risk Assessment Reference Library, Volume 2, Site-Specific Risk Assessment Technical Resource Document", which may be obtained through the EPA's Air Toxics Web site at [http://www.epa.gov/ttn/fera/risk\\_atoxic.html](http://www.epa.gov/ttn/fera/risk_atoxic.html).

(a) Your facility is eligible for the HCl alternative compliance option if your site-specific compliance demonstration shows that the maximum HI for HCl and  $Cl_2$  from your subpart DDDDD sources is less than or equal to 1.0.

(b) Your facility is eligible for the TSM alternative compliance option if your site-specific compliance demonstration shows that the maximum HQ for manganese from your subpart DDDDD sources is less than or equal to 1.0.

(c) At a minimum, your site-specific compliance demonstration must:

(1) Estimate long-term inhalation exposures through the estimation of annual or multi-year average ambient concentrations;

(2) Estimate the inhalation exposure for the individual most exposed to the facility's emissions;

(3) Use site-specific, quality-assured data wherever possible;

(4) Use health-protective default assumptions wherever site-specific data are not available, and;

(5) Contain adequate documentation of the data and methods used for the assessment so that it is transparent and can be reproduced by an experienced risk assessor and emissions measurement expert.

(d) Your site-specific compliance demonstration need not:

(1) Assume any attenuation of exposure concentrations due to the penetration of outdoor pollutants into indoor exposure areas;

(2) Assume any reaction or deposition of the emitted pollutants during transport from the emission point to the point of exposure.

#### 8. What Must My Health-Based Eligibility Demonstration Contain?

(a) Your health-based eligibility demonstration must contain, at a minimum, the information specified in paragraphs (a)(1) through (6) of this section.

(1) Identification of each appropriate emission point at the affected source facility, including the maximum rated capacity of each appropriate emission point.

(2) Stack parameters for each appropriate emission point including, but not limited to, the parameters listed in paragraphs (a)(2)(i) through (iv) below:

(i) Emission release type.

(ii) Stack height, stack area, stack gas temperature, and stack gas exit velocity.

(iii) Plot plan showing all emission points, nearby residences, and fenceline.

(iv) Identification of any control devices used to reduce emissions from each appropriate emission point.

(3) Emission test reports for each pollutant and appropriate emission point which has been tested using the test methods specified in Table 1 of this appendix, including a description of the process parameters identified as being worst case. Fuel analyses for each fuel and emission point which has been conducted including collection and analytical methods used.

(4) Identification of the RfC values used in your look-up table analysis or site-specific compliance demonstration.

(5) Calculations used to determine the HCl-equivalent or manganese emission rates according to sections 6(a) or (b) of this appendix.

(6) Identification of the controlling process factors (including, but not limited to, fuel type, heat input rate, type of control devices, process parameters reflecting the emissions rates used for your eligibility demonstration) that will become Federally enforceable permit conditions used to show that your facility remains eligible for the health-based compliance alternatives.

(b) If you use the look-up table analysis in section 6 of this appendix to demonstrate that your facility is eligible for either health-based compliance alternative, your eligibility demonstration must contain, at a minimum, the information in paragraphs (a) and (b)(1) through (3) of this section.

(1) Calculations used to determine the weighted average stack height of the subpart DDDDD emission points that emit manganese, HCl, or Cl<sub>2</sub>.

(2) Identification of the subpart DDDDD emission point, that emits either manganese or HCl and Cl<sub>2</sub>, with the minimum distance to the property boundary of the facility.

(3) Comparison of the values in the look-up tables (Tables 2 and 3 of this appendix) to your maximum HCl-equivalent or manganese emission rates.

(c) If you use a site-specific compliance demonstration as described in section 7 of this appendix to demonstrate that your facility is eligible, your eligibility demonstration must contain, at a minimum, the information in paragraphs (a) and (c)(1) through (7) of this section:

(1) Identification of the risk assessment methodology used.

(2) Documentation of the fate and transport model used.

(3) Documentation of the fate and transport model inputs, including the information described in paragraphs (a)(1) through (5) of this section converted to the dimensions required for the model and all of the following that apply: meteorological data; building, land use, and terrain data; receptor locations and population data; and other facility-specific parameters input into the model.

(4) Documentation of the fate and transport model outputs.

(5) Documentation of any exposure assessment and risk characterization calculations.

(6) Comparison of the HQ HI to the limit of 1.0.

(d) To be eligible for either health-based compliance alternative, the parameters that defined your affected source as eligible for the health-based compliance alternatives must be submitted to your permitting authority for incorporation into your title V permit, as federally enforceable limits, at the same time you submit your health-based eligibility demonstration. These parameters include, but are not limited to, fuel type, fuel mix (annual average), emission rate, type of control devices, process parameters (e.g., maximum heat input), and non-process parameters (e.g., stack height).

## 9. When Do I Have To Complete and Submit My Health-Based Eligibility Demonstration?

(a) If you have an existing affected source, you must complete and submit your eligibility demonstration to your permitting authority, along with a signed certification that the demonstration is an accurate depiction of your facility, no later than the date one year prior to the compliance date of subpart DDDDD. A separate copy of the eligibility demonstration must be submitted to: U.S. EPA, Risk and Exposure Assessment Group, Emission Standards Division (C404-01), Attn: Group Leader, Research Triangle Park, North Carolina 27711, electronic mail address [REAG@epa.gov](mailto:REAG@epa.gov).

(b) If you have a new or reconstructed affected source that starts up before the effective date of subpart DDDDD, or an affected source that is an area source that increases its emissions or its potential to emit such that it becomes a major source of HAP before the effective date of subpart DDDDD, then you may submit an eligibility demonstration at any time after September 13, 2004 but you must comply with the emissions limits in table 1 to this subpart and all other requirements of subpart DDDDD until your eligibility demonstration is submitted to your permitting authority in accordance with the requirements of section 10 of this appendix.

(c) If you have a new or reconstructed affected source that starts up after the effective date of subpart DDDDD, or an affected source that is an area source that increases its emissions or its potential to emit such that it becomes a major source of HAP after the effective date for subpart DDDDD, then you must follow the schedule in paragraphs (c)(1) and (2) of this section.

(1) You must complete and submit a preliminary eligibility demonstration based on the information (e.g., equipment types, estimated emission rates, process and non-process parameters, reference values, etc.) that will be used to apply for your title V permit. This preliminary eligibility demonstration must be submitted with your application for approval of construction or reconstruction. You must base your preliminary eligibility demonstration on the maximum emissions allowed under your title V permit. If the

preliminary eligibility demonstration indicates that your affected source facility is eligible for either compliance alternative, then you may start up your new affected source and your new affected source will be considered in compliance with the alternative standard and subject to the compliance requirements in this appendix.

(2) You must conduct the emission tests or analyses specified in section 4 of this appendix upon initial startup and use the results of these emissions tests to complete and submit your eligibility demonstration within 180 days following your initial startup date.

#### 10. When Do I Become Eligible for the Health-Based Compliance Alternatives?

(a) For existing sources, new sources, or reconstructed sources that start up before the effective date of subpart DDDDD, or an affected source that is an area source that increases its emissions or its potential to emit such that it becomes a major source of HAP before the effective date of subpart DDDDD, you are eligible to comply with a health-based compliance alternative upon submission of a complete demonstration meeting all the requirements of paragraph 8 for the applicable alternative. However, your eligibility demonstration may be reviewed by the permitting authority or by EPA to verify that the demonstration meets the requirements of appendix A to this subpart and is technically sound (i.e. use of the look-up tables is appropriate or the site-specific assessment is technically valid). If you are notified by the permitting authority or by EPA of any deficiencies in your submission, then you are not eligible for the health-based compliance alternative until the permitting authority or EPA verifies that the deficiencies are corrected.

(b) For new or reconstructed sources that start up after the effective date of subpart DDDDD, you are eligible to comply with a the health-based compliance alternatives upon submission of a complete preliminary eligibility determination in accordance with paragraph (c)(1) of section 9 that demonstrates your affected source is eligible for the applicable alternative. You may then start up your source and conduct the necessary testing in accordance with paragraph (c)(2) of section 9. The eligibility demonstration submitted in accordance with paragraph (c)(2) of section 9 may be reviewed by the permitting authority or by EPA to verify that the demonstration meets the requirements of appendix A to this subpart and is technically sound (i.e. use of the look-up tables is appropriate or the site-specific assessment is technically valid). If you are notified in writing by the permitting authority of any deficiencies in your submission, then you have 30 days to correct the deficiencies unless the permitting authority agrees to extend this time to a period not to exceed 90 days. If the deficiencies are not corrected within the applicable time period, you will not be eligible for the health-based compliance alternative until the permitting authority verifies that the deficiencies are corrected.

(c) If the title V permit conditions requested in accordance with paragraph (d) of section 8 are disapproved by the permitting authority, then your affected source must comply with the applicable emission limits, operating limits, and work practice standards in subpart DDDDD by the compliance dates specified in §63.7495. Until the requested conditions (or alternative conditions meeting the requirements of paragraph (d) of section 8) are incorporated into the permit, compliance with the proposed conditions shall be considered compliance with the health-based alternative.

#### 11. How Do I Ensure That My Facility Remains Eligible for the Health-Based Compliance Alternatives?

(a) You must update your eligibility demonstration and resubmit it each time that any of the parameters that defined your affected source as eligible for the health-based compliance alternatives changes in a way that could result in increased HAP emissions or increased risk from exposure to emissions. These parameters include, but are not limited to, fuel type, fuel mix (annual average), type of control devices, HAP emission rate, stack height, process parameters (e.g., heat input capacity), relevant reference values, and locations where people live).

(b) If you are updating your eligibility demonstration to account for an action in paragraph (a) of this section that is under your control (e.g. change in heat input capacity of your boiler), you must submit your revised eligibility demonstration to the permitting authority prior to making the change and revise your permit to incorporate the change. If your affected source is no longer eligible for the health-based compliance alternatives, then you must comply with the applicable emission limits, operating limits, and compliance requirements in subpart DDDDD prior to making the process change and revising your permit. If you are updating your eligibility demonstration to account for an action in paragraph (a) of this section that is outside of your control (e.g. change in a reference value), and that change causes your source to no longer be able to meet the criteria for the health-based compliance alternatives, your source must comply with the applicable emission limits, operating limits, and compliance requirements in subpart DDDDD within 3 years.

(c) Your revised eligibility demonstration may be reviewed by the permitting authority or EPA to verify that the demonstration meets the requirements of appendix A to this subpart and is technically sound (i.e. use of the look-up tables is appropriate or the site-specific assessment is technically valid). If you are notified by the permitting authority or EPA of any deficiencies in your submission, you will not remain eligible for the health-based compliance alternatives until the permitting authority or EPA verifies that the deficiencies are corrected.

## 12. What Records Must I Keep?

You must keep records of the information used in developing the eligibility demonstration for your affected source, including all of the information specified in section 8 of this appendix.

## 13. Definitions

The definitions in §63.7575 of subpart DDDDD apply to this appendix. Additional definitions applicable for this appendix are as follows:

*Hazard Index (HI)* means the sum of more than one hazard quotient for multiple substances and/or multiple exposure pathways.

*Hazard Quotient (HQ)* means the ratio of the predicted media concentration of a pollutant to the media concentration at which no adverse effects are expected. For inhalation exposures, the HQ is calculated as the air concentration divided by the RfC.

*Look-up table analysis* means a risk screening analysis based on comparing the HAP or HAP-equivalent emission rate from the affected source to the appropriate maximum allowable HAP or HAP-equivalent emission rates specified in Tables 2 and 3 of this appendix.

*Reference Concentration (RfC)* means an estimate (with uncertainty spanning perhaps an order of magnitude) of a continuous inhalation exposure to the human population (including sensitive subgroups) that is likely to be without an appreciable risk of deleterious effects during a lifetime. It can be derived from various types of human or animal data, with uncertainty factors generally applied to reflect limitations of the data used.

*Worst-case operating conditions* means operation of an affected unit during emissions testing under the conditions that result in the highest HAP emissions or that result in the emissions stream composition (including HAP and non-HAP) that is most challenging for the control device if a control device is used. For example, worst-case conditions could include operation of an affected unit firing solid fuel likely to produce the most HAP.

### **Table 1 to Appendix B of Subpart DDDDD—Emission Test Methods**

For . . .	You must . . .	Using . . .
(1) Each subpart DDDDD emission point for which you choose to use a compliance alternative	Select sampling ports' location and the number of traverse points	Method 1 of 40 CFR part 60, appendix A.
(2) Each subpart DDDDD emission point for which you choose to use a compliance alternative	Determine velocity and volumetric flow rate;	Method 2, 2F, or 2G in appendix A to 40 CFR part 60.
(3) Each subpart DDDDD emission point for which you choose to use a compliance alternative	Conduct gas molecular weight analysis	Method 3A or 3B in appendix A to 40 CFR part 60.
(4) Each subpart DDDDD emission point for which you choose to use a compliance alternative	Measure moisture content of the stack gas	Method 4 in appendix A to 40 CFR part 60.
(5) Each subpart DDDDD emission point for which you choose to use the HCl compliance alternative	Measure the hydrogen chloride and chlorine emission concentrations	Method 26 or 26A in appendix A to 40 CFR part 60.
(6) Each subpart DDDDD emission point for which you choose to use the TSM compliance alternative	Measure the manganese emission concentration	Method 29 in appendix A to 40 CFR part 60.
(7) Each subpart DDDDD emission point for which you choose to use a compliance alternative	Convert emissions concentration to lb per MMBtu emission rates	Method 19 F-factor methodology in appendix A to part 60 of this chapter.

**Table 2 to Appendix A of Subpart DDDDD—Allowable Toxicity-Weighted Emission Rate Expressed in HCl Equivalents (lbs/hr)**

Stack ht. (m)	Distance to property boundary (m)											
	0	50	100	150	200	250	500	1000	1500	2000	3000	5000
5	114.9	114.9	114.9	114.9	114.9	114.9	144.3	287.3	373.0	373.0	373.0	373.0
10	188.5	188.5	188.5	188.5	188.5	188.5	195.3	328.0	432.5	432.5	432.5	432.5
20	386.1	386.1	386.1	386.1	386.1	386.1	386.1	425.4	580.0	602.7	602.7	602.7
30	396.1	396.1	396.1	396.1	396.1	396.1	396.1	436.3	596.2	690.6	807.8	816.5
40	408.1	408.1	408.1	408.1	408.1	408.1	408.1	448.2	613.3	715.5	832.2	966.0
50	421.4	421.4	421.4	421.4	421.4	421.4	421.4	460.6	631.0	746.3	858.2	1002.8
60	435.5	435.5	435.5	435.5	435.5	435.5	435.5	473.4	649.0	778.6	885.0	1043.4
70	450.2	450.2	450.2	450.2	450.2	450.2	450.2	486.6	667.4	813.8	912.4	1087.4
80	465.5	465.5	465.5	465.5	465.5	465.5	465.5	500.0	685.9	849.8	940.9	1134.8
100	497.5	497.5	497.5	497.5	497.5	497.5	497.5	527.4	723.6	917.1	1001.2	1241.3
200	677.3	677.3	677.3	677.3	677.3	677.3	677.3	682.3	919.8	1167.1	1390.4	1924.6

**Table 3 to Appendix A of Subpart DDDDD—Allowable Manganese Emission Rate (lbs/hr)**

Stack ht. (m)	Distance to property boundary (m)											
	0	50	100	150	200	250	500	1000	1500	2000	3000	5000
5	0.29	0.29	0.29	0.29	0.29	0.29	0.36	0.72	0.93	0.93	0.93	0.94
10	0.47	0.47	0.47	0.47	0.47	0.47	0.49	0.82	1.08	1.08	1.08	1.08
20	0.97	0.97	0.97	0.97	0.97	0.97	0.97	1.06	1.45	1.51	1.51	1.51
30	0.99	0.99	0.99	0.99	0.99	0.99	0.99	1.09	1.49	1.72	2.02	2.04
40	1.02	1.02	1.02	1.02	1.02	1.02	1.02	1.12	1.53	1.79	2.08	2.42
50	1.05	1.05	1.05	1.05	1.05	1.05	1.05	1.15	1.58	1.87	2.15	2.51
60	1.09	1.09	1.09	1.09	1.09	1.09	1.09	1.18	1.62	1.95	2.21	2.61
70	1.13	1.13	1.13	1.13	1.13	1.13	1.13	1.22	1.67	2.03	2.28	2.72
80	1.16	1.16	1.16	1.16	1.16	1.16	1.16	1.25	1.71	2.12	2.35	2.84
100	1.24	1.24	1.24	1.24	1.24	1.24	1.24	1.32	1.81	2.29	2.50	3.10
200	1.69	1.69	1.69	1.69	1.69	1.69	1.69	1.71	2.30	2.92	3.48	4.81

[69 FR 55253, Sept. 13, 2004, as amended at 70 FR 76933, Dec. 28, 2005]

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

**Technical Support Document (TSD) for a Part 70 Minor Source Modification**

**Source Description and Location**

Source Name:	Bunge North America (East), LLC
Source Location:	1200 North 2 <sup>nd</sup> Street, Decatur, Indiana 46733
County:	Adams
SIC Code:	2075, 2079, 5153, and 2048
Operation Permit No.:	T 001-23640-00005
Operation Permit Issuance Date:	April 8, 2008
Minor Source Modification No.:	001-32520-00005
Permit Reviewer:	Brian Williams

**Existing Approvals**

The source was issued Part 70 Operating Permit Renewal No. T001-23640-00005 on April 8, 2008. The source has since received the following approvals:

- (a) Administrative Amendment No. 001-26472-00005, issued May 7, 2008;
- (b) Administrative Amendment No. 001-27445-00005, issued February 27, 2009;
- (c) Administrative Amendment No. 001-27635-00005, issued April 28, 2009;
- (d) Significant Source Modification No. 001-28224-00005, issued November 6, 2009;
- (e) Significant Permit Modification No. 001-27816-00005, issued November 24, 2009;
- (f) Significant Source Modification No. 001-29100-00005, issued July 8, 2010;
- (g) Interim Significant Source Modification No. 001-293471-00005, issued July 9, 2010;
- (h) Significant Permit Modification No. 001-29164-00005, issued August 4, 2010;
- (i) Significant Source Modification No. 001-29347-00005, issued August 17, 2010;
- (j) Significant Permit Modification No. 001-29371-00005, issued September 1, 2010;
- (k) Significant Permit Modification No.: 001-29887-00005, issued July 29, 2011;
- (l) Significant Source Modification No. 001-30622-00005, issued October 4, 2011;
- (m) Significant Permit Modification No.: 001-30609-00005, issued October 21, 2011; and
- (n) Significant Permit Modification No.: 001-30642-00005, issued January 26, 2012.

**County Attainment Status**

The source is located in Adams 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 June 15, 2004, for the 8-hour ozone standard. <sup>1</sup>
PM <sub>10</sub>	Unclassifiable effective November 15, 1990.
NO <sub>2</sub>	Cannot be classified or better than national standards.
Pb	Not designated.
<sup>1</sup> Unclassifiable or attainment effective October 18, 2000, for the 1-hour ozone standard which was revoked effective June 15, 2005. Unclassifiable or attainment effective April 5, 2005, for PM <sub>2.5</sub> .	

- (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. Adams 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>**  
 Adams 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. See the State Rule Applicability – Entire Source section.
  
- (c) **Other Criteria Pollutants**  
 Adams 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**

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, however, the grain elevator has an applicable New Source Performance Standard that was in effect on August 7, 1980, therefore fugitive emissions are counted toward the determination of PSD, Emission Offset, and Part 70 Permit applicability.

**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:

Pollutant	Emissions (ton/yr)
PM	>250
PM <sub>10</sub>	>250
PM <sub>2.5</sub>	>250
SO <sub>2</sub>	>250
VOC	>250
CO	>250
NO <sub>x</sub>	>250
GHG as CO <sub>2</sub> e	>100,000
Total HAPs	>25
Single HAPs	>10

- (a) This existing source is a major stationary source, under PSD (326 IAC 2-2), because a regulated pollutant is emitted at a rate of 250 tons per year or more, emissions of GHGs are equal to or greater 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 a major source of HAPs, as defined in 40 CFR 63.2, because HAP emissions are greater than ten (10) tons per year for a single HAP and greater than twenty-five (25) tons per year for a combination of HAPs. Therefore, this source is a major source under Section 112 of the Clean Air Act (CAA).
- (c) These emissions are based upon the Technical Support Document for Significant Permit Modification No. 001-30642-00005, issued on January 26, 2012.

**Description of Proposed Modification**

The Office of Air Quality (OAQ) has reviewed a modification application, submitted by Bunge North America (East), LLC on November 16, 2012, relating to the construction of a new 99 MMBtu per hour natural gas-fired boiler, which is equipped with low NO<sub>x</sub> burners and flue gas recirculation. The following is a list of the proposed emission unit and pollution control devices:

- (a) One (1) natural gas-fired boiler, identified as 9SP1, approved for construction in 2012, with a maximum heat input capacity of 99 MMBtu/hr, equipped with low NO<sub>x</sub> burners and flue gas recirculation (FGR) for NO<sub>x</sub> control, and exhausting to stack 9SP. This is an affected facility under the New Source Performance Standards for Small Industrial - Commercial - Institutional Steam Generating Units 40 CFR 60, Subpart Dc and an affected source under the National Emission Standards for Hazardous Air Pollutants for Industrial, Commercial, and Institutional Boilers and Process Heaters 40 CFR 63, Subpart DDDDD.

**Enforcement Issues**

There are no pending enforcement actions related to this modification.

**Stack Summary**

Stack ID	Operation	Height (ft)	Diameter (ft)	Flow Rate (acfm)	Temperature (°F)
9SP	Boiler 9SP1	27.6	4.5	18,000	350

### 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.

Increase in PTE Before Controls of the Modification	
Pollutant	Potential To Emit (ton/yr)
PM	0.82
PM <sub>10</sub>	3.30
PM <sub>2.5</sub>	3.30
SO <sub>2</sub>	0.26
NO <sub>x</sub>	13.88
VOC	2.38
CO	36.42
GHGs as CO <sub>2</sub> e	52,351
Single HAPs	0.78 (Hexane)
Total HAPs	0.82

(1) Approval to construct:

This source modification is subject to 326 IAC 2-7-10.5(e)(3), because the proposed modification involves the construction of an emission unit with the potential to emit (PTE) within the following ranges:

- (a) Less than twenty-five (25) tons per year and equal to or greater than ten (10) tons per year of Nitrogen oxides (NO<sub>x</sub>).
- (b) Less than one hundred (100) tons per year and equal to or greater than twenty-five (25) tons per year of carbon monoxide (CO).

(2) Approval to operate:

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 a case-by-case determination of an emission limitation and is a modification under Title 1 of the Clean Air Act.

However, IDEM will not be issuing a separate significant permit modification. Instead, the approval to operate the proposed boiler will be included in the pending Title V Renewal No.: 001-31996-00005.

Note: This is considered a Title I modification because the boiler is subject to NSPS 40 CFR 60, Subpart Dc and NESHAP 40 CFR 63, Subpart DDDDD (see Federal Rule Applicability Determination portion of this TSD for details).

**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 modification, and only to the extent that the effect of the control equipment is made practically enforceable in the permit.

Process / Emission Unit	Potential to Emit (ton/yr)							
	PM	PM <sub>10</sub>	PM <sub>2.5</sub> *	SO <sub>2</sub>	VOC	CO	NO <sub>x</sub>	GHGs
Natural Gas-Fired Boiler (9SP1)	0.82	3.30	3.30	0.26	2.38	36.42	13.88	52,351
Total for Modification	0.82	3.30	3.30	0.26	2.38	36.42	13.88	52,351
PSD Significant Level	25	15	10	40	40	100	40	75,000 CO <sub>2e</sub>

\*PM<sub>2.5</sub> listed is direct PM<sub>2.5</sub>.

This modification to an existing major stationary source is not major because the emissions increase is less than the PSD significant levels. Therefore, pursuant to 326 IAC 2-2, the PSD requirements do not apply.

**Federal Rule Applicability Determination**

The following federal rules are applicable to the source due to this modification:

**NSPS:**

- (a) The new natural gas-fired boiler (9SP1) is subject to the New Source Performance Standards for Small Industrial-Commercial-Institutional Steam Generating Units (40 CFR 60.40c, Subpart Dc), which is incorporated by reference as 326 IAC 12. The unit subject to this rule is the following:

One (1) natural gas-fired boiler, identified as 9SP1, approved for construction in 2012, with a maximum heat input capacity of 99 MMBtu/hr, equipped with low NO<sub>x</sub> burners and flue gas recirculation (FGR) for NO<sub>x</sub> control, and exhausting to stack 9SP.

Nonapplicable portions of the NSPS will not be included in the permit. This boiler is subject to the following portions of Subpart Dc:

- (1) 40 CFR 60.40c (a) and (b)
- (2) 40 CFR 60.41c
- (3) 40 CFR 60.48(c) (a)(1), (g), and (i)

**NESHAP:**

- (b) This source is subject to the National Emission Standards for Hazardous Air Pollutants (NESHAPs) for Industrial, Commercial, and Institutional Boilers and Process Heaters (40 CFR Part 63, Subpart DDDDD), which is incorporated by reference in 326 IAC 20-95, because the source operates at least one industrial, commercial, or institutional boiler or process heater as defined in §63.7575 that is located at, or is part of, a major source of HAP.

The emission units subject to this rule include the following:

- (1) One (1) natural gas fired hydrogen generator furnace, identified as 107EO1, constructed in 1992, with a maximum heat input capacity of 25.2 MMBtu/hr, and exhausting to stack 107EO.

- (2) One (1) natural gas fired steam generator, identified as 110EO1, constructed in 2002, with a maximum heat input capacity of 14 MMBtu/hr, and exhausting to stack 110EO. This is an affected facility under the New Source Performance Standards for Small Industrial - Commercial - Institutional Steam Generating Units 40 CFR 60, Subpart Dc.
- (3) One (1) natural gas fired steam generator #3, identified as 108EO1, constructed in 1994, with a maximum heat input capacity of 14 MMBtu/hr, and exhausting to stack 108EO. This is an affected facility under the New Source Performance Standards for Small Industrial - Commercial - Institutional Steam Generating Units 40 CFR 60, Subpart Dc.
- (4) One (1) B & W coal fired boiler, identified as 1SP1, constructed in 1950, with a maximum heat input capacity of 108 MMBtu/hr, using multiple cyclones and a baghouse for control of particulate and HAPs, and exhausting to stack 1SP.
- (5) One (1) Keeler coal fired boiler, identified as 2SP1, constructed in 1963, with a maximum heat input capacity of 52.75 MMBtu/hr, using multiple cyclones and a baghouse for control of particulate and HAPs, and exhausting to stack 1SP.
- (6) One (1) Murray natural gas fired, vegetable oil-fired, used oil-fired, and hazardous chemical fired boiler, identified as 3SP1, constructed in 1968, with a maximum heat input capacity of 110.2 MMBtu/hr, and exhausting to stack 1SP.
- (7) One (1) natural gas-fired boiler, identified as 9SP1, approved for construction in 2012, with a maximum heat input capacity of 99 MMBtu/hr, equipped with low NOx burners and flue gas recirculation (FGR) for NOx control, and exhausting to stack 9SP.

Applicable portions of the NESHAP are the following:

- (1) 40 CFR 63.7480
- (2) 40 CFR 63.7485
- (3) 40 CFR 63.7490
- (4) 40 CFR 63.7495(a), (b), and (d)
- (5) 40 CFR 63.7499
- (6) 40 CFR 63.7500
- (7) 40 CFR 63.7505
- (8) 40 CFR 63.7506(b)
- (9) 40 CFR 63.7507
- (10) 40 CFR 63.7510(a), (b), (c), (d), and (g)
- (11) 40 CFR 63.7515
- (12) 40 CFR 63.7520(a), (b), (d), (e), (f), and (g)
- (13) 40 CFR 63.7521
- (14) 40 CFR 63.7522
- (15) 40 CFR 63.7525
- (16) 40 CFR 63.7530(a), (c), (d), and (e)
- (17) 40 CFR 63.7535
- (18) 40 CFR 63.7540
- (19) 40 CFR 63.7541
- (20) 40 CFR 63.7545(a), (b), (c), (d), (e)(1-7), and (e)(9)
- (21) 40 CFR 63.7550
- (22) 40 CFR 63.7555
- (23) 40 CFR 63.7560
- (24) 40 CFR 63.7565
- (25) 40 CFR 63.7570
- (26) 40 CFR 63.7575
- (27) Table 1 to 40 CFR 63
- (28) Table 2 to 40 CFR 63

- (29) Table 3 to 40 CFR 63
- (30) Table 4 to 40 CFR 63
- (31) Table 5 to 40 CFR 63
- (32) Table 6 to 40 CFR 63
- (33) Table 7 to 40 CFR 63
- (34) Table 8 to 40 CFR 63
- (35) Table 9 to 40 CFR 63
- (36) Table 10 to 40 CFR 63
- (37) Appendix A to 40 CFR 63

This is a new requirement in the permit and this NESHAP contains applicable testing requirements.

The requirements of 40 CFR Part 63, Subpart A – General Provisions, which are incorporated as 326 IAC 20-1-1, apply to these facilities except as otherwise specified in 40 CFR 63, Subpart DDDDD.

- (c) This requirements of the National Emission Standards for Hazardous Air Pollutants for Industrial, Commercial, and Institutional Boilers and Process Heaters, 40 CFR Part 63, Subpart DDDDD (326 IAC 20-95), are not included in this proposed modification for the four (4) existing natural gas-fired grain dryers (#1, #2, #4, and #5) because each dryer does not meet the definition of a boiler or process heater in 40 CFR 63.7575.
- (d) 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.

Based on this evaluation, the requirements of 40 CFR Part 64, CAM are not applicable to the new emission unit as part of this modification because the emission unit does not meet the criteria outlined above.

### State Rule Applicability Determination

The following state rules are applicable to the source due to the modification:

**326 IAC 2-2 and 2-3 (PSD and Emission Offset)**

PSD and Emission Offset applicability is discussed under the Permit Level Determination – PSD and Emission Offset section.

**326 IAC 2-4.1 (Major Sources of Hazardous Air Pollutants (HAP))**

The operation of the new natural gas-fired boiler 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 5-1 (Opacity Limitations)**

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

- (1) 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.
- (2) 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.

### **326 IAC 6-4 (Fugitive Dust Emissions Limitations)**

Pursuant to 326 IAC 6-4 (Fugitive Dust Emissions Limitations), the source 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.

## **Natural Gas-Fired Boiler (9SP1)**

### **326 IAC 6-2 (Particulate Emission Limitations for Sources of Indirect Heating)**

The one (1) natural gas-fired boiler (9SP1) is subject to 326 IAC 6-2-4 because it was constructed after September 21, 1983 and is a source of indirect heating. Pursuant to 326 IAC 6-2-4(a), particulate emissions from this boiler must be calculated using the following equation:

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

Where:

$P_t$  = pounds of particulate matter emitted per million Btu heat input (lb/MMBtu)

$Q$  = total source operating capacity (324.15 + 99.0 = 423.15 MMBtu/hr)

$$P_t = \frac{1.09}{423.15^{0.26}}$$

$P_t$  = 0.23 lb/MMBtu

Based on the calculations below, this boiler can comply with this limit.

When burning natural gas:

PM Emissions = 1.9 lb PM/MMSCF \* MMSCF/1,020 MMBtu = 0.0019 lbs/MMBtu

### **326 IAC 6-3 (Particulate Emission Limitations for Manufacturing Processes)**

The natural gas-fired boiler (9SP1) is exempt from the requirements of 326 IAC 6-3, because, pursuant to 326 IAC 1-2-59, liquid and gaseous fuels and combustion air are not considered as part of the process weight.

### **326 IAC 7-1.1-1 (Sulfur Dioxide Emission Limitations)**

The natural gas-fired boiler (9SP1) is not subject to 326 IAC 7-1.1-1 (Sulfur Dioxide Emission Limitations) because the potential to emit sulfur dioxide from this unit is less than twenty-five (25) tons per year and ten (10) pounds per hour.

### **326 IAC 8-1-6 (New Facilities; General Reduction Requirements)**

The natural gas-fired boiler (9SP1) is not subject to 326 IAC 8-1-6 (New Facilities; General Reduction Requirements), because this unit has the potential to emit VOC of less than twenty-five (25) tons per year.

**326 IAC 9-1-1 (Carbon Monoxide Emission Limits)**

The natural gas-fired boiler (9SP1) is not subject to 326 IAC 9-1-1 (Carbon Monoxide Emission Limits) because there is no applicable emission limits for the source under 326 IAC 9-1-2.

**326 IAC 10-1-1 (Nitrogen Oxides Control)**

The natural gas-fired boiler (9SP1) is not subject to 326 IAC 10-1-1 (Nitrogen Oxides Control) because the source is not located in Clark or Floyd counties.

**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.

The compliance determination and monitoring requirements will not change as a result of this modification.

**Proposed Changes**

The changes listed below have been made to Part 70 Operating Permit No. 001-23640-00005. Deleted language appears as ~~strike throughs~~ and new language appears in **bold**:

**Modification #1**

Sections A.2 and D.3 have been revised to include descriptive information for the proposed boiler and existing boilers.

...  
A.2 Emission Units and Pollution Control Equipment Summary [326 IAC 2-7-4(c)(3)]  
[326 IAC 2-7-5(15)]

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

- ...
- (x) One (1) natural gas fired hydrogen generator furnace, identified as 107EO1, constructed in 1992, with a maximum heat input capacity of 25.2 MMBtu/hr, and exhausting to stack 107EO. **This is an affected source under the National Emission Standards for Hazardous Air Pollutants for Industrial, Commercial, and Institutional Boilers and Process Heaters 40 CFR 63, Subpart DDDDD.**
  - ...
  - (ss) One (1) natural gas fired steam generator, identified as 110EO1, constructed in 2002, with a maximum heat input capacity of 14 MMBtu/hr, and exhausting to stack 110EO. This is an affected facility under the New Source Performance Standards for Small Industrial - Commercial - Institutional Steam Generating Units 40 CFR 60, Subpart Dc **and an affected source under the National Emission Standards for Hazardous Air Pollutants for Industrial, Commercial, and Institutional Boilers and Process Heaters 40 CFR 63, Subpart DDDDD.**

- (tt) One (1) natural gas fired steam generator #3, identified as 108EO1, constructed in 1994, with a maximum heat input capacity of 14 MMBtu/hr, and exhausting to stack 108EO. This is an affected facility under the New Source Performance Standards for Small Industrial - Commercial - Institutional Steam Generating Units 40 CFR 60, Subpart Dc **and an affected source under the National Emission Standards for Hazardous Air Pollutants for Industrial, Commercial, and Institutional Boilers and Process Heaters 40 CFR 63, Subpart DDDDD.**
- (uu) One (1) B & W coal fired boiler, identified as 1SP1, constructed in 1950, with a maximum heat input capacity of 108 MMBtu/hr, using multiple cyclones and a baghouse for control of particulate and HAPs, and exhausting to stack 1SP. **This is an affected source under the National Emission Standards for Hazardous Air Pollutants for Industrial, Commercial, and Institutional Boilers and Process Heaters 40 CFR 63, Subpart DDDDD.**
- (vv) One (1) Keeler coal fired boiler, identified as 2SP1, constructed in 1963, with a maximum heat input capacity of 52.75 MMBtu/hr, using multiple cyclones and a baghouse for control of particulate and HAPs, and exhausting to stack 1SP. **This is an affected source under the National Emission Standards for Hazardous Air Pollutants for Industrial, Commercial, and Institutional Boilers and Process Heaters 40 CFR 63, Subpart DDDDD.**
- (ww) One (1) Murray natural gas fired, vegetable oil-fired, used oil-fired, and hazardous chemical fired boiler, identified as 3SP1, constructed in 1968, with a maximum heat input capacity of 110.2 MMBtu/hr, and exhausting to stack 1SP. **This is an affected source under the National Emission Standards for Hazardous Air Pollutants for Industrial, Commercial, and Institutional Boilers and Process Heaters 40 CFR 63, Subpart DDDDD.**
- ...
- (fff) **One (1) natural gas-fired boiler, identified as 9SP1, approved for construction in 2012, with a maximum heat input capacity of 99 MMBtu/hr, equipped with low NOx burners and flue gas recirculation (FGR) for NOx control, and exhausting to stack 9SP. This is an affected facility under the New Source Performance Standards for Small Industrial - Commercial - Institutional Steam Generating Units 40 CFR 60, Subpart Dc and an affected source under the National Emission Standards for Hazardous Air Pollutants for Industrial, Commercial, and Institutional Boilers and Process Heaters 40 CFR 63, Subpart DDDDD.**

SECTION D.3

EMISSIONS UNIT OPERATION CONDITIONS

Emissions Unit Description: Boilers and Heaters

- (a) One (1) natural gas fired hydrogen generator furnace, identified as 107EO1, constructed in 1992, with a maximum heat input capacity of 25.2 MMBtu/hr, and exhausting to stack 107EO. **This is an affected source under the National Emission Standards for Hazardous Air Pollutants for Industrial, Commercial, and Institutional Boilers and Process Heaters 40 CFR 63, Subpart DDDDD.**
- (b) One (1) natural gas fired steam generator, identified as 110EO1, constructed in 2002, with a maximum heat input capacity of 14 MMBtu/hr, and exhausting to stack 110EO. This is an affected facility under the New Source Performance Standards for Small Industrial - Commercial - Institutional Steam Generating Units 40 CFR 60, Subpart Dc **and an affected source under the National Emission Standards for Hazardous Air Pollutants for Industrial, Commercial, and Institutional Boilers and Process Heaters 40 CFR 63, Subpart DDDDD.**
- (c) One (1) natural gas fired steam generator #3, identified as 108EO1, constructed in 1994, with a

- maximum heat input capacity of 14 MMBtu/hr, and exhausting to stack 108EO. This is an affected facility under the New Source Performance Standards for Small Industrial - Commercial - Institutional Steam Generating Units 40 CFR 60, Subpart Dc **and an affected source under the National Emission Standards for Hazardous Air Pollutants for Industrial, Commercial, and Institutional Boilers and Process Heaters 40 CFR 63, Subpart DDDDD.**
- (d) One (1) B & W coal fired boiler, identified as 1SP1, constructed in 1950, with a maximum heat input capacity of 108 MMBtu/hr, using multiple cyclones and a baghouse for control of particulate and HAPs, and exhausting to stack 1SP. **This is an affected source under the National Emission Standards for Hazardous Air Pollutants for Industrial, Commercial, and Institutional Boilers and Process Heaters 40 CFR 63, Subpart DDDDD.**
- (e) One (1) Keeler coal fired boiler, identified as 2SP1, constructed in 1963, with a maximum heat input capacity of 52.75 MMBtu/hr, using multiple cyclones and a baghouse for control of particulate and HAPs, and exhausting to stack 1SP. **This is an affected source under the National Emission Standards for Hazardous Air Pollutants for Industrial, Commercial, and Institutional Boilers and Process Heaters 40 CFR 63, Subpart DDDDD.**
- (f) One (1) Murray natural gas fired, vegetable oil-fired, used oil-fired, and hazardous chemical fired boiler, identified as 3SP1, constructed in 1968, with a maximum heat input capacity of 110.2 MMBtu/hr, and exhausting to stack 1SP. **This is an affected source under the National Emission Standards for Hazardous Air Pollutants for Industrial, Commercial, and Institutional Boilers and Process Heaters 40 CFR 63, Subpart DDDDD.**
- (g) **One (1) natural gas-fired boiler, identified as 9SP1, approved for construction in 2012, with a maximum heat input capacity of 99 MMBtu/hr, equipped with low NOx burners and flue gas recirculation (FGR) for NOx control, and exhausting to stack 9SP. This is an affected facility under the New Source Performance Standards for Small Industrial - Commercial - Institutional Steam Generating Units 40 CFR 60, Subpart Dc and an affected source under the National Emission Standards for Hazardous Air Pollutants for Industrial, Commercial, and Institutional Boilers and Process Heaters 40 CFR 63, Subpart DDDDD.**
- ...

#### Modification #2

Condition D.3.1 - Particulate Matter Limitation (PM) has been revised to include a new PM emission limit for the new proposed boiler.

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

D.3.1 Particulate Matter Limitation (PM) [326 IAC 6-2-3] [326 IAC 6-2-4]

...

- (e) **Pursuant to 326 IAC 6-2-4 (Particulate Emission Limitations for Source of Indirect Heating), the particulate matter (PM) emissions from the boiler identified as 9SP1 shall be limited to less than 0.23 pounds per MMBtu of heat input.**

The emission limits for boilers 107EO1, 108EO1, and 110EO1, **9SP1** were calculated by the following equation:

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

Where Pt = emission rate limit (lbs/MMBtu)

Q = total source heat input capacity (MMBtu/hr)

**Q = 423.15 MMBtu/hr for 9SP1**

...

**Modification #3**

Section E.2 has been revised to include the new proposed boiler, which is subject to the requirements of 40 CFR 60, Subpart Dc. In addition, the emission unit descriptions for the existing boilers have been revised.

SECTION E.2 New Source Performance Standards (NSPS) For Small Industrial-  
Commercial-Institutional Steam Generating Units [40 CFR 60, Subpart Dc] [326 IAC 12]

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

- (a) One (1) natural gas fired hydrogen generator furnace, identified as 107EO1, constructed in 1992, with a maximum heat input capacity of 25.2 MMBtu/hr, and exhausting to stack 107EO. **This is an affected source under the National Emission Standards for Hazardous Air Pollutants for Industrial, Commercial, and Institutional Boilers and Process Heaters 40 CFR 63, Subpart DDDDD.**
- (b) One (1) natural gas fired steam generator, identified as 110EO1, constructed in 2002, with a maximum heat input capacity of 14 MMBtu/hr, and exhausting to stack 110EO. This is an affected facility under the New Source Performance Standards for Small Industrial - Commercial - Institutional Steam Generating Units 40 CFR 60, Subpart Dc **and an affected source under the National Emission Standards for Hazardous Air Pollutants for Industrial, Commercial, and Institutional Boilers and Process Heaters 40 CFR 63, Subpart DDDDD.**
- (c) One (1) natural gas fired steam generator #3, identified as 108EO1, constructed in 1994, with a maximum heat input capacity of 14 MMBtu/hr, and exhausting to stack 108EO. This is an affected facility under the New Source Performance Standards for Small Industrial - Commercial - Institutional Steam Generating Units 40 CFR 60, Subpart Dc **and an affected source under the National Emission Standards for Hazardous Air Pollutants for Industrial, Commercial, and Institutional Boilers and Process Heaters 40 CFR 63, Subpart DDDDD.**
- (d) **One (1) natural gas-fired boiler, identified as 9SP1, approved for construction in 2012, with a maximum heat input capacity of 99 MMBtu/hr, equipped with low NOx burners and flue gas recirculation (FGR) for NOx control, and exhausting to stack 9SP. This is an affected facility under the New Source Performance Standards for Small Industrial - Commercial - Institutional Steam Generating Units 40 CFR 60, Subpart Dc and an affected source under the National Emission Standards for Hazardous Air Pollutants for Industrial, Commercial, and Institutional Boilers and Process Heaters 40 CFR 63, Subpart DDDDD.**

...

New Source Performance Standards (NSPS) [40 CFR 60]

E.2.1 General Provisions Relating to New Source Performance Standards [326 IAC 12-1] [40 CFR 60, Subpart A]

- (a) The provisions of 40 CFR 60, Subpart A – General Provisions, which are incorporated by reference in 326 IAC 12-1, apply to the facilities described in this SECTION E.42, except when otherwise specified in 40 CFR 60, Subpart Dc.

...

**Modification #4**

Due to this modification this source is now subject to the requirements of 40 CFR 63, Subpart DDDDD. Therefore, the applicable requirements of this NESHAP have been included in a new Section E.4.

**SECTION E.4 National Emission Standards for Hazardous Air Pollutants for Industrial, Commercial, and Institutional Boilers and Process Heaters [40 CFR 63, Subpart DDDDD] [326 IAC 20-95]**

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

- (a) One (1) natural gas fired hydrogen generator furnace, identified as 107EO1, constructed in 1992, with a maximum heat input capacity of 25.2 MMBtu/hr, and exhausting to stack 107EO. This is an affected source under the National Emission Standards for Hazardous Air Pollutants for Industrial, Commercial, and Institutional Boilers and Process Heaters 40 CFR 63, Subpart DDDDD.
- (b) One (1) natural gas fired steam generator, identified as 110EO1, constructed in 2002, with a maximum heat input capacity of 14 MMBtu/hr, and exhausting to stack 110EO. This is an affected facility under the New Source Performance Standards for Small Industrial - Commercial - Institutional Steam Generating Units 40 CFR 60, Subpart Dc and an affected source under the National Emission Standards for Hazardous Air Pollutants for Industrial, Commercial, and Institutional Boilers and Process Heaters 40 CFR 63, Subpart DDDDD.
- (c) One (1) natural gas fired steam generator #3, identified as 108EO1, constructed in 1994, with a maximum heat input capacity of 14 MMBtu/hr, and exhausting to stack 108EO. This is an affected facility under the New Source Performance Standards for Small Industrial - Commercial - Institutional Steam Generating Units 40 CFR 60, Subpart Dc and an affected source under the National Emission Standards for Hazardous Air Pollutants for Industrial, Commercial, and Institutional Boilers and Process Heaters 40 CFR 63, Subpart DDDDD.
- (d) One (1) B & W coal fired boiler, identified as 1SP1, constructed in 1950, with a maximum heat input capacity of 108 MMBtu/hr, using multiple cyclones and a baghouse for control of particulate and HAPs, and exhausting to stack 1SP. This is an affected source under the National Emission Standards for Hazardous Air Pollutants for Industrial, Commercial, and Institutional Boilers and Process Heaters 40 CFR 63, Subpart DDDDD.
- (e) One (1) Keeler coal fired boiler, identified as 2SP1, constructed in 1963, with a maximum heat input capacity of 52.75 MMBtu/hr, using multiple cyclones and a baghouse for control of particulate and HAPs, and exhausting to stack 1SP. This is an affected source under the National Emission Standards for Hazardous Air Pollutants for Industrial, Commercial, and Institutional Boilers and Process Heaters 40 CFR 63, Subpart DDDDD.
- (f) One (1) Murray natural gas fired, vegetable oil-fired, used oil-fired, and hazardous chemical fired boiler, identified as 3SP1, constructed in 1968, with a maximum heat input capacity of 110.2 MMBtu/hr, and exhausting to stack 1SP. This is an affected source under the National Emission Standards for Hazardous Air Pollutants for Industrial, Commercial, and Institutional Boilers and Process Heaters 40 CFR 63, Subpart DDDDD.
- (g) One (1) natural gas-fired boiler, identified as 9SP1, approved for construction in 2012, with a maximum heat input capacity of 99 MMBtu/hr, equipped with low NOx burners

**and flue gas recirculation (FGR) for NOx control, and exhausting to stack 9SP. This is an affected facility under the New Source Performance Standards for Small Industrial - Commercial - Institutional Steam Generating Units 40 CFR 60, Subpart Dc and an affected source under the National Emission Standards for Hazardous Air Pollutants for Industrial, Commercial, and Institutional Boilers and Process Heaters 40 CFR 63, Subpart DDDDD.**

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

**National Emission Standards for Hazardous Air Pollutants (NESHAP) [40 CFR 60]**

**E.4.1 General Provisions Relating to NESHAP DDDDD [326 IAC 20-1] [40 CFR Part 63, Subpart A]**

- (a) Pursuant to 40 CFR 63.7565, the Permittee shall comply with the provisions of 40 CFR Part 63, Subpart A – General Provisions, which are incorporated by reference as 326 IAC 20-1-1, as specified in 40 CFR Part 63, Subpart DDDDD.
- (b) Pursuant to 40 CFR 63.10, the Permittee shall submit all required notifications and reports 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

**E.4.2 National Emission Standards for Hazardous Air Pollutants for Industrial, Commercial, and Institutional Boilers and Process Heaters [326 IAC 20-95] [40 CFR Part 63, Subpart DDDDD]**

The Permittee shall comply with the following provisions of 40 CFR 63, Subpart DDDDD (included as Attachment D of this permit), which are incorporated by reference as 326 IAC 20-95:

- (1) 40 CFR 63.7480
- (2) 40 CFR 63.7485
- (3) 40 CFR 63.7490
- (4) 40 CFR 63.7495(a), (b), and (d)
- (5) 40 CFR 63.7499
- (6) 40 CFR 63.7500
- (7) 40 CFR 63.7505
- (8) 40 CFR 63.7506(b)
- (9) 40 CFR 63.7507
- (10) 40 CFR 63.7510(a), (b), (c), (d), and (g)
- (11) 40 CFR 63.7515
- (12) 40 CFR 63.7520(a), (b), (d), (e), (f), and (g)
- (13) 40 CFR 63.7521
- (14) 40 CFR 63.7522
- (15) 40 CFR 63.7525
- (16) 40 CFR 63.7530(a), (c), (d), and (e)
- (17) 40 CFR 63.7535

- (18) 40 CFR 63.7540
- (19) 40 CFR 63.7541
- (20) 40 CFR 63.7545(a), (b), (c), (d), (e)(1-7), and (e)(9)
- (21) 40 CFR 63.7550
- (22) 40 CFR 63.7555
- (23) 40 CFR 63.7560
- (24) 40 CFR 63.7565
- (25) 40 CFR 63.7570
- (26) 40 CFR 63.7575
- (27) Table 1 to 40 CFR 63
- (28) Table 2 to 40 CFR 63
- (29) Table 3 to 40 CFR 63
- (30) Table 4 to 40 CFR 63
- (31) Table 5 to 40 CFR 63
- (32) Table 6 to 40 CFR 63
- (33) Table 7 to 40 CFR 63
- (34) Table 8 to 40 CFR 63
- (35) Table 9 to 40 CFR 63
- (36) Table 10 to 40 CFR 63
- (37) Appendix A to 40 CFR 63

**E.4.3 Testing Requirements [326 IAC 2-7-6(1),(6)] [326 IAC 2-1.1-11]**

The Permittee shall perform the stack testing required under NESHAP 40 CFR 63, Subpart DDDDD, utilizing methods as approved by the Commissioner to document compliance with Condition E.4.2. These tests shall be repeated at least once every five (5) years from the date of the last valid compliance demonstration. 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.

...

**Conclusion and Recommendation**

The construction of this proposed modification shall be subject to the conditions of the attached proposed Part 70 Minor Source Modification No. 001-32520-00005. The staff recommends to the Commissioner that this Part 70 Minor Source Modification be approved.

**IDEM Contact**

- (a) Questions regarding this proposed permit can be directed to Brian Williams 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) 234-5375 or toll free at 1-800-451-6027 extension 4-5375.
- (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 Only**  
**MM BTU/HR <100**  
**Boiler (9SP1)**

**Company Name: Bunge North America (East), LLC**  
**Address City IN Zip: 1200 North Second Street, Decatur, Indiana 46733**  
**Permit Number: 001-32520-00005**  
**Reviewer: Brian Williams**

Heat Input Capacity  
MMBtu/hr

99.00

Potential Throughput  
MMCF/yr

867.2

Emission Factor in lb/MMCF	Pollutant						
	PM*	PM10*	direct PM2.5*	SO2	NOx	VOC	CO
	1.9	7.6	7.6	0.6	32 **see below	5.5	84
Potential Emission in tons/yr	0.82	3.30	3.30	0.26	13.88	2.38	36.42

\*PM emission factor is filterable PM only. PM10 and PM2.5 emission factors are filterable and condensable PM10 and PM2.5 combined, respectively.

\*\*Emission Factors for NOx: Uncontrolled = 100, Low NOx Burner = 50, Low NOx Burners/Flue gas recirculation = 32

Emission Factor in lb/MMcf	HAPs - Organics				
	Benzene	Dichlorobenzene	Formaldehyde	Hexane	Toluene
	2.1E-03	1.2E-03	7.5E-02	1.8E+00	3.4E-03
Potential Emission in tons/yr	9.106E-04	5.203E-04	3.252E-02	7.805E-01	1.474E-03

Emission Factor in lb/MMcf	HAPs - Metals				
	Lead	Cadmium	Chromium	Manganese	Nickel
	5.0E-04	1.1E-03	1.4E-03	3.8E-04	2.1E-03
Potential Emission in tons/yr	2.168E-04	4.770E-04	6.071E-04	1.648E-04	9.106E-04

Emission Factor in lb/MMcf	Greenhouse Gas		
	CO2	CH4	N2O
	120,000	2.3	2.2
Potential Emission in tons/yr	52,034	9.97E-01	9.54E-01
Summed Potential Emissions in tons/yr	52,036		
CO2e Total in tons/yr	52,351		

**Methodology**

All emission factors are based on normal firing.

MMBtu = 1,000,000 Btu

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/1,000 MMBtu

Emission (tons/yr) = Throughput (MMCF/yr) x Emission Factor (lb/MMCF)/2,000 lb/ton

The five highest organic and metal HAPs emission factors are provided above. Additional HAPs emission factors are available in AP-42, Chapter 1.4.

The N2O Emission Factor for uncontrolled is 2.2. The N2O Emission Factor for low Nox burner is 0.64.

Greenhouse Warming Potentials (GWP) from Table A-1 of 40 CFR Part 98 Subpart A.

CO2e (tons/yr) = CO2 Potential Emission ton/yr x CO2 GWP (1) + CH4 Potential Emission ton/yr x CH4 GWP (21) + N2O Potential Emission ton/yr x N2O GWP (310).



# INDIANA DEPARTMENT OF ENVIRONMENTAL MANAGEMENT

*We Protect Hoosiers and Our Environment.*

*Mitchell E. Daniels Jr.*  
**Governor**

*Thomas W. Easterly*  
**Commissioner**

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

## **SENT VIA U.S. MAIL: CONFIRMED DELIVERY AND SIGNATURE REQUESTED**

**TO:** Christine Thomas  
Bunge North America (East), LLC  
1200 N 2<sup>nd</sup> Street  
Decatur, IN 46733

**DATE:** December 11, 2012

**FROM:** Matt Stuckey, Branch Chief  
Permits Branch  
Office of Air Quality

**SUBJECT:** Final Decision  
Minor Source Modification  
001-32520-00005

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:  
Keith Sanders – Facility 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 11/30/07

# Mail Code 61-53

IDEM Staff	GHOTOPP 12/11/2012 Bunge North America (East), LLC 001-32520-00005 Final		Type of Mail:  <b>CERTIFICATE OF MAILING ONLY</b>	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		

Line	Article Number	Name, Address, Street and Post Office Address	Postage	Handing Charges	Act. Value (If Registered)	Insured Value	Due Send if COD	R.R. Fee	S.D. Fee	S.H. Fee	Rest. Del. Fee	Remarks
1		Christine Thomas Bunge North America (East), LLC 1200 N 2nd St Decatur IN 46733-1160 (Source CAATS) via confirmed delivery										
2		Keith Sanders Facility Mgr Bunge North America (East), LLC 1200 N 2nd St Decatur IN 46733-1160 (RO CAATS)										
3		Adams County Commissioners 313 West Jefferson Street Decatur IN 46733 (Local Official)										
4		Adams County Health Department County Svcs Complex, 313 W. Jefferson # 314 Decatur IN 46733-1673 (Health Department)										
5		Decatur City Council and Mayors Office 225 W. Monroe St. Decatur IN 46733 (Local Official)										
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