INDIANA DEPARTMENT OF ENVIRONMENTAL MANAGEMENT
We Protect Hoosiers and Our Environment.
100 N. Senate Avenue • Indianapolis, IN 46204
(800) 451-6027 • (317) 232-8603 • www.idem.IN.gov

Michael R. Pence
Governor

Thomas W. Easterly
Commissioner

TO: Interested Parties / Applicant

DATE: September 25, 2013

RE: Ohio Valley Resources, LLC / 147-32322-00062

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 13-15-5-3, this permit 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 13-15-6-1(b) or IC 13-15-6-1(a) 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 of Environmental Adjudication, 100 North Senate Avenue, Government Center North, Suite N 501E, Indianapolis, IN 46204.

For an **initial Title V Operating Permit**, a petition for administrative review must be submitted to the Office of Environmental Adjudication within **thirty (30)** days from the receipt of this notice provided under IC 13-15-5-3, pursuant to IC 13-15-6-1(b).

For a **Title V Operating Permit renewal**, a petition for administrative review must be submitted to the Office of Environmental Adjudication within **fifteen (15)** days from the receipt of this notice provided under IC 13-15-5-3, pursuant to IC 13-15-6-1(a).

The filing of a petition for administrative review is complete on the earliest of the following dates that apply to the filing:
(1) the date the document is delivered to the Office of Environmental Adjudication (OEA);
(2) the date of the postmark on the envelope containing the document, if the document is mailed to OEA by U.S. mail; or
(3) The date on which the document is deposited with a private carrier, as shown by receipt issued by the carrier, if the document is sent to the OEA by private carrier.

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

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

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

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

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

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

Enclosures
FNTVOP.dot 6/13/2013

INDIANA DEPARTMENT OF ENVIRONMENTAL MANAGEMENT
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PSD/New Source Construction and Part 70 Operating Permit
OFFICE OF AIR QUALITY

Ohio Valley Resources, LLC
300-400 East CR 350 North
Rockport, Indiana 47635

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

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

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

Operation Permit No.: T 147-32322-00062	
Issued by: Matthew Stuckey, Branch Chief Permits Branch Office of Air Quality	Issuance Date: September 25, 2013 Expiration Date: September 25, 2018

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SECTION A SOURCE SUMMARY

This permit is based on information requested by the Indiana Department of Environmental Management (IDEM), Office of Air Quality (OAQ). The information describing the source contained in conditions A.1 through A.5 is descriptive information and does not constitute enforceable conditions. However, the Permittee should be aware that a physical change or a change in the method of operation that may render this descriptive information obsolete or inaccurate may trigger requirements for the Permittee to obtain additional permits or seek modification of this permit pursuant to 326 IAC 2, or change other applicable requirements presented in the permit application.

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

The Permittee owns and operates a stationary nitrogenous fertilizer production plant.

Source Address:	300-400 East CR 350 North, Rockport, Indiana 47635
General Source Phone Number:	(812) 686-9113
SIC Code:	2873
County Location:	Spencer
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 1 of 28 Source Categories

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

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

(a) A reformer process for production of hydrogen and nitrogen syngas consisting of the following emission units and emission control devices:

(1) One (1) primary reformer, identified as EU-003, approved for construction in 2013, with a maximum rated heat input capacity of 1,006.4 MMBtu/hr, using selective catalytic reduction for NO_x emissions control, equipped with a NO_x CEMS and exhausting to the ambient atmosphere through stack EP-003. [40 CFR 63, Subpart DDDDD]

(2) One (1) CO_2 purification process, identified as EU-004, with a maximum rated CO_2 production of 3,570 ton per day, approved for construction in 2013, and exhausting to the ambient atmosphere through stack EP-004. [40 CFR 63, Subpart FFFF]

(3) One (1) front end process flare for combusting intermittent process gas emissions from maintenance, startup, shutdown, and malfunctions, identified as EU-007, with a pilot nominally rated at 0.253 MMBtu/hr, approved for construction in 2013, utilizing proper flare design and operation minimization practices, and exhausting to the ambient atmosphere through the emission point EP-007.

(b) An ammonia unit with a maximum throughput capacity of 2,800 ton/day of ammonia consisting of the following emission units and emission control devices:

(1) One (1) ammonia catalyst startup heater, identified as EU-010, approved for construction in 2013, with a maximum rated heat input capacity of 106.3 MMBtu/hr, utilizing no control devices, and exhausting to the ambient atmosphere through stack EP-010. [40 CFR 63, Subpart DDDDD]

(2) One (1) back end ammonia process vent flare for combusting intermittent process gas emissions from maintenance, startup, shutdown, and malfunctions, identified as EU-006, approved for construction in 2013, with pilot capacity of 0.253 MMBtu per hour, utilizing proper flare design and operation minimization practices, and exhausting to the ambient atmosphere through emission point EP-006.

(3) Four (4) ammonia bullet tanks, identified as EU-023A through EU-023D, with a maximum rated capacity of 90,000 gallons each, approved for construction in 2013, utilizing the flare identified as EU-005 as an emission control device, and exhausting to the ambient atmosphere through emissions point EP-005.

(4) Three (3) ammonia cold storage tanks, identified as EU-013A, EU-013B, and EU-013C, with a maximum rated capacity of 40,000 tons each, approved for construction in 2013, utilizing the flare identified as EU-005 as an emission control device, and exhausting to the ambient atmosphere through emission point EP-005.

(5) One (1) ammonia storage flare, identified as EU-005, approved for construction in 2013, with pilot capacity of 0.126 MMBtu per hour, utilizing proper flare design and operation minimization practices, and exhausting to the ambient atmosphere through emission point EP-005.

(c) Two (2) urea ammonium nitrate (UAN) plants, including the production of urea, nitric acid, ammonium nitrate, and diesel exhaust fluid (DEF), consisting of the following emission units and emission control devices:

(1) Two (2) nitric acid units, identified as EU-001A and EU-001B, with a maximum throughput capacity of 630 ton/day of 100% nitric acid each, approved for construction in 2013, equipped with selective catalytic reduction for NO_x control, catalytic decomposition for N_2O control, and a NO_x CEMS, and exhausting to the ambient atmosphere through tailgas stacks EP-001A and EP-001B.
[40 CFR 60, Subpart Ga]

(2) Two (2) nitric acid storage tanks, identified as EU-022A and EU-022B, approved for construction in 2013, with a maximum throughput of 1,105 ton/day of 57% nitric acid each, and exhausting to the ambient atmosphere through the UAN process vent stacks EP-002A and EP-002B.

(3) Two (2) ammonium nitrate (AN) units, identified as EU-002A and EU-002B, approved for construction in 2013, with a maximum throughput capacity of 798 ton/day of ammonium nitrate each, utilizing a scrubber with particulate demister for particulate matter control, and exhausting to the ambient atmosphere through stacks EP-002A and EP-002B. [40 CFR 60, Subpart VVa]

(4) Two (2) UAN Storage Tanks, identified as EU-012A and EU-012B, approved for construction in 2013, with a maximum rated capacity of 30,000 tons each, and exhausting to the ambient atmosphere through vents EP-012A and EP-012B.
[40 CFR 60, Subpart VVa]

(5) Three (3) UAN Day Tanks, identified as EU-020A, EU-020B, and EU-020C, approved for construction in 2013, with a maximum rated capacity of 750 tons each, and exhausting to the ambient atmosphere through vents EP-020A, EP-020B, and EP-020C. [40 CFR 60, Subpart VVa]

(6) Two (2) UAN loadout facilities (one (1) truck and one (1) for rail), identified as EU-024A and EU-024B, approved for construction in 2013, and exhausting to the ambient atmosphere as fugitive emission sources EP-024A and EP-024B. [40 CFR 60, Subpart VVa]

(7) One (1) UAN plant vent flare for combusting intermittent process gas emissions from maintenance, startup, shutdown, and malfunctions, identified as EU-017, approved for construction in 2013, with a pilot capacity of 0.189 MMBtu per hour, utilizing proper flare design and operation minimization practices, and exhausting to the ambient atmosphere through emission point EP-017.

(8) One (1) DEF tank, identified as EU-021, approved for construction in 2013, with capacity of 100 tons, and exhausting to the ambient atmosphere through vent EP-021. [40 CFR 60, Subpart VVa]

(9) One (1) DEF truck loadout facility, identified as EU-025, approved for construction in 2013, and exhausting to the ambient atmosphere as fugitive emission source EP-025. [40 CFR 60, Subpart VVa]

(d) Four (4) natural gas-fired boilers, identified as EU-011A, EU-011B, EU-011C, and EU-011D, approved for construction in 2013, with a maximum rated heat input capacity of 218 MMBtu/hr each, using ultra low NO_x burners and flue gas recirculation for NO_x emissions control, equipped with NO_x CEMS, and exhausting to the ambient atmosphere through stacks EP-011A, EP-011B, EP-011C, and EP-011D. [40 CFR 60, Subpart Db] [40 CFR 63, Subpart DDDDD]

(e) One (1) diesel-fired emergency generator, identified as EU-009, approved for construction in 2013, with a maximum rated capacity of 4,690 horsepower, utilizing no control devices, and exhausting to the ambient atmosphere through stack EP-009. [40 CFR 60, Subpart IIII] [40 CFR 63, Subpart ZZZZ]

A.3 Specifically Regulated Insignificant Activities [326 IAC 2-7-1(21)] [326 IAC 2-7-4(c)] [326 IAC 2-7-5(14)]

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

(a) One (1) diesel-fired emergency firewater pump, identified as EU-016, approved for construction in 2013, with a maximum rated capacity of 481 horsepower, utilizing no control devices, and exhausting to the ambient atmosphere through stack EP-016. [40 CFR 60, Subpart IIII] [40 CFR 63, Subpart ZZZZ] [326 IAC 2-2]

(b) Two (2) cooling towers, with a total of fourteen (14) cells, identified as EU-008A through EU-008H and EU-019A through EU-019F, approved for construction in 2013, with a combined maximum rated capacity of 179,720 gallons per minute, utilizing high efficiency drift eliminators for particulate matter control, and exhausting to the ambient atmosphere through cells EP-008A through EP-008H and EP-019A through EP-019F. [326 IAC 2-2]

(c) Fuel dispensing activities, including the gasoline fuel transfer dispensing operation, identified as EU-015, approved for construction in 2013, handling less than or equal to one thousand three hundred (1,300) gallons per day and filling storage tanks having a capacity equal to or less than ten thousand five hundred (10,500) gallons. Such storage tanks may be in a fixed location or on mobile equipment. [326 IAC 2-2]

(d) Fuel dispensing activities, including a petroleum fuel other than gasoline dispensing facility, identified as EU-014, approved for construction in 2013, having a storage tank capacity less than or equal to ten thousand five hundred (10,500) gallons, and dispensing three thousand five hundred (3,500) gallons per day or less. [326 IAC 2-2]

(e) Fugitive NO_x, VOC, and GHG Emissions from Equipment Leaks [326 IAC 2-2] [40 CFR 60, Subpart VVa]

(f) Paved roadways and parking lots with public access. [326 IAC 6-4] [326 IAC 2-2]

A.4 Insignificant Activities [326 IAC 2-7-1(21)] [326 IAC 2-7-4(c)] [326 IAC 2-7-5(14)]

This stationary source also includes the following insignificant activities, which are not specifically regulated, as defined in 326 IAC 2-7-1(21):

(a) The following activities:

(1) Water based activities, including the following:

(A) Activities associated with the treatment of wastewater streams with an oil and grease content less than or equal to one percent (1%) by volume.

(B) Any operation using aqueous solutions containing less than or equal to one percent (1%) by weight of VOCs excluding HAPs.

(2) Flue gas conditioning systems and associated chemicals, such as ammonia.

(3) Equipment used to collect any material that might be released during a malfunction, process upset, or spill cleanup, including tanks.

(4) Blowdown for boilers and cooling towers.

A.5 Trivial Activities [326 IAC 2-7-1(40)]

(a) Any activity or emission unit not regulated by a NESHAP, with potential uncontrolled emissions that are equal to or less than one (1) pound per day on an emission unit basis for any single HAP or combination of HAPs; and for which the potential uncontrolled emissions meet the exemption levels specified in the following:

(1) For VOC, potential uncontrolled emissions that are equal to or less than one (1) pound per day.

(2) For nitrogen oxides (NO_x), potential uncontrolled emissions that are equal to or less than one (1) pound per day.

(3) For particulate matter with an aerodynamic diameter less than or equal to ten (10) micrometers (PM_{10}), potential uncontrolled emissions that are equal to or less than one (1) pound per day.

(b) Water related activities, including the following:

(1) Production of hot water for on-site personal use not related to any industrial or production process.

(2) Water treatment activities used to provide potable and process water for the plant, excluding any activities associated with wastewater treatment.

    (3) Steam traps, vents, leaks, and safety relief valves.

    (4) Demineralized water tanks and demineralizer vents.

    (5) Boiler water treatment operations, not including cooling towers.

(c) Activities related to ventilation, venting equipment, and refrigeration, including the following:

    (1) Ventilation exhaust, central chiller water systems, refrigeration, and air conditioning equipment, not related to any industrial or production process, including natural draft hoods or ventilating systems that do not remove air pollutants.

    (2) Stack and vents from plumbing traps used to prevent the discharge of sewer gases, handling domestic sewage only, excluding those at wastewater treatment plants or those handling any industrial waste.

    (3) Vents from continuous emissions monitors and other analyzers.

(d) Housekeeping and janitorial activities and supplies, including the following:

    (1) Vacuum cleaning systems used exclusively for housekeeping or custodial activities, or both.

    (2) Steam cleaning activities.

    (3) Restrooms and associated cleanup operations and supplies.

    (4) Mobile floor sweepers and floor scrubbers.

    (5) Pest control fumigation.

(e) Office related activities, including the following:

    (1) Office supplies and equipment.

    (2) Photocopying equipment and associated supplies.

    (3) Paper shredding.

(f) Storage equipment and activities, including the following:

    (1) Pressurized storage tanks and associated piping for anhydrous ammonia.

    (2) Storage tanks, vessels, and containers holding or storing liquid substances that do not contain any VOC or HAP.

    (3) Storage of drums containing maintenance raw materials.

    (4) Portable containers used for the collection, storage, or disposal of materials provided the container capacity is equal to or less than forty-six hundredths (0.46) cubic meters and the container is closed, except when the material is added or removed.

(g) Emergency and standby equipment, including process safety relief devices installed solely for the purpose of minimizing injury to persons or damage to equipment that could result from abnormal process operating conditions, including rupture discs and safety relief valves.

(h) Sampling and testing equipment and activities, including the following:

  (1) Equipment used for quality control/assurance or inspection purposes, including sampling equipment used to withdraw materials for analysis.

  (2) Instrument air dryers and distribution.

(i) Activities generating limited amounts of fugitive dust, including the following:

  (1) Fugitive emissions related to movement of passenger vehicles, provided the emissions are not counted for applicability purposes under subdivision (22)(B), and any required fugitive dust control plan or its equivalent is submitted.

  (2) Road salting and sanding.

A.6 Part 70 Permit Applicability [326 IAC 2-7-2]

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

(a) It is a major source, as defined in 326 IAC 2-7-1(22); and

(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]

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 Revocation of Permits [326 IAC 2-2-8]

Pursuant to 326 IAC 2-1.1-9(5)(Revocation of Permits), the Commissioner may revoke this permit 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.

B.3 Affidavit of Construction [326 IAC 2-5.1-3(h)] [326 IAC 2-5.1-4]

This document shall also become the approval to operate pursuant to 326 IAC 2-5.1-4 when prior to the start of operation, the following requirements are met:

(a) The attached Affidavit of Construction shall be submitted to the Office of Air Quality (OAQ), verifying that the emission units were constructed as proposed in the application or the permit. The emission units covered in this permit may begin operating on the date the Affidavit of Construction is postmarked or hand delivered to IDEM if constructed as proposed.

(b) If actual construction of the emission units differs from the construction proposed in the application, the source may not begin operation until the permit has been revised pursuant to 326 IAC 2 and an Operation Permit Validation Letter is issued.

(c) The Permittee shall attach the Operation Permit Validation Letter received from the Office of Air Quality (OAQ) to this permit.

B.4 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, T 147-32322-00062, 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.5 Term of Conditions [326 IAC 2-1.1-9.5]

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.6 Enforceability [326 IAC 2-7-7] [IC 13-17-12]

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

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

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

B.9 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.10 Certification [326 IAC 2-7-4(f)] [326 IAC 2-7-6(1)] [326 IAC 2-7-5(3)(C)]

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

(1) it contains a certification by a "responsible official" as defined by 326 IAC 2-7-1(35), and

(2) the certification states that, based on information and belief formed after reasonable inquiry, the statements and information in the document are true, accurate, and complete.

(b) The Permittee may use the attached Certification Form or its equivalent with each submittal requiring certification. One (1) certification may cover multiple forms in one (1) submittal.

(c) A "responsible official" is defined at 326 IAC 2-7-1(35).

B.11 Annual Compliance Certification [326 IAC 2-7-6(5)]

(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. The initial certification shall cover the time period from the date of final permit issuance through December 31 of the same year. All subsequent certifications shall cover the time period from January 1 to December 31 of the previous year, and shall be submitted no later than July 1 of each year to:

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

and

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

(b) The annual compliance certification report required by this permit shall be considered timely if the date postmarked on the envelope or certified mail receipt, or affixed by the shipper on the private shipping receipt, is on or before the date it is due. If the document is submitted by any other means, it shall be considered timely if received by IDEM, OAQ, on or before the date it is due.

(c) The annual compliance certification report shall include the following:

(1) The appropriate identification of each term or condition of this permit that is the basis of the certification;

(2) The compliance status;

(3) Whether compliance was continuous or intermittent;

(4) The methods used for determining the compliance status of the source, currently and over the reporting period consistent with 326 IAC 2-7-5(3); and

(5) Such other facts, as specified in Sections D of this permit, as IDEM, OAQ may require to determine the compliance status of the source.

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

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

(a) If required by specific condition(s) in Section D of this permit, the Permittee shall prepare and maintain Preventive Maintenance Plans (PMPs) no later than ninety (90) days after issuance of this permit or ninety (90) days after initial start-up, whichever is later, including the following information on each facility:

(1) Identification of the individual(s) responsible for inspecting, maintaining, and repairing emission control devices;

(2) A description of the items or conditions that will be inspected and the inspection schedule for said items or conditions; and

(3) Identification and quantification of the replacement parts that will be maintained in inventory for quick replacement.

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

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

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

The Permittee shall implement the PMPs.

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

(c) 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.13 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, or Southwest Regional Office 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
Southwest Regional Office phone: (812) 380-2305; fax: (812) 380-2304.

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

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

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

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

(A) A description of the emergency;

(B) Any steps taken to mitigate the emissions; and

(C) Corrective actions taken.

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

(6) The Permittee immediately took all reasonable steps to correct the emergency.

(c) In any enforcement proceeding, the Permittee seeking to establish the occurrence of an emergency has the burden of proof.

(d) This emergency provision supersedes 326 IAC 1-6 (Malfunctions). This permit condition is in addition to any emergency or upset provision contained in any applicable requirement.

(e) The Permittee seeking to establish the occurrence of an emergency shall make records available upon request to ensure that failure to implement a PMP did not cause or contribute to an exceedance of any limitations on emissions. However, IDEM, OAQ may require that the Preventive Maintenance Plans required under 326 IAC 2-7-4(c)(8) be revised in response to an emergency.

(f) Failure to notify IDEM, OAQ by telephone or facsimile of an emergency lasting more than one (1) hour in accordance with (b)(4) and (5) of this condition shall constitute a violation of 326 IAC 2-7 and any other applicable rules.

(g) If the emergency situation causes a deviation from a technology-based limit, the Permittee may continue to operate the affected emitting facilities during the emergency provided the Permittee immediately takes all reasonable steps to correct the emergency and minimize emissions.

B.14 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) In addition to the nonapplicability determinations set forth in Section D of this permit, the IDEM, OAQ has made the following determinations regarding this source.

(1) **326 IAC 4-2 (Incinerators):** This source is not subject to 326 IAC 4-2 because none of the combustion units at the source meets the definition of an incinerator as defined in 326 IAC 1-2-34.

(2) **326 IAC 6-3 (Particulate Emissions for Manufacturing Processes):** This source is not subject to 326 IAC 6-3 because pursuant to 326 IAC 6-3-1(c)(1) the source is subject to more stringent Best Available Control Technology (BACT) particulate matter emission limitations in a Prevention of Significant Deterioration (PSD) permit.

(3) **326 IAC 6-5 (Fugitive Particulate Matter Emission Limitations):** This source is not subject to 326 IAC 6-5 because the potential to emit fugitive particulate matter from the source is less than 25 tons per year.

(4) **326 IAC 7 (Sulfur Dioxide Emission Limitations):** This source is not subject to 326 IAC 4-2 because none of the emission units at the source have the potential to emit sulfur dioxide at a rate greater than either 25 tons per year or 10 pounds per hour.

(5) **326 IAC 8-4-3 (Petroleum Liquid Storage Facilities):** This source is not subject to 326 IAC 8-4-3 because the diesel fuel storage tank and the gasoline fuel storage tank have storage capacities less than 39,000 gallons and there are no other petroleum liquid storage facilities at the source.

(6) **326 IAC 8-4-6 (Gasoline Dispensing Facilities):** This source is not subject to 326 IAC 8-4-6 because pursuant to 326 IAC 8-4-1(d) the gasoline dispensing operation at the site dispenses less than 10,000 gallons of gasoline per month.

(7) **326 IAC 9-1-2 (Carbon Monoxide Emission Limitations):** This source is not subject to 326 IAC 9 because the source does not include a petroleum refinery, a ferrous metal smelter, or an incinerator.

(8) **326 IAC 10 (Nitrogen Oxides Rules):** This source is not subject to 326 IAC 10 because the source does not meet any of the following applicability criteria:

(A) The source will not be constructed in Clark or Floyd County;

(B) The boilers will not burn blast furnace gas; or

(C) The capacity of each boiler is less than 250 MMBtu/hr.

(9) **326 IAC 24-1 (Clean Air Interstate Rule Nitrogen Oxides Annual Trading Program):** This source is not subject to 326 IAC 24-1 because the source does not include any emission units that will generate 25 megawatts of electricity for sale.

(10) **326 IAC 24-2 (Clean Air Interstate Rule Sulfur Dioxide Trading Program):** This source is not subject to 326 IAC 24-2 because the source does not include any emission units that will generate 25 megawatts of electricity for sale.

(11) **326 IAC 24-3 (Clean Air Interstate Rule NO_x Ozone Season Trading Program):** This source is not subject to 326 IAC 24-3 because the source does not meet any of the following applicability criteria:

(A) The boilers at the source each have a maximum rated heat input capacity of less than 250 MMBtu/hr; and

(B) The reformer does not generate steam.

(12) **40 CFR 60, Subpart D - Standards of Performance for Fossil-Fuel Fired Steam Generators for which construction is commenced after August 17, 1971**

(A) This source is not subject to 40 CFR Part 60, Subpart D because each of the boilers have a heat input capacity less than 250 MMBtu/hr.

(B) This source is not subject to 40 CFR Part 60, Subpart D because the ammonia catalyst preheater has a heat input capacity less than 250 MMBtu/hr.

(B) This source is not subject to 40 CFR Part 60, Subpart D because the reformer is not a steam-generating unit.

(13) **40 CFR 60, Subpart Da - Standards of Performance for Electric Utility Steam Generating Units for which Construction is Commenced after September 18, 1978:** This source is not subject to 40 CFR Part 60, Subpart Da because none of the combustion or steam generating units at the source will generate electricity for utility power distribution.

(14) **40 CFR 60, Subpart Dc Standards of Performance for Small Industrial Commercial Institutional Steam Generating Units:** This source is not subject to 40 CFR Part 60, Subpart Dc because the boilers have a heat input capacity greater 100 MMBtu/hr and the other combustion units at the source are not steam generating units.

(15) **40 CFR 60, Subpart K - Standards of Performance for Volatile Organic Liquid Storage Vessels for Which Construction, Reconstruction, or Modification Commenced after June 11, 1973 and prior to May 19, 1978:** Subpart K does not apply to this source because all tanks at the site will be constructed after May 19, 1978.

(16) **40 CFR 60, Subpart Ka - Standards of Performance for Volatile Organic Liquid Storage Vessels for Which Construction, Reconstruction, or Modification Commenced after May 19, 1978 and prior to July 23, 1984:** Subpart Ka does not apply to this source because all tanks at the site will be constructed after July 23, 1984.

(17) **40 CFR 60, Subpart Kb - Standards of Performance for Volatile Organic Liquid Storage Vessels (including Petroleum Liquid Storage Vessels) for Which Construction, Reconstruction, or Modification Commenced after July 23, 1984:** 40 CFR Part 60, Subpart Kb is not applicable to this source because none of the tanks storing organic materials have capacities greater than 151 cubic meters (m^3) and store organic liquids with maximum true vapor pressure greater than 3.5 kPa. Urea and urea ammonium nitrate (UAN) are organic liquids with vapor pressure less than 3.5 kPa.

(18) **40 CFR 60, Subparts T, U, V, W, and X – Standards of Performance that apply to phosphate fertilizer plants**: These rules are not applicable to this source because this source manufactures ammonia and urea ammonium nitrate (UAN) fertilizers and does not manufacture any phosphate fertilizers.

(19) **40 CFR 60, Subpart GG and KKKK - Standards of Performance for Stationary Gas Turbines:** Subpart GG does not apply to this source because the turbines at this source are steam turbines and not gas-fired turbines.

(20) **40 CFR 60, Subparts III, NNN, RRR and YYY – Standards of Performance that apply to the Synthetic Organic Chemicals Manufacturing Industry**: These Subparts do not apply to this source because it does not produce any of the chemicals listed in 40 CFR 60.489. Methanol is created as an emission by-product at the source, but such emissions are not defined as a product that would render any of these subparts applicable.

(21) **40 CFR 60, Subpart JJJJ - Standards of Performance for Stationary Spark Ignition Internal Combustion Engines:** These rules are not applicable to this source because it applies only to spark ignition engines. The engines at this source will be compression ignition engines that are subject to 40 CFR 60, Subpart IIII.

(22) **40 CFR 63, Subpart B - Requirements For Control Technology Determinations for Major Sources in Accordance with Clean Air Act Sections, Sections 112(g) And 112(j):** These rules are not applicable to the source because other sections in Part 63 are applicable to the source.

(23) **40 CFR 63, Subparts F, G, and H - National Emission Standards for Organic Hazardous Air Pollutants from the Synthetic Organic Chemical Manufacturing Industry**: These rules are not applicable to the source because the source will not manufacture or produce any of the chemicals listed in Table 1 of 40 CFR 63, Subpart F, Table 1.

(24) **40 CFR 63, Subpart Q - National Emission Standards for Hazardous Air Pollutants for Industrial Process Cooling Towers:** These rules are not applicable to this source because the source will not use chromium based materials in its cooling towers.

(25) **40 CFR 63, Subpart BB – National Emission Standards for Hazardous Air Pollutants from Phosphate Fertilizers Production Plants:** These rules are not applicable to this source because it applies to the production of phosphate based fertilizers. This source manufactures ammonia and urea ammonium nitrate (UAN) fertilizers, which do not contain phosphorous.

(26) **40 CFR 63, Subparts OO and PP – National Emission Standards for Tanks and Containers**: These rules apply to storage and containers when another NSPS or NESHAP standard that is applicable to a source refers to these standards. This source is not subject to any NSPS or NESHAP rules that reference these standards.

(27) **40 CFR 63, Subpart EEEE – National Emission Standards for Hazardous Air Pollutants for Organic Liquids Distribution:** These rules are not applicable to this source because it will only distribute ammonia and urea ammonium nitrate (UAN) products. Neither ammonia nor UAN are considered hazardous air pollutants, and therefore, this subpart does not apply.

(28) **40 CFR 63, Subpart YYYY – National Emission Standards for Hazardous Air Pollutants for Stationary Combustion Turbines:** These rules do not apply to this source because the turbines at the site are steam turbines and not combustion turbines.

(29) **40 CFR 63, Subpart CCCCCC – National Emission Standards for Hazardous Air Pollutants for Source Category Gasoline Dispensing Facilities:** This rule does not apply to this source because it is applicable to area sources of hazardous air pollutants, and this source is a major source of hazardous air pollutants.

(30) **40 CFR 63, Subpart JJJJJJ – National Emission Standards for Hazardous Air Pollutants for Industrial, Commercial, and Institutional Boilers Area Sources:** This rule does not apply to this source because it is applicable to area sources of hazardous air pollutants, and this source is a major source of hazardous air pollutants.

(31) **40 CFR 63, Subpart VVVVVV – National Emission Standards for Hazardous Air Pollutants for Chemical Manufacturing Area Sources:** This rule does not apply to this source because it is applicable to area sources of hazardous air pollutants, and this source is a major source of hazardous air pollutants.

(32) **40 CFR 63, Subpart BBBBBBB – National Emission Standards for Hazardous Air Pollutants for Area Sources Chemical Preparations Industry:** This rule does not apply to this source because it is applicable to area sources of hazardous air pollutants, and this source is a major source of hazardous air pollutants.

(c) 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.

(d) 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.

(e) 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.

(f) 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).

(g) 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)]

(h) 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.15 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 T 147-32322-00062 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.16 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.17 Permit Modification, Reopening, Revocation and Reissuance, or Termination [326 IAC 2-7-5(6)(C)] [326 IAC 2-7-8(a)] [326 IAC 2-7-9]

(a) This permit may be modified, reopened, revoked and reissued, or terminated for cause. The filing of a request by the Permittee for a Part 70 Operating Permit modification, revocation and reissuance, or termination, or of a notification of planned changes or anticipated noncompliance does not stay any condition of this permit. [326 IAC 2-7-5(6)(C)] The notification by the Permittee does require a certification that meets the requirements of 326 IAC 2-7-6(1) by a "responsible official" as defined by 326 IAC 2-7-1(35).

(b) This permit shall be reopened and revised under any of the circumstances listed in IC 13-15-7-2 or if IDEM, OAQ determines any of the following:

(1) That this permit contains a material mistake.

(2) That inaccurate statements were made in establishing the emissions standards or other terms or conditions.

(3) That this permit must be revised or revoked to assure compliance with an applicable requirement. [326 IAC 2-7-9(a)(3)]

(c) Proceedings by IDEM, OAQ to reopen and revise this permit shall follow the same procedures as apply to initial permit issuance and shall affect only those parts of this permit for which cause to reopen exists. Such reopening and revision shall be made as expeditiously as practicable. [326 IAC 2-7-9(b)]

(d) The reopening and revision of this permit, under 326 IAC 2-7-9(a), shall not be initiated before notice of such intent is provided to the Permittee by IDEM, OAQ at least thirty (30) days in advance of the date this permit is to be reopened, except that IDEM, OAQ may provide a shorter time period in the case of an emergency. [326 IAC 2-7-9(c)]

B.18 Permit Renewal [326 IAC 2-7-3] [326 IAC 2-7-4] [326 IAC 2-7-8(e)]

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

Request for renewal shall be submitted to:

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

(b) A timely renewal application is one that is:

(1) Submitted at least nine (9) months prior to the date of the expiration of this permit; and

(2) If the date postmarked on the envelope or certified mail receipt, or affixed by the shipper on the private shipping receipt, is on or before the date it is due. If the document is submitted by any other means, it shall be considered timely if received by IDEM, OAQ on or before the date it is due.

(c) If the Permittee submits a timely and complete application for renewal of this permit, the source’s failure to have a permit is not a violation of 326 IAC 2-7 until IDEM, OAQ takes final action on the renewal application, except that this protection shall cease to apply if, subsequent to the completeness determination, the Permittee fails to submit by the deadline specified, pursuant to 326 IAC 2-7-4(a)(2)(D), in writing by IDEM, OAQ any additional information identified as being needed to process the application.

B.19 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(35).

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

B.20 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.21 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) or (c) without a prior permit revision, if each of the following conditions is met:

(1) The changes are not modifications under any provision of Title I of the Clean Air Act;

(2) Any preconstruction approval required by 326 IAC 2-7-10.5 has been obtained;

(3) The changes do not result in emissions which exceed the limitations provided in this permit (whether expressed herein as a rate of emissions or in terms of total emissions);

(4) The Permittee notifies the:

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

and

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

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

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

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

(b) The Permittee may make Section 502(b)(10) of the Clean Air Act changes (this term is defined at 326 IAC 2-7-1(36)) without a permit revision, subject to the constraint of 326 IAC 2-7-20(a). For each such Section 502(b)(10) of the Clean Air Act change, the required written notification shall include the following:

(1) A brief description of the change within the source;

(2) The date on which the change will occur;

(3) Any change in emissions; and

(4) Any permit term or condition that is no longer applicable as a result of the change.

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

(c) Emission Trades [326 IAC 2-7-20(c)]
The Permittee may trade emissions increases and decreases at the source, where the applicable SIP provides for such emission trades without requiring a permit revision, subject to the constraints of Section (a) of this condition and those in 326 IAC 2-7-20(c).

(d) Alternative Operating Scenarios [326 IAC 2-7-20(d)]
The Permittee may make changes at the source within the range of alternative operating scenarios that are described in the terms and conditions of this permit in accordance with 326 IAC 2-7-5(9). No prior notification of IDEM, OAQ, or U.S. EPA is required.

(e) Backup fuel switches specifically addressed in, and limited under, Section D of this permit shall not be considered alternative operating scenarios. Therefore, the notification requirements of part (a) of this condition do not apply.

B.22 Source Modification Requirement [326 IAC 2-7-10.5]

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

B.23 Inspection and Entry [326 IAC 2-7-6] [IC 13-14-2-2] [IC 13-30-3-1] [IC 13-17-3-2]

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.24 Transfer of Ownership or Operational Control [326 IAC 2-7-11]

(a) The Permittee must comply with the requirements of 326 IAC 2-7-11 whenever the Permittee seeks to change the ownership or operational control of the source and no other change in the permit is necessary.

(b) Any application requesting a change in the ownership or operational control of the source shall contain a written agreement containing a specific date for transfer of permit responsibility, coverage, and liability between the current and new Permittee. The application shall be submitted to:

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

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

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

B.25 Annual Fee Payment [326 IAC 2-7-19] [326 IAC 2-7-5(7)] [326 IAC 2-1.1-7]

(a) The Permittee shall pay annual fees to IDEM, OAQ within thirty (30) calendar days of receipt of a billing. Pursuant to 326 IAC 2-7-19(b), if the Permittee does not receive a bill from IDEM, OAQ the applicable fee is due April 1 of each year.

(b) Except as provided in 326 IAC 2-7-19(e), failure to pay may result in administrative enforcement action or revocation of this permit.

(c) The Permittee may call the following telephone numbers: 1-800-451-6027 or 317-233-4230 (ask for OAQ, Billing, Licensing, and Training Section), to determine the appropriate permit fee.

B.26 Credible Evidence [326 IAC 2-7-5(3)] [326 IAC 2-7-6] [62 FR 8314] [326 IAC 1-1-6]

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

SECTION C SOURCE OPERATION CONDITIONS

Entire Source

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

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

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

C.2 Opacity [326 IAC 5-1]

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

(a) Opacity shall not exceed an average of forty percent (40%) in any one (1) six (6) minute averaging period as determined in 326 IAC 5-1-4.

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

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

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

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

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

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

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

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

The Permittee shall comply with the applicable provisions of 326 IAC 1-7 (Stack Height Provisions), for all exhaust stacks through which a potential (before controls) of twenty-five (25) tons per year or more of particulate matter or sulfur dioxide is emitted 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]

The Permittee shall comply with the applicable requirements of 326 IAC 14-10, 326 IAC 18, and 40 CFR 61.140. The requirement in 326 IAC 14-10-1(a) that the owner or operator shall use an Indiana Licensed Asbestos Inspector and all the requirements in 326 IAC 18 related to licensing requirements for asbestos inspectors are not federally enforceable.

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

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

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

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

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

(b) The Permittee shall notify IDEM, OAQ of the actual test date at least fourteen (14) days prior to the actual test date. The notification submitted by the Permittee does not require a certification that meets the requirements of 326 IAC 2-7-6(1) by a "responsible official" as defined by 326 IAC 2-7-1(35).

(c) Pursuant to 326 IAC 3-6-4(b), all test reports must be received by IDEM, OAQ not later than forty-five (45) days after the completion of the testing. An extension may be granted by IDEM, OAQ if the Permittee submits to IDEM, OAQ a reasonable written explanation not later than five (5) days prior to the end of the initial forty-five (45) day period.

Compliance Requirements [326 IAC 2-1.1-11]

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

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)] [40 CFR 64] [326 IAC 3-8]

(a) 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 of the emission unit for which the monitoring is required, 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 of the emission unit for which the monitoring is required, whichever is later, the Permittee may extend the compliance schedule related to the equipment for an additional ninety (90) days provided the Permittee notifies:

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

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

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

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

(b) For monitoring required by CAM, at all times, the Permittee shall maintain the monitoring, including but not limited to, maintaining necessary parts for routine repairs of the monitoring equipment.

(c) For monitoring required by CAM, except for, as applicable, monitoring malfunctions, associated repairs, and required quality assurance or control activities (including, as applicable, calibration checks and required zero and span adjustments), the Permittee shall conduct all monitoring in continuous operation (or shall collect data at all required intervals) at all times that the pollutant-specific emissions unit is operating. Data recorded during monitoring malfunctions, associated repairs, and required quality assurance or control activities shall not be used for purposes of this part, including data averages and calculations, or fulfilling a minimum data availability requirement, if applicable. The owner or operator shall use all the data collected during all other periods in assessing the operation of the control device and associated control system. 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.

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

(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]

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

(a) The Permittee shall prepare written emergency reduction plans (ERPs) consistent with safe operating procedures.

(b) These ERPs shall be submitted for approval 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 180 days from the date on which this source commences operation.

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

(c) If the ERP is disapproved by IDEM, OAQ, the Permittee shall have an additional thirty (30) days to resolve the differences and submit an approvable ERP.

(d) These ERPs shall state those actions that will be taken, when each episode level is declared, to reduce or eliminate emissions of the appropriate air pollutants.

(e) Said ERPs shall also identify the sources of air pollutants, the approximate amount of reduction of the pollutants, and a brief description of the manner in which the reduction will be achieved.

(f) 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(11)] [40 CFR 68]

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 [40 CFR 64] [326 IAC 3-8] [326 IAC 2-7-5] [326 IAC 2-7-6]

(a) Upon detecting an excursion where a response step is required by the D Section, not subject to CAM, in this permit:

(1) 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.

(2) The response shall include minimizing the period of any startup, shutdown, or malfunction. The response may include, but is not limited to, the following:

(A) initial inspection and evaluation;

(B) recording that operations returned or are returning to normal without operator action (such as through response by a computerized distribution control system); or

(C) any necessary follow-up actions to return operation to normal or usual manner of operation.

(3) 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:

(A) monitoring results;

(B) review of operation and maintenance procedures and records; and/or

(C) inspection of the control device, associated capture system, and the process.

(4) Failure to take reasonable response steps shall be considered a deviation from the permit.

(5) The Permittee shall record the reasonable response steps taken.

(b) (1) CAM Response to excursions or exceedances.

(A) Upon detecting an excursion or exceedance, subject to CAM, the Permittee shall restore operation of the pollutant-specific emissions unit (including the 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 emissions. The response shall include minimizing the period of any startup, shutdown, or malfunction and taking any necessary corrective actions to restore normal operation and prevent the likely recurrence of the cause of an excursion or exceedance (other than those caused by excused startup or shutdown conditions). Such actions may include initial inspection and evaluation, recording that operations returned to normal without operator action (such as through response by a computerized distribution control system), or any necessary follow-up actions to return operation to within the indicator range, designated condition, or below the applicable emission limitation or standard, as applicable.

(B) 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, monitoring results, review of operation and maintenance procedures and records, and inspection of the control device, associated capture system, and the process.

(2) If the Permittee identifies a failure to achieve compliance with an emission limitation, subject to CAM, or standard, subject to CAM, for which the approved monitoring did not provide an indication of an excursion or exceedance while providing valid data, or the results of compliance or performance testing document a need to modify the existing indicator ranges or designated conditions, the Permittee shall promptly notify the IDEM, OAQ and, if necessary, submit a proposed significant permit modification to this permit to address the necessary monitoring changes. Such a modification may include, but is not limited to, reestablishing indicator ranges or designated conditions, modifying the frequency of conducting monitoring and collecting data, or the monitoring of additional parameters.

(3) Based on the results of a determination made under paragraph (b)(1)(B) of this condition, the EPA or IDEM, OAQ may require the Permittee to develop and implement a quality improvement plan (QIP). The Permittee shall develop and implement a QIP if notified to in writing by the EPA or IDEM, OAQ.

(4) **Elements of a QIP:**
The Permittee shall maintain a written QIP, if required, and have it available for inspection. The plan shall conform to 40 CFR 64.8b(2).

(5) If a QIP is required, the Permittee shall develop and implement a QIP as expeditiously as practicable and shall notify the IDEM, OAQ if the period for completing the improvements contained in the QIP exceeds 180 days from the date on which the need to implement the QIP was determined.

(6) Following implementation of a QIP, upon any subsequent determination pursuant to paragraph (II)(a)(2) of this condition the EPA or the IDEM, OAQ may require that the Permittee make reasonable changes to the QIP if the QIP is found to have:

(A) Failed to address the cause of the control device performance problems; or

(B) Failed to provide adequate procedures for correcting control device performance problems as expeditiously as practicable in accordance with good air pollution control practices for minimizing emissions.

(7) Implementation of a QIP shall not excuse the Permittee from compliance with any existing emission limitation or standard, or any existing monitoring, testing, reporting, or recordkeeping requirement that may apply under federal, state, or local law, or any other applicable requirements under the Act.

(8) CAM recordkeeping requirements.

(A) The Permittee shall maintain records of monitoring data, monitor performance data, corrective actions taken, any written quality improvement plan required pursuant to paragraph (b)(2)(B) of this condition and any activities undertaken to implement a quality improvement plan, and other supporting information required to be maintained under this condition (such as data used to document the adequacy of monitoring, or records of monitoring maintenance or corrective actions). Section C - General Record Keeping Requirements of this permit contains the Permittee's obligations with regard to the records required by this condition.

(B) Instead of paper records, the owner or operator may maintain records on alternative media, such as microfilm, computer files, magnetic tape disks, or microfiche, provided that the use of such alternative media allows for expeditious inspection and review, and does not conflict with other applicable recordkeeping requirements

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

(a) When the results of a stack test performed in conformance with Section C - Performance Testing, of this permit exceed the level specified in any condition of this permit, the Permittee shall submit a description of its response actions to IDEM, OAQ, no later than seventy-five (75) days after the date of the test.

(b) A retest to demonstrate compliance shall be performed no later than one hundred eighty (180) days after the date of the test. Should the Permittee demonstrate to IDEM, OAQ that retesting in one hundred eighty (180) days is not practicable, IDEM, OAQ may extend the retesting deadline

(c) IDEM, OAQ reserves the authority to take any actions allowed under law in response to noncompliant stack tests.

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

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

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

In accordance with the compliance schedule specified in 326 IAC 2-6-3(b)(3), starting in 2015 and every three (3) years thereafter, the Permittee shall submit by July 1 an emission statement covering the previous calendar year. The emission statement shall contain, at a minimum, the information specified in 326 IAC 2-6-4(c) and shall meet the following requirements:

(1) Indicate estimated actual emissions of all pollutants listed in 326 IAC 2-6-4(a);

(2) Indicate estimated actual emissions of regulated pollutants as defined by 326 IAC 2-7-1(32) (“Regulated pollutant, which is used only for purposes of Section 19 of this rule”) from the source, for purpose of fee assessment.

The statement must be submitted to:

Indiana Department of Environmental Management
Technical Support and Modeling Section, Office of Air Quality
100 North Senate Avenue
MC 61-50 IGCN 1003
Indianapolis, Indiana 46204-2251

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

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

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

(AA) All calibration and maintenance records.

(BB) All original strip chart recordings for continuous monitoring instrumentation.

(CC) Copies of all reports required by the Part 70 permit.

Records of required monitoring information include the following:

(AA) The date, place, as defined in this permit, and time of sampling or measurements.

(BB) The dates analyses were performed.

(CC) The company or entity that performed the analyses.

(DD) The analytical techniques or methods used.

(EE) The results of such analyses.

(FF) The operating conditions as existing at the time of sampling or measurement.

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

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

(c) If there is a reasonable possibility (as defined in 326 IAC 2-2-8 (b)(6)(A), 326 IAC 2-2-8 (b)(6)(B), 326 IAC 2-3-2 (l)(6)(A), and/or 326 IAC 2-3-2 (l)(6)(B)) that a “project” (as defined in 326 IAC 2-2-1(oo) and/or 326 IAC 2-3-1(jj)) 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(dd) and/or 326 IAC 2-3-1(y)) may result in significant emissions increase and the Permittee elects to utilize the “projected actual emissions” (as defined in 326 IAC 2-2-1(pp) and/or 326 IAC 2-3-1(kk)), the Permittee shall comply with the following:

(1) Before beginning actual construction of the “project” (as defined in 326 IAC 2-2-1(oo) and/or 326 IAC 2-3-1(jj)) 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(pp)(2)(A)(iii) and/or 326 IAC 2-3-1 (kk)(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 (326 IAC 2-2-8 (b)(6)(A) and/or 326 IAC 2-3-2 (l)(6)(A)) that a "project" (as defined in 326 IAC 2-2-1(oo) and/or 326 IAC 2-3-1(jj)) 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(dd) and/or 326 IAC 2-3-1(y)) may result in significant emissions increase and the Permittee elects to utilize the "projected actual emissions" (as defined in 326 IAC 2-2-1(pp) and/or 326 IAC 2-3-1(kk)), 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] [40 CFR 64] [326 IAC 3-8]

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

On and after the date by which the Permittee must use monitoring that meets the requirements of 40 CFR Part 64 and 326 IAC 3-8, the Permittee shall submit CAM reports to the IDEM, OAQ.

A report for monitoring under 40 CFR Part 64 and 326 IAC 3-8 shall include, at a minimum, the information required under paragraph (a) of this condition and the following information, as applicable:

(1) Summary information on the number, duration and cause (including unknown cause, if applicable) of excursions or exceedances, as applicable, and the corrective actions taken;

(2) Summary information on the number, duration and cause (including unknown cause, if applicable) for monitor downtime incidents (other than downtime associated with zero and span or other daily calibration checks, if applicable); and

(3) A description of the actions taken to implement a QIP during the reporting period as specified in Section C-Response to Excursions or Exceedances. Upon completion of a QIP, the owner or operator shall include in the next summary report documentation that the implementation of the plan has been completed and reduced the likelihood of similar levels of excursions or exceedances occurring.

The Permittee may combine the Quarterly Deviation and Compliance Monitoring Report and a report pursuant to 40 CFR 64 and 326 IAC 3-8.

(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) The first report shall cover the period commencing on the date of issuance of this permit or the date of initial start-up, whichever is later, and ending on the last day of the reporting period. 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 (ll)) 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 (ww) and/or 326 IAC 2-3-1 (pp), 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

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:

(a) Four (4) natural gas-fired boilers, identified as EU-011A, EU-011B, EU-011C, and EU-011D, approved for construction in 2013, with a maximum rated heat input capacity of 218 MMBtu/hr each, using ultra low NO_x burners and flue gas recirculation for NO_x emissions control, equipped with NO_x CEMS, and exhausting to the ambient atmosphere through stacks EP-011A, EP-011B, EP-011C, and EP-011D. [40 CFR 60, Subpart Db]
[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.)

Construction Conditions

General Construction Conditions

D.1.1 Permit No Defense

This permit 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 there under, as well as other applicable local, state, and federal requirements.

Effective Date of the Permit

D.1.2 Effective Date of the Permit [IC 13-15-5-3]

Pursuant to IC 13-15-5-3, this section of this permit becomes effective upon its issuance.

D.1.3 Modifications to Construction Conditions [326 IAC 2]

All requirements of these construction conditions shall remain in effect unless modified in a manner consistent with procedures established for revisions pursuant to 326 IAC 2.

Operating Conditions

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

D.1.4 PSD Best Available Control Technology Limits [326 IAC 2-2-3]

Pursuant to PSD/Operating Permit T 147-32322-00062 and 326 IAC 2-2-3 (Prevention of Significant Deterioration), the best available control technology (BACT) for Boiler Units EU-011A, EU-011B, EU-011C, and EU-011D shall be as follows:

Common PM, PM_{10}, $PM_{2.5}$, NO_x, CO, VOC and GHG Conditions:

(a) PM, PM_{10}, $PM_{2.5}$, NO_x, CO, VOC and GHG from the boilers (EU-011A, EU-011B, EU-011C and EU-011D) shall be controlled through the use of proper boiler design and good combustion practices.

(b) Combined fuel usage in the boilers (EU-011A, EU-011B, EU-011C and EU-011D) shall not exceed 2,802 MMCF per twelve consecutive month period with compliance determined at the end of each month.

(c) The boilers (EU-011A, EU-011B, EU-011C, and EU-011D) shall combust natural gas.

PM, PM$_{10}$ and PM$_{2.5}$:

(d) PM, PM$_{10}$ and PM$_{2.5}$ emissions from each of the boilers (EU-011A, EU-011B, EU-011C and EU-011D) shall not exceed 1.9, 7.6 and 7.6 lb/MMCF, respectively, based on a three-hour average. PM includes filterable particulate matter, while, PM$_{10}$ and PM$_{2.5}$ include both filterable and condensable particulate matter.

NO$_x$:

(e) NO$_x$ emissions from the boilers (EU-011A, EU-011B, EU-011C, and EU-011D) shall be controlled by the use of Ultra Low NO$_x$ Burners and Flue Gas Recirculation (FGR).

(f) NO$_x$ emissions from each of the boilers (EU-011A, EU-011B, EU-011C, and EU-011D) shall not exceed 20.40 lb/MMCF, based on a twenty-four hour average.

CO:

(g) CO emissions from each of the boilers (EU-011A, EU-011B, EU-011C, and EU-011D) shall not exceed 37.22 lb/MMCF, based on a three-hour average.

VOC:

(h) VOC emissions from each of the boilers (EU-011A, EU-011B, EU-011C, and EU-011D) shall not exceed 5.5 lb/MMCF, based on a three-hour average.

GHG:

(i) CO$_2$ emissions from each of the boilers (EU-011A, EU-011B, EU-011C, and EU-011D) shall not exceed 59.61 tons/MMCF, based on a three-hour average.

(j) Each of the boilers (EU-011A, EU-011B, EU-011C and EU-011D) shall be equipped with the following energy efficient design features: air inlet controls, heat recovery, condensate recovery, and blowdown heat recovery.

(k) Each of the boilers (EU-011A, EU-011B, EU-011C and EU-011D) shall be designed to achieve a thermal efficiency of 80% (HHV).

D.1.5 General Provisions Relating to New Source Performance Standards (NSPS) [40 CFR 60, Subpart A] [326 IAC 12]

The provisions of 40 CFR 60, Subpart A – General Provisions, which are incorporated by reference in 326 IAC 12-1-1, apply to the natural gas-fired boilers, identified as EU-011A, EU-011B, EU-011C and EU-011D, except when otherwise specified in 40 CFR 60, Subpart Dd.

D.1.6 New Source Performance Standards (NSPS) [40 CFR 60, Subpart Db] [326 IAC 12]

The Permittee shall comply with the following provisions of 40 CFR 60, Subpart Db (Standards of Performance for Industrial-Commercial-Institutional Steam Generating Units) included as Attachment F of this permit, which are incorporated by reference as 326 IAC 12, for the natural gas-fired boilers, identified as EU-011A, EU-011B, EU-011C and EU-011D as specified as follows:

(1) 40 CFR 60.42b(k)(2);
(2) 40 CFR 60.44b(h) and (i);
(3) 40 CFR 60.44b(l);

(4) 40 CFR 60.46b(a);
(5) 40 CFR 60.46b(c);
(6) 40 CFR 60.46b(e);
(7) 40 CFR 60.48b(b) to (f);
(8) 40 CFR 60.49b(a) and (b);
(9) 40 CFR 60.49b(d);
(10) 40 CFR 60.49b(g);
(11) 40 CFR 60.49b(i); and
(12) 40 CFR 60.49b(o).

D.1.7 General Provisions Relating to National Emission Standards for Hazardous Air Pollutants (NESHAP) [40 CFR 63, Subpart A] [326 IAC 20-1]

Pursuant to 40 CFR 63.7495, the Permittee shall comply with the provisions of 40 CFR 60, Subpart A – General Provisions, which are incorporated by reference as 326 IAC 20-1, in accordance with the schedule in 40 CFR 63.7545, Subpart DDDDD.

D.1.8 National Emission Standards for Hazardous Air Pollutants for Major Sources: Industrial, Commercial, and Institutional Boilers and Process Heaters [40 CFR 63, Subpart DDDDD] [326 IAC 20-95]

The Permittee shall comply with the following provisions of 40 CFR 63, Subpart DDDDD, which are incorporated by reference as 326 IAC 20-95 (included as Attachment H of this permit), for the boilers, identified as EU-011A, EU-011B, EU-011C, and EU-011D, upon startup of the affected source:

(1) 40 CFR 63.7485;
(2) 40 CFR 63.7490 (b);
(3) 40 CFR 63.7495 (a), (b);
(4) 40 CFR 63.7500;
(5) 40 CFR 63.7505;
(6) 40 CFR 63.7510;
(7) 40 CFR 63.7525;
(8) 40 CFR 63.7540(a)(10);
(9) 40 CFR 63.7545;
(10) 40 CFR 63.7550;
(11) 40 CFR 63.7555;
(12) 40 CFR 63.7560;
(13) 40 CFR 63.7565; and
(14) Table 3(2).

D.1.9 Preventive Maintenance Plan [326 IAC 2-7-5(12)]

A Preventive Maintenance Plan is required for the natural gas-fired boilers, identified as EU-011A, EU-011B, EU-011C, and EU-011D. Section B – Preventive Maintenance Plan contains the Permittee’s obligation with regard to the preventive maintenance plan required by this condition.

Compliance Monitoring Requirements

D.1.10 Maintenance of Continuous Emission Monitoring Equipment [326 IAC 3-5]

(a) The Permittee shall install, calibrate, maintain, and operate all necessary continuous emission monitoring systems (CEMS) and related equipment for NO_x emissions on stacks EP-011A, EP-011B, EP-011C, and EP-011D.

(b) All CEMS required by this permit shall meet all applicable performance specification of 40 CFR 60, and are subject to monitor system certification requirements pursuant to 326 IAC 3-5-3.

(c) In the event that a breakdown of a continuous emission monitoring system occurs, a record shall be made of the times and reasons for the breakdown and the efforts made to correct the problem.

(d) Whenever a NO_x CEMS is down for more than twenty-four (24) hours, the Permittee shall follow the best combustion practice.

Compliance Determination Requirements

D.1.11 Testing Requirements [326 IAC 2-7-6(1)] [326 IAC 2-7-6(6)]

(a) In order to demonstrate the compliance status with Condition D.1.4(g) and within sixty (60) days of reaching maximum capacity but no later than one hundred and eighty (180) days after initial startup, the Permittee shall perform CO testing on stacks EP-011A, EP-011B, EP-011C and EP-011D utilizing methods as approved by the Commissioner. Testing shall be conducted in accordance with the provisions of 326 IAC 3-6 (Source Sampling Procedures). Section C – Performance Testing contains the Permittee's obligation with regard to the performance testing required by this condition.

(b) In order to demonstrate the compliance status with Condition D.1.4(i) and within sixty (60) days of reaching maximum capacity but no later than one hundred and eighty (180) days after initial startup, the Permittee shall perform CO_2 testing on stacks EP-011A, EP-011B, EP-011C and EP-011D utilizing methods as approved by the Commissioner. Testing shall be conducted in accordance with the provisions of 326 IAC 3-6 (Source Sampling Procedures). Section C – Performance Testing contains the Permittee's obligation with regard to the performance testing required by this condition.

(c) In order to demonstrate the compliance status with Condition D.1.4(k) – GHGs PSD BACT, and within sixty (60) days of reaching maximum capacity but no later than one hundred and eighty (180) days after initial startup, the Permittee shall perform thermal efficiency testing of the natural gas-fired boilers, identified as EU-011A, EU-011B, EU-011C and EU-011D utilizing methods as approved by the Commissioner. These tests shall be conducted once. 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.

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

D.1.12 Record Keeping Requirements

(a) In order to document the compliance status with Condition D.1.4(b), the Permittee shall maintain monthly records of the combined fuel usage in natural gas-fired boilers EU-011A, EU-011B, EU-011C, and EU-011D.

(b) In order to document the compliance status with Condition D.1.4(c), the Permittee shall maintain monthly records of the type of fuel combusted in EU-011A, EU-011B, EU-011C, and EU-011D.

(c) In order to document the compliance status with Condition D.1.4(f) and Condition D.1.10, the Permittee shall maintain records of the output of the continuous emission monitoring system for NO_x and shall perform the required record keeping requirements pursuant to 326 IAC 3-5-6.

(d) In order to document the compliance status with Condition D.1.4(f) and Condition D.1.10, the Permittee shall maintain records of all CEMS malfunctions, out of control periods, calibration and adjustment activities, and repair or maintenance activities.

(e) Section C – General Record Keeping Requirements contains the Permittee's obligations with regard to the record keeping required by this condition.

D.1.13 Reporting Requirements

(a) A quarterly summary of the information to document the compliance status with Condition D.1.4(b) shall be submitted not later than thirty (30) days after the end of the quarter being reported. Section C – General Reporting Requirements contains the Permittee's obligation with regard to the reporting required by 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 in 326 IAC 2-7-1(35).

(b) In order to document the compliance status with Condition D.1.4(f) and Condition D.1.10, the Permittee shall comply with all of the reporting requirements pursuant to 326 IAC 3-5-7.

SECTION D.2 EMISSIONS UNIT OPERATION CONDITIONS

Emissions Unit Description:

(a) A reformer process for production of hydrogen and nitrogen syngas consisting of the following emission units and emission control devices:

(1) One (1) primary reformer, identified as EU-003, approved for construction in 2013, with a maximum rated heat input capacity of 1,006.4 MMBtu/hr, using selective catalytic reduction for NO_x emissions control, equipped with a NO_x CEMS, and exhausting to the ambient atmosphere through stack EP-003. [40 CFR 63, Subpart DDDDD]

(2) One (1) CO_2 purification process, identified as EU-004, with a maximum rated CO_2 production of 3,570 ton per day, approved for construction in 2013, and exhausting to the ambient atmosphere through stack EP-004.
[40 CFR 63, Subpart FFFF]

(3) One (1) front end process flare for combusting intermittent process gas emissions from maintenance, startup, shutdown, and malfunctions, identified as EU-007, with a pilot nominally rated at 0.253 MMBtu/hr, approved for construction in 2013, utilizing proper flare design and operation minimization practices, and exhausting to the ambient atmosphere through the emission point EP-007.

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

Construction Conditions

General Construction Conditions

D.2.1 Permit No Defense

This permit 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 there under, as well as other applicable local, state, and federal requirements.

Effective Date of the Permit

D.2.2 Effective Date of the Permit [IC 13-15-5-3]

Pursuant to IC 13-15-5-3, this section of this permit becomes effective upon its issuance.

D.2.3 Modifications to Construction Conditions [326 IAC 2]

All requirements of these construction conditions shall remain in effect unless modified in a manner consistent with procedures established for revisions pursuant to 326 IAC 2.

Operating Conditions

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

D.2.4 PSD Best Available Control Technology Limits [326 IAC 2-2-3] and VOC Best Available Control Technology (BACT) Limits [326 IAC 8-1-6]

Pursuant to PSD/Operating Permit T 147-32322-00062 and 326 IAC 2-2 (Prevention of Significant Deterioration (PSD)), the best available control technology (BACT) for the Primary Reformer (EU-003), the CO_2 Purification Process (EU-004), and the Front End Process Flare (EU-007) shall be as follows:

(a) **Primary Reformer (EU-003):**

Common PM, PM_{10}, $PM_{2.5}$, NO_x, CO, VOC and GHG Conditions:

(1) PM, PM_{10}, $PM_{2.5}$, NO_x, CO, VOC and GHG emissions from the operation of Primary Reformer (EU-003) shall be controlled through the use of good combustion practices.

(2) The Primary Reformer (EU-003) shall combust natural gas and/or process off gas streams.

PM, PM_{10}, $PM_{2.5}$:

(3) PM, PM_{10} and $PM_{2.5}$ emissions from the operation of Primary Reformer (EU-003) shall not exceed 1.9, 7.6 and 7.6 lb/MMCF respectively, based on a three-hour average. PM includes filterable particulate matter, while, PM_{10} and $PM_{2.5}$ include both filterable and condensable particulate matter.

NO_x:

(4) NO_x emissions from the Primary Reformer (EU-003) shall be controlled by selective catalytic reduction (SCR) at all times the reformer is in operation.

(5) NO_x emissions from the Primary Reformer (EU-003) shall not exceed 9 ppm_{vd}, based on a thirty-day rolling average.

CO:

(6) CO emissions from the Primary Reformer (EU-003) shall not exceed 43.45 lb/MMCF, based on a three-hour average.

VOC:

(7) VOC emissions from the Primary Reformer (EU-003) shall not exceed 5.51 lb/MMCF, based on a three-hour average.

GHG:

(8) CO_2 emissions from the Primary Reformer (EU-003) shall not exceed 59.61 tons/MMCF, based on a three-hour average.

(9) The Primary Reformer (EU-003) shall be equipped with the following energy efficiency features: air inlet controls and flue gas heat recovery to pre-heat inlet fuel, inlet air and inlet steam flows.

(10) The Primary Reformer (EU-003) shall be designed to achieve a thermal efficiency of 90% (HHV).

(11) CO_2 emissions from the Primary Reformer (EU-003) shall not exceed 515,246 tons per twelve consecutive month period with compliance determined at the end of each month.

(b) **<u>CO_2 Purification Process (EU-004):</u>**

Common CO, VOC, and GHG Conditions:

(1) Ammonia production shall not exceed 1,022,000 tons per twelve consecutive month period with compliance determined at the end of each month.

CO:

(2) CO emissions from the CO_2 Purification Process Vent (EU-004) shall be controlled by the use of good operational procedures and the use of a process catalyst.

(3) The CO emission rate shall not exceed 0.0117 lb/ton of ammonia produced, based on a three-hour average.

VOC:

(4) The use of a low VOC catalyst providing a maximum VOC emission rate of 0.0558 lb VOC per ton of ammonia produced or less, based on a three-hour average.

GHG:

(5) Good Operational Practices to achieve a CO_2 emission rate of 1.275 tons CO_2 per ton of ammonia, based on a three-hour average.

(c) **<u>Front End Process Flare (EU-007):</u>**

Common PM, PM_{10}, $PM_{2.5}$, NO_x, CO, VOC and GHG Conditions:

(1) In order to control PM, PM_{10}, $PM_{2.5}$, NO_x, CO, VOC and GHG emissions, the pilot and purge gas fuels used in the flare shall be natural gas.

(2) Venting in the Front End Process Flare (EU-007) shall not exceed 336 hours per twelve consecutive month period with compliance determined at the end of each month.

(3) Comply with the following flare minimization practices to reduce emissions during startups, shutdowns, and other flaring events:

(A) Flare Use Minimization: Process syngas streams to flare EU-007 shall not contain ammonia. During the startup of the sequential reformer, only one process stream at a time shall be sent to the flare to the extent practicable. Maximize the use of process syngas during the startup of the Ammonia Unit;

(B) The Permittee shall train all operators responsible for the day-to-day operation of the flares on the flare minimization practices and the specific procedures to follow during process startup, shutdown, and other flaring events; and

(C) The Permittee shall investigate the "root cause" of malfunction events that cause flaring events other than at startup or shutdown. This root cause analysis shall identify the apparent cause of unanticipated flaring event and shall recommend additional preventive measures that will minimize the chance of a repeat event. The Permittee shall implement the recommended preventive measures.

(4) NO_x, CO, PM, PM_{10} and $PM_{2.5}$, VOC, and GHG emissions shall be controlled by the use of the following practices:

(A) Flares shall be designed for and operated with no visible emissions, except for periods not to exceed 5 minutes during any two consecutive hours;

(B) Flares shall be operated with a flame present at all times; and

(C) Flares shall be continuously monitored to assure the presence of a pilot flame with a thermocouple, infrared monitor, or other approved device.

PM, PM_{10}, $PM_{2.5}$:

(5) PM emissions shall not exceed 0.0019 lb/MMBtu, based on a three-hour average.

(6) PM_{10} and $PM_{2.5}$ emissions shall not exceed 0.0075 lb/MMBtu, based on a three-hour average.

NO_x:

(7) NO_x emissions from the Front End Process Flare (EU-007) shall not exceed 0.068 lb /MMBtu, based on a three-hour average, during normal operation, non-venting periods.

(8) NO_x emissions from the Front End Process Flare (EU-007) shall not exceed 595.47 lb/hr, based on a three-hour average, during venting events.

CO:

(9) CO emissions from the Front End Process Flare (EU-007) shall not exceed 0.37 lb/MMBtu, based on a three-hour average, during normal operations, non-venting periods.

(10) CO emissions from the Front End Process Flare (EU-007) shall not exceed 3,240.16 lb/hr, based on a three-hour average, during venting events.

VOC:

(11) VOC emissions from the Front End Process Flare (EU-007) shall not exceed 0.0054 lb/MMBtu, based on a three-hour average, during normal operations, non-venting periods.

(12) VOC emissions from the Front End Process Flare (EU-007) shall not exceed 47.26 lb/hr, based on a three-hour average, during venting events.

GHG:

(13) CO_2 emissions from the Front End Process Flare (EU-007) shall not exceed 116.89 lb CO_2/MMBtu, based on a three-hour average, during normal operation, non-venting periods.

(14) CO_2 emissions from the Front End Process Flare (EU-007) shall not exceed 511.80 ton CO_2/hr, based on a three-hour average, during venting events.

D.2.5 General Provisions Relating to National Emission Standards for Hazardous Air Pollutants (NESHAP) [40 CFR 63, Subpart A] [326 IAC 20-1]

Pursuant to 40 CFR 63.2540, the Permittee shall comply with the provisions of 40 CFR 60, Subpart A – General Provisions, which are incorporated by reference as 326 IAC 20-1, as specified in Table 12 of 40 CFR 63, Subpart FFFF, in accordance with the schedule in 40 CFR 63, Subpart FFFF.

D.2.6 National Emission Standards for Hazardous Air Pollutants: Miscellaneous Organic Chemical Manufacturing [40 CFR 63, Subpart FFFF] [326 IAC 20-84]

The Permittee shall comply with the following provisions of 40 CFR 63, Subpart FFFF, which are incorporated by reference as 326 IAC 20-84 (included as Attachment A of this permit), for all affected facilities upon startup of the affected source:

(1) 40 CFR 63.2435;
(2) 40 CFR 63.2440;
(3) 40 CFR 63.2445 (a)(2);
(4) 40 CFR 63.2450;
(5) 40 CFR 63.2455;
(6) 40 CFR 63.2480;
(7) 40 CFR 63.2495;
(8) 40 CFR 63.2500;
(9) 40 CFR 63.2515;
(10) 40 CFR 63.2520;
(11) 40 CFR 63.2525;
(12) 40 CFR 63.2540; and
(13) Table 6

D.2.7 General Provisions Relating to National Emission Standards for Hazardous Air Pollutants (NESHAP) [40 CFR 63, Subpart A] [326 IAC 20-1]

Pursuant to 40 CFR 63.7495, the Permittee shall comply with the provisions of 40 CFR 60, Subpart A – General Provisions, which are incorporated by reference as 326 IAC 20-1, in accordance with the schedule in 40 CFR 63.7545, Subpart DDDDD.

D.2.8 National Emission Standards for Hazardous Air Pollutants for Major Sources: Industrial, Commercial, and Institutional Boilers and Process Heaters [40 CFR 63, Subpart DDDDD] [326 IAC 20-95]

The Permittee shall comply with the following provisions of 40 CFR 63, Subpart DDDDD, which are incorporated by reference as 326 IAC 20-95 (included as Attachment H of this permit), for the Primary Reformer (EU-003), upon startup of the affected source:

(1) 40 CFR 63.7485;
(2) 40 CFR 63.7490 (b);
(3) 40 CFR 63.7495 (a), (b);
(4) 40 CFR 63.7500;
(5) 40 CFR 63.7505;
(6) 40 CFR 63.7510;
(7) 40 CFR 63.7525;
(8) 40 CFR 63.7540(a)(10);
(9) 40 CFR 63.7545;
(10) 40 CFR 63.7550;
(11) 40 CFR 63.7555;
(12) 40 CFR 63.7560;
(13) 40 CFR 63.7565; and
(14) Table 3(2).

D.2.9 Preventive Maintenance Plan [326 IAC 2-7-5(12)]

A Preventive Maintenance Plan is required for the Primary Reformer (EU-003), the CO_2 Purification Process (EU-004), and the Front End Process Flare (EU-007). Section B – Preventive Maintenance Plan contains the Permittee's obligation with regard to the preventive maintenance plan required by this condition.

Compliance Determination Requirements

D.2.10 Testing Requirements [326 IAC 2-7-6(1)] [326 IAC 2-7-6(6)]

(a) In order to demonstrate the compliance status with Condition D.2.4(a)(7) and within sixty (60) days of reaching maximum capacity but no later than one hundred and eighty (180) days after initial startup, the Permittee shall perform CO testing on stack EP-003 utilizing methods as approved by the Commissioner. Testing shall be conducted in accordance with the provisions of 326 IAC 3-6 (Source Sampling Procedures). Section C – Performance Testing contains the Permittee's obligation with regard to the performance testing required by this condition.

(b) In order to demonstrate the compliance status with Condition D.2.4(a)(9) and within sixty (60) days of reaching maximum capacity but no later than one hundred and eighty (180) days after initial startup, the Permittee shall perform CO_2 testing on stack EP-003 utilizing methods as approved by the Commissioner. This test shall be repeated at least once every five 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.

(c) In order to demonstrate the compliance status with Condition D.2.4(b)(3) and within sixty (60) days of reaching maximum capacity but no later than one hundred and eighty (180) days after initial startup, the Permittee shall perform CO testing on stack EP-004 utilizing methods as approved by the Commissioner. Testing shall be conducted in accordance with the provisions of 326 IAC 3-6 (Source Sampling Procedures). Section C – Performance Testing contains the Permittee's obligation with regard to the performance testing required by this condition.

(d) In order to demonstrate the compliance status with Condition D.2.4(b)(4) and within sixty (60) days of reaching maximum capacity but no later than one hundred and eighty (180) days after initial startup, the Permittee shall perform VOC testing on stack EP-004 utilizing methods as approved by the Commissioner. Testing shall be conducted in accordance with the provisions of 326 IAC 3-6 (Source Sampling Procedures). Section C – Performance Testing contains the Permittee's obligation with regard to the performance testing required by this condition.

(e) In order to demonstrate the compliance status with Condition D.2.4(b)(5) and within sixty (60) days of reaching maximum capacity but no later than one hundred and eighty (180) days after initial startup, the Permittee shall perform CO_2 testing on stack EP-004 utilizing methods as approved by the Commissioner. This test shall be repeated at least once every five 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.

(f) In order to demonstrate the compliance status with Condition D.2.4(a)(11) – GHGs PSD BACT, and within sixty (60) days of reaching maximum capacity but no later than one hundred and eighty (180) days after initial startup, the Permittee shall perform thermal efficiency testing of the Primary Reformer (EU-003) utilizing methods as approved by the Commissioner. These tests shall be conducted once. Testing shall be conducted in accordance with the provisions of 326 IAC 3-6 (Source Sampling Procedures). Section C – Performance Testing contains the Permittee's obligation with regard to the performance testing required by this condition.

D.2.11 Flare Emissions [326 IAC 2-7-6(1)][326 IAC 2-7-6(6)]

(a) In order to demonstrate compliance with the emission limits in Conditions D.2.4(c)(8), (10), (12), and (14), the Permittee shall use the following equations:

For NO_x, CO, VOC, and CO_2:

$E = (H \times EF) + PE$

Where:

E= Pollutant Emissions (lb/hr)

EF_{NOx} = 0.068 lb/MMBtu

EF_{CO} = 0.3700 lb/MMBtu

EF_{VOC} = 0.0054 lb/MMBtu

EF_{CO2} = 116.8879 lb/MMBtu

PE_{NOx} = 2.566 lb/hr from pilot and purge

PE_{CO} = 13.964 lb/hr from pilot and purge

PE_{VOC} = 0.204 lb/hr from pilot and purge

PE_{CO2} = 4,411.47 lb/hr from pilot and purge

H = Hourly Heat Input (MMBtu/hr) = F_{1-4} (lb/hr) x HHV x 100% (portion of flare stream combusted) x 1 MMBtu/1,000,000 Btu

Where:

F_{1-4} = Flow of flared gas from ammonia free streams (lb/hr)

HHV_1 = 2,830.8 Btu/lb or other value determined by testing

HHV_2 = 2,775.0 Btu/lb or other value determined by testing

HHV_3 = 6,767.2 Btu/lb or other value determined by testing

HHV_4 = 2,830.8 Btu/lb or other value determined by testing

(b) The value F_{1-4} shall be determined through flow monitoring of gases sent to the flare, process operational data, mass balance or other engineering methods.

D.2.12 Carbon Dioxide (CO_2) Calculations

To determine the compliance status with Condition D.2.4(a)(12), the Permittee shall use the following equation for each fuel burned to determine the CO_2 emissions from the Primary Reformer (EU-003):

CO_2 emissions (ton/month) = (Fuel Usage (MMSCF/month) x (CO_2 EF (lb/MMSCF) x 1 ton/2,000 lb)

The monthly emission rate for each fuel shall be summed together.

Where:

Fuel Usage (MMSCF/month) = monthly reformer fuel usage data determined through flow monitoring, process operational data, mass balance, or other engineering methods.

CO_2 EF (lb/MMSCF) = 119,220 lb CO_2/MMSCF for natural gas
CO_2 EF (lb/MMSCF) = 119,220 lb CO_2/MMSCF x % volume methane in process off-gas

The percent volume methane in process off-gases shall be determined through measurement, process operational data, mass balance, or other engineering methods.

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

D.2.13 Maintenance of Continuous Emission Monitoring Equipment [326 IAC 3-5]

(a) The Permittee shall install, calibrate, maintain, and operate all necessary continuous emission monitoring systems (CEMS) and related equipment for NO_x emissions on stack EP-003.

(b) All CEMS required by this permit shall meet all applicable performance specifications of 40 CFR 60, and are subject to monitor system certification requirements pursuant to 326 IAC 3-5-3.

(c) In the event that a breakdown of a continuous emission monitoring system occurs, a record shall be made of the times and reasons for the breakdown and the efforts made to correct the problem.

(d) Whenever a NO_x CEMS is down for more than twenty-four (24) hours, the Permittee shall monitor the catalyst bed inlet temperature used in conjunction with the Primary Reformer (EU-003) with a continuous temperature monitoring system no less often than once per four (4) hours. When for any one reading, the catalyst bed inlet temperature is below the minimum temperature, the Permittee shall take a reasonable response. The minimum temperature for this catalyst bed inlet is 380 °F, unless a new minimum temperature is determined during the most recent valid compliant stack test. Section C – Response to Excursions or Exceedances contains the Permittee's obligation with regard to the reasonable response steps required by this condition. A temperature reading that is below the minimum temperature is not a deviation from this permit. Failure to take response steps shall be considered a deviation from this permit.

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

D.2.14 Record Keeping Requirements

(a) In order to document the compliance status with Conditions D.2.4(a)(2) and D.2.4(a)(11), the Permittee shall maintain monthly records of the type of fuel combusted in the Primary Reformer (EU-003).

(b) In order to document the compliance status with Condition D.2.4(b)(1), the Permittee shall maintain monthly records of ammonia production.

(c) In order to document the compliance status with Condition D.2.4(c)(1), the Permittee shall maintain monthly records of the type of fuel combusted in the Front End Process Flare (EU-007).

(d) In order to document the compliance status with Condition D.2.4(c)(2), the Permittee shall maintain monthly records of the hours of venting for the Front End Process Flare (EU-007). The Permittee shall include in its monthly record when a venting hours entry is not recorded and the reason for a lack of a venting hours entry. (e.g. the process did not operate that month).

(e) In order to document the compliance status with the emission limits in Conditions D.2.4(a)(11) and D.2.4(c)(8), (10), (12), and (14), the Permittee shall maintain records of flow monitoring data, process operational data, mass balance, or other engineering estimation methods used to determine emissions.

(f) In order to document the compliance status with Condition D.2.4(a)(5) and Condition D.2.13, the Permittee shall maintain records of the output of the continuous emission monitoring system for NO_x and shall perform the required record keeping requirements of 326 IAC 3-5-6.

(g) In order to document the compliance status with Condition D.2.4(a)(5) and Condition D.2.13, the Permittee shall maintain records of all CEMS malfunctions, out of control periods, calibration and adjustment activities, and repair of maintenance activities.

(h) To document the compliance status with Condition D.2.4(b)(4), the Permittee shall maintain a record of the use of a low VOC catalyst for the CO_2 Purification Process.

(i) Section C – General Record Keeping Requirements contains the Permittee's obligations with regard to the record keeping required by this condition.

D.2.15 Reporting Requirements

(a) A quarterly summary of the information to document the compliance status with Conditions D.2.4(a)(12), D.2.4(b)(1) and Condition D.2.4(c)(2) shall be submitted not later than thirty (30) days after the end of the quarter being reported. Section C – General Reporting Requirements contains the Permittee’s obligation with regard to the reporting required by 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 in 326 IAC 2-7-1(35).

(b) In order to document the compliance status with Condition D.2.4(a)(5) and Condition D.2.13, the Permittee shall comply with all of the reporting requirements pursuant to 326 IAC 3-5-7.

SECTION D.3 EMISSIONS UNIT OPERATION CONDITIONS

Emissions Unit Description:

(b) An ammonia unit with a maximum throughput capacity of 2,800 ton/day of ammonia consisting of the following emission units and emission control devices:

(1) One (1) ammonia catalyst startup heater, identified as EU-010, approved for construction in 2013, with a maximum rated heat input capacity of 106.3 MMBtu/hr, utilizing no control devices, and exhausting to the ambient atmosphere through stack EP-010. [40 CFR 63, Subpart DDDDD]

(2) One (1) back end ammonia process vent flare for combusting intermittent process gas emissions from maintenance, startup, shutdown, and malfunctions, identified as EU-006, approved for construction in 2013, with pilot capacity of 0.253 MMBtu per hour, utilizing proper flare design and operation minimization practices, and exhausting to the ambient atmosphere through emission point EP-006.

(3) Four (4) ammonia bullet tanks, identified as EU-023A through EU-023D, with a maximum rated capacity of 90,000 gallons each, approved for construction in 2013, utilizing the flare identified as EU-005 as an emission control device, and exhausting to the ambient atmosphere through emissions point EP-005.

(4) Three (3) ammonia cold storage tanks, identified as EU-013A, EU-013B, and EU-013C, with a maximum rated capacity of 40,000 tons each, approved for construction in 2013, utilizing the flare identified as EU-005 as an emission control device, and exhausting to the ambient atmosphere through emission point EP-005.

(5) One (1) ammonia storage flare, identified as EU-005, approved for construction in 2013, with pilot capacity of 0.126 MMBtu per hour, utilizing proper flare design and operation minimization practices, and exhausting to the ambient atmosphere through emission point EP-005.

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

Construction Conditions

General Construction Conditions

D.3.1 Permit No Defense

This permit 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 there under, as well as other applicable local, state, and federal requirements.

Effective Date of the Permit

D.3.2 Effective Date of the Permit [IC 13-15-5-3]

Pursuant to IC 13-15-5-3, this section of this permit becomes effective upon its issuance.

D.3.3 Modifications to Construction Conditions [326 IAC 2]

All requirements of these construction conditions shall remain in effect unless modified in a manner consistent with procedures established for revisions pursuant to 326 IAC 2.

Operating Conditions

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

D.3.4 PSD Best Available Control Technology Limits [326 IAC 2-2-3]

Pursuant to PSD/Operating Permit T 147-32322-00062 and 326 IAC 2-2 (Prevention of Significant Deterioration (PSD)), the best available control technology (BACT) for the Ammonia Catalyst Startup Heater (EU-010), the Back End Ammonia Process Flare (EU-006) and the Ammonia Storage Flare (EU-005) shall be as follows:

(a) **Ammonia Catalyst Startup Heater (EU-010):**

Common PM, PM_{10}, $PM_{2.5}$, NO_x, CO, VOC and GHG Conditions:

(1) In order to control PM, PM_{10}, $PM_{2.5}$, NO_x, CO, VOC and GHG emissions, the Ammonia Catalyst Startup Heater (EU-010) shall combust natural gas.

(2) In order to control PM, PM_{10}, $PM_{2.5}$, NO_x, CO, VOC and GHG emissions, the Ammonia Catalyst Startup Heater (EU-010) shall be controlled by good heater design and good combustion practices.

(3) Fuel usage in the Ammonia Catalyst Startup Heater (EU-010) shall not exceed 20.84 MMCF per twelve consecutive month period with compliance determined at the end of each month.

PM, PM_{10}, $PM_{2.5}$:

(4) PM, PM_{10} and $PM_{2.5}$ emissions from the Ammonia Catalyst Startup Heater (EU-010) shall not exceed 1.9, 7.6, and 7.6 lb/MMCF respectively, based on a three-hour average. PM includes filterable particulate matter, while, PM_{10} and $PM_{2.5}$ include both filterable and condensable particulate matter.

NO_x:

(5) NO_x emissions from the Ammonia Catalyst Startup Heater (EU-010) shall not exceed 183.70 lb/MMCF, based on a three-hour average.

CO:

(6) CO emissions from the Ammonia Catalyst Startup Heater (EU-010) shall not exceed 37.23 lb/MMCF, based on a three-hour average.

VOC:

(7) VOC emissions from the Ammonia Catalyst Startup Heater (EU-010) shall not exceed 5.50 lb/MMCF, based on a three-hour average.

GHG:

(8) CO_2 emissions from the Ammonia Catalyst Startup Heater (EU-010) shall not exceed 59.61 ton/MMCF, based on a three-hour average.

(b) **Back End Ammonia Process Flare (EU-006):**

Common PM, PM_{10}, $PM_{2.5}$, NO_x, CO, VOC and GHG Conditions:

(1) In order to control PM, PM_{10}, $PM_{2.5}$, NO_x, CO, VOC and GHG emissions, the pilot and purge gas fuels used in the flare shall be natural gas.

(2) Venting in the Back End Ammonia Process Flare (EU-006) shall not exceed 336 hours per twelve consecutive month period with compliance determined at the end of each month.

(3) Comply with the following flare minimization practices to reduce emissions during startups, shutdowns, and other flaring events:

(A) Flare Use Minimization: Flare EU-006 shall be limited to flaring ammonia during high-pressure events to the extent practicable. The ammonia compressor main shall be depressurized prior to compressor maintenance. The Permittee shall limit venting ammonia rich streams to Flare EU-006 to the extent practicable during non-emergency startup and shutdown operations;

(B) The Permittee shall train all operators responsible for the day-to-day operation of the flares on the flare minimization practices and the specific procedures to follow during process startup, shutdown, and other flaring events; and

(C) The Permittee shall investigate the “root cause” of malfunction events that cause flaring events other than at startup or shutdown. This root cause analysis shall identify the apparent cause of unanticipated flaring event and shall recommend additional preventive measures that will minimize the chance of a repeat event. The Permittee shall implement the recommended preventive measures.

(4) PM, PM_{10}, $PM_{2.5}$, NO_x, CO, VOC and GHG emissions from the Back End Ammonia Process Vent Flare (EU-006) shall be controlled by the use of the following practices:

(A) Flares shall be designed for and operated with no visible emissions, except for periods not to exceed 5 minutes during any two consecutive hours;

(B) Flares shall be operated with a flame present at all times; and

(C) Flares shall be continuously monitored to assure the presence of a pilot flame with a thermocouple, infrared monitor, or other approved device.

PM, PM_{10}, $PM_{2.5}$:

(5) PM emissions in the Back End Ammonia Process Flare (EU-006) shall not exceed 0.0019 lb/MMBtu, based on a three-hour average.

(6) PM_{10} and $PM_{2.5}$ emissions in the Back End Ammonia Process Flare (EU-006) shall not exceed 0.0075 lb/MMBtu, based on a three-hour average.

NO_x:

(7) NO_x emissions from the Back End Ammonia Process Vent Flare (EU-006) shall not exceed 0.068 lb/MMBtu, based on a three-hour average, during normal operation, non-venting periods.

(8) NO_x emissions from the Back End Ammonia Process Vent Flare (EU-006) shall not exceed 624.94 lb/hr, based on a three-hour average, during venting events.

CO:

(9) CO emissions from the Back End Ammonia Process Flare (EU-006) shall not exceed 0.37 lb/MMBtu, based on a three-hour average, during normal operations, non-venting periods.

(10) CO emissions from the Back End Ammonia Process Flare (EU-006) shall not exceed 804.76 lb/hr, based on a three-hour average, during venting events.

VOC:

(11) VOC emissions from the Back End Process Flare (EU-006) shall not exceed 0.0054 lb/MMBtu, based on a three-hour average, during normal operations, non-venting period.

(12) VOC emission from the Back End Process Flare (EU-006) shall not exceed 11.73 lb/hr, based on a three-hour average, during venting events.

GHG:

(13) CO_2 emissions from the Back End Ammonia Process Vent Flare (EU-006) shall not exceed 116.89 lb/MMBtu, based on a three-hour average, during normal operations, non-venting periods.

(14) CO_2 emissions from the Back End Ammonia Process Vent Flare (EU-006) shall not exceed 127.12 ton CO_2/hr, based on a three-hour average, during venting events.

(c) **<u>Ammonia Storage Flare (EU-005):</u>**

Common PM, PM_{10}, $PM_{2.5}$, NO_x, CO, VOC and GHG Conditions:

(1) In order to control PM, PM_{10}, $PM_{2.5}$, NO_x, CO, VOC and GHG emissions, the pilot and purge gas fuels used in the flare shall be natural gas.

(2) Venting for Startup, Shutdown and Malfunction shall not exceed 168 hours per twelve consecutive month period with compliance determined at the end of each month.

(3) Comply with the following flare minimization practices to reduce emissions during startups, shutdowns, and other flaring events:

  (A) Flare Use Minimization: The Permittee shall limit periods when the backup storage compressor and the ammonia refrigeration compressor are offline at the same time to the extent practicable;

  (B) The Permittee shall train all operators responsible for the day-to-day operation of the flares on the flare minimization practices and the specific procedures to follow during process startup, shutdown, and other flaring events; and

  (C) The Permittee shall investigate the “root cause” of malfunction events that cause flaring events other than at startup or shutdown. This root cause analysis shall identify the apparent cause of unanticipated flaring event and shall recommend additional preventive measures that will minimize the chance of a repeat event. The Permittee shall implement the recommended preventive measures.

(4) PM, PM_{10}, $PM_{2.5}$, NO_x, CO, VOC and GHG emissions shall be controlled by the use of the following practices:

  (A) Flares shall be designed for and operated with no visible emissions, except for periods not to exceed 5 minutes during any two consecutive hours;

  (B) Flares shall be operated with a flame present at all times; and

  (C) Flares shall be continuously monitored to assure the presence of a pilot flame with a thermocouple, infrared monitor, or other approved device.

PM, PM_{10}, $PM_{2.5}$:

(5) PM emissions from the Ammonia Storage Flare (EU-005) shall not exceed 0.0019 lb/MMBtu, based on a three-hour average.

(6) PM_{10} and $PM_{2.5}$ emissions Ammonia Storage Flare (EU-005) shall not exceed 0.0075 lb/MMBtu, based on a three-hour average.

NO_x:

(7) NO_x emissions from the Ammonia Storage Flare (EU-005) shall not exceed 0.068 lb/MMBtu, based on a three-hour average, during normal operation, non-venting periods.

(8) NO_x emissions from the Ammonia Storage Flare (EU-005) shall not exceed 125.0 lb/hour, based on a three-hour average, during venting events.

CO:

(9) CO emissions from the Ammonia Storage Flare (EU-005) shall not exceed 0.37 lb/MMBtu, based on a three-hour average.

VOC:

(10) VOC emissions from the Ammonia Storage System Flare (EU-005) shall not exceed 0.0054 lb/MMBtu, based on a three-hour average.

GHG:

(11) CO_2 emissions from the Ammonia Storage Flare (EU-005) shall not exceed 52.02 lb/hr, based on a three-hour average.

D.3.5 General Provisions Relating to National Emission Standards for Hazardous Air Pollutants (NESHAP) [40 CFR 63, Subpart A] [326 IAC 20-1]

Pursuant to 40 CFR 63.7495, the Permittee shall comply with the provisions of 40 CFR 60, Subpart A – General Provisions, which are incorporated by reference as 326 IAC 20-1, in accordance with the schedule in 40 CFR 63.7545, Subpart DDDDD.

D.3.6 National Emission Standards for Hazardous Air Pollutants for Major Sources: Industrial, Commercial, and Institutional Boilers and Process Heaters [40 CFR 63, Subpart DDDDD] [326 IAC 20-95]

The Permittee shall comply with the following provisions of 40 CFR 63, Subpart DDDDD, which are incorporated by reference as 326 IAC 20-95 (included as Attachment H of this permit), for the Ammonia Catalyst Startup Heater (EU-010), upon startup of the affected source:

(1) 40 CFR 63.7485;
(2) 40 CFR 63.7490 (b);
(3) 40 CFR 63.7495 (a), (b);
(4) 40 CFR 63.7500;
(5) 40 CFR 63.7505;
(6) 40 CFR 63.7510;
(7) 40 CFR 63.7525;
(8) 40 CFR 63.7540(a)(10);
(9) 40 CFR 63.7545;
(10) 40 CFR 63.7550;
(11) 40 CFR 63.7555;
(12) 40 CFR 63.7560;
(13) 40 CFR 63.7565; and
(14) Table 3(2).

D.3.7 Preventive Maintenance Plan [326 IAC 2-7-5(12)]

A Preventive Maintenance Plan is required for the Ammonia Catalyst Startup Heater (EU-010), the Back End Ammonia Process Vent Flare (EU-006), and the Ammonia Storage Flare (EU-005). Section B – Preventive Maintenance Plan contains the Permittee’s obligation with regard to the preventive maintenance plan required by this condition.

Compliance Determination Requirements

D.3.8 Flare Emissions [326 IAC 2-7-6(1)][326 IAC 2-7-6(6)]

(a) In order to demonstrate compliance with the emission limits in Conditions D.3.4(b)(8), (10), (12), and (14), the Permittee shall use the following equations:

(1) For CO, VOC, and CO_2:

E = (H x EF) + PE

Where:

E= Pollutant Emissions (lb/hr)

EF_{CO} = 0.3700 lb/MMBtu

EF_{VOC} = 0.0054 lb/MMBtu

EF_{CO2} = 116.8879 lb/MMBtu

PE_{CO} = 14.158 lb/hr from pilot and purge

PE_{VOC} = 0.206 lb/hr from pilot and purge

PE_{CO2} = 4,472.60 lb/hr from pilot and purge

H = Hourly Heat Input (MMBtu/hr) = F_1 (lb/hr) x HHV_1 x 100% (portion of flare stream combusted) x 1 MMBtu/1,000,000 Btu

Where:

F_1 = Flow of flared gases from ammonia free streams (lb/hr)

HHV_1 = 9,020.7 Btu/lb or other value determined by testing

(2) For NO_x:

E = (H x EF) + PE + FE

Where:

E= Pollutant Emissions (lb/hr)

EF_{NOx} = 0.068 lb/MMBtu

PE_{NOX} = 2.60 lb/hr from pilot and purge

H = Hourly Heat Input (MMBtu/hr) = (F_1 (lb/hr) x HHV_1 x 100% (portion of flare stream combusted) x 1 MMBtu/1,000,000 Btu) + (F_2 (lb/hr) x HHV_2 x 98% (portion of flare stream combusted) x 1 MMBtu/1,000,000 Btu)

Where:
F_1 = Flow of flared gases from ammonia free streams (lb/hr)
HHV_1 = 9,020.7 Btu/lb or other value determined during testing
F_2 = Flow of flared gases from ammonia streams (lb/hr)
HHV_2 = 7,996.5 Btu/lb or other value determined by testing

FE_{NOx} = F (lb/hr) x (Ammonia Combusted) x (Ammonia in Flare Gas) x (M.W. of NO_2 / M.W. of NH_3) x FN%

Where:
F = Flow of Flared Gases (lb/hr)
Ammonia Combusted = 98%
Ammonia in Flare Gas = 99.9%
M.W. of NO_2 = molecular weight of nitrogen dioxide = 46 lb/lb.mole
M.W. of NH_3 = molecular weight of ammonia = 17 lb/lb.mole
FN = Fuel NO_x factor for ammonia = 0.50%

(b) In order to demonstrate compliance with the emission limits in Conditions D.3.4(c)(8) and (11), the Permittee shall use the following equations:

(1) For NO_x and CO_2:

E = (H x EF) + PE + FE

Where:
E= Pollutant Emissions (lb/hr)
EF_{NOx} = 0.068 lb/MMBtu
EF_{CO2} = 0 lb/MMBtu as there are no carbon containing vent streams
PE_{NOx} = 0.03 lb/hr from pilot and purge
PE_{CO2} = 52.02 lb/hr from pilot and purge

H = Hourly Heat Input (MMBtu/hr) = F (lb/hr) x HHV x 98% (portion of flare stream combusted) x 1 MMBtu/1,000,000 Btu

Where:
F = Flow of Flared Gases (lb/hr)
HHV = 7,779.7 Btu/lb or other value determined by testing

FE_{NOX} = F (lb/hr) x (Ammonia Combusted) x (Ammonia in Flare Gas) x (M.W. of NO_2 / M.W. of NH_3) x FN%

Where:
F = Flow of Flared Gases (lb/hr)
Ammonia Combusted = 98%
Ammonia in Flare Gas = 98.3%
M.W. of NO_2 = molecular weight of nitrogen dioxide = 46 lb/lb.mole
M.W. of NH_3 = molecular weight of ammonia = 17 lb/lb.mole
FN = Fuel NOx factor for ammonia = 0.50%

(c) The Permittee shall determine flow rates used in the equations in Conditions D.3.8(a) and (b) through flow monitoring of gases sent to the flare, process operational data, mass balance, or other engineering methods.

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

D.3.9 Record Keeping Requirements

(a) In order to document the compliance status with Condition D.3.4(a)(1), the Permittee shall maintain monthly records of the type of fuel combusted in the Ammonia Catalyst Startup Heater (EU-010).

(b) In order to document the compliance status with Condition D.3.4(a)(3), the Permittee shall maintain monthly records of the amount of fuel combusted in the Ammonia Catalyst Startup Heater (EU-010).

(c) In order to document the compliance status with Condition D.3.4(b)(1), the Permittee shall maintain monthly records of the type of fuel combusted in the Back End Ammonia Process Flare (EU-006).

(d) In order to document the compliance status with Condition D.3.4(b)(2), the Permittee shall maintain a monthly record of the hours the Back End Ammonia Process Flare (EU-006) vents. The Permittee shall include in its monthly record when a venting hours entry is not recorded and the reason for a lack of a venting hours entry. (e.g. the process did not operate that month).

(e) In order to document the compliance status with Condition D.3.4(c)(1), the Permittee shall maintain monthly records of the type of fuel combusted in the Ammonia Storage Flare (EU-005).

(f) In order to document the compliance status with Condition D.3.4(c)(2), the Permittee shall maintain a monthly record of the hours the Ammonia Storage Flare (EU-005) vents. The Permittee shall include in its monthly record when a venting hours entry is not recorded and the reason for a lack of a venting hours entry. (e.g. the process did not operate that month).

(g) In order to document compliance with the emission limits in Conditions D.3.4(b)(8), (10), (12), and (14), and D.3.4(c)(8) and (11), the Permittee shall maintain records of flow monitoring data, process operational data, mass balance, or other engineering estimation methods used to determine flare emissions.

(h) Section C – General Record Keeping Requirements contains the Permittee’s obligations with regard to the record keeping required by this condition.

D.3.10 Reporting Requirements

A quarterly summary of the information to document the compliance status with Condition D.3.4(a)(3), Condition D.3.4(b)(2) and Condition D.3.4(c)(2) shall be submitted not later than thirty (30) days after the end of the quarter being reported. Section C – General Reporting Requirements contains the Permittee’s obligation with regard to the reporting required by 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 in 326 IAC 2-7-1(35).

SECTION D.4 EMISSIONS UNIT OPERATION CONDITIONS

Emissions Unit Description:

(c) Two (2) urea ammonium nitrate (UAN) plants, including the production of urea, nitric acid, ammonium nitrate, and diesel exhaust fluid (DEF), consisting of the following emission units and emission control devices:

(1) Two (2) nitric acid units, identified as EU-001A and EU-001B, with a maximum throughput capacity of 630 ton/day of 100% nitric acid each, approved for construction in 2013, equipped with selective catalytic reduction for NO_x control, catalytic decomposition for N_2O control, and a NO_x CEMS, and exhausting to the ambient atmosphere through tailgas stacks EP-001A and EP-001B. [40 CFR 60, Subpart Ga]

(2) Two (2) nitric acid storage tanks, identified as EU-022A and EU-022B, approved for construction in 2013, with a maximum throughput of 1,105 ton/day of 57% nitric acid each, and exhausting to the ambient atmosphere through the UAN process vent stacks EP-002A and EP-002B.

(3) Two (2) ammonium nitrate (AN) units, identified as EU-002A and EU-002B, approved for construction in 2013, with a maximum throughput capacity of 798 ton/day of ammonium nitrate each, utilizing a scrubber with particulate demister for particulate matter control, and exhausting to the ambient atmosphere through stacks EP-002A and EP-002B. [40 CFR 60, Subpart VVa]

(4) Two (2) UAN Storage Tanks, identified as EU-012A and EU-012B, approved for construction in 2013, with a maximum rated capacity of 30,000 tons each, and exhausting to the ambient atmosphere through vents EP-012A and EP-012B.
[40 CFR 60, Subpart VVa]

(5) Three (3) UAN Day Tanks, identified as EU-020A, EU-020B, and EU-020C, approved for construction in 2013, with a maximum rated capacity of 750 tons each, and exhausting to the ambient atmosphere through vents EP-020A, EP-020B, and EP-020C. [40 CFR 60, Subpart VVa]

(6) Two (2) UAN loadout facilities (one (1) truck and one (1) for rail), identified as EU-024A and EU-024B, approved for construction in 2013, and exhausting to the ambient atmosphere as fugitive emission sources EP-024A and EP-024B.
[40 CFR 60, Subpart VVa]

(7) One (1) UAN plant vent flare for combusting intermittent process gas emissions from maintenance, startup, shutdown, and malfunctions, identified as EU-017, approved for construction in 2013, with a pilot capacity of 0.189 MMBtu per hour, utilizing proper flare design and operation minimization practices, and exhausting to the ambient atmosphere through emission point EP-017.

(8) One (1) DEF tank, identified as EU-021, approved for construction in 2013, with capacity of 100 tons, and exhausting to the ambient atmosphere through vent EP-021.
[40 CFR 60, Subpart VVa]

(9) One (1) DEF truck loadout facility, identified as EU-025, approved for construction in 2013, and exhausting to the ambient atmosphere as fugitive emission source EP-025.
[40 CFR 60, Subpart VVa]

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

Construction Conditions

General Construction Conditions

D.4.1 Permit No Defense

This permit 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 there under, as well as other applicable local, state, and federal requirements.

Effective Date of the Permit

D.4.2 Effective Date of the Permit [IC 13-15-5-3]

Pursuant to IC 13-15-5-3, this section of this permit becomes effective upon its issuance.

D.4.3 Modifications to Construction Conditions [326 IAC 2]

All requirements of these construction conditions shall remain in effect unless modified in a manner consistent with procedures established for revisions pursuant to 326 IAC 2.

Operating Conditions

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

D.4.4 PSD Best Available Control Technology Limits [326 IAC 2-2-3]

Pursuant to PSD/Operating Permit T 147-32322-00062 and 326 IAC 2-2 (Prevention of Significant Deterioration (PSD)), the best available control technology (BACT) for the Nitric Acid Units (EU-001A and EU-001B), the Ammonium Nitrate Units (EU-002A and EU-002B), the UAN Loadout Facilities (EU-024A and EU-024B), the UAN Plant Vent Flare (EU-017), the UAN Storage Tanks (EU-012A and EU-012B), the UAN Day Tanks (EU-020A, EU-020B and EU-020C), the UAN Loadout Facilities (EU-024A and EU-024B), the DEF Tank (EU-021), the DEF Truck Loadout (EU-025) and the Nitric Acid Storage Tanks (EU-022A and EU-022B) shall be as follows:

(a) **<u>Nitric Acid Units (EU-001A and EU-001B):</u>**

Common NO_x and GHG Conditions:

(1) The combined nitric acid production from Nitric Acid Units (EU-001A and EU-001B) shall not exceed 459,900 tons of 100% nitric acid per twelve consecutive month period with compliance determined at the end of each month.

NO_x:

(2) NO_x emissions from the Nitric Acid Units (EU-001A and EU-001B) shall not exceed 0.5 lb NO_x per ton acid, based on a thirty day average, each, using Selective Catalytic Reduction (SCR).

GHG:

(3) N_2O emissions from each of the Nitric Acid Units (EU-001A and EU-001B) shall be controlled at all times by a catalytic decomposition process.

(4) N_2O emissions from each of the Nitric Acid Units (EU-001A and EU-001B) shall not exceed 1.05 lb N_2O per ton of nitric acid, based on a three-hour average.

(b) **Ammonium Nitrate Units (EU-002A and EU-002B):**

Common PM, PM_{10}, $PM_{2.5}$ and GHG Conditions

(1) The maximum combined production of urea ammonium nitrate (UAN) for the Ammonium Nitrate Units (EU-002A and EU-002B) shall not exceed 1,314,000 tons per year.

PM, PM_{10}, $PM_{2.5}$:

(2) The PM, PM_{10} and $PM_{2.5}$ emissions from the operation of each Ammonium Nitrate Units (EU-002A and EU-002B) shall not exceed 0.0128 lb per ton of urea ammonium nitrate (UAN), based on a three-hour average, through the use of a wet scrubber with demister.

GHG:

(3) CO_2 emissions from the Ammonium Nitrate Units (EU-002A and EU-002B) shall be controlled by good operational practices in the reformer process including the Primary Reformer (EU-003) and CO_2 Purification Process (EU-004).

(4) CO_2 emissions from each of the Ammonium Nitrate Units (EU-002A and EU-002B) shall not exceed 132.31 lb CO_2 per ton UAN, based on a three-hour average.

(c) **UAN Loadout Facilities (EU-024A and EU-024B):**

VOC:

VOC emissions from the UAN Loadout Facilities (EU-024A and EU-024B) shall each be controlled by the use of submerged/bottom fill and dedicated or clean cargo carrier operation.

(d) **UAN Plant Vent Flare (EU-017):**

Common PM, PM_{10}, $PM_{2.5}$, NO_x, CO, VOC and GHG Conditions:

(1) In order to control PM, PM_{10}, $PM_{2.5}$, NO_x, CO, VOC and GHG emissions, the pilot and purge gas fuels used in the flare shall be natural gas.

(2) Venting for Startup, Shutdown and Malfunction shall not exceed 336 hours per twelve consecutive month period with compliance determined at the end of each month.

(3) Comply with the following flare minimization practices to reduce emissions during startups, shutdowns, and other flaring events:

(A) Flare Use Minimization: The UAN process shall be properly operated to avoid emergency upsets. Startup time of the Nitric Acid Units shall be minimized. During emergency upsets of the Nitric Acid Units, the Permittee shall return some of the high and low-pressure off-gas back to the urea process as soon as urea production is reduced to a level that safely allows this;

(B) The Permittee shall train all operators responsible for the day-to-day operation of the flares on the flare minimization practices and the specific procedures to follow during process startup, shutdown, and other flaring events; and

(C) The Permittee shall investigate the “root cause” of malfunction events that cause flaring events other than at startup or shutdown. This root cause analysis shall identify the apparent cause of unanticipated flaring event and shall recommend additional preventive measures that will minimize the chance of a repeat event. The Permittee shall implement the recommended preventive measures.

(4) PM, PM_{10}, $PM_{2.5}$, NO_x, CO, VOC and GHG emissions shall be controlled by the use of the following practices:

(A) Flares shall be designed for and operated with no visible emissions, except for periods not to exceed 5 minutes during any two consecutive hours;

(B) Flares shall be operated with a flame present at all times; and

(C) Flares shall be continuously monitored to assure the presence of a pilot flame with a thermocouple, infrared monitor, or other approved device.

PM, PM_{10}, $PM_{2.5}$:

(5) PM emissions from the UAN Plant Vent Flare (EU-017) shall not exceed 0.0019 lb/MMBtu, based on a three-hour average.

(6) PM_{10} and $PM_{2.5}$ emissions from the UAN Plant Vent Flare (EU-017) shall not exceed 0.0075 lb/MMBtu, based on a three-hour average.

NO_x:

(7) NO_x emissions from the UAN Plant Vent Flare (EU-017) shall not exceed 0.068 lb/MMBtu, based on a three-hour average, during normal operation, non-venting periods.

(8) NO_x emissions from the UAN Plant Vent Flare (EU-017) shall not exceed 332.08 lb/hr, based on a three-hour average, during venting events.

CO:

(9) CO emissions from the UAN Plant Vent Flare (EU-017) shall not exceed 0.37 lb/MMBtu, based on a three-hour average.

VOC:

(10) VOC emissions from the UAN Plant Vent Flare (EU-017) shall not exceed 0.0054 lb/MMBtu, based on a three-hour average.

GHG:

(11) CO_2 emissions from the UAN Plant Vent Flare (EU-017) shall not exceed 116.89 lb/MMBtu, based on a three-hour average, during normal operations, non-venting events.

(12) CO_2 emissions from the UAN Plant Vent Flare (EU-017) shall not exceed 5.59 tons/hr, based on a three-hour average, during venting events.

(e) **Two (2) UAN Storage Tanks (EU-012A and EU-012B):**

VOC:

(1) The use of white tank shells.

(2) The use of submerged/bottom fills.

(f) **Three (3) UAN Day Tanks (EU-020A, EU-020B, and EU-020C):**

VOC:

(1) The use of white tank shells.

(2) The use of submerged/bottom fills.

(g) **One (1) DEF Tank (EU-021):**

VOC:

(1) The use of a white tank shell.

(2) The use of submerged/bottom fill.

(h) **One DEF Truck Loadout (EU-025):**

VOC:

The use of submerged/bottom fill.

(i) **Nitric Acid Storage Tanks (EU-022A and EU-022B):**

NO_x:

(1) NO_x emissions from each of the Nitric Acid Storage Tanks (EU-022A and EU-022B) shall be controlled by the use of submerged/bottom fill.

(2) Combined throughput of the Nitric Acid Storage Tanks (EU-022A and EU-022B) shall not exceed 806,842 tons of 57% nitric acid per twelve consecutive month period with compliance determined at the end of each month.

(3) NO_x emissions from each of the Nitric Acid Storage Tanks (EU-022A and EU-022B) shall not exceed 0.0015 lb NO_x per ton of 57% nitric acid.

D.4.5 General Provisions Relating to New Source Performance Standards (NSPS) [40 CFR 60, Subpart A] [326 IAC 12]

(a) The provisions of 40 CFR 60, Subpart A – General Provisions, which are incorporated by reference in 326 IAC 12-1-1, apply to the nitric acid units, identified as EU-001A and EU-001B, except when otherwise specified in 40 CFR 60, Subpart Ga.

(b) The provisions of 40 CFR 60, Subpart A – General Provisions, which are incorporated by reference in 326 IAC 12-1-1, apply to the ammonia nitrate units, identified as EU-002A and EU-002B, the UAN Storage Tanks, identified as EU-012A and EU-012B, the UAN Day Tanks, identified as EU-020A, EU-020B and EU-020C, the UAN loadout facilities, identified as EU-024A and EU-024B, the DEF tank, identified as EU-021, and the DEF truck loadout facility, identified as EU-025, except when otherwise specified in 40 CFR 60, Subpart VVa.

D.4.6 New Source Performance Standards (NSPS) [40 CFR 60, Subpart Ga] [326 IAC 12]

The Permittee shall comply with the following provisions of 40 CFR 60, Subpart Ga (Standards of Performance for Nitric Acid Plants for Which Construction, Reconstruction, or Modification Commenced after October 14, 2011 (included as Attachment D of this permit) which are incorporated by reference as 326 IAC 12, for the nitric acid units, identified as EU-001A and EU-001B as specified as follows:

(1) 40 CFR 60.70a;
(2) 40 CFR 60.72a;
(3) 40 CFR 60.73a;
(4) 40 CFR 60.74a;
(5) 40 CFR 60.75a;
(6) 40 CFR 60.76a; and
(7) 40 CFR 60.77a.

D.4.7 New Source Performance Standards (NSPS) [40 CFR 60, Subpart VVa] [326 IAC 12]

The Permittee shall comply with the following provisions of 40 CFR 60, Subpart VVa (Standards of Performance for Equipment Leaks of VOC in the Synthetic Organic Chemicals Manufacturing Industry for Which Construction, Reconstruction, or Modification Commenced After November 7, 2006 (included as Attachment C of this permit) which are incorporated by reference as 326 IAC 12, for the ammonium nitrate units, identified as EU-002A and EU-002B, the UAN Storage Tanks, identified as EU-012A and EU-012B, the UAN Day Tanks, identified as EU-020A, EU-020B and EU-020C, the UAN loadout facilities, identified as EU-024A and EU-024B, the DEF tank, identified as EU-021, and the DEF truck loadout facility, identified as EU-025, as specified as follows:

(1) 40 CFR 60.480a(a) to (c);
(2) 40 CFR 60.480a(d)(1) and (d)(3); and
(3) 40 CFR 60.486a(i).

D.4.8 Preventive Maintenance Plan [326 IAC 2-7-5(12)]

A Preventive Maintenance Plan is required for the nitric acid units, identified as EU-001A and EU-001B, the ammonium nitrate units, identified as EU-002A and EU-002B and the UAN plant vent flare (EU-017). Section B – Preventive Maintenance Plan contains the Permittee’s obligation with regard to the preventive maintenance plan required by this condition.

Compliance Determination Requirements

D.4.9 Testing Requirements [326 IAC 2-7-6(1)] [326 IAC 2-7-6(6)]

(a) In order to demonstrate the compliance status with Condition D.4.4(a)(4) and within sixty (60) days of reaching maximum capacity but no later than one hundred and eighty (180) days after initial startup, the Permittee shall perform N_2O testing on stacks EP-001A and EP-001B utilizing methods as approved by the Commissioner. Testing shall be conducted in accordance with the provisions of 326 IAC 3-6 (Source Sampling Procedures). Section C – Performance Testing contains the Permittee's obligation with regard to the performance testing required by this condition.

(b) In order to demonstrate the compliance status with Condition D.4.4(b)(2) and within sixty (60) days of reaching maximum capacity but no later than one hundred and eighty (180) days after initial startup, the Permittee shall perform PM, PM_{10}, $PM_{2.5}$ testing on stacks EP-002A and EP-002B 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. PM_{10} and $PM_{2.5}$ include condensable and filterable PM.

(c) In order to demonstrate the compliance status with Condition D.4.4(b)(4) and within sixty (60) days of reaching maximum capacity but no later than one hundred and eighty (180) days after initial startup, the Permittee shall perform CO_2 testing on stacks EP-002A and EP-002B utilizing methods as approved by the Commissioner. Testing shall be conducted in accordance with the provisions of 326 IAC 3-6 (Source Sampling Procedures). Section C – Performance Testing contains the Permittee's obligation with regard to the performance testing required by this condition.

D.4.10 Maintenance of Continuous Emission Monitoring Equipment [326 IAC 3-5]

(a) The Permittee shall install, calibrate, maintain, and operate all necessary continuous emission monitoring systems (CEMS) and related equipment for NO_x emissions on stacks EP-001A and EP-001B.

(b) All CEMS required by this permit shall meet all applicable performance specification of 40 CFR 60 and are subject to monitor system certification requirements pursuant to 326 IAC 3-5-3.

(c) In the event that a breakdown of a continuous emission monitoring system occurs, a record shall be made of the times and reasons for the breakdown and the efforts made to correct the problem.

(d) Whenever a NO_x CEMS is down for more than twenty-four (24) hours, the Permittee shall follow the best operational practices.

D.4.11 Flare Emissions [326 IAC 2-7-6(1)][326 IAC 2-7-6(6)]

(a) In order to demonstrate compliance with the emission limits in Conditions D.4.4(d)(8) and (12), the Permittee shall use the following equations:

(1) For NO_x:

E = (H x EF) + PE + FE

Where:

E= Pollutant Emissions (lb/hr)

EF_{NOx} = 0.068 lb/MMBtu

PE_{NOx} = 0.44 lb/hr from pilot and purge

H = Hourly Heat Input (MMBtu/hr) = F (lb/hr) x HHV x 98% (portion of flare stream combusted) x 1 MMBtu/1,000,000 Btu

Where:

F = Flow of Flared Gases (lb/hr)
HHV = 4,605 Btu/lb or other value determined by testing

FE_{NOx} = F (lb/hr) x (Ammonia Combusted) x (Ammonia in Flare Gas) x M.W. of NO_2 / M.W. of NH_3) x FN%

Where:

F = Flow of Flares Gases (lb/hr)
Ammonia Combusted = 98%
Ammonia in Flare Gas = 72.18%
M.W. of NO_2 = molecular weight of nitrogen dioxide = 46 lb/lb.mole
M.W. of NH_3 = molecular weight of ammonia = 17 lb/lb.mole
FN = Fuel NO_x factor for ammonia = 0.50%

(2) For CO_2:

E = (H x EF) + PE

Where:

E = Pollutant Emissions (lb/hr)
F = Flow of Flared Gases (lb/hr)
EF CO_2 = 31%
PE CO_2 = 751.12 lb/hr from pilot and purge

(b) The Permittee shall determine flow rates used in the equations in Condition D.4.11(a)(1) and (2) through flow monitoring of gases sent to the flare, process operational data, mass balance, or other engineering methods.

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

D.4.12 Parametric Monitoring

(a) The Permittee shall record the pressure drop across the particulate demisters following the scrubbers used in conjunction with the ammonium nitrate (AN) units, identified as EU-002A and EU-002B at least once per day when the listed process are in operation. When for any one reading, the pressure drop is outside the normal range, the Permittee shall take a reasonable response. The normal pressure drop range for these particulate demisters is 1.5 to 11 inches of water, unless a different upper-bound or lower-bound value for this range is determined during the latest valid compliant stack test. Section C – Response to Excursions or Exceedances contains the Permittee's obligation with regard to the reasonable response steps required by this condition. A pressure drop reading that is outside the range mentioned above is not a deviation from this permit. Failure to take response steps shall be considered a deviation from this permit.

The instruments used for determining the particulate demister pressure drop 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.

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

D.4.13 Record Keeping Requirements

(a) In order to document the compliance status with Condition D.4.4(a)(1), the Permittee shall maintain monthly records of the combined 100% nitric acid production from Nitric Acid Units (EU-001A and EU-001B).

(b) In order to document the compliance status with Condition D.4.4(b)(1), the Permittee shall maintain monthly records of the combined urea ammonium nitrate (UAN) production from Ammonium Nitrate Units (EU-002A and EU-002B).

(c) In order to document the compliance status with Condition D.4.4(d)(2), the Permittee shall maintain monthly records of the hours of process venting for the UAN Plant Vent Flare (EU-017).

(d) In order to document the compliance status with Condition D.4.4(i)(2), the Permittee shall maintain monthly records of the combined 57% nitric acid throughput of the Nitric Acid Storage Tanks (EU-022A and EU-022B).

(e) In order to document the compliance status with Conditions D.4.4(d)(8) and (12), the Permittee shall maintain records of flow monitoring data, process operational data, mass balance, or other engineering estimation methods used to determine flare emissions.

(f) Section C – General Record Keeping Requirements contains the Permittee's obligations with regard to the record keeping required by this condition.

D.4.14 Reporting Requirements

A quarterly summary of the information to document the compliance status with Conditions D.4.4(a)(1), D.4.4(b)(1), D.4.4(d)(2) and D4.4(i)(2) shall be submitted not later than thirty (30) days after the end of the quarter being reported. Section C – General Reporting Requirements contains the Permittee's obligation with regard to the reporting required by 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 in 326 IAC 2-7-1(35).

SECTION D.5 EMISSIONS UNIT OPERATION CONDITIONS

Emissions Unit Description:

(a) One (1) diesel-fired emergency generator, identified as EU-009, approved for construction in 2013, with a maximum rated capacity of 4,690 horsepower, utilizing no control devices, and exhausting to the ambient atmosphere through stack EP-009.
[40 CFR 60, Subpart IIII][40 CFR 63, Subpart ZZZZ]

Insignificant Activity:

(b) One (1) diesel-fired emergency firewater pump, identified as EU-016, approved for construction in 2013, with a maximum rated capacity of 481 horsepower, utilizing no control devices, and exhausting to the ambient atmosphere through stack EP-016.
[40 CFR 60, Subpart IIII][40 CFR 63, Subpart ZZZZ][326 IAC 2-2]

(c) Two (2) cooling towers, with a total of fourteen (14) cells, identified as EU-008A through EU-008H and EU-019A through EU-019F, approved for construction in 2013, with a combined maximum rated capacity of 179,720 gallons per minute, utilizing high efficiency drift eliminators for particulate matter control, and exhausting to the ambient atmosphere through cells EP-008A through EP-008H and EP-019A through EP-019F.
[326 IAC 2-2]

(d) Fugitive NO_x, VOC and GHG Emissions from Equipment Leaks
[326 IAC 2-2][40 CFR 60, Subpart VVa]

(e) Paved roadways and parking lots with public access. [326 IAC 6-4][326 IAC 2-2]

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

Construction Conditions

General Construction Conditions

D.5.1 Permit No Defense

This permit 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 there under, as well as other applicable local, state, and federal requirements.

Effective Date of the Permit

D.5.2 Effective Date of the Permit [IC 13-15-5-3]

Pursuant to IC 13-15-5-3, this section of this permit becomes effective upon its issuance.

D.5.3 Modifications to Construction Conditions [326 IAC 2]

All requirements of these construction conditions shall remain in effect unless modified in a manner consistent with procedures established for revisions pursuant to 326 IAC 2.

Operating Conditions

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

D.5.4 PSD Best Available Control Technology Limits [326 IAC 2-2-3]

Pursuant to PSD/Operating Permit T 147-32322-00062 and 326 IAC 2-2 (Prevention of Significant Deterioration (PSD)), the best available control technology (BACT) for the diesel-fired emergency generator (EU-009), the diesel-fired emergency firewater pump (EU-016), the two (2) cooling towers with a total of fourteen (14) cells (EU-008A through EU-008H and EU-019A through EU-019F), paved roadways and parking lots with public access, and the fugitive NO_x, VOC and GHG emissions from equipment leaks shall be as follows:

(a) **<u>Diesel-Fired Emergency Generator (EU-009):</u>**

Common PM, PM_{10}, $PM_{2.5}$, NO_x, CO, VOC and GHG Conditions:

(1) The hours of operation of the diesel-fired emergency generator (EU-009) shall not exceed 200 hours per twelve consecutive month period with compliance determined at the end of each month.

(2) PM, PM_{10}, $PM_{2.5}$, NO_x, CO, VOC and GHG emissions shall be controlled by the use of good combustion practices.

PM, PM_{10}, $PM_{2.5}$:

(3) The PM, PM_{10} and $PM_{2.5}$ emissions from the operation of the diesel-fired emergency generator (EU-0009) shall not exceed 0.15 g/hp-hr, based on a three-hour average.

NO_x:

(4) NO_x emissions from the diesel-fired emergency generator (EU-009) shall not exceed 4.46 g/hp-hr, based on a three-hour average.

CO:

(5) CO emissions from the diesel-fired emergency generator (EU-009) shall not exceed 2.61 g/hp-hr, based on a three-hour average.

VOC:

(6) VOC emissions from the diesel-fired emergency generator (EU-009) shall not exceed 0.31 g/hp-hr, based on a three-hour average.

GHG:

(7) CO_2 emissions from the diesel-fired emergency generator (EU-009) shall not exceed 526.39 g/hp-hr, based on a three-hour average.

(b) **Diesel-Fired Emergency Firewater Pump (EU-016):**

Common PM, PM_{10}, $PM_{2.5}$, NO_x, CO, VOC, and GHG Conditions:

(1) Operation of the Diesel-Fired Emergency Firewater Pump (EU-016) shall not exceed 200 hours per twelve consecutive month period with compliance determined at the end of each month.

(2) PM, PM_{10}, $PM_{2.5}$, NO_x, CO, VOC and GHG emissions from the Diesel-Fired Emergency Firewater Pump (EU-016) shall be controlled by the use of good combustion practices.

PM, PM_{10}, $PM_{2.5}$:

(3) The PM, PM_{10} and $PM_{2.5}$ emissions from the operation of the Diesel-Fired Emergency Firewater Pump (EU-016) shall not exceed 0.15 g/hp-hr, based on a three-hour average.

NO_x:

(4) NO_x emissions from the diesel-fired emergency firewater pump (EU-016) shall not exceed 2.86 g/hp-hr, based on a three-hour average.

CO:

(5) CO emissions from the diesel-fired emergency firewater pump (EU-016) shall not exceed 2.60 g/hp-hr, based on a three-hour average.

VOC:

(6) VOC emissions from the diesel-fired emergency firewater pump (EU-016) shall not exceed 0.141 g/hp-hr, based on a three-hour average.

GHG:

(7) CO_2 emissions from the diesel-fired emergency firewater pump (EU-016) shall not exceed 527.40 g/hp-hr, based on a three-hour average.

(c) **Two (2) Cooling Towers (EU-008A through EU-008H and EU-019A through EU-019F):**

PM, PM_{10}, $PM_{2.5}$:

(1) The PM, PM_{10} and $PM_{2.5}$ emissions from the Cooling Towers (EU-008A to H and EU-019A to F) shall be controlled by high efficiency drift eliminators designed with a drift loss rate of less than 0.0005%.

(2) The total dissolved solids in the water used in Cooling Towers (EU-008A to H and EU-019A to F) shall not exceed 2,000 mg/l, averaged on a daily basis.

(d) **Paved Roadways and Parking Lots with Public Access:**

PM, PM_{10}, $PM_{2.5}$:

The PM, PM_{10}, and $PM_{2.5}$ emissions from paved haul roads shall be controlled to an overall control efficiency of 90% by employing the following work practices:

(1) Paving all plant haul roads;

(2) Daily sweeping with wet suppression; and

(3) Prompt cleanup of any spilled materials.

(e) **Fugitive VOC Emissions from Equipment Leaks:**

IDEM, OAQ has approved the proposed VOC BACT for fugitive VOC emissions from equipment leaks as the use of a leak detection and repair (LDAR) program. The leak detection and repair program specified in 40 CFR 60, Subpart VVa, as identified in Condition D.4.7 shall serve as BACT for VOC fugitive emissions.

D.5.5 General Provisions Relating to New Source Performance Standards (NSPS) [40 CFR 60, Subpart A] [326 IAC 12]

The provisions of 40 CFR 60, Subpart A – General Provisions, which are incorporated by reference in 326 IAC 12-1-1, apply to the diesel-fired emergency generator, identified as EU-009, and the diesel-fired emergency firewater pump, identified as EU-016, except when otherwise specified in 40 CFR 60, Subpart IIII.

D.5.6 New Source Performance Standards (NSPS) [40 CFR 60, Subpart IIII] [326 IAC 12]

The Permittee shall comply with the following provisions of 40 CFR 60, Subpart IIII (Standards of Performance for Stationary Compression Ignition Internal Combustion Engines (included as Attachment E of this permit) which are incorporated by reference as 326 IAC 12, for the diesel-fired emergency generator, identified as EU-009, and the diesel-fired emergency firewater pump, identified as EU-016, as specified as follows:

The emergency diesel-fired emergency generator (EU-009) is subject to the following portions of Subpart IIII.

(1) 40 CFR 60.4200(a)(2)(i);
(2) 40 CFR 60.4205;
(3) 40 CFR 60.4206:
(4) 40 CFR 60.4207;
(5) 40 CFR 60.4208;
(6) 40 CFR 60.4209(a);
(7) 40 CFR 60.4211(a), (c) and (e)
(8) 40 CFR 60.4212;
(9) 40 CFR 60.4214(b); and
(10) 40 CFR 60.4218.

The emergency diesel-fired firewater pump (EU-016) is subject to the following portions of Subpart IIII.

(1) 40 CFR 60.4200(a)(2)(ii);
(2) 40 CFR 60.4205;
(3) 40 CFR 60.4206;
(4) 40 CFR 60.4207;
(5) 40 CFR 60.4208;
(6) 40 CFR 60.4209(a);
(7) 40 CFR 60.4211(a), (c) and (e);
(8) 40 CFR 60.4212;
(9) 40 CFR 60.4214(b);
(10) 40 CFR 60.4218; and
(11) Table 4

D.5.7 General Provisions Relating to National Emission Standards for Hazardous Air Pollutants (NESHAP) [40 CFR 63, Subpart A] [326 IAC 20-1]

Pursuant to 40 CFR 63.6665, the Permittee shall comply with the provisions of 40 CFR 60, Subpart A – General Provisions, which are incorporated by reference as 326 IAC 20-1, as specified in Table 8 of 40 CFR 63, Subpart ZZZZ, in accordance with the schedule in 40 CFR 63, Subpart ZZZZ.

D.5.8 National Emission Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines [40 CFR 63, Subpart ZZZZ] [326 IAC 20-82]

The Permittee shall comply with the following provisions of 40 CFR 63, Subpart ZZZZ, which are incorporated by reference as 326 IAC 20-82 (included as Attachment B of this permit), for all affected facilities upon startup of the affected source:

The emergency diesel-fired emergency generator (EU-009) is subject to the following portions of 40 CFR 63, Subpart ZZZZ:

(1) 40 CFR 63.6605;
(2) 40 CFR 63.6640; and
(3) 40 CFR 63.6645(f).

The emergency diesel-fired firewater pump (EU-016) is subject to the following portions of 40 CFR 63, Subpart ZZZZ:

(1) 40 CFR 63.6590(c)(6).

D.5.9 Preventive Maintenance Plan [326 IAC 2-7-5(12)]

A Preventive Maintenance Plan is required for the diesel-fired emergency generator, identified as EU-009, the diesel-fired emergency firewater pump, identified as EU-016, and the cooling towers, identified as EU-008A through EU-008H and EU-019A through EU-019H. Section B – Preventive Maintenance Plan contains the Permittee's obligation with regard to the preventive maintenance plan required by this condition.

Compliance Determination Requirements

D.5.10 Compliance Determination Requirements

To demonstrate compliance with Condition D.5.4(d), PM, PM_{10} and $PM_{2.5}$ PSD BACT:

(a) Wet Suppression for roadway dust control shall be performed on paved roads except when:

(1) It is raining or snowing at the time of the scheduled treatment,

(2) The subject portion of the haul roads is covered by ice or snow or remains wet from recent precipitation or the previous wet suppression, or

(3) The road is not being used as a haul road on that day.

If ambient air temperature is below 32 °F at the time of a scheduled wet suppression treatment, the Permittee may clean the roadway dust with a vacuum sweeper in lieu of the wet suppression treatment.

(b) Compliance shall be demonstrated for each active haul road using records of haul road usage and control measures. The frequency of required roadway dust control treatments for haul roads shall be at least daily, unless a treatment is not required for one of the reasons under (a) above, and the frequency shall be sufficient to achieve 90% control based on the following formula or an equivalent:

Control Efficiency = 96 – (0.263 * (T/C))

Where: Control Efficiency = percent control efficiency
T = Daily truck trips on roadway (truck trips/calendar day)
C = Number of roadway dust control treatments per calendar day.

For the purposes of this formula, if at the time of a scheduled roadway dust control treatment, the treatment is not required for one of the reasons under (a) above, such an event shall be counted as a roadway dust control treatment.

(c) Haul truck speed limits shall be posted as 15 miles per hour or less.

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

D.5.11 Parametric Monitoring

(a) In order to demonstrate the compliance status with Condition D.5.4(a)(1), the Permittee shall record the hours of operation of the diesel-fired emergency generator (EU-009) at least once a month.

(b) In order to demonstrate the compliance status with Condition D.5.4(b)(1), the Permittee shall record the hours of operation of the diesel-fired emergency firewater pump (EU-016) at least once per month.

(c) In order to demonstrate the compliance status with Condition D.5.4(c)(2), the Permittee shall record the level of total dissolved solids in the water used in each cooling tower at least once per month when the cooling tower is in operation. When for any one reading, the level of total dissolved solids is above 2,000 ppm, the Permittee shall take a 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 single reading in excess of the above mentioned concentration is not a deviation from this permit. Failure to take response steps shall be considered a deviation from this permit.

D.5.12 Ambient Temperature Monitoring

To demonstrate the compliance status with Condition D.5.10, the Permittee shall maintain an ambient temperature monitor when ambient temperatures may drop below 32 °F.

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

D.5.13 Record Keeping Requirements

(a) In order to document the compliance status with Condition D.5.4(a)(1), the Permittee shall maintain a monthly record of the hours of operation of the diesel-fired emergency generator (EU-009).

(b) In order to document the compliance status with Condition D.5.4(b)(1), the Permittee shall maintain a monthly record of the hours of operation of the diesel-fired emergency firewater pump (EU-016).

(c) In order to document the compliance status with Condition D.5.4(c)(2), the Permittee shall maintain a monthly record of the total dissolved solids concentration in the water used in each cooling tower (EU-008A through EU-008H and EU-019A through EU-019F). The Permittee shall include in its monthly record when the total dissolved solids are not recorded and the reason for a lack of a total dissolved solids reading. (e.g. the process did not operate that month).

(d) To document the compliance status with Conditions D.5.4(d) and D.5.10, the Permittee shall maintain the following daily records for haul roads:

(1) The number of trucks on the haul road each calendar day.

(2) The date, approximate time, and type of each roadway dust control treatment.

(3) If a treatment of the haul roads is not required and not performed in accordance with D.5.10, records shall be maintained documenting the reason for the lack of a treatment (i.e. ambient temperature, precipitation, etc.).

(e) Section C – General Record Keeping Requirements contains the Permittee's obligations with regard to the record keeping required by this condition.

D.5.14 Reporting Requirements

A quarterly summary of the information to document the compliance status with Condition D.5.4(a)(1) and Condition D.5.4(b)(1) shall be submitted not later than thirty (30) days after the end of the quarter being reported. Section C – General Reporting Requirements contains the Permittee's obligation with regard to the reporting required by 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 in 326 IAC 2-7-1(35).

SECTION D.6 EMISSIONS UNIT OPERATION CONDITIONS

Emissions Unit Description:

Entire Source

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

D.6.1 General Provisions Relating to National Emission Standards for Hazardous Air Pollutants (NESHAP) [40 CFR 61, Subpart A] [326 IAC 14-1-1]

The Permittee shall comply with the provisions of 40 CFR 61, Subpart A – General Provisions, which are incorporated by reference as 326 IAC 14-1-1.

D.6.2 National Emission Standards for Hazardous Air Pollutants for Benzene Waste Operations [40 CFR 61, Subpart FF]

The Permittee shall comply with the following provisions of 40 CFR 61, Subpart FF, which are included as Attachment G of this permit for all affected facilities upon startup of the affected source. The entire source is subject to the following portions of 40 CFR 61, Subpart FF:

(1) 40 CFR 61.340(a)
(2) 40 CFR 61.341
(3) 40 CFR 61.342(a)
(4) 40 CFR 61.355
(5) 40 CFR 61.356
(6) 40 CFR 61.357(a) and (b)

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

Source Name:	Ohio Valley Resources, LLC
Source Address:	300-400 East CR 350 North, Rockport, Indiana 47635
Part 70 Permit No.:	T 147-32322-00062

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: Ohio Valley Resources, LLC
Source Address: 300-400 East CR 350 North, Rockport, Indiana 47635
Part 70 Permit No.: T 147-32322-00062

This form consists of 2 pages **Page 1 of 2**

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

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

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

If any of the following are not applicable, mark N/A **Page 2 of 2**

Date/Time Emergency started:
Date/Time Emergency was corrected:
Was the facility being properly operated at the time of the emergency? Y N
Type of Pollutants Emitted: TSP, PM-10, SO_2, VOC, NO_x, CO, Pb, other:
Estimated amount of pollutant(s) emitted during emergency:
Describe the steps taken to mitigate the problem:
Describe the corrective actions/response steps taken:
Describe the measures taken to minimize emissions:
If applicable, describe the reasons why continued operation of the facilities are necessary to prevent imminent injury to persons, severe damage to equipment, substantial loss of capital investment, or loss of product or raw materials of substantial economic value:

Form Completed by:_______________________________

Title / Position: ________________________________

Date:____

Phone: _______________________________________

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

Part 70 Quarterly Report – Boiler (EU-011A to EU-011D) Fuel Usage

Source Name:	Ohio Valley Resources, LLC
Source Address:	300-400 East CR 350 North, Rockport, Indiana 47635
Part 70 Permit No.:	T 147-32322-00062
Facility:	Boiler Units EU-011A, EU-011B, EU-011C, EU-011D
Parameter:	Fuel Usage
Limit:	Combined usage shall be less than 2,802 MMCF per twelve consecutive month period

QUARTER: YEAR:

Month	Column 1	Column 2	Column 1 + Column 2
	This Month	Previous 11 Months	12 Month Total
Month 1			
Month 2			
Month 3			

☐ No deviation occurred in this quarter.

☐ Deviation/s occurred in this quarter.
Deviation has been reported on:

Submitted by: ______________________
Title / Position: ______________________
Signature: ______________________
Date: ______________________
Phone: ______________________

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

Part 70 Quarterly Report – Primary Reformer (EU-003) CO_2 Emissions

Source Name: Ohio Valley Resources, LLC
Source Address: 300-400 East CR 350 North, Rockport, Indiana 47635
Part 70 Permit No.: T 147-32322-00062
Facility: Primary Reformer (EU-003)
Parameter: CO_2 emissions
Limit: 515,246 tons CO_2 per twelve consecutive month period.

QUARTER: YEAR:

Month	Column 1	Column 2	Column 1 + Column 2
	This Month	Previous 11 Months	12 Month Total
Month 1			
Month 2			
Month 3			

☐ No deviation occurred in this quarter.

☐ Deviation/s occurred in this quarter.
Deviation has been reported on:

Submitted by: ______________________________
Title / Position: ______________________________
Signature: ______________________________
Date: ______________________________
Phone: ______________________________

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

Part 70 Quarterly Report – Ammonia Production (EU-004)

Source Name:	Ohio Valley Resources, LLC
Source Address:	300-400 East CR 350 North, Rockport, Indiana 47635
Part 70 Permit No.:	T 147-32322-00062
Facility:	CO_2 Purification Process (EU-004)
Parameter:	Ammonia Production
Limit:	1,022,000 tons per twelve consecutive month period

QUARTER: YEAR:

Month	Column 1	Column 2	Column 1 + Column 2
	This Month	Previous 11 Months	12 Month Total
Month 1			
Month 2			
Month 3			

☐ No deviation occurred in this quarter.

☐ Deviation/s occurred in this quarter.
Deviation has been reported on:

Submitted by: ____
Title / Position: ____
Signature: ____
Date: ____
Phone: ____

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

Part 70 Quarterly Report – Front End Flare (EU-007) Venting

Source Name:	Ohio Valley Resources, LLC
Source Address:	300-400 East CR 350 North, Rockport, Indiana 47635
Part 70 Permit No.:	T 147-32322-00062
Facility:	Front End Process Flare (EU-007)
Parameter:	Process Venting Hours
Limit:	336 hours per twelve consecutive month period

QUARTER: YEAR:

Month	Column 1	Column 2	Column 1 + Column 2
	This Month	Previous 11 Months	12 Month Total
Month 1			
Month 2			
Month 3			

☐ No deviation occurred in this quarter.

☐ Deviation/s occurred in this quarter.
Deviation has been reported on:

Submitted by: ________________________________
Title / Position: ________________________________
Signature: ________________________________
Date: ________________________________
Phone: ________________________________

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

Part 70 Quarterly Report – Ammonia Catalyst Startup Heater (EU-010) Fuel Usage

Source Name: Ohio Valley Resources, LLC
Source Address: 300-400 East CR 350 North, Rockport, Indiana 47635
Part 70 Permit No.: T 147-32322-00062
Facility: Ammonia Catalyst Startup Heater (EU-010)
Parameter: Fuel Usage
Limit: 20.84 MMCF per twelve consecutive month period.

QUARTER: YEAR:

Month	Column 1	Column 2	Column 1 + Column 2
	This Month	Previous 11 Months	12 Month Total
Month 1			
Month 2			
Month 3			

☐ No deviation occurred in this quarter.

☐ Deviation/s occurred in this quarter.
Deviation has been reported on:

Submitted by: ______________________________
Title / Position: ______________________________
Signature: ______________________________
Date: ______________________________
Phone: ______________________________

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

Part 70 Quarterly Report – Back End Flare (U-006) Venting

Source Name:	Ohio Valley Resources, LLC
Source Address:	300-400 East CR 350 North, Rockport, Indiana 47635
Part 70 Permit No.:	T 147-32322-00062
Facility:	Back End Ammonia Process Flare (EU-006)
Parameter:	Ammonia Process Venting Hours
Limit:	336 hours per twelve consecutive month period.

QUARTER: YEAR:

Month	Column 1	Column 2	Column 1 + Column 2
	This Month	Previous 11 Months	12 Month Total
Month 1			
Month 2			
Month 3			

☐ No deviation occurred in this quarter.

☐ Deviation/s occurred in this quarter.
Deviation has been reported on:

Submitted by: ____
Title / Position: ____
Signature: ____
Date: ____
Phone: ____

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

Part 70 Quarterly Report – Ammonia Storage Flare (EU-005) Venting

Source Name:	Ohio Valley Resources, LLC
Source Address:	300-400 East CR 350 North, Rockport, Indiana 47635
Part 70 Permit No.:	T 147-32322-00062
Facility:	Ammonia Storage Flare (EU-005)
Parameter:	Ammonia Storage Flare Venting Hours
Limit:	168 hours per twelve consecutive month period.

QUARTER: YEAR:

Month	Column 1	Column 2	Column 1 + Column 2
	This Month	Previous 11 Months	12 Month Total
Month 1			
Month 2			
Month 3			

☐ No deviation occurred in this quarter.

☐ Deviation/s occurred in this quarter.
Deviation has been reported on:

Submitted by: ____________________
Title / Position: ____________________
Signature: ____________________
Date: ____________________
Phone: ____________________

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

Part 70 Quarterly Report – Nitric Acid Production (EU-001A and B)

Source Name:	Ohio Valley Resources, LLC
Source Address:	300-400 East CR 350 North, Rockport, Indiana 47635
Part 70 Permit No.:	T 147-32322-00062
Facility:	Nitric Acid Units (EU-001A and EU-001B)
Parameter:	Combined 100% Nitric Acid Throughput
Limit:	459,900 tons of 100 % nitric acid per twelve consecutive month period.

QUARTER: YEAR:

Month	Column 1	Column 2	Column 1 + Column 2
	This Month	Previous 11 Months	12 Month Total
Month 1			
Month 2			
Month 3			

☐ No deviation occurred in this quarter.

☐ Deviation/s occurred in this quarter.
Deviation has been reported on:

Submitted by: ______________________________
Title / Position: ______________________________
Signature: ______________________________
Date: ______________________________
Phone: ______________________________

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

Part 70 Quarterly Report – UAN Production (EU-002A and B)

Source Name: Ohio Valley Resources, LLC
Source Address: 300-400 East CR 350 North, Rockport, Indiana 47635
Part 70 Permit No.: T 147-32322-00062
Facility: Ammonium Nitrate Units (EU-002A and EU-002B)
Parameter: Combined UAN Production
Limit: 1,314,000 tons of UAN per twelve consecutive month period.

QUARTER: YEAR:

Month	Column 1	Column 2	Column 1 + Column 2
	This Month	Previous 11 Months	12 Month Total
Month 1			
Month 2			
Month 3			

☐ No deviation occurred in this quarter.

☐ Deviation/s occurred in this quarter.
Deviation has been reported on:

Submitted by: ____
Title / Position: ____
Signature: ____
Date: ____
Phone: ____

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

Part 70 Quarterly Report – UAN Plant Vent Flare (EU-017) Venting

Source Name:	Ohio Valley Resources, LLC
Source Address:	300-400 East CR 350 North, Rockport, Indiana 47635
Part 70 Permit No.:	T 147-32322-00062
Facility:	UAN Plant Vent Flare (EU-017)
Parameter:	UAN Plant Vent Flare Venting Hours
Limit:	336 hours per twelve consecutive month period.

QUARTER: YEAR:

Month	Column 1	Column 2	Column 1 + Column 2
	This Month	Previous 11 Months	12 Month Total
Month 1			
Month 2			
Month 3			

☐ No deviation occurred in this quarter.

☐ Deviation/s occurred in this quarter.
Deviation has been reported on:

Submitted by: ______________________________
Title / Position: ______________________________
Signature: ______________________________
Date: ______________________________
Phone: ______________________________

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

Part 70 Quarterly Report – Nitric Acid Storage Throughput (EU-022A and B)

Source Name: Ohio Valley Resources, LLC
Source Address: 300-400 East CR 350 North, Rockport, Indiana 47635
Part 70 Permit No.: T 147-32322-00062
Facility: Nitric Acid Storage Tanks (EU-022A and EU-022B)
Parameter: Combined 57% nitric acid throughput
Limit: 806,842 tons of 57% nitric acid per twelve consecutive month period.

QUARTER:

YEAR:

Month	Column 1	Column 2	Column 1 + Column 2
	This Month	Previous 11 Months	12 Month Total
Month 1			
Month 2			
Month 3			

☐ No deviation occurred in this quarter.

☐ Deviation/s occurred in this quarter.
Deviation has been reported on:

Submitted by: ________________________________
Title / Position: ________________________________
Signature: ________________________________
Date: ________________________________
Phone: ________________________________

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

Part 70 Quarterly Report – Generator (EU-009) Operating Hours

Source Name: Ohio Valley Resources, LLC
Source Address: 300-400 East CR 350 North, Rockport, Indiana 47635
Part 70 Permit No.: T 147-32322-00062
Facility: Diesel-Fired Emergency Generator (EU-009)
Parameter: Operating Hours
Limit: 200 hours per twelve consecutive month period.

QUARTER: YEAR:

Month	Column 1	Column 2	Column 1 + Column 2
	This Month	Previous 11 Months	12 Month Total
Month 1			
Month 2			
Month 3			

☐ No deviation occurred in this quarter.

☐ Deviation/s occurred in this quarter.
Deviation has been reported on:

Submitted by: ____
Title / Position: ____
Signature: ____
Date: ____
Phone: ____

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

Part 70 Quarterly Report – Firewater Pump (EU-016) Operating Hours

Source Name:	Ohio Valley Resources, LLC
Source Address:	300-400 East CR 350 North, Rockport, Indiana 47635
Part 70 Permit No.:	T 147-32322-00062
Facility:	Diesel-Fired Emergency Firewater Pump (EU-016)
Parameter:	Operating Hours
Limit:	200 hours per twelve consecutive month period.

QUARTER: YEAR:

Month	Column 1	Column 2	Column 1 + Column 2
	This Month	Previous 11 Months	12 Month Total
Month 1			
Month 2			
Month 3			

☐ No deviation occurred in this quarter.

☐ Deviation/s occurred in this quarter.
Deviation has been reported on:

Submitted by: ______________________________
Title / Position: ______________________________
Signature: ______________________________
Date: ______________________________
Phone: ______________________________

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

Source Name: Ohio Valley Resources, LLC
Source Address: 300-400 East CR 350 North, Rockport, Indiana 47635
Part 70 Permit No.: T 147-32322-00062

Months: ______ to ________ Year: ________

Page 1 of 2

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

Page 2 of 2

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

Form Completed by:______________________________

Title / Position: _________________________________

Date:____

Phone: ____

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

Ohio Valley Resources, LLC
300-400 East CR 350 North
Rockport, Indiana 47635

Affidavit of Construction

I, ____, being duly sworn upon my oath, depose and say:
(Name of the Authorized Representative)

1. I live in ______________________________ County, Indiana and being of sound mind and over twenty-one (21) years of age, I am competent to give this affidavit.

2. I hold the position of ________________________ for ________________________.
(Title) (Company Name)

3. By virtue of my position with __________________________________, I have personal
(Company Name)
knowledge of the representations contained in this affidavit and am authorized to make these representations on behalf of ____.
(Company Name)

4. I hereby certify that Ohio Valley Resources, LLC 300-400 East CR 350 North, Rockport, Indiana 47635, completed construction of the nitrogenous fertilizer production plant. on _____________________in conformity with the requirements and intent of the construction permit application received by the Office of Air Quality on September 17, 2012 and as permitted pursuant to New Source Construction Permit and Part 70 Operating Permit No. T 147-32322-00062, Plant ID No. 14-00062 issued on __________.

5. **Permittee, please cross out the following statement if it does not apply:** Additional (operations/facilities) were constructed/substituted as described in the attachment to this document and were not made in accordance with the construction permit.

Further Affiant said not.

I affirm under penalties of perjury that the representations contained in this affidavit are true, to the best of my information and belief.

Signature____
Date____

STATE OF INDIANA)
)SS

COUNTY OF ____________________)

Subscribed and sworn to me, a notary public in and for ______________________ County and State of Indiana on this ___________________ day of _________________, 20 ____. My Commission expires: _______________.

Signature______________________________
Name__________________________ (typed or printed)

Indiana Department of Environmental Management
Office of Air Quality

Attachment A to a Part 70 Operating Permit

Source Background and Description

Source Name:	Ohio Valley Resources, LLC
Source Location:	300-400 East CR 350 North, Rockport, Indiana 47635
County:	Spencer
SIC Code:	2873
Permit No.:	T 147-32322-00062
Permit Reviewer:	David Matousek

40 CFR 63, Subpart FFFF

40 CFR 63, Subpart FFFF **National Emissions Standards for Hazardous Air Pollutants: Miscellaneous Organic Chemical Manufacturing**

Source: 68 FR 63888, Nov. 10, 2003, unless otherwise noted.

What This Subpart Covers

§ 63.2430 What is the purpose of this subpart?

This subpart establishes national emission standards for hazardous air pollutants (NESHAP) for miscellaneous organic chemical manufacturing. This subpart also establishes requirements to demonstrate initial and continuous compliance with the emission limits, operating limits, and work practice standards.

§ 63.2435 Am I subject to the requirements in this subpart?

(a) You are subject to the requirements in this subpart if you own or operate miscellaneous organic chemical manufacturing process units (MCPU) that are located at, or are part of, a major source of hazardous air pollutants (HAP) emissions as defined in section 112(a) of the Clean Air Act (CAA).

(b) An MCPU includes equipment necessary to operate a miscellaneous organic chemical manufacturing process, as defined in § 63.2550, that satisfies all of the conditions specified in paragraphs (b)(1) through (3) of this section. An MCPU also includes any assigned storage tanks and transfer racks; equipment in open systems that is used to convey or store water having the same concentration and flow characteristics as wastewater; and components such as pumps, compressors, agitators, pressure relief devices, sampling connection systems, open-ended valves or lines, valves, connectors, and instrumentation systems that are used to manufacture any material or family of materials described in paragraphs (b)(1)(i) through (v) of this section.

(1) The MCPU produces material or family of materials that is described in paragraph (b)(1)(i), (ii), (iii), (iv), or (v) of this section.

(i) An organic chemical(s) classified using the 1987 version of SIC code 282, 283, 284, 285, 286, 287, 289, or 386, except as provided in paragraph (c)(5) of this section.

(ii) An organic chemical(s) classified using the 1997 version of NAICS code 325, except as provided in paragraph (c)(5) of this section.

(iii) Quaternary ammonium compounds and ammonium sulfate produced with caprolactam.

(iv) Hydrazine.

(v) Organic solvents classified in any of the SIC or NAICS codes listed in paragraph (b)(1)(i) or (ii) of this section that are recovered using nondedicated solvent recovery operations.

(2) The MCPU processes, uses, or generates any of the organic HAP listed in section 112(b) of the CAA or hydrogen halide and halogen HAP, as defined in § 63.2550.

(3) The MCPU is not an affected source or part of an affected source under another subpart of this part 63, except for process vents from batch operations within a chemical manufacturing process unit (CMPU), as identified in § 63.100(j)(4). For this situation, the MCPU is the same as the CMPU as defined in § 63.100, and you are subject only to the requirements for batch process vents in this subpart.

(c) The requirements in this subpart do not apply to the operations specified in paragraphs (c)(1) through (7) of this section.

(1) Research and development facilities, as defined in section 112(c)(7) of the CAA.

(2) The manufacture of ammonium sulfate as a by-product, if the slurry entering the by-product manufacturing process contains 50 parts per million by weight (ppmw) HAP or less or 10 ppmw benzene or less. You must retain information, data, and analysis to document the HAP concentration in the entering slurry in order to claim this exemption.

(3) The affiliated operations located at an affected source under subparts GG (National Emission Standards for Aerospace Manufacturing and Rework Facilities), KK (National Emission Standards for the Printing and Publishing Industry), JJJJ (NESHAP: Paper and Other Web Coating), future MMMM (NESHAP: Surface Coating of Miscellaneous Metal Parts and Products), and SSSS (NESHAP: Surface Coating of Metal Coil) of this part 63. Affiliated operations include, but are not limited to, mixing or dissolving of coating ingredients; coating mixing for viscosity adjustment, color tint or additive blending, or pH adjustment; cleaning of coating lines and coating line parts; handling and storage of coatings and solvent; and conveyance and treatment of wastewater.

(4) Fabricating operations (such as spinning or compressing a solid polymer into its end use); compounding operations (in which blending, melting, and resolidification of a solid polymer product occur for the purpose of incorporating additives, colorants, or stabilizers); and extrusion and drawing operations (converting an already produced solid polymer into a different shape by melting or mixing the polymer and then forcing it or pulling it through an orifice to create an extruded product). An operation is not exempt if it involves processing with HAP solvent or if an intended purpose of the operation is to remove residual HAP monomer.

(5) Production activities described using the 1997 version of NAICS codes 325131, 325181, 325188 (except the requirements do apply to hydrazine), 325314, 325991 (except the requirements do apply to reformulating plastics resins from recycled plastics products), and 325992 (except the requirements do apply to photographic chemicals).

(6) Tall oil recovery systems.

(7) Carbon monoxide production.

(d) If the predominant use of a transfer rack loading arm or storage tank (including storage tanks in series) is associated with a miscellaneous organic chemical manufacturing process, and the loading arm or storage tank is not part of an affected source under a subpart of this part 63, then you must assign the loading arm or storage tank to the MCPU for that miscellaneous organic chemical manufacturing process. If the predominant use cannot be determined, then you may assign the loading arm or storage tank to any MCPU that shares it and is subject to this subpart. If the use varies from year to year, then you must base the determination on the utilization that occurred during the year preceding November 10, 2003 or, if the loading arm or storage tank was not in operation during that year, you must base the use on the expected use for the first 5-year period after startup. You must include the determination in the notification of compliance status report specified in § 63.2520(d). You must redetermine the primary use at least once every 5 years, or any time you implement emissions averaging or pollution prevention after the compliance date.

(e) For nondedicated equipment used to create at least one MCPU, you may elect to develop process unit groups (PUG), determine the primary product of each PUG, and comply with the requirements of the subpart in 40 CFR part 63 that applies to that primary product as specified in § 63.2535(l).

[68 FR 63888, Nov. 10, 2003, as amended at 71 FR 40331, July 14, 2006]

§ 63.2440 What parts of my plant does this subpart cover?

(a) This subpart applies to each miscellaneous organic chemical manufacturing affected source.

(b) The miscellaneous organic chemical manufacturing affected source is the facilitywide collection of MCPU and heat exchange systems, wastewater, and waste management units that are associated with manufacturing materials described in § 63.2435(b)(1).

(c) A new affected source is described by either paragraph (c)(1) or (2) of this section.

(1) Each affected source defined in paragraph (b) of this section for which you commenced construction or reconstruction after April 4, 2002, and you meet the applicability criteria at the time you commenced construction or reconstruction.

(2) Each dedicated MCPU that has the potential to emit 10 tons per year (tpy) of any one HAP or 25 tpy of combined HAP, and you commenced construction or reconstruction of the MCPU after April 4, 2002. For the purposes of this paragraph, an MCPU is an affected source in the definition of the term "reconstruction" in § 63.2.

(d) An MCPU that is also a CMPU under § 63.100 is reconstructed for the purposes of this subpart if, and only if, the CMPU meets the requirements for reconstruction in § 63.100(l)(2).

Compliance Dates

§ 63.2445 When do I have to comply with this subpart?

(a) If you have a new affected source, you must comply with this subpart according to the requirements in paragraphs (a)(1) and (2) of this section.

(1) If you startup your new affected source before November 10, 2003, then you must comply with the requirements for new sources in this subpart no later than November 10, 2003.

(2) If you startup your new affected source after November 10, 2003, then you must comply with the requirements for new sources in this subpart upon startup of your affected source.

(b) If you have an existing source on November 10, 2003, you must comply with the requirements for existing sources in this subpart no later than May 10, 2008.

(c) You must meet the notification requirements in § 63.2515 according to the dates specified in that section and in subpart A of this part 63. Some of the notifications must be submitted before you are required to comply with the emission limits, operating limits, and work practice standards in this subpart.

(d) If you have a Group 2 emission point that becomes a Group 1 emission point after the compliance date for your affected source, you must comply with the Group 1 requirements beginning on the date the switch occurs. An initial compliance demonstration as specified in this subpart must be conducted within 150 days after the switch occurs.

(e) If, after the compliance date for your affected source, hydrogen halide and halogen HAP emissions from process vents in a process increase to more than 1,000 lb/yr, or HAP metals emissions from a process at a new affected source increase to more than 150 lb/yr, you must comply with the applicable emission limits specified in Table 3 to this subpart and the associated compliance requirements beginning on the date the emissions exceed the applicable threshold. An initial compliance demonstration as specified in this subpart must be conducted within 150 days after the switch occurs.

(f) If you have a small control device for process vent or transfer rack emissions that becomes a large control device, as defined in § 63.2550(i), you must comply with monitoring and associated recordkeeping and reporting requirements for large control devices beginning on the date the switch occurs. An initial compliance demonstration as specified in this subpart must be conducted within 150 days after the switch occurs.

[68 FR 63888, Nov. 10, 2003, as amended at 71 FR 10442, Mar. 1, 2006; 71 FR 40332, July 14, 2006]

Emission Limits, Work Practice Standards, and Compliance Requirements

§ 63.2450 What are my general requirements for complying with this subpart?

(a) You must be in compliance with the emission limits and work practice standards in tables 1 through 7 to this subpart at all times, except during periods of startup, shutdown, and malfunction (SSM), and you must meet the requirements specified in §§ 63.2455 through 63.2490 (or the alternative means of compliance in § 63.2495, § 63.2500, or § 63.2505), except as specified in paragraphs (b) through (s) of this section. You must meet the notification, reporting, and recordkeeping requirements specified in §§ 63.2515, 63.2520, and 63.2525.

(b) *Determine halogenated vent streams.* You must determine if an emission stream is a halogenated vent stream, as defined in § 63.2550, by calculating the mass emission rate of halogen atoms in accordance with § 63.115(d)(2)(v). Alternatively, you may elect to designate the emission stream as halogenated.

(c) *Requirements for combined emission streams.* When organic HAP emissions from different emission types (*e.g.,* continuous process vents, batch process vents, storage tanks, transfer operations, and waste management units) are combined, you must comply with the requirements of either paragraph (c)(1) or (2) of this section.

(1) Comply with the applicable requirements of this subpart for each kind of organic HAP emissions in the stream (*e.g.,* the requirements of table 1 to this subpart for continuous process vents and the requirements of table 4 to this subpart for emissions from storage tanks).

(2) Determine the applicable requirements based on the hierarchy presented in paragraphs (c)(2)(i) through (vi) of this section. For a combined stream, the applicable requirements are specified in the highest-listed paragraph in the hierarchy that applies to any of the individual streams that make up the combined stream. For example, if a combined stream consists of emissions from Group 1 batch process vents and any other type of emission stream, then you must comply with the requirements in paragraph (c)(2)(i) of this section for the combined stream; compliance with the requirements in paragraph (c)(2)(i) of this section constitutes compliance for the other emission streams in the combined stream. Two exceptions are that you must comply with the requirements in table 3 to this subpart and § 63.2465 for all process vents with hydrogen halide and halogen HAP emissions, and recordkeeping requirements for Group 2 applicability or compliance are still required (*e.g.,* the requirement in § 63.2525(f) to track the number of batches produced and calculate rolling annual emissions for processes with Group 2 batch process vents).

(i) The requirements of table 2 to this subpart and § 63.2460 for Group 1 batch process vents, including applicable monitoring, recordkeeping, and reporting.

(ii) The requirements of table 1 to this subpart and § 63.2455 for continuous process vents that are routed to a control device, as defined in § 63.981, including applicable monitoring, recordkeeping, and reporting.

(iii) The requirements of table 5 to this subpart and § 63.2475 for transfer operations, including applicable monitoring, recordkeeping, and reporting.

(iv) The requirements of table 7 to this subpart and § 63.2485 for emissions from waste management units that are used to manage and treat Group 1 wastewater streams and residuals from Group 1 wastewater streams, including applicable monitoring, recordkeeping, and reporting.

(v) The requirements of table 4 to this subpart and § 63.2470 for control of emissions from storage tanks, including applicable monitoring, recordkeeping, and reporting.

(vi) The requirements of table 1 to this subpart and § 63.2455 for continuous process vents after a recovery device including applicable monitoring, recordkeeping, and reporting.

(d) [Reserved]

(e) *Requirements for control devices.* (1) Except when complying with § 63.2485, if you reduce organic HAP emissions by venting emissions through a closed-vent system to any combination of control devices (except a flare) or recovery devices, you must meet the requirements of § 63.982(c) and the requirements referenced therein.

(2) Except when complying with § 63.2485, if you reduce organic HAP emissions by venting emissions through a closed-vent system to a flare, you must meet the requirements of § 63.982(b) and the requirements referenced therein.

(3) If you use a halogen reduction device to reduce hydrogen halide and halogen HAP emissions from halogenated vent streams, you must meet the requirements of § 63.994 and the requirements referenced therein. If you use a halogen reduction device before a combustion device, you must determine the halogen atom emission rate prior to the combustion device according to the procedures in § 63.115(d)(2)(v).

(f) *Requirements for flare compliance assessments.* (1) As part of a flare compliance assessment required in § 63.987(b), you have the option of demonstrating compliance with the requirements of § 63.11(b) by complying with the requirements in either § 63.11(b)(6)(i) or § 63.987(b)(3)(ii).

(2) If you elect to meet the requirements in § 63.11(b)(6)(i), you must keep flare compliance assessment records as specified in paragraphs (f)(2)(i) and (ii) of this section.

(i) Keep records as specified in § 63.998(a)(1)(i), except that a record of the heat content determination is not required.

(ii) Keep records of the flare diameter, hydrogen content, exit velocity, and maximum permitted velocity. Include these records in the flare compliance report required in § 63.999(a)(2).

(g) *Requirements for performance tests.* The requirements specified in paragraphs (g)(1) through (5) of this section apply instead of or in addition to the requirements specified in subpart SS of this part 63.

(1) Conduct gas molecular weight analysis using Method 3, 3A, or 3B in appendix A to part 60 of this chapter.

(2) Measure moisture content of the stack gas using Method 4 in appendix A to part 60 of this chapter.

(3) If the uncontrolled or inlet gas stream to the control device contains carbon disulfide, you must conduct emissions testing according to paragraph (g)(3)(i) or (ii) of this section.

(i) If you elect to comply with the percent reduction emission limits in tables 1 through 7 to this subpart, and carbon disulfide is the principal organic HAP component (*i.e.,* greater than 50 percent of the HAP in the stream by volume), then you must use Method 18, or Method 15 (40 CFR part 60, appendix A) to measure carbon disulfide at the inlet and outlet of the control device. Use the percent reduction in carbon disulfide as a surrogate for the percent reduction in total organic HAP emissions.

(ii) If you elect to comply with the outlet total organic compound (TOC) concentration emission limits in tables 1 through 7 to this subpart, and the uncontrolled or inlet gas stream to the control device contains greater than 10 percent (volume concentration) carbon disulfide, you must use Method 18 or Method 15 to separately determine the carbon disulfide concentration. Calculate the total HAP or TOC emissions by totaling the carbon disulfide emissions measured using Method 18 or 15 and the other HAP emissions measured using Method 18 or 25A.

(4) As an alternative to using Method 18, Method 25/25A, or Method 26/26A of 40 CFR part 60, appendix A, to comply with any of the emission limits specified in tables 1 through 7 to this subpart, you may use Method 320 of 40 CFR part 60, appendix A. When using Method 320, you must follow the analyte spiking procedures of section 13 of Method 320, unless you demonstrate that the complete spiking procedure has been conducted at a similar source.

(5) Section 63.997(c)(1) does not apply. For the purposes of this subpart, results of all initial compliance demonstrations must be included in the notification of compliance status report, which is due 150 days after the compliance date, as specified in § 63.2520(d)(1).

(h) *Design evaluation.* To determine the percent reduction of a small control device that is used to comply with an emission limit specified in table 1, 2, 3, or 5 to this subpart, you may elect to conduct a design evaluation as specified in § 63.1257(a)(1) instead of a performance test as specified in subpart SS of this part 63. You must establish the value(s) and basis for the operating limits as part of the design evaluation. For continuous process vents, the design evaluation must be conducted at maximum representative operating conditions for the process, unless the Administrator specifies or approves alternate operating conditions. For transfer racks, the design evaluation must demonstrate that the control device achieves the required control efficiency during the reasonably expected maximum transfer loading rate.

(i) *Outlet concentration correction for combustion devices.* When § 63.997(e)(2)(iii)(C) requires you to correct the measured concentration at the outlet of a combustion device to 3 percent oxygen if you add supplemental combustion air, the requirements in either paragraph (i)(1) or (2) of this section apply for the purposes of this subpart.

(1) You must correct the concentration in the gas stream at the outlet of the combustion device to 3 percent oxygen if you add supplemental gases, as defined in § 63.2550, to the vent stream, or;

(2) You must correct the measured concentration for supplemental gases using Equation 1 of § 63.2460; you may use process knowledge and representative operating data to determine the fraction of the total flow due to supplemental gas.

(j) *Continuous emissions monitoring systems.* Each continuous emissions monitoring system (CEMS) must be installed, operated, and maintained according to the requirements in § 63.8 and paragraphs (j)(1) through (5) of this section.

(1) Each CEMS must be installed, operated, and maintained according to the applicable Performance Specification of 40 CFR part 60, appendix B, and according to paragraph (j)(2) of this section, except as specified in paragraph (j)(1)(i) of this section. For any CEMS meeting Performance Specification 8, you must also comply with appendix F, procedure 1 of 40 CFR part 60.

(i) If you wish to use a CEMS other than an Fourier Transform Infrared Spectroscopy (FTIR) meeting the requirements of Performance Specification 15 to measure hydrogen halide and halogen HAP before we promulgate a Performance Specification for such CEMS, you must prepare a monitoring plan and submit it for approval in accordance with the procedures specified in § 63.8.

(ii) [Reserved]

(2) You must determine the calibration gases and reporting units for TOC CEMS in accordance with paragraph (j)(2)(i), (ii), or (iii) of this section.

(i) For CEMS meeting Performance Specification 9 or 15 requirements, determine the target analyte(s) for calibration using either process knowledge of the control device inlet stream or the screening procedures of Method 18 on the control device inlet stream.

(ii) For CEMS meeting Performance Specification 8 used to monitor performance of a combustion device, calibrate the instrument on the predominant organic HAP and report the results as carbon (C1), and use Method 25A or any approved alternative as the reference method for the relative accuracy tests.

(iii) For CEMS meeting Performance Specification 8 used to monitor performance of a noncombustion device, determine the predominant organic HAP using either process knowledge or the screening procedures of Method 18 on the control device inlet stream, calibrate the monitor on the predominant organic HAP, and report the results as C_1 . Use Method 18, ASTM D6420-99, or any approved alternative as the reference method for the relative accuracy tests, and report the results as C_1 .

(3) You must conduct a performance evaluation of each CEMS according to the requirements in 40 CFR 63.8 and according to the applicable Performance Specification of 40 CFR part 60, appendix B, except that the schedule in § 63.8(e)(4) does not apply, and the results of the performance evaluation must be included in the notification of compliance status report.

(4) The CEMS data must be reduced to operating day or operating block averages computed using valid data consistent with the data availability requirements specified in § 63.999(c)(6)(i)(B) through (D), except monitoring data also are sufficient to constitute a valid hour of data if measured values are available for at least two of the 15-minute periods during an hour when calibration, quality assurance, or maintenance activities are being performed. An operating block is a period of time from the beginning to end of batch operations within a process. Operating block averages may be used only for batch process vent data.

(5) If you add supplemental gases, you must correct the measured concentrations in accordance with paragraph (i) of this section and § 63.2460(c)(6).

(k) *Continuous parameter monitoring.* The provisions in paragraphs (k)(1) through (6) of this section apply in addition to the requirements for continuous parameter monitoring system (CPMS) in subpart SS of this part 63.

(1) You must record the results of each calibration check and all maintenance performed on the CPMS as specified in § 63.998(c)(1)(ii)(A).

(2) When subpart SS of this part 63 uses the term "a range" or "operating range" of a monitored parameter, it means an "operating limit" for a monitored parameter for the purposes of this subpart.

(3) As an alternative to continuously measuring and recording pH as specified in §§ 63.994(c)(1)(i) and 63.998(a)(2)(ii)(D), you may elect to continuously monitor and record the caustic strength of the effluent. For halogen scrubbers used to control only batch process vents you may elect to monitor and record either the pH or the caustic strength of the scrubber effluent at least once per day.

(4) As an alternative to the inlet and outlet temperature monitoring requirements for catalytic incinerators as specified in § 63.988(c)(2) and the related recordkeeping requirements specified in § 63.998(a)(2)(ii)(B)(*2*) and (c)(2)(ii), you may elect to comply with the requirements specified in paragraphs (k)(4)(i) through (iv) of this section.

(i) Monitor and record the inlet temperature as specified in subpart SS of this part 63.

(ii) Check the activity level of the catalyst at least every 12 months and take any necessary corrective action, such as replacing the catalyst to ensure that the catalyst is performing as designed.

(iii) Maintain records of the annual checks of catalyst activity levels and the subsequent corrective actions.

(iv) Recording the downstream temperature and temperature difference across the catalyst bed as specified in § 63.998(a)(2)(ii)(B)(*2*) and (b)(2)(ii) is not required.

(5) For absorbers that control organic compounds and use water as the scrubbing fluid, you must conduct monitoring and recordkeeping as specified in paragraphs (k)(5)(i) through (iii) of this section instead of the monitoring and recordkeeping requirements specified in §§ 63.990(c)(1), 63.993(c)(1), and 63.998(a)(2)(ii)(C).

(i) You must use a flow meter capable of providing a continuous record of the absorber influent liquid flow.

(ii) You must determine gas stream flow using one of the procedures specified in § 63.994(c)(1)(ii)(A) through (D).

(iii) You must record the absorber liquid-to-gas ratio averaged over the time period of any performance test.

(6) For a control device with total inlet HAP emissions less than 1 tpy, you must establish an operating limit(s) for a parameter(s) that you will measure and record at least once per averaging period (i.e., daily or block) to verify that the control device is operating properly. You may elect to measure the same parameter(s) that is required for control devices that control inlet HAP emissions equal to or greater than 1 tpy. If the parameter will not be measured continuously, you must request approval of your proposed procedure in the precompliance report. You must identify the operating limit(s) and the measurement frequency, and you must provide rationale to support how these measurements demonstrate the control device is operating properly.

(l) *Startup, shutdown, and malfunction.* Sections 63.152(f)(7)(ii) through (iv) and 63.998(b)(2)(iii) and (b)(6)(i)(A), which apply to the exclusion of monitoring data collected during periods of SSM from daily averages, do not apply for the purposes of this subpart.

(m) *Reporting.* (1) When §§ 63.2455 through 63.2490 reference other subparts in this part 63 that use the term “periodic report,” it means “compliance report” for the purposes of this subpart. The compliance report must include the information specified in § 63.2520(e), as well as the information specified in referenced subparts.

(2) When there are conflicts between this subpart and referenced subparts for the due dates of reports required by this subpart, reports must be submitted according to the due dates presented in this subpart.

(3) Excused excursions, as defined in subparts G and SS of this part 63, are not allowed.

(n) [Reserved]

(o) You may not use a flare to control halogenated vent streams or hydrogen halide and halogen HAP emissions.

(p) Opening a safety device, as defined in § 63.2550, is allowed at any time conditions require it to avoid unsafe conditions.

(q) If an emission stream contains energetics or organic peroxides that, for safety reasons, cannot meet an applicable emission limit specified in Tables 1 through 7 to this subpart, then you must submit documentation in your precompliance report explaining why an undue safety hazard would be created if the air emission controls were installed, and you must describe the procedures that you will implement to minimize HAP emissions from these vent streams.

(r) *Surge control vessels and bottoms receivers.* For each surge control vessel or bottoms receiver that meets the capacity and vapor pressure thresholds for a Group 1 storage tank, you must meet emission limits and work practice standards specified in Table 4 to this subpart.

(s) For the purposes of determining Group status for continuous process vents, batch process vents, and storage tanks in §§ 63.2455, 63.2460, and 63.2470, hydrazine is to be considered an organic HAP.

[68 FR 63888, Nov. 10, 2003, as amended at 70 FR 38559, July 1, 2005; 71 FR 40332, July 14, 2006]

§ 63.2455 What requirements must I meet for continuous process vents?

(a) You must meet each emission limit in Table 1 to this subpart that applies to your continuous process vents, and you must meet each applicable requirement specified in paragraphs (b) through (c) of this section.

(b) For each continuous process vent, you must either designate the vent as a Group 1 continuous process vent or determine the total resource effectiveness (TRE) index value as specified in § 63.115(d), except as specified in paragraphs (b)(1) through (3) of this section.

(1) You are not required to determine the Group status or the TRE index value for any continuous process vent that is combined with Group 1 batch process vents before a control device or recovery device because the requirements of § 63.2450(c)(2)(i) apply to the combined stream.

(2) When a TRE index value of 4.0 is referred to in § 63.115(d), TRE index values of 5.0 for existing affected sources and 8.0 for new and reconstructed affected sources apply for the purposes of this subpart.

(3) When § 63.115(d) refers to “emission reductions specified in § 63.113(a),” the reductions specified in Table 1 to this subpart apply for the purposes of this subpart.

(c) If you use a recovery device to maintain the TRE above a specified threshold, you must meet the requirements of § 63.982(e) and the requirements referenced therein, except as specified in § 63.2450 and paragraph (c)(1) of this section.

(1) When § 63.993 uses the phrase “the TRE index value is between the level specified in a referencing subpart and 4.0,” the phrase “the TRE index value is >1.9 but ≤5.0” applies for an existing affected source, and the phrase “the TRE index value is >5.0 but ≤8.0” applies for a new and reconstructed affected source, for the purposes of this subpart.

(2) [Reserved]

§ 63.2460 What requirements must I meet for batch process vents?

(a) You must meet each emission limit in Table 2 to this subpart that applies to you, and you must meet each applicable requirement specified in paragraphs (b) and (c) of this section.

(b) *Group status.* If a process has batch process vents, as defined in § 63.2550, you must determine the group status of the batch process vents by determining and summing the uncontrolled organic HAP emissions from each of the batch process vents within the process using the procedures specified in § 63.1257(d)(2)(i) and (ii), except as specified in paragraphs (b)(1) through (7) of this section.

(1) To calculate emissions caused by the heating of a vessel without a process condenser to a temperature lower than the boiling point, you must use the procedures in § 63.1257(d)(2)(i)(C)(*3*).

(2) To calculate emissions from depressurization of a vessel without a process condenser, you must use the procedures in § 63.1257(d)(2)(i)(D)(*10*).

(3) To calculate emissions from vacuum systems for the purposes of this subpart, the receiving vessel is part of the vacuum system, and terms used in Equation 33 to 40 CFR part 63, subpart GGG, are defined as follows:

P_{system} = absolute pressure of the receiving vessel;

P_i = partial pressure of the HAP determined at the exit temperature and exit pressure conditions of the condenser or at the conditions of the dedicated receiver;

P_j = partial pressure of condensables (including HAP) determined at the exit temperature and exit pressure conditions of the condenser or at the conditions of the dedicated receiver;

MW_{HAP} = molecular weight of the HAP determined at the exit temperature and exit pressure conditions of the condenser or at the conditions of the dedicated receiver.

(4) To calculate uncontrolled emissions when a vessel is equipped with a process condenser, you must use the procedures in § 63.1257(d)(3)(i)(B), except as specified in paragraphs (b)(4)(i) through (vii) of this section.

(i) You must determine the flowrate of gas (or volume of gas), partial pressures of condensables, temperature (T), and HAP molecular weight (MW_{HAP}) at the exit temperature and exit pressure conditions of the condenser or at the conditions of the dedicated receiver.

(ii) You must assume that all of the components contained in the condenser exit vent stream are in equilibrium with the same components in the exit condensate stream (except for noncondensables).

(iii) You must perform a material balance for each component.

(iv) For the emissions from gas evolution, the term for time, t, must be used in Equation 12 to 40 CFR part 63, subpart GGG.

(v) Emissions from empty vessel purging shall be calculated using Equation 36 to 40 CFR part 63, subpart GGG and the exit temperature and exit pressure conditions of the condenser or the conditions of the dedicated receiver.

(vi) You must conduct an engineering assessment as specified in § 63.1257(d)(2)(ii) for each emission episode that is not due to vapor displacement, purging, heating, depressurization, vacuum operations, gas evolution, air drying, or empty vessel purging. The requirements of paragraphs (b)(3) through (4) of this section shall apply.

(vii) You may elect to conduct an engineering assessment if you can demonstrate to the Administrator that the methods in § 63.1257(d)(3)(i)(B) are not appropriate.

(5) You may elect to designate the batch process vents within a process as Group 1 and not calculate uncontrolled emissions under either of the situations in paragraph (b)(5)(i), (ii), or (iii) of this section.

(i) If you comply with the alternative standard specified in § 63.2505.

(ii) If all Group 1 batch process vents within a process are controlled; you conduct the performance test under hypothetical worst case conditions, as defined in § 63.1257(b)(8)(i)(B); and the emission profile is based on capture and control system limitations as specified in § 63.1257(b)(8)(ii)(C).

(iii) If you comply with an emission limit using a flare that meets the requirements specified in § 63.987.

(6) You may change from Group 2 to Group 1 in accordance with either paragraph (b)(6)(i) or (ii) of this section. You must comply with the requirements of this section and submit the test report in the next Compliance report.

(i) You may switch at any time after operating as Group 2 for at least 1 year so that you can show compliance with the 10,000 pounds per year (lb/yr) threshold for Group 2 batch process vents for at least 365 days before the switch. You may elect to start keeping records of emissions from Group 2 batch process vents before the compliance date. Report a switch based on this provision in your next compliance report in accordance with § 63.2520(e)(10)(i).

(ii) If the conditions in paragraph (b)(6)(i) of this section are not applicable, you must provide a 60-day advance notice in accordance with § 63.2520(e)(10)(ii) before switching.

(7) As an alternative to determining the uncontrolled organic HAP emissions as specified in § 63.1257(d)(2)(i) and (ii), you may elect to demonstrate that non-reactive organic HAP are the only HAP used in the process and non-reactive HAP usage in the process is less than 10,000 lb/yr. You must provide data and supporting rationale in your notification of compliance status report explaining why the non-reactive organic HAP usage will be less than 10,000 lb/yr. You must keep records of the non-reactive organic HAP usage as specified in § 63.2525(e)(2) and include information in compliance reports as specified in § 63.2520(e)(5)(iv).

(c) Exceptions to the requirements in subparts SS and WW of this part 63 are specified in paragraphs (c)(1) through (9) of this section.

(1) *Process condensers.* Process condensers, as defined in § 63.2550(i), are not considered to be control devices for batch process vents. You must determine whether a condenser is a control device for a batch process vent or a process condenser from which the uncontrolled HAP emissions are evaluated as part of the initial compliance demonstration for each MCPU and report the results with supporting rationale in your notification of compliance status report.

(2) *Initial compliance.* (i) To demonstrate initial compliance with a percent reduction emission limit in Table 2 to this subpart FFFF, you must compare the sums of the controlled and uncontrolled emissions for the applicable Group 1 batch process vents within the process, and show that the specified reduction is met. This requirement does not apply if you comply with the emission limits of Table 2 to this subpart FFFF by using a flare that meets the requirements of § 63.987.

(ii) When you conduct a performance test or design evaluation for a non-flare control device used to control emissions from batch process vents, you must establish emission profiles and conduct the test under worst-case conditions according to § 63.1257(b)(8) instead of under normal operating conditions as specified in § 63.7(e)(1). The requirements in § 63.997(e)(1)(i) and (iii) also do not apply for performance tests conducted to determine compliance with the emission limits for batch process vents. For purposes of this subpart FFFF, references in § 63.997(b)(1) to “methods specified in § 63.997(e)” include the methods specified in § 63.1257(b)(8).

(iii) As an alternative to conducting a performance test or design evaluation to demonstrate initial compliance with a percent reduction requirement for a condenser, you may determine controlled emissions using the procedures specified in § 63.1257(d)(3)(i)(B) and paragraphs (b)(3) through (4) of this section.

(iv) When § 63.1257(d)(3)(i)(B)(*7*) specifies that condenser-controlled emissions from an air dryer must be calculated using Equation 11 of 40 CFR part 63, subpart GGG, with “V equal to the air flow rate,” it means “V equal to the dryer outlet gas flow rate,” for the purposes of this subpart. Alternatively, you may use Equation 12 of 40 CFR part 63, subpart GGG, with V equal to the dryer inlet air flow rate. Account for time as appropriate in either equation.

(v) If a process condenser is used for any boiling operations, you must demonstrate that it is properly operated according to the procedures specified in § 63.1257(d)(2)(i)(C)(*4*)(*ii*) and (d)(3)(iii)(B), and the demonstration must occur only during the boiling operation. The reference in § 63.1257(d)(3)(iii)(B) to the alternative standard in § 63.1254(c) means § 63.2505 for the purposes of this subpart. As an alternative to measuring the exhaust gas temperature, as required by § 63.1257(d)(3)(iii)(B), you may elect to measure the liquid temperature in the receiver.

(vi) You must conduct a subsequent performance test or compliance demonstration equivalent to an initial compliance demonstration within 180 days of a change in the worst-case conditions.

(3) *Establishing operating limits.* You must establish operating limits under the conditions required for your initial compliance demonstration, except you may elect to establish operating limit(s) for conditions other than those under which a performance test was conducted as specified in paragraph (c)(3)(i) of this section and, if applicable, paragraph (c)(3)(ii) of this section.

(i) The operating limits may be based on the results of the performance test and supplementary information such as engineering assessments and manufacturer's recommendations. These limits may be established for conditions as unique as individual emission episodes for a batch process. You must provide rationale in the precompliance report for the specific level for each operating limit, including any data and calculations used to develop the limit and a description of why the limit indicates proper operation of the control device. The procedures provided in this paragraph (c)(3)(i) have not been approved by the Administrator and determination of the operating limit using these procedures is subject to review and approval by the Administrator.

(ii) If you elect to establish separate monitoring levels for different emission episodes within a batch process, you must maintain records in your daily schedule or log of processes indicating each point at which you change from one operating limit to another, even if the duration of the monitoring for an operating limit is less than 15 minutes. You must maintain a daily schedule or log of processes according to § 63.2525(c).

(4) *Averaging periods.* As an alternative to the requirement for daily averages in § 63.998(b)(3), you may determine averages for operating blocks. An operating block is a period of time that is equal to the time from the beginning to end of batch process operations within a process.

(5) [Reserved]

(6) *Outlet concentration correction for supplemental gases.* If you use a control device other than a combustion device to comply with a TOC, organic HAP, or hydrogen halide and halogen HAP outlet concentration emission limit for batch process vents, you must correct the actual concentration for supplemental gases using Equation 1 of this section; you may use process knowledge and representative operating data to determine the fraction of the total flow due to supplemental gas.

$$C_a = C_m\left(\frac{Q_s + Q_a}{Q_a}\right) \qquad (Eq.\ 1)$$

Where:

C_a = corrected outlet TOC, organic HAP, or hydrogen halide and halogen HAP concentration, dry basis, ppmv;

C_m = actual TOC, organic HAP, or hydrogen halide and halogen HAP concentration measured at control device outlet, dry basis, ppmv;

Q_a = total volumetric flowrate of all gas streams vented to the control device, except supplemental gases;

Q_s = total volumetric flowrate of supplemental gases.

(7) If flow to a control device could be intermittent, you must install, calibrate, and operate a flow indicator at the inlet or outlet of the control device to identify periods of no flow. Periods of no flow may not be used in daily or block averages, and it may not be used in fulfilling a minimum data availability requirement.

(8) *Terminology.* When the term “storage vessel” is used in subpart WW of this part 63, the term “process tank,” as defined in § 63.2550(i), applies for the purposes of this section.

(9) *Requirements for a biofilter.* If you use a biofilter to meet either the 95 percent reduction requirement or outlet concentration requirement specified in Table 2 to this subpart, you must meet the requirements specified in paragraphs (c)(9)(i) through (iv) of this section.

(i) *Operational requirements.* The biofilter must be operated at all times when emissions are vented to it.

(ii) *Performance tests.* To demonstrate initial compliance, you must conduct a performance test according to the procedures in § 63.997 and paragraphs (c)(9)(ii)(A) through (D) of this section. The design evaluation option for small control devices is not applicable if you use a biofilter.

(A) Keep up-to-date, readily accessible continuous records of either the biofilter bed temperature averaged over the full period of the performance test or the outlet total organic HAP or TOC concentration averaged over the full period of the performance test. Include these data in your notification of compliance status report as required by § 63.999(b)(3)(ii).

(B) Record either the percent reduction of total organic HAP achieved by the biofilter determined as specified in § 63.997(e)(2)(iv) or the concentration of TOC or total organic HAP determined as specified in § 63.997(e)(2)(iii) at the outlet of the biofilter, as applicable.

(C) If you monitor the biofilter bed temperature, you may elect to use multiple thermocouples in representative locations throughout the biofilter bed and calculate the average biofilter bed temperature across these thermocouples prior to reducing the temperature data to 15 minute (or shorter) averages for purposes of establishing operating limits for the biofilter. If you use multiple thermocouples, include your rationale for their site selection in your notification of compliance status report.

(D) Submit a performance test report as specified in § 63.999(a)(2)(i) and (ii). Include the records from paragraph (c)(9)(ii)(B) of this section in your performance test report.

(iii) *Monitoring requirements.* Use either a biofilter bed temperature monitoring device (or multiple devices) capable of providing a continuous record or an organic monitoring device capable of providing a continuous record. Keep records of temperature or other parameter monitoring results as specified in § 63.998(b) and (c), as applicable. General requirements for monitoring are contained in § 63.996. If you monitor temperature, the operating temperature range must be based on only the temperatures measured during the performance test; these data may not be supplemented by engineering assessments or manufacturer's recommendations as otherwise allowed in § 63.999(b)(3)(ii)(A). If you establish the operating range (minimum and maximum temperatures) using data from previous performance tests in accordance with § 63.996(c)(6), replacement of the biofilter media with the same type of media is not considered a process change under § 63.997(b)(1). You may expand your biofilter bed temperature operating range by conducting a repeat performance test that demonstrates compliance with the 95 percent reduction requirement or outlet concentration limit, as applicable.

(iv) *Repeat performance tests.* You must conduct a repeat performance test using the applicable methods specified in § 63.997 within 2 years following the previous performance test and within 150 days after each replacement of any portion of the biofilter bed media with a different type of media or each replacement of more than 50 percent (by volume) of the biofilter bed media with the same type of media.

[68 FR 63888, Nov. 10, 2003, as amended at 70 FR 38559, July 1, 2005; 71 FR 40333, July 14, 2006]

§ 63.2465 What requirements must I meet for process vents that emit hydrogen halide and halogen HAP or HAP metals?

(a) You must meet each emission limit in Table 3 to this subpart that applies to you, and you must meet each applicable requirement in paragraphs (b) through (d) of this section.

(b) If any process vents within a process emit hydrogen halide and halogen HAP, you must determine and sum the uncontrolled hydrogen halide and halogen HAP emissions from each of the process vents within the process using the procedures specified in § 63.1257(d)(2)(i) and/or (ii), as appropriate. When § 63.1257(d)(2)(ii)(E) requires documentation to be submitted in the precompliance report, it means the notification of compliance status report for the purposes of this paragraph.

(c) If collective uncontrolled hydrogen halide and halogen HAP emissions from the process vents within a process are greater than or equal to 1,000 pounds per year (lb/yr), you must comply with § 63.994 and the requirements referenced therein, except as specified in paragraphs (c)(1) through (3) of this section.

(1) When § 63.994(b)(1) requires a performance test, you may elect to conduct a design evaluation in accordance with § 63.1257(a)(1).

(2) When § 63.994(b)(1) refers to “a combustion device followed by a halogen scrubber or other halogen reduction device,” it means any combination of control devices used to meet the emission limits specified in Table 3 to this subpart.

(3) Section 63.994(b)(2) does not apply for the purposes of this section.

(d) To demonstrate compliance with the emission limit in Table 3 to this subpart for HAP metals at a new source, you must comply with paragraphs (d)(1) through (3) of this section.

(1) Determine the mass emission rate of HAP metals based on process knowledge, engineering assessment, or test data.

(2) Conduct an initial performance test of each control device that is used to comply with the emission limit for HAP metals specified in Table 3 to this subpart. Conduct the performance test according to the procedures in § 63.997. Use Method 29 of appendix A of 40 CFR part 60 to determine the HAP metals at the inlet and outlet of each control device, or use Method 5 of appendix A of 40 CFR part 60 to determine the total particulate matter (PM) at the inlet and outlet of each control device. You have demonstrated initial compliance if the overall reduction of either HAP metals or total PM from the process is greater than or equal to 97 percent by weight.

(3) Comply with the monitoring requirements specified in § 63.1366(b)(1)(xi) for each fabric filter used to control HAP metals.

[68 FR 63888, Nov. 10, 2003, as amended at 71 FR 40334, July 14, 2006]

§ 63.2470 What requirements must I meet for storage tanks?

(a) You must meet each emission limit in Table 4 to this subpart that applies to your storage tanks, and you must meet each applicable requirement specified in paragraphs (b) through (e) of this section.

(b) [Reserved]

(c) *Exceptions to subparts SS and WW of this part 63.* (1) If you conduct a performance test or design evaluation for a control device used to control emissions only from storage tanks, you must establish operating limits, conduct monitoring, and keep records using the same procedures as required in subpart SS of this part 63 for control devices used to reduce emissions from process vents instead of the procedures specified in §§ 63.985(c), 63.998(d)(2)(i), and 63.999(b)(2).

(2) When the term "storage vessel" is used in subparts SS and WW of this part 63, the term "storage tank," as defined in § 63.2550 applies for the purposes of this subpart.

(d) *Planned routine maintenance.* The emission limits in Table 4 to this subpart for control devices used to control emissions from storage tanks do not apply during periods of planned routine maintenance. Periods of planned routine maintenance of each control device, during which the control device does not meet the emission limit specified in Table 4 to this subpart, must not exceed 240 hours per year (hr/yr). You may submit an application to the Administrator requesting an extension of this time limit to a total of 360 hr/yr. The application must explain why the extension is needed, it must indicate that no material will be added to the storage tank between the time the 240-hr limit is exceeded and the control device is again operational, and it must be submitted at least 60 days before the 240-hr limit will be exceeded.

(e) *Vapor balancing alternative.* As an alternative to the emission limits specified in Table 4 to this subpart, you may elect to implement vapor balancing in accordance with § 63.1253(f), except as specified in paragraphs (e)(1) through (3) of this section.

(1) When § 63.1253(f)(6)(i) refers to a 90 percent reduction, 95 percent applies for the purposes of this subpart.

(2) To comply with § 63.1253(f)(6)(i), the owner or operator of an offsite cleaning or reloading facility must comply with §§ 63.2445 through 63.2550 instead of complying with § 63.1253(f)(7)(ii), except as specified in paragraph (e)(2)(i) or (ii) of this section.

(i) The reporting requirements in § 63.2520 do not apply to the owner or operator of the offsite cleaning or reloading facility.

(ii) As an alternative to complying with the monitoring, recordkeeping, and reporting provisions in §§ 63.2445 through 63.2550, the owner or operator of an offsite cleaning or reloading facility may comply as specified in § 63.2535(a)(2) with any other subpart of this part 63 which has monitoring, recordkeeping, and reporting provisions as specified in § 63.2535(a)(2).

(3) You may elect to set a pressure relief device to a value less than the 2.5 pounds per square inch gage pressure (psig) required in § 63.1253(f)(5) if you provide rationale in your notification of compliance status report explaining why the alternative value is sufficient to prevent breathing losses at all times.

(4) You may comply with the vapor balancing alternative in § 63.1253(f) when your storage tank is filled from a barge. All requirements for tank trucks and railcars specified in § 63.1253(f) also apply to barges, except as specified in § 63.2470(e)(4)(i).

(i) When § 63.1253(f)(2) refers to pressure testing certifications, the requirements in 40 CFR 61.304(f) apply for barges.

(ii) [Reserved]

[68 FR 63888, Nov. 10, 2003, as amended at 70 FR 38559, July 1, 2005; 71 FR 40335, July 14, 2006]

§ 63.2475 What requirements must I meet for transfer racks?

(a) You must comply with each emission limit and work practice standard in table 5 to this subpart that applies to your transfer racks, and you must meet each applicable requirement in paragraphs (b) and (c) of this section.

(b) When the term "high throughput transfer rack" is used in subpart SS of this part 63, the term "Group 1 transfer rack," as defined in § 63.2550, applies for the purposes of this subpart.

[68 FR 63888, Nov. 10, 2003, as amended at 71 FR 40335, July 14, 2006]

§ 63.2480 What requirements must I meet for equipment leaks?

(a) You must meet each requirement in table 6 to this subpart that applies to your equipment leaks, except as specified in paragraphs (b) through (d) of this section.

(b) If you comply with either subpart H or subpart UU of this part 63, you may elect to comply with the provisions in paragraphs (b)(1) through (5) of this section as an alternative to the referenced provisions in subpart H or subpart UU of this part.

(1) The requirements for pressure testing in § 63.179(b) or § 63.1036(b) may be applied to all processes, not just batch processes.

(2) For the purposes of this subpart, pressure testing for leaks in accordance with § 63.179(b) or § 63.1036(b) is not required after reconfiguration of an equipment train if flexible hose connections are the only disturbed equipment.

(3) For an existing source, you are not required to develop an initial list of identification numbers for connectors as would otherwise be required under § 63.1022(b)(1) or § 63.181(b)(1)(i).

(4) For connectors in gas/vapor and light liquid service at an existing source, you may elect to comply with the requirements in § 63.169 or § 63.1029 for connectors in heavy liquid service, including all associated recordkeeping and reporting requirements, rather than the requirements of § 63.174 or § 63.1027.

(5) For pumps in light liquid service in an MCPU that has no continuous process vents and is part of an existing source, you may elect to consider the leak definition that defines a leak to be 10,000 parts per million (ppm) or greater as an alternative to the values specified in § 63.1026(b)(2)(i) through (iii) or § 63.163(b)(2).

(c) If you comply with 40 CFR part 65, subpart F, you may elect to comply with the provisions in paragraphs (c)(1) through (9) of this section as an alternative to the referenced provisions in 40 CFR part 65, subpart F.

(1) The requirements for pressure testing in § 65.117(b) may be applied to all processes, not just batch processes.

(2) For the purposes of this subpart, pressure testing for leaks in accordance with § 65.117(b) is not required after reconfiguration of an equipment train if flexible hose connections are the only disturbed equipment.

(3) For an existing source, you are not required to develop an initial list of identification numbers for connectors as would otherwise be required under § 65.103(b)(1).

(4) You may elect to comply with the monitoring and repair requirements specified in § 65.108(e)(3) as an alternative to the requirements specified in § 65.108(a) through (d) for any connectors at your affected source.

(5) For pumps in light liquid service in an MCPU that has no continuous process vents and is part of an existing source, you may elect to consider the leak definition that defines a leak to be 10,000 ppm or greater as an alternative to the values specified in § 65.107(b)(2)(i) through (iii).

(6) When 40 CFR part 65, subpart F refers to the implementation date specified in § 65.1(f), it means the compliance date specified in § 63.2445.

(7) When §§ 65.105(f) and 65.117(d)(3) refer to § 65.4, it means § 63.2525.

(8) When § 65.120(a) refers to § 65.5(d), it means § 63.2515.

(9) When § 65.120(b) refers to § 65.5(e), it means § 63.2520.

(d) The provisions of this section do not apply to bench-scale processes, regardless of whether the processes are located at the same plant site as a process subject to the provisions of this subpart.

[71 FR 40335, July 14, 2006]

§ 63.2485 What requirements must I meet for wastewater streams and liquid streams in open systems within an MCPU?

(a) You must meet each requirement in table 7 to this subpart that applies to your wastewater streams and liquid streams in open systems within an MCPU, except as specified in paragraphs (b) through (o) of this section.

(b) *Wastewater HAP.* Where § 63.105 and §§ 63.132 through 63.148 refer to compounds in table 9 of subpart G of this part 63, the compounds in tables 8 and 9 to this subpart apply for the purposes of this subpart.

(c) *Group 1 wastewater.* Section 63.132(c)(1) (i) and (ii) do not apply. For the purposes of this subpart, a process wastewater stream is Group 1 for compounds in tables 8 and 9 to this subpart if any of the conditions specified in paragraphs (c) (1) through (3) of this section are met.

(1) The total annual average concentration of compounds in table 8 to this subpart is greater than or equal to 10,000 ppmw at any flowrate, and the total annual load of compounds in table 8 to this subpart is greater than or equal to 200 lb/yr.

(2) The total annual average concentration of compounds in table 8 to this subpart is greater than or equal to 1,000 ppmw, and the annual average flowrate is greater than or equal to 1 l/min.

(3) The combined total annual average concentration of compounds in tables 8 and 9 to this subpart is greater than or equal to 30,000 ppmw, and the combined total annual load of compounds in tables 8 and 9 to this subpart is greater than or equal to 1 tpy.

(d) *Wastewater tank requirements.* (1) When §§ 63.133 and 63.147 reference floating roof requirements in §§ 63.119 and 63.120, the corresponding requirements in subpart WW of this part 63 may be applied for the purposes of this subpart.

(2) When § 63.133(a) refers to table 10 of subpart G of this part 63, the maximum true vapor pressure in the table shall be limited to the HAP listed in tables 8 and 9 of this subpart FFFF.

(3) For the purposes of this subpart, the requirements of § 63.133(a)(2) are satisfied by operating and maintaining a fixed roof if you demonstrate that the total soluble and partially soluble HAP emissions from the wastewater tank are no more than 5 percent higher than the emissions would be if the contents of the wastewater tank were not heated, treated by an exothermic reaction, or sparged.

(4) The emission limits specified in §§ 63.133(b)(2) and 63.139 for control devices used to control emissions from wastewater tanks do not apply during periods of planned routine maintenance of the control device(s) of no more than 240 hr/yr. You may request an extension to a total of 360 hr/yr in accordance with the procedures specified in § 63.2470(d).

(e) *Individual drain systems.* The provisions of § 63.136(e)(3) apply except as specified in paragraph (e)(1) of this section.

(1) A sewer line connected to drains that are in compliance with § 63.136(e)(1) may be vented to the atmosphere, provided that the sewer line entrance to the first downstream junction box is water sealed and the sewer line vent pipe is designed as specified in § 63.136(e)(2)(ii)(A).

(2) [Reserved]

(f) *Closed-vent system requirements.* When § 63.148(k) refers to closed vent systems that are subject to the requirements of § 63.172, the requirements of either § 63.172 or § 63.1034 apply for the purposes of this subpart.

(g) *Halogenated vent stream requirements.* For each halogenated vent stream from a Group 1 wastewater stream or residual removed from a Group 1 wastewater stream that is vented through a closed-vent system to a combustion device to reduce organic HAP emissions, you must meet the same emission limits as specified for batch process vents in item 2 of table 2 to this subpart.

(h) *Alternative test methods.* (1) As an alternative to the test methods specified in § 63.144(b)(5)(i), you may use Method 8260 or 8270 as specified in § 63.1257(b)(10)(iii).

(2) As an alternative to using the methods specified in § 63.144(b)(5)(i), you may conduct wastewater analyses using Method 1666 or 1671 of 40 CFR part 136 and comply with the sampling protocol requirements specified in § 63.144(b)(5)(ii). The validation requirements specified in § 63.144(b)(5)(iii) do not apply if you use Method 1666 or 1671 of 40 CFR part 136.

(3) As an alternative to using Method 18 of 40 CFR part 60, as specified in §§ 63.139(c)(1)(ii) and 63.145(i)(2), you may elect to use Method 25A of 40 CFR part 60 as specified in § 63.997.

(i) *Offsite management and treatment option.* (1) If you ship wastewater to an offsite treatment facility that meets the requirements of § 63.138(h), you may elect to document in your notification of compliance status report that the wastewater will be treated as hazardous waste at a facility that meets the requirements of § 63.138(h) as an alternative to having the offsite facility submit the certification specified in § 63.132(g)(2).

(2) As an alternative to the management and treatment options specified in § 63.132(g)(2), any affected wastewater stream (or residual removed from an affected wastewater stream) with a total annual average concentration of compounds in Table 8 to this subpart less than 50 ppmw may be transferred offsite in accordance with paragraphs (i)(2) (i) and (ii) of this section.

(i) The transferee (or you) must demonstrate that less than 5 percent of the HAP in Table 9 to this subpart is emitted from the waste management units up to the activated sludge unit.

(ii) The transferee must treat the wastewater stream or residual in a biological treatment unit in accordance with §§ 63.138 and 63.145 and the requirements referenced therein.

(j) You must determine the annual average concentration and annual average flowrate for wastewater streams for each MCPU. The procedures for flexible operation units specified in § 63.144 (b) and (c) do not apply for the purposes of this subpart.

(k) The requirement to correct outlet concentrations from combustion devices to 3 percent oxygen in §§ 63.139(c)(1)(ii) and 63.146(i)(6) applies only if supplemental gases are combined with a vent stream from a Group 1 wastewater stream. If emissions are controlled with a vapor recovery system as specified in § 63.139(c)(2), you must correct for supplemental gases as specified in § 63.2460(c)(6).

(l) *Requirements for liquid streams in open systems.* (1) References in § 63.149 to § 63.100(b) mean § 63.2435(b) for the purposes of this subpart.

(2) When § 63.149(e) refers to 40 CFR 63.100(l) (1) or (2), § 63.2445(a) applies for the purposes of this subpart.

(3) When § 63.149 uses the term “chemical manufacturing process unit,” the term “MCPU” applies for the purposes of this subpart.

(4) When § 63.149(e)(1) refers to characteristics of water that contain compounds in Table 9 to 40 CFR part 63, subpart G, the characteristics specified in paragraphs (c) (1) through (3) of this section apply for the purposes of this subpart.

(5) When § 63.149(e)(2) refers to characteristics of water that contain compounds in Table 9 to 40 CFR part 63, subpart G, the characteristics specified in paragraph (c)(2) of this section apply for the purposes of this subpart.

(m) When § 63.132(f) refers to “a concentration of greater than 10,000 ppmw of table 9 compounds,” the phrase “a concentration of greater than 30,000 ppmw of total partially soluble HAP (PSHAP) and soluble HAP (SHAP) or greater than 10,000 ppmw of PSHAP” shall apply for the purposes of this subpart.

(n) *Alternative requirements for wastewater that is Group 1 for soluble HAP only.* The option specified in this paragraph (n) applies to wastewater that is Group 1 for soluble HAP in accordance with paragraph (c)(3) of this section and is discharged to biological treatment. Except as provided in paragraph (n)(4) of this section, this option does not apply to wastewater that is Group 1 for partially soluble HAP in accordance with paragraph (c)(1), (c)(2), or (c)(4) of this section. For wastewater that is Group 1 for SHAP, you need not comply with §§ 63.133 through 63.137 for any equalization unit, neutralization unit, and/or clarifier prior to the activated sludge unit, and you need not comply with the venting requirements in § 63.136(e)(2)(ii)(A) for lift stations with a volume larger than 10,000 gal, provided you comply with the requirements specified in paragraphs (n)(1) through (3) of this section and all otherwise applicable requirements specified in table 7 to this subpart. For this option, the treatment requirements in § 63.138 and the performance testing requirements in § 63.145 do not apply to the biological treatment unit, except as specified in paragraphs (n)(2)(i) through (iv) of this section.

(1) Wastewater must be hard-piped between the equalization unit, clarifier, and activated sludge unit. This requirement does not apply to the transfer between any of these types of units that are part of the same structure and one unit overflows into the next.

(2) Calculate the destruction efficiency of the biological treatment unit using Equation 1 of this section in accordance with the procedures described in paragraphs (n)(2)(i) through (vi) of this section. You have demonstrated initial compliance if E is greater than or equal to 90 percent.

$$E = \frac{\left(QMW_a - QMG_e - QMG_n - QMG_c\right)\left(F_{bio}\right)}{QMW_a} \times 100 \qquad \text{(Eq. 1)}$$

Where:

E = destruction efficiency of total PSHAP and SHAP for the biological treatment unit including the equalization unit, neutralization unit, and/or clarifier, percent;

QMW_a = mass flow rate of total PSHAP and SHAP compounds entering the equalization unit (or whichever of the three types of units is first), kilograms per hour (kg/hr);

QMG_e = mass flow rate of total PSHAP and SHAP compounds emitted from the equalization unit, kg/hr;

QMG_n = mass flow rate of total PSHAP and SHAP compounds emitted from the neutralization unit, kg/hr;

QMG_c = mass flow rate of total PSHAP and SHAP compounds emitted from the clarifier, kg/hr

F_{bio} = site-specific fraction of PSHAP and SHAP compounds biodegraded in the biological treatment unit.

(i) Include all PSHAP and SHAP compounds in both Group 1 and Group 2 wastewater streams from all MCPU, except you may exclude any compounds that meet the criteria specified in § 63.145(a)(6)(ii) or (iii).

(ii) Conduct the demonstration under representative process unit and treatment unit operating conditions in accordance with § 63.145(a)(3) and (4).

(iii) Determine PSHAP and SHAP concentrations and the total wastewater flow rate at the inlet to the equalization unit in accordance with § 63.145(f)(1) and (2). References in § 63.145(f)(1) and (2) to required mass removal and actual mass removal do not apply for the purposes of this section.

(iv) Determine F_{bio} for the activated sludge unit as specified in § 63.145(h), except as specified in paragraph (n)(2)(iv)(A) or paragraph (n)(2)(iv)(B) of this section.

(A) If the biological treatment process meets both of the requirements specified in § 63.145(h)(1)(i) and (ii), you may elect to replace the F_{bio} term in Equation 1 of this section with the numeral "1."

(B) You may elect to assume f_{bio} is zero for any compounds on List 2 of table 36 in subpart G.

(v) Determine QMG_e , QMG_n , and QMG_c using EPA's WATER9 model or the most recent update to this model, and conduct testing or use other procedures to validate the modeling results.

(vi) Submit the data and results of your demonstration, including both a description of and the results of your WATER9 modeling validation procedures, in your notification of compliance status report as specified in § 63.2520(d)(2)(ii).

(3) As an alternative to the venting requirements in § 63.136(e)(2)(ii)(A), a lift station with a volume larger than 10,000 gal may have openings necessary for proper venting of the lift station. The size and other design characteristics of these openings may be established based on manufacturer recommendations or engineering judgment for venting under normal operating conditions. You must describe the design of such openings and your supporting calculations and other rationale in your notification of compliance status report.

(4) For any wastewater streams that are Group 1 for both PSHAP and SHAP, you may elect to meet the requirements specified in table 7 to this subpart for the PSHAP and then comply with paragraphs (n)(1) through (3) of this section for the SHAP in the wastewater system. You may determine the SHAP mass removal rate, in kg/hr, in treatment units that are used to meet the requirements for PSHAP and add this amount to both the numerator and denominator in Equation 1 of this section.

(o) *Compliance records.* For each CPMS used to monitor a nonflare control device for wastewater emissions, you must keep records as specified in § 63.998(c)(1) in addition to the records required in § 63.147(d).

[68 FR 63888, Nov. 10, 2003, as amended at 70 FR 38559, July 1, 2005; 71 FR 40335, July 14, 2006]

§ 63.2490 What requirements must I meet for heat exchange systems?

(a) You must comply with each requirement in Table 10 to this subpart that applies to your heat exchange systems, except as specified in paragraphs (b) and (c) of this section.

(b) The phrase “a chemical manufacturing process unit meeting the conditions of § 63.100 (b)(1) through (b)(3) of this section” in § 63.104(a) means “an MCPU meeting the conditions of § 63.2435” for the purposes of this subpart.

(c) The reference to § 63.100(c) in § 63.104(a) does not apply for the purposes of this subpart.

Alternative Means of Compliance

§ 63.2495 How do I comply with the pollution prevention standard?

(a) You may elect to comply with the pollution prevention alternative requirements specified in paragraphs (a) (1) and (2) of this section in lieu of the emission limitations and work practice standards contained in Tables 1 through 7 to this subpart for any MCPU for which initial startup occurred before April 4, 2002.

(1) You must reduce the production-indexed HAP consumption factor (HAP factor) by at least 65 percent from a 3-year average baseline beginning no earlier than the 1994 through 1996 calendar years. For any reduction in the HAP factor that you achieve by reducing HAP that are also volatile organic compounds (VOC), you must demonstrate an equivalent reduction in the production-indexed VOC consumption factor (VOC factor) on a mass basis. For any reduction in the HAP factor that you achieve by reducing a HAP that is not a VOC, you may not increase the VOC factor.

(2) Any MCPU for which you seek to comply by using the pollution prevention alternative must begin with the same starting material(s) and end with the same product(s). You may not comply by eliminating any steps of a process by transferring the step offsite (to another manufacturing location). You may also not merge a solvent recovery step conducted offsite to onsite and as part of an existing process as a method of reducing consumption.

(3) You may comply with the requirements of paragraph (a)(1) of this section for a series of processes, including situations where multiple processes are merged, if you demonstrate to the satisfaction of the

Administrator that the multiple processes were merged after the baseline period into an existing process or processes.

(b) *Exclusions.* (1) You must comply with the emission limitations and work practice standards contained in tables 1 through 7 of this subpart for all HAP that are generated in the MCPU and that are not included in consumption, as defined in § 63.2550. If any vent stream routed to the combustion control is a halogenated vent stream, as defined in § 63.2550, then hydrogen halides that are generated as a result of combustion control must be controlled according to the requirements of § 63.994 and the requirements referenced therein.

(2) You may not merge nondedicated formulation or nondedicated solvent recovery processes with any other processes.

(c) *Initial compliance procedures.* To demonstrate initial compliance with paragraph (a) of this section, you must prepare a demonstration summary in accordance with paragraph (c) (1) of this section and calculate baseline and target annual HAP and VOC factors in accordance with paragraphs (c) (2) and (3) of this section.

(1) *Demonstration plan.* You must prepare a pollution prevention demonstration plan that contains, at a minimum, the information in paragraphs (c)(1) (i) through (iii) of this section for each MCPU for which you comply with paragraph (a) of this section.

(i) Descriptions of the methodologies and forms used to measure and record consumption of HAP and VOC compounds.

(ii) Descriptions of the methodologies and forms used to measure and record production of the product(s).

(iii) Supporting documentation for the descriptions provided in accordance with paragraphs (c)(1) (i) and (ii) of this section including, but not limited to, samples of operator log sheets and daily, monthly, and/or annual inventories of materials and products. You must describe how this documentation will be used to calculate the annual factors required in paragraph (d) of this section.

(2) *Baseline factors.* You must calculate baseline HAP and VOC factors by dividing the consumption of total HAP and total VOC by the production rate, per process, for the first 3-year period in which the process was operational, beginning no earlier than the period consisting of the 1994 through 1996 calendar years.

(3) *Target annual factors.* You must calculate target annual HAP and VOC factors. The target annual HAP factor must be equal to 35 percent of the baseline HAP factor. The target annual VOC factor must be lower than the baseline VOC factor by an amount equivalent to the reduction in any HAP that is also a VOC, on a mass basis. The target annual VOC factor may be the same as the baseline VOC factor if the only HAP you reduce is not a VOC.

(d) *Continuous compliance requirements.* You must calculate annual rolling average values of the HAP and VOC factors (annual factors) in accordance with the procedures specified in paragraphs (d) (1) through (3) of this section. To show continuous compliance, the annual factors must be equal to or less than the target annual factors calculated according to paragraph (c)(3) of this section.

(1) To calculate the annual factors, you must divide the consumption of both total HAP and total VOC by the production rate, per process, for 12-month periods at the frequency specified in either paragraph (d) (2) or (3) of this section, as applicable.

(2) For continuous processes, you must calculate the annual factors every 30 days for the 12-month period preceding the 30th day (i.e., annual rolling average calculated every 30 days). A process with both batch and continuous operations is considered a continuous process for the purposes of this section.

(3) For batch processes, you must calculate the annual factors every 10 batches for the 12-month period preceding the 10th batch (*i.e.,* annual rolling average calculated every 10 batches), except as specified in paragraphs (d)(3) (i) and (ii) of this section.

(i) If you produce more than 10 batches during a month, you must calculate the annual factors at least once during that month.

(ii) If you produce less than 10 batches in a 12-month period, you must calculate the annual factors for the number of batches in the 12-month period since the previous calculations.

(e) *Records.* You must keep records of HAP and VOC consumption, production, and the rolling annual HAP and VOC factors for each MCPU for which you are complying with paragraph (a) of this section.

(f) *Reporting.* (1) You must include the pollution prevention demonstration plan in the precompliance report required by § 63.2520(c).

(2) You must identify all days when the annual factors were above the target factors in the compliance reports.

[68 FR 63888, Nov. 10, 2003, as amended at 71 FR 40336, July 14, 2006]

§ 63.2500 How do I comply with emissions averaging?

(a) For an existing source, you may elect to comply with the percent reduction emission limitations in Tables 1, 2, 4, 5, and 7 to this subpart by complying with the emissions averaging provisions specified in § 63.150, except as specified in paragraphs (b) through (f) of this section.

(b) The batch process vents in an MCPU collectively are considered one individual emission point for the purposes of emissions averaging, except that only individual batch process vents must be excluded to meet the requirements of § 63.150(d)(5).

(c) References in § 63.150 to §§ 63.112 through 63.130 mean the corresponding requirements in §§ 63.2450 through 63.2490, including applicable monitoring, recordkeeping, and reporting.

(d) References to “periodic reports” in § 63.150 mean “compliance report” for the purposes of this subpart.

(e) For batch process vents, estimate uncontrolled emissions for a standard batch using the procedures in § 63.1257(d)(2)(i) and (ii) instead of the procedures in § 63.150(g)(2). Multiply the calculated emissions per batch by the number of batches per month when calculating the monthly emissions for use in calculating debits and credits.

(f) References to “storage vessels” in § 63.150 mean “storage tank” as defined in § 63.2550 for the purposes of this subpart.

§ 63.2505 How do I comply with the alternative standard?

As an alternative to complying with the emission limits and work practice standards for process vents and storage tanks in Tables 1 through 4 to this subpart and the requirements in §§ 63.2455 through 63.2470, you may comply with the emission limits in paragraph (a) of this section and demonstrate compliance in accordance with the requirements in paragraph (b) of this section.

(a) *Emission limits and work practice standards.* (1) You must route vent streams through a closed-vent system to a control device that reduces HAP emissions as specified in either paragraph (a)(1)(i) or (ii) of this section.

(i) If you use a combustion control device, it must reduce HAP emissions as specified in paragraphs (a)(1)(i)(A), (B), and (C) of this section.

(A) To an outlet TOC concentration of 20 parts per million by volume (ppmv) or less.

(B) To an outlet concentration of hydrogen halide and halogen HAP of 20 ppmv or less.

(C) As an alternative to paragraph (a)(1)(i)(B) of this section, if you control halogenated vent streams emitted from a combustion device followed by a scrubber, reduce the hydrogen halide and halogen HAP generated in the combustion device by greater than or equal to 95 percent by weight in the scrubber.

(ii) If you use a noncombustion control device(s), it must reduce HAP emissions to an outlet total organic HAP concentration of 50 ppmv or less, and an outlet concentration of hydrogen halide and halogen HAP of 50 ppmv or less.

(2) Any Group 1 process vents within a process that are not controlled according to this alternative standard must be controlled according to the emission limits in tables 1 through 3 to this subpart.

(b) *Compliance requirements.* To demonstrate compliance with paragraph (a) of this section, you must meet the requirements of § 63.1258(b)(5) beginning no later than the initial compliance date specified in § 63.2445, except as specified in paragraphs (b)(1) through (9) of this section.

(1) You must comply with the requirements in § 63.983 and the requirements referenced therein for closed-vent systems.

(2) When § 63.1258(b)(5)(i) refers to §§ 63.1253(d) and 63.1254(c), the requirements in paragraph (a) of this section apply for the purposes of this subpart FFFF.

(3) When § 63.1258(b)(5)(i)(B) refers to “HCl,” it means “total hydrogen halide and halogen HAP” for the purposes of this subpart FFFF.

(4) When § 63.1258(b)(5)(ii) refers to § 63.1257(a)(3), it means § 63.2450(j)(5) for the purposes of this subpart FFFF.

(5) You must submit the results of any determination of the target analytes of predominant HAP in the notification of compliance status report.

(6) If you elect to comply with the requirement to reduce hydrogen halide and halogen HAP by greater than or equal to 95 percent by weight in paragraph (a)(1)(i)(C) of this section, you must meet the requirements in paragraphs (b)(6)(i) and (ii) of this section.

(i) Demonstrate initial compliance with the 95 percent reduction by conducting a performance test and setting a site-specific operating limit(s) for the scrubber in accordance with § 63.994 and the requirements referenced therein. You must submit the results of the initial compliance demonstration in the notification of compliance status report.

(ii) Install, operate, and maintain CPMS for the scrubber as specified in §§ 63.994(c) and 63.2450(k), instead of as specified in § 63.1258(b)(5)(i)(C).

(7) If flow to the scrubber could be intermittent, you must install, calibrate, and operate a flow indicator as specified in § 63.2460(c)(7).

(8) Use the operating day as the averaging period for CEMS data and scrubber parameter monitoring data.

(9) The requirements in paragraph (a) of this section do not apply to emissions from storage tanks during periods of planned routine maintenance of the control device that do not exceed 240 hr/yr. You may submit an application to the Administrator requesting an extension of this time limit to a total of 360 hr/yr in accordance with the procedures specified in § 63.2470(d). You must comply with the recordkeeping and reporting specified in §§ 63.998(d)(2)(ii) and 63.999(c)(4) for periods of planned routine maintenance.

[68 FR 63888, Nov. 10, 2003, as amended at 70 FR 38559, July 1, 2005]

Notification, Reports, and Records

§ 63.2515 What notifications must I submit and when?

(a) You must submit all of the notifications in §§ 63.6(h)(4) and (5), 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) *Initial notification.* As specified in § 63.9(b)(2), if you startup your affected source before November 10, 2003, you must submit an initial notification not later than 120 calendar days after November 10, 2003.

(2) As specified in § 63.9(b)(3), if you startup your new affected source on or after November 10, 2003, you must submit an initial notification not later than 120 calendar days after you become subject to this subpart.

(c) *Notification of performance test.* If you are required to conduct a performance test, you must submit a notification of intent to conduct a performance test at least 60 calendar days before the performance test is scheduled to begin as required in § 63.7(b)(1). For any performance test required as part of the initial compliance procedures for batch process vents in table 2 to this subpart, you must also submit the test plan required by § 63.7(c) and the emission profile with the notification of the performance test.

§ 63.2520 What reports must I submit and when?

(a) You must submit each report in Table 11 to this subpart that applies to you.

(b) Unless the Administrator has approved a different schedule for submission of reports under § 63.10(a), you must submit each report by the date in table 11 to this subpart and according to 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 § 63.2445 and ending on June 30 or December 31, whichever date is the first

date following the end of the first 6 months after the compliance date that is specified for your affected source in § 63.2445.

(2) The first compliance report must be postmarked or delivered no later than August 31 or February 28, whichever date is the first date following the end of the first reporting period specified in paragraph (b)(1) of this section.

(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 August 31 or February 28, 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) *Precompliance report.* You must submit a precompliance report to request approval for any of the items in paragraphs (c)(1) through (7) of this section. We will either approve or disapprove the report within 90 days after we receive it. If we disapprove the report, you must still be in compliance with the emission limitations and work practice standards in this subpart by the compliance date. To change any of the information submitted in the report, you must notify us 60 days before the planned change is to be implemented.

(1) Requests for approval to set operating limits for parameters other than those specified in §§ 63.2455 through 63.2485 and referenced therein. Alternatively, you may make these requests according to § 63.8(f).

(2) Descriptions of daily or per batch demonstrations to verify that control devices subject to § 63.2460(c)(5) are operating as designed.

(3) A description of the test conditions, data, calculations, and other information used to establish operating limits according to § 63.2460(c)(3).

(4) Data and rationale used to support an engineering assessment to calculate uncontrolled emissions in accordance with § 63.1257(d)(2)(ii). This requirement does not apply to calculations of hydrogen halide and halogen HAP emissions as specified in § 63.2465(b), to determinations that the total HAP concentration is less than 50 ppmv, or if you use previous test data to establish the uncontrolled emissions.

(5) The pollution prevention demonstration plan required in § 63.2495(c)(1), if you are complying with the pollution prevention alternative.

(6) Documentation of the practices that you will implement to minimize HAP emissions from streams that contain energetics and organic peroxides, and rationale for why meeting the emission limit specified in tables 1 through 7 to this subpart would create an undue safety hazard.

(7) For fabric filters that are monitored with bag leak detectors, an operation and maintenance plan that describes proper operation and maintenance procedures, and a corrective action plan that describes corrective actions to be taken, and the timing of those actions, when the PM concentration exceeds the set point and activates the alarm.

(d) *Notification of compliance status report.* You must submit a notification of compliance status report according to the schedule in paragraph (d)(1) of this section, and the notification of compliance status report must contain the information specified in paragraph (d)(2) of this section.

(1) You must submit the notification of compliance status report no later than 150 days after the applicable compliance date specified in § 63.2445.

(2) The notification of compliance status report must include the information in paragraphs (d)(2)(i) through (ix) of this section.

(i) The results of any applicability determinations, emission calculations, or analyses used to identify and quantify HAP usage or HAP emissions from the affected source.

(ii) The results of emissions profiles, performance tests, engineering analyses, design evaluations, flare compliance assessments, inspections and repairs, and calculations used to demonstrate initial compliance according to §§ 63.2455 through 63.2485. For performance tests, results must include descriptions of sampling and analysis procedures and quality assurance procedures.

(iii) Descriptions of monitoring devices, monitoring frequencies, and the operating limits established during the initial compliance demonstrations, including data and calculations to support the levels you establish.

(iv) All operating scenarios.

(v) Descriptions of worst-case operating and/or testing conditions for control devices.

(vi) Identification of parts of the affected source subject to overlapping requirements described in § 63.2535 and the authority under which you will comply.

(vii) The information specified in § 63.1039(a)(1) through (3) for each process subject to the work practice standards for equipment leaks in Table 6 to this subpart.

(viii) Identify storage tanks for which you are complying with the vapor balancing alternative in § 63.2470(e).

(ix) Records as specified in § 63.2535(l)(1) through (3) of process units used to create a PUG and calculations of the initial primary product of the PUG.

(e) *Compliance report.* The compliance report must contain the information specified in paragraphs (e)(1) through (10) of this section.

(1) Company name and address.

(2) Statement by a responsible official with that official's name, title, and signature, certifying the accuracy of the content of the report.

(3) Date of report and beginning and ending dates of the reporting period.

(4) For each SSM during which excess emissions occur, the compliance report must include records that the procedures specified in your startup, shutdown, and malfunction plan (SSMP) were followed or documentation of actions taken that are not consistent with the SSMP, and include a brief description of each malfunction.

(5) The compliance report must contain the information on deviations, as defined in § 63.2550, according to paragraphs (e)(5)(i), (ii), (iii), and (iv) of this section.

(i) If there are no deviations from any emission limit, operating limit or work practice standard specified in this subpart, include a statement that there were no deviations from the emission limits, operating limits, or work practice standards during the reporting period.

(ii) For each deviation from an emission limit, operating limit, and work practice standard that occurs at an affected source where you are not using a continuous monitoring system (CMS) to comply with the emission limit or work practice standard in this subpart, you must include the information in paragraphs (e)(5)(ii)(A) through (C) of this section. This includes periods of SSM.

(A) The total operating time of the affected source during the reporting period.

(B) Information on the number, duration, and cause of deviations (including unknown cause, if applicable), as applicable, and the corrective action taken.

(C) Operating logs of processes with batch vents from batch operations for the day(s) during which the deviation occurred, except operating logs are not required for deviations of the work practice standards for equipment leaks.

(iii) For each deviation from an emission limit or operating limit occurring at an affected source where you are using a CMS to comply with an emission limit in this subpart, you must include the information in paragraphs (e)(5)(iii)(A) through (L) of this section. This includes periods of SSM.

(A) The date and time that each CMS was inoperative, except for zero (low-level) and high-level checks.

(B) The date, time, and duration that each CEMS was out-of-control, including the information in § 63.8(c)(8).

(C) 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.

(D) A summary of the total duration of the deviation during the reporting period, and the total duration as a percent of the total operating time of the affected source during that reporting period.

(E) 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.

(F) A summary of the total duration of CMS downtime during the reporting period, and the total duration of CMS downtime as a percent of the total operating time of the affected source during that reporting period.

(G) An identification of each HAP that is known to be in the emission stream.

(H) A brief description of the process units.

(I) A brief description of the CMS.

(J) The date of the latest CMS certification or audit.

(K) Operating logs of processes with batch vents from batch operations for each day(s) during which the deviation occurred.

(L) The operating day or operating block average values of monitored parameters for each day(s) during which the deviation occurred.

(iv) If you documented in your notification of compliance status report that an MCPU has Group 2 batch process vents because the non-reactive HAP is the only HAP and usage is less than 10,000 lb/yr, the total uncontrolled organic HAP emissions from the batch process vents in an MCPU will be less than 1,000 lb/yr for the anticipated number of standard batches, or total uncontrolled hydrogen halide and halogen HAP emissions from all batch process vents and continuous process vents in a process are less than 1,000 lb/yr, include the records associated with each calculation required by § 63.2525(e) that exceeds an applicable HAP usage or emissions threshold.

(6) If you use a CEMS, and there were no periods during which it was out-of-control as specified in § 63.8(c)(7), include a statement that there were no periods during which the CEMS was out-of-control during the reporting period.

(7) Include each new operating scenario which has been operated since the time period covered by the last compliance report and has not been submitted in the notification of compliance status report or a previous compliance report. For each new operating scenario, you must provide verification that the operating conditions for any associated control or treatment device have not been exceeded and that any required calculations and engineering analyses have been performed. For the purposes of this paragraph, a revised operating scenario for an existing process is considered to be a new operating scenario.

(8) Records of process units added to a PUG as specified in § 63.2525(i)(4) and records of primary product redeterminations as specified in § 63.2525(i)(5).

(9) Applicable records and information for periodic reports as specified in referenced subparts F, G, H, SS, UU, WW, and GGG of this part and subpart F of 40 CFR part 65.

(10) *Notification of process change.* (i) Except as specified in paragraph (e)(10)(ii) of this section, whenever you make a process change, or change any of the information submitted in the notification of compliance status report or a previous compliance report, that is not within the scope of an existing operating scenario, you must document the change in your compliance report. A process change does not include moving within a range of conditions identified in the standard batch, and a nonstandard batch does not constitute a process change. The notification must include all of the information in paragraphs (e)(10)(i)(A) through (C) of this section.

(A) A description of the process change.

(B) Revisions to any of the information reported in the original notification of compliance status report under paragraph (d) of this section.

(C) Information required by the notification of compliance status report under paragraph (d) of this section for changes involving the addition of processes or equipment at the affected source.

(ii) You must submit a report 60 days before the scheduled implementation date of any of the changes identified in paragraph (e)(10)(ii)(A), (B), or (C) of this section.

(A) Any change to the information contained in the precompliance report.

(B) A change in the status of a control device from small to large.

(C) A change from Group 2 to Group 1 for any emission point except for batch process vents that meet the conditions specified in § 63.2460(b)(6)(i).

[68 FR 63888, Nov. 10, 2003, as amended at 70 FR 38560, July 1, 2005; 71 FR 40336, July 14, 2006]

§ 63.2525 What records must I keep?

You must keep the records specified in paragraphs (a) through (k) of this section.

(a) Each applicable record required by subpart A of this part 63 and in referenced subparts F, G, SS, UU, WW, and GGG of this part 63 and in referenced subpart F of 40 CFR part 65.

(b) Records of each operating scenario as specified in paragraphs (b)(1) through (8) of this section.

(1) A description of the process and the type of process equipment used.

(2) An identification of related process vents, including their associated emissions episodes if not complying with the alternative standard in § 63.2505; wastewater point of determination (POD); storage tanks; and transfer racks.

(3) The applicable control requirements of this subpart, including the level of required control, and for vents, the level of control for each vent.

(4) The control device or treatment process used, as applicable, including a description of operating and/or testing conditions for any associated control device.

(5) The process vents, wastewater POD, transfer racks, and storage tanks (including those from other processes) that are simultaneously routed to the control device or treatment process(s).

(6) The applicable monitoring requirements of this subpart and any parametric level that assures compliance for all emissions routed to the control device or treatment process.

(7) Calculations and engineering analyses required to demonstrate compliance.

(8) For reporting purposes, a change to any of these elements not previously reported, except for paragraph (b)(5) of this section, constitutes a new operating scenario.

(c) A schedule or log of operating scenarios for processes with batch vents from batch operations updated each time a different operating scenario is put into effect.

(d) The information specified in paragraphs (d)(1) and (2) of this section for Group 1 batch process vents in compliance with a percent reduction emission limit in Table 2 to this subpart if some of the vents are controlled to less the percent reduction requirement.

(1) Records of whether each batch operated was considered a standard batch.

(2) The estimated uncontrolled and controlled emissions for each batch that is considered to be a nonstandard batch.

(e) The information specified in paragraph (e)(2), (3), or (4) of this section, as applicable, for each process with Group 2 batch process vents or uncontrolled hydrogen halide and halogen HAP emissions from the sum of all batch and continuous process vents less than 1,000 lb/yr. No records are required for situations described in paragraph (e)(1) of this section.

(1) No records are required if you documented in your notification of compliance status report that the MCPU meets any of the situations described in paragraph (e)(1)(i), (ii), or (iii) of this section.

(i) The MCPU does not process, use, or generate HAP.

(ii) You control the Group 2 batch process vents using a flare that meets the requirements of § 63.987.

(iii) You control the Group 2 batch process vents using a control device for which your determination of worst case for initial compliance includes the contribution of all Group 2 batch process vents.

(2) If you documented in your notification of compliance status report that an MCPU has Group 2 batch process vents because the non-reactive organic HAP is the only HAP and usage is less than 10,000 lb/yr, as specified in § 63.2460(b)(7), you must keep records of the amount of HAP material used, and calculate the daily rolling annual sum of the amount used no less frequently than monthly. If a record indicates usage exceeds 10,000 lb/yr, you must estimate emissions for the preceding 12 months based on the number of batches operated and the estimated emissions for a standard batch, and you must begin recordkeeping as specified in paragraph (e)(4) of this section. After 1 year, you may revert to recording only usage if the usage during the year is less than 10,000 lb.

(3) If you documented in your notification of compliance status report that total uncontrolled organic HAP emissions from the batch process vents in an MCPU will be less than 1,000 lb/yr for the anticipated number of standard batches, then you must keep records of the number of batches operated and calculate a daily rolling annual sum of batches operated no less frequently than monthly. If the number of batches operated results in organic HAP emissions that exceed 1,000 lb/yr, you must estimate emissions for the preceding 12 months based on the number of batches operated and the estimated emissions for a standard batch, and you must begin recordkeeping as specified in paragraph (e)(4) of this section. After 1 year, you may revert to recording only the number of batches if the number of batches operated during the year results in less than 1,000 lb of organic HAP emissions.

(4) If you meet none of the conditions specified in paragraphs (e)(1) through (3) of this section, you must keep records of the information specified in paragraphs (e)(4)(i) through (iv) of this section.

(i) A record of the day each batch was completed and/or the operating hours per day for continuous operations with hydrogen halide and halogen emissions.

(ii) A record of whether each batch operated was considered a standard batch.

(iii) The estimated uncontrolled and controlled emissions for each batch that is considered to be a nonstandard batch.

(iv) Records of the daily 365-day rolling summations of emissions, or alternative records that correlate to the emissions (e.g., number of batches), calculated no less frequently than monthly.

(f) A record of each time a safety device is opened to avoid unsafe conditions in accordance with § 63.2450(s).

(g) Records of the results of each CPMS calibration check and the maintenance performed, as specified in § 63.2450(k)(1).

(h) For each CEMS, you must keep 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.

(i) For each PUG, you must keep records specified in paragraphs (i)(1) through (5) of this section.

(1) Descriptions of the MCPU and other process units in the initial PUG required by § 63.2535(l)(1)(v).

(2) Rationale for including each MCPU and other process unit in the initial PUG (*i.e.,* identify the overlapping equipment between process units) required by § 63.2535(l)(1)(v).

(3) Calculations used to determine the primary product for the initial PUG required by § 63.2535(l)(2)(iv).

(4) Descriptions of process units added to the PUG after the creation date and rationale for including the additional process units in the PUG as required by § 63.2535(l)(1)(v).

(5) The calculation of each primary product redetermination required by § 63.2535(l)(2)(iv).

(j) In the SSMP required by § 63.6(e)(3), you are not required to include Group 2 emission points, unless those emission points are used in an emissions average. For equipment leaks, the SSMP requirement is limited to control devices and is optional for other equipment.

(k) For each bag leak detector used to monitor PM HAP emissions from a fabric filter, maintain records of any bag leak detection alarm, including the date and time, with a brief explanation of the cause of the alarm and the corrective action taken.

[68 FR 63888, Nov. 10, 2003, as amended at 70 FR 38560, July 1, 2005; 71 FR 40337, July 14, 2006]

Other Requirements and Information

§ 63.2535 What compliance options do I have if part of my plant is subject to both this subpart and another subpart?

For any equipment, emission stream, or wastewater stream subject to the provisions of both this subpart and another rule, you may elect to comply only with the provisions as specified in paragraphs (a) through (l) of this section. You also must identify the subject equipment, emission stream, or wastewater stream, and the provisions with which you will comply, in your notification of compliance status report required by § 63.2520(d).

(a) *Compliance with other subparts of this part 63.* (1) If you have an MCPU that includes a batch process vent that also is part of a CMPU as defined in subparts F and G of this part 63, you must comply with the emission limits; operating limits; work practice standards; and the compliance, monitoring, reporting, and recordkeeping requirements for batch process vents in this subpart, and you must continue to comply with the requirements in subparts F, G, and H of this part 63 that are applicable to the CMPU and associated equipment.

(2) After the compliance dates specified in § 63.2445, at an offsite reloading or cleaning facility subject to § 63.1253(f), as referenced from § 63.2470(e), compliance with the monitoring, recordkeeping, and reporting provisions of any other subpart of this part 63 constitutes compliance with the monitoring, recordkeeping, and reporting provisions of § 63.1253(f)(7)(ii) or § 63.1253(f)(7)(iii). You must identify in your notification of compliance status report required by § 63.2520(d) the subpart of this part 63 with which the owner or operator of the offsite reloading or cleaning facility complies.

(b) *Compliance with 40 CFR parts 264 and 265, subparts AA, BB, and/or CC.* (1) After the compliance dates specified in § 63.2445, if a control device that you use to comply with this subpart is also subject to monitoring, recordkeeping, and reporting requirements in 40 CFR part 264, subpart AA, BB, or CC; or the monitoring and recordkeeping requirements in 40 CFR part 265, subpart AA, BB, or CC; and you comply with the periodic reporting requirements under 40 CFR part 264, subpart AA, BB, or CC that would apply to the device if your facility had final-permitted status, you may elect to comply either with the monitoring, recordkeeping, and reporting requirements of this subpart; or with the monitoring and recordkeeping requirements in 40 CFR part 264 or 265 and the reporting requirements in 40 CFR part 264, as described in this paragraph (b)(1), which constitute compliance with the monitoring, recordkeeping, and reporting requirements of this subpart. If you elect to comply with the monitoring, recordkeeping, and reporting requirements in 40 CFR parts 264 and/or 265, you must report the information described in § 63.2520(e).

(2) After the compliance dates specified in § 63.2445, if you have an affected source with equipment that is also subject to 40 CFR part 264, subpart BB, or to 40 CFR part 265, subpart BB, then compliance with the recordkeeping and reporting requirements of 40 CFR parts 264 and/or 265 may be used to comply with the recordkeeping and reporting requirements of this subpart, to the extent that the requirements of 40 CFR parts 264 and/or 265 duplicate the requirements of this subpart.

(c) *Compliance with 40 CFR part 60, subpart Kb and 40 CFR part 61, subpart Y.* After the compliance dates specified in § 63.2445, you are in compliance with the provisions of this subpart FFFF for any storage tank that is assigned to an MCPU and that is both controlled with a floating roof and in compliance with the provisions of either 40 CFR part 60, subpart Kb, or 40 CFR part 61, subpart Y. You are in compliance with this subpart FFFF if you have a storage tank with a fixed roof, closed-vent system, and control device in compliance with the provisions of either 40 CFR part 60, subpart Kb, or 40 CFR part 61, subpart Y, except that you must comply with the monitoring, recordkeeping, and reporting requirements in this subpart FFFF. Alternatively, if a storage tank assigned to an MCPU is subject to control under 40 CFR part 60, subpart Kb, or 40 CFR part 61, subpart Y, you may elect to comply only with the requirements for Group 1 storage tanks in this subpart FFFF.

(d) *Compliance with subpart I, GGG, or MMM of this part 63.* After the compliance dates specified in § 63.2445, if you have an affected source with equipment subject to subpart I, GGG, or MMM of this part 63, you may elect to comply with the provisions of subpart H, GGG, or MMM of this part 63, respectively, for all such equipment.

(e) *Compliance with subpart GGG of this part 63 for wastewater.* After the compliance dates specified in § 63.2445, if you have an affected source subject to this subpart and you have an affected source that generates wastewater streams that meet the applicability thresholds specified in § 63.1256, you may elect to comply with the provisions of this subpart FFFF for all such wastewater streams.

(f) *Compliance with subpart MMM of this part 63 for wastewater.* After the compliance dates specified in § 63.2445, if you have an affected source subject to this subpart, and you have an affected source that generates wastewater streams that meet the applicability thresholds specified in § 63.1362(d), you may elect to comply with the provisions of this subpart FFFF for all such wastewater streams (except that the 99 percent reduction requirement for streams subject to § 63.1362(d)(10) still applies).

(g) *Compliance with other regulations for wastewater.* After the compliance dates specified in § 63.2445, if you have a Group 1 wastewater stream that is also subject to provisions in 40 CFR parts 260 through 272, you may elect to determine whether this subpart or 40 CFR parts 260 through 272 contain the more stringent control requirements (*e.g.,* design, operation, and inspection requirements for waste management units; numerical treatment standards; etc.) and the more stringent testing, monitoring, recordkeeping, and reporting requirements. Compliance with provisions of 40 CFR parts 260 through 272 that are determined to be more stringent than the requirements of this subpart constitute compliance with this subpart. For example, provisions of 40 CFR parts 260 through 272 for treatment units that meet the conditions specified in § 63.138(h) constitute compliance with this subpart. You must identify in the notification of compliance status report required by § 63.2520(d) the information and procedures that you used to make any stringency determinations.

(h) *Compliance with 40 CFR part 60, subpart DDD, III, NNN, or RRR.* After the compliance dates specified in § 63.2445, if you have an MCPU that contains equipment subject to the provisions of this subpart that are also subject to the provisions of 40 CFR part 60, subpart DDD, III, NNN, or RRR, you may elect to apply this subpart to all such equipment in the MCPU. If an MCPU subject to the provisions of this subpart has equipment to which this subpart does not apply but which is subject to a standard in 40 CFR part 60, subpart DDD, III, NNN, or RRR, you may elect to comply with the requirements for Group 1 process vents in this subpart for such equipment. If you elect any of these methods of compliance, you must consider all total organic compounds, minus methane and ethane, in such equipment for purposes of compliance with this subpart, as if they were organic HAP. Compliance with the provisions of this subpart, in the manner described in this paragraph (h), will constitute compliance with 40 CFR part 60, subpart DDD, III, NNN, or RRR, as applicable.

(i) *Compliance with 40 CFR part 61, subpart BB.* (1) After the compliance dates specified in § 63.2445, a Group 1 transfer rack, as defined in § 63.2550, that is also subject to the provisions of 40 CFR part 61, subpart BB, you are required to comply only with the provisions of this subpart.

(2) After the compliance dates specified in § 63.2445, a Group 2 transfer rack, as defined in § 63.2550, that is also subject to the provisions of 40 CFR part 61, subpart BB, is required to comply with the provisions of either paragraph (I)(2)(i) or (ii) of this section.

(i) If the transfer rack is subject to the control requirements specified in § 61.302 of 40 CFR part 61, subpart BB, then you may elect to comply with either the requirements of 40 CFR part 61, subpart BB, or the requirements for Group 1 transfer racks under this subpart FFFF.

(ii) If the transfer rack is subject only to reporting and recordkeeping requirements under 40 CFR part 61, subpart BB, then you are required to comply only with the reporting and recordkeeping requirements specified in this subpart for Group 2 transfer racks, and you are exempt from the reporting and recordkeeping requirements in 40 CFR part 61, subpart BB.

(j) *Compliance with 40 CFR part 61, subpart FF.* After the compliance date specified in § 63.2445, for a Group 1 or Group 2 wastewater stream that is also subject to the provisions of 40 CFR 61.342(c) through (h), and is not exempt under 40 CFR 61.342(c)(2) or (3), you may elect to comply only with the requirements for Group 1 wastewater streams in this subpart FFFF. If a Group 2 wastewater stream is exempted from 40 CFR 61.342(c)(1) under 40 CFR 61.342(c)(2) or (3), then you are required to comply only with the reporting and recordkeeping requirements specified in this subpart for Group 2 wastewater streams, and you are exempt from the requirements in 40 CFR part 61, subpart FF.

(k) *Compliance with 40 CFR part 60, subpart VV, and 40 CFR part 61, subpart V.* After the compliance date specified in § 63.2445, if you have an affected source with equipment that is also subject to the requirements of 40 CFR part 60, subpart VV, or 40 CFR part 61, subpart V, you may elect to apply this subpart to all such equipment. After the compliance date specified in § 63.2445, if you have an affected source with equipment to which this subpart does not apply, but which is subject to the requirements of 40 CFR part 60, subpart VV, or 40 CFR part 61, subpart V, you may elect to apply this subpart to all such equipment. If you elect either of these methods of compliance, you must consider all total organic compounds, minus methane and ethane, in such equipment for purposes of compliance with this subpart, as if they were organic HAP. Compliance with the provisions of this subpart, in the manner described in this paragraph (k), will constitute compliance with 40 CFR part 60, subpart VV and 40 CFR part 61, subpart V, as applicable.

(l) *Applicability of process units included in a process unit group.* You may elect to develop and comply with the requirements for PUG in accordance with paragraphs (l)(1) through (3) of this section.

(1) *Procedures to create process unit groups.* Develop and document changes in a PUG in accordance with the procedures specified in paragraphs (l)(1)(i) through (v) of this section.

(i) Initially, identify an MCPU that is created from nondedicated equipment that will operate on or after November 10, 2003 and identify all processing equipment that is part of this MCPU, based on descriptions in operating scenarios.

(ii) Add to the group any other nondedicated MCPU and other nondedicated process units expected to be operated in the 5 years after the date specified in paragraph (l)(1)(i) of this section, provided they satisfy the criteria specified in paragraphs (l)(1)(ii)(A) through (C) of this section. Also identify all of the processing equipment used for each process unit based on information from operating scenarios and other applicable documentation.

(A) Each process unit that is added to a group must have some processing equipment that is also part of one or more process units in the group.

(B) No process unit may be part of more than one PUG.

(C) The processing equipment used to satisfy the requirement of paragraph (l)(1)(ii)(A) of this section may not be a storage tank or control device.

(iii) The initial PUG consists of all of the processing equipment for the process units identified in paragraphs (l)(1)(i) and (ii) of this section. As an alternative to the procedures specified in paragraphs (l)(1)(i) and (ii) of this section, you may use a PUG that was developed in accordance with § 63.1360(h) as your initial PUG.

(iv) Add process units developed in the future in accordance with the conditions specified in paragraphs (l)(1)(ii)(A) and (B) of this section.

(v) Maintain records that describe the process units in the initial PUG, the procedure used to create the PUG, and subsequent changes to each PUG as specified in § 63.2525(i). Submit the records in reports as specified in § 63.2520(d)(2)(ix) and (e)(8).

(2) *Determine primary product.* You must determine the primary product of each PUG created in paragraph (l)(1) of this section according to the procedures specified in paragraphs (l)(2)(i) through (iv) of this section.

(i) The primary product is the type of product (*e.g.,* organic chemicals subject to § 63.2435(b)(1), pharmaceutical products subject to § 63.1250, or pesticide active ingredients subject to § 63.1360) expected to be produced for the greatest operating time in the 5-year period specified in paragraph (l)(1)(ii) of this section.

(ii) If the PUG produces multiple types of products equally based on operating time, then the primary product is the type of product with the greatest production on a mass basis over the 5-year period specified in paragraph (l)(1)(ii) of this section.

(iii) At a minimum, you must redetermine the primary product of the PUG following the procedure specified in paragraphs (l)(2)(i) and (ii) of this section every 5 years.

(iv) You must record the calculation of the initial primary product determination as specified in § 63.2525(i)(3) and report the results in the notification of compliance status report as specified in § 63.2520(d)(8)(ix). You must record the calculation of each redetermination of the primary product as specified in § 63.2525(i)(5) and report the calculation in a compliance report submitted no later than the report covering the period for the end of the 5th year after cessation of production of the previous primary product, as specified in § 63.2520(e)(8).

(3) *Compliance requirements.* (i) If the primary product of the PUG is determined according to paragraph (l)(2) of this section to be material described in § 63.2435(b)(1), then you must comply with this subpart for each MCPU in the PUG. You may also elect to comply with this subpart for all other process units in the PUG, which constitutes compliance with other part 63 rules.

(ii) If the primary product of the PUG is determined according to paragraph (l)(2) of this section to be material not described in § 63.2435(b)(1), then you must comply with paragraph (l)(3)(ii)(A), (B), or (C) of this section, as applicable.

(A) If the primary product is subject to subpart GGG of this part 63, then comply with the requirements of subpart GGG for each MCPU in the PUG.

(B) If the primary product is subject to subpart MMM of this part 63, then comply with the requirements of subpart MMM for each MCPU in the PUG.

(C) If the primary product is subject to any subpart in this part 63 other than subpart GGG or subpart MMM, then comply with the requirements of this subpart for each MCPU in the PUG.

(iii) The requirements for new and reconstructed sources in the alternative subpart apply to all MCPU in the PUG if and only if the affected source under the alternative subpart meets the requirements for construction or reconstruction.

[68 FR 63888, Nov. 10, 2003, as amended at 71 FR 40337, July 14, 2006]

§ 63.2540 What parts of the General Provisions apply to me?

Table 12 to this subpart shows which parts of the General Provisions in §§ 63.1 through 63.15 apply to you.

§ 63.2545 Who implements and enforces this subpart?

(a) This subpart can be implemented and enforced by us, the U.S. Environmental Protection Agency (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 also 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 40 CFR part 63, subpart E, the authorities contained in paragraphs (b)(1) through (4) of this section are retained by the Administrator of U.S. EPA and are not delegated to the State, local, or tribal agency.

(1) Approval of alternatives to the non-opacity emission limits and work practice standards in § 63.2450(a) under § 63.6(g).

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

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

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

§ 63.2550 What definitions apply to this subpart?

(a) For an affected source complying with the requirements in subpart SS of this part 63, the terms used in this subpart and in subpart SS of this part 63 have the meaning given them in § 63.981, except as specified in §§ 63.2450(k)(2) and (m), 63.2470(c)(2), 63.2475(b), and paragraph (i) of this section.

(b) For an affected source complying with the requirements in 40 CFR part 65, subpart F, the terms used in this subpart and in 40 CFR part 65, subpart F have the meaning given to them in § 65.2.

(c) For an affected source complying with the requirements in subpart UU of this part 63, the terms used in this subpart and in subpart UU of this part 63 have the meaning given them in § 63.1020.

(d) For an affected source complying with the requirements in subpart WW of this part 63, the terms used in this subpart and subpart WW of this part 63 have the meaning given them in § 63.1061, except as specified in §§ 63.2450(m), 63.2470(c)(2), and paragraph (i) of this section.

(e) For an affected source complying with the requirements in §§ 63.132 through 63.149, the terms used in this subpart and §§ 63.132 through 63.149 have the meaning given them in §§ 63.101 and 63.111, except as specified in § 63.2450(m) and paragraph (i) of this section.

(f) For an affected source complying with the requirements in §§ 63.104 and 63.105, the terms used in this subpart and in §§ 63.104 and 63.105 of this subpart have the meaning given them in § 63.101, except as specified in §§ 63.2450(m), 63.2490(b), and paragraph (i) of this section.

(g) For an affected source complying with requirements in §§ 63.1253, 63.1257, and 63.1258, the terms used in this subpart and in §§ 63.1253, 63.1257, and 63.1258 have the meaning given them in § 63.1251, except as specified in § 63.2450(m) and paragraph (i) of this section.

(h) For an affected source complying with the requirements in 40 CFR part 65, subpart F, the terms used in this subpart and in 40 CFR part 65, subpart F, have the meaning given them in 40 CFR 65.2.

(i) All other terms used in this subpart are defined in the Clean Air Act (CAA), in 40 CFR 63.2, and in this paragraph (i). If a term is defined in § 63.2, § 63.101, § 63.111, § 63.981, § 63.1020, § 63.1061, § 63.1251, or § 65.2 and in this paragraph (i), the definition in this paragraph (i) applies for the purposes of this subpart.

Ancillary activities means boilers and incinerators (not used to comply with the emission limits in Tables 1 through 7 to this subpart), chillers and refrigeration systems, and other equipment and activities that are not directly involved (*i.e.,* they operate within a closed system and materials are not combined with process fluids) in the processing of raw materials or the manufacturing of a product or isolated intermediate.

Batch operation means a noncontinuous operation involving intermittent or discontinuous feed into equipment, and, in general, involves the emptying of the equipment after the operation ceases and prior to beginning a new operation. Addition of raw material and withdrawal of product do not occur simultaneously in a batch operation.

Batch process vent means a vent from a unit operation or vents from multiple unit operations within a process that are manifolded together into a common header, through which a HAP-containing gas stream is, or has the potential to be, released to the atmosphere. Examples of batch process vents include, but are not limited to, vents on condensers used for product recovery, reactors, filters, centrifuges, and process tanks. The following are not batch process vents for the purposes of this subpart:

(1) Continuous process vents;

(2) Bottoms receivers;

(3) Surge control vessels;

(4) Gaseous streams routed to a fuel gas system(s);

(5) Vents on storage tanks, wastewater emission sources, or pieces of equipment subject to the emission limits and work practice standards in Tables 4, 6, and 7 to this subpart;

(6) Drums, pails, and totes;

(7) Flexible elephant trunk systems that draw ambient air (*i.e.,* the system is not ducted, piped, or otherwise connected to the unit operations) away from operators when vessels are opened; and

(8) Emission streams from emission episodes that are undiluted and uncontrolled containing less than 50 ppmv HAP are not part of any batch process vent. A vent from a unit operation, or a vent from multiple unit operations that are manifolded together, from which total uncontrolled HAP emissions are less than 200 lb/yr is not a batch process vent; emissions for all emission episodes associated with the unit operation(s) must be included in the determination of the total mass emitted. The HAP concentration or mass emission rate may be determined using any of the following: process knowledge that no HAP are present in the emission stream; an engineering assessment as discussed in § 63.1257(d)(2)(ii), except that you do not need to demonstrate that the equations in § 63.1257(d)(2)(i) do not apply, and the precompliance reporting requirements specified in § 63.1257(d)(2)(ii)(E) do not apply for the purposes of this demonstration; equations specified in § 63.1257(d)(2)(i), as applicable; test data using Method 18 of 40 CFR part 60, appendix A; or any other test method that has been validated according to the procedures in Method 301 of appendix A of this part.

Biofilter means an enclosed control system such as a tank or series of tanks with a fixed roof that contact emissions with a solid media (such as bark) and use microbiological activity to transform organic pollutants in a process vent stream to innocuous compounds such as carbon dioxide, water, and inorganic salts. Wastewater treatment processes such as aeration lagoons or activated sludge systems are not considered to be biofilters.

Bottoms receiver means a tank that collects bottoms from continuous distillation before the stream is sent for storage or for further downstream processing.

Construction means the onsite fabrication, erection, or installation of an affected source or MCPU. Addition of new equipment to an MCPU subject to existing source standards does not constitute construction, but it may constitute reconstruction of the affected source or MCPU if it satisfies the definition of reconstruction in § 63.2.

Consumption means the quantity of all HAP raw materials entering a process in excess of the theoretical amount used as reactant, assuming 100 percent stoichiometric conversion. The raw materials include reactants, solvents, and any other additives. If a HAP is generated in the process as well as added as a raw material, consumption includes the quantity generated in the process.

Continuous operation means any operation that is not a batch operation.

Continuous process vent means the point of discharge to the atmosphere (or the point of entry into a control device, if any) of a gas stream if the gas stream has the characteristics specified in § 63.107(b) through (h), or meets the criteria specified in § 63.107(i), except:

(1) The reference in § 63.107(e) to a chemical manufacturing process unit that meets the criteria of § 63.100(b) means an MCPU that meets the criteria of § 63.2435(b);

(2) The reference in § 63.107(h)(4) to § 63.113 means Table 1 to this subpart;

(3) The references in § 63.107(h)(7) to §§ 63.119 and 63.126 mean tables 4 and 5 to this subpart; and

(4) For the purposes of § 63.2455, all references to the characteristics of a process vent (*e.g.,* flowrate, total HAP concentration, or TRE index value) mean the characteristics of the gas stream.

(5) The reference to “total organic HAP” in § 63.107(d) means “total HAP” for the purposes of this subpart FFFF.

(6) The references to an “air oxidation reactor, distillation unit, or reactor” in § 63.107 mean any continuous operation for the purposes of this subpart.

(7) A separate determination is required for the emissions from each MCPU, even if emission streams from two or more MCPU are combined prior to discharge to the atmosphere or to a control device.

Dedicated MCPU means an MCPU that consists of equipment that is used exclusively for one process, except that storage tanks assigned to the process according to the procedures in § 63.2435(d) also may be shared by other processes.

Deviation means any instance in which an affected source subject to this subpart, or an owner or operator of such a source:

(1) 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; or

(2) 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

(3) 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.

Emission point means each continuous process vent, batch process vent, storage tank, transfer rack, and wastewater stream.

Energetics means propellants, explosives, and pyrotechnics and include materials listed at 49 CFR 172.101 as Hazard Class I Hazardous Materials, Divisions 1.1 through 1.6.

Equipment means each pump, compressor, agitator, pressure relief device, sampling connection system, open-ended valve or line, valve, connector, and instrumentation system in organic HAP service; and any control devices or systems used to comply with Table 6 to this subpart.

Excess emissions means emissions greater than those allowed by the emission limit.

Family of materials means a grouping of materials with the same basic composition or the same basic end use or functionality produced using the same basic feedstocks with essentially identical HAP emission profiles (primary constituent and relative magnitude on a pound per product basis) and manufacturing equipment configuration. Examples of families of materials include multiple grades of the same product or different variations of a product (*e.g.,* blue, black, and red resins).

Group 1 batch process vent means each of the batch process vents in a process for which the collective uncontrolled organic HAP emissions from all of the batch process vents are greater than or equal to 10,000 lb/yr at an existing source or greater than or equal to 3,000 lb/yr at a new source.

Group 2 batch process vent means each batch process vent that does not meet the definition of Group 1 batch process vent.

Group 1 continuous process vent means a continuous process vent for which the flow rate is greater than or equal to 0.005 standard cubic meter per minute, and the total resource effectiveness index value, calculated according to § 63.2455(b), is less than or equal to 1.9 at an existing source and less than or equal to 5.0 at a new source.

Group 2 continuous process vent means a continuous process vent that does not meet the definition of a Group 1 continuous process vent.

Group 1 storage tank means a storage tank with a capacity greater than or equal to 10,000 gal storing material that has a maximum true vapor pressure of total HAP greater than or equal to 6.9 kilopascals at an existing source or greater than or equal to 0.69 kilopascals at a new source.

Group 2 storage tank means a storage tank that does not meet the definition of a Group 1 storage tank.

Group 1 transfer rack means a transfer rack that loads more than 0.65 million liters/year of liquids that contain organic HAP with a rack-weighted average partial pressure, as defined in § 63.111, greater than or equal to 1.5 pound per square inch absolute.

Group 2 transfer rack means a transfer rack that does not meet the definition of a Group 1 transfer rack.

Group 1 wastewater stream means a wastewater stream consisting of process wastewater at an existing or new source that meets the criteria for Group 1 status in § 63.2485(c) for compounds in Tables 8 and 9 to this subpart and/or a wastewater stream consisting of process wastewater at a new source that meets the criteria for Group 1 status in § 63.132(d) for compounds in Table 8 to subpart G of this part 63.

Group 2 wastewater stream means any process wastewater stream that does not meet the definition of a Group 1 wastewater stream.

Halogen atoms mean chlorine and fluorine.

Halogenated vent stream means a vent stream determined to have a mass emission rate of halogen atoms contained in organic compounds of 0.45 kilograms per hour or greater determined by the procedures presented in § 63.115(d)(2)(v).

HAP metals means the metal portion of antimony compounds, arsenic compounds, beryllium compounds, cadmium compounds, chromium compounds, cobalt compounds, lead compounds, manganese compounds, mercury compounds, nickel compounds, and selenium compounds.

Hydrogen halide and halogen HAP means hydrogen chloride, hydrogen fluoride, and chlorine.

In organic HAP service means that a piece of equipment either contains or contacts a fluid (liquid or gas) that is at least 5 percent by weight of total organic HAP as determined according to the provisions of § 63.180(d). The provisions of § 63.180(d) also specify how to determine that a piece of equipment is not in organic HAP service.

Isolated intermediate means a product of a process that is stored before subsequent processing. An isolated intermediate is usually a product of a chemical synthesis, fermentation, or biological extraction process. Storage of an isolated intermediate marks the end of a process. Storage occurs at any time the intermediate is placed in equipment used solely for storage. The storage equipment is part of the MCPU that produces the isolated intermediate and is not assigned as specified in § 63.2435(d).

Large control device means a control device that controls total HAP emissions of greater than or equal to 10 tpy, before control.

Maintenance wastewater means wastewater generated by the draining of process fluid from components in the MCPU into an individual drain system in preparation for or during maintenance activities. Maintenance wastewater can be generated during planned and unplanned shutdowns and during periods not associated with a shutdown. Examples of activities that can generate maintenance wastewater include descaling of heat exchanger tubing bundles, cleaning of distillation column traps, draining of pumps into an individual drain system, and draining of portions of the MCPU for repair. Wastewater from routine cleaning operations occurring as part of batch operations is not considered maintenance wastewater.

Maximum true vapor pressure has the meaning given in § 63.111, except that it applies to all HAP rather than only organic HAP.

Miscellaneous organic chemical manufacturing process means all equipment which collectively function to produce a product or isolated intermediate that are materials described in § 63.2435(b). For the purposes of this subpart, process includes any, all or a combination of reaction, recovery, separation, purification, or other activity, operation, manufacture, or treatment which are used to produce a product or isolated intermediate. A process is also defined by the following:

(1) Routine cleaning operations conducted as part of batch operations are considered part of the process;

(2) Each nondedicated solvent recovery operation is considered a single process;

(3) Each nondedicated formulation operation is considered a single process that is used to formulate numerous materials and/or products;

(4) Quality assurance/quality control laboratories are not considered part of any process; and

(5) Ancillary activities are not considered a process or part of any process.

(6) The end of a process that produces a solid material is either up to and including the dryer or extruder, or for a polymer production process without a dryer or extruder, it is up to and including the extruder, die plate, or solid-state reactor, except in two cases. If the dryer, extruder, die plate, or solid-state reactor is followed by an operation that is designed and operated to remove HAP solvent or residual HAP monomer from the solid, then the solvent removal operation is the last step in the process. If the dried solid is diluted or mixed with a HAP-based solvent, then the solvent removal operation is the last step in the process.

Nondedicated solvent recovery operation means a distillation unit or other purification equipment that receives used solvent from more than one MCPU.

Nonstandard batch means a batch process that is operated outside of the range of operating conditions that are documented in an existing operating scenario but is still a reasonably anticipated event. For example, a nonstandard batch occurs when additional processing or processing at different operating conditions must be conducted to produce a product that is normally produced under the conditions described by the standard batch. A nonstandard batch may be necessary as a result of a malfunction, but it is not itself a malfunction.

On-site or on site means, with respect to records required to be maintained by this subpart or required by another subpart referenced by this subpart, that records are stored at a location within a major source which encompasses the affected source. On-site includes, but is not limited to, storage at the affected source or MCPU to which the records pertain, or storage in central files elsewhere at the major source.

Operating scenario means, for the purposes of reporting and recordkeeping, any specific operation of an MCPU as described by records specified in § 63.2525(b).

Organic group means structures that contain primarily carbon, hydrogen, and oxygen atoms.

Organic peroxides means organic compounds containing the bivalent -o-o-structure which may be considered to be a structural derivative of hydrogen peroxide where one or both of the hydrogen atoms has been replaced by an organic radical.

Point of determination means each point where process wastewater exits the MCPU or control device.

Note to definition for point of determination: The regulation allows determination of the characteristics of a wastewater stream: At the point of determination; or downstream of the point of determination if corrections are made for changes in flow rate and annual average concentration of soluble HAP and partially soluble HAP compounds as determined according to procedures in § 63.144 of subpart G in this part 63. Such changes include losses by air emissions; reduction of annual average concentration or changes in flow rate by mixing with other water or wastewater streams; and reduction in flow rate or annual average concentration by treating or otherwise handling the wastewater stream to remove or destroy HAP.

Predominant HAP means as used in calibrating an analyzer, the single organic HAP that constitutes the largest percentage of the total organic HAP in the analyzed gas stream, by volume.

Process condenser means a condenser whose primary purpose is to recover material as an integral part of an MCPU. All condensers recovering condensate from an MCPU at or above the boiling point or all condensers in line prior to a vacuum source are considered process condensers. Typically, a primary condenser or condensers in series are considered to be integral to the MCPU if they are capable of and normally used for the purpose of recovering chemicals for fuel value (i.e., net positive heating value), use, reuse or for sale for fuel value, use, or reuse. This definition does not apply to a condenser that is used to remove materials that would hinder performance of a downstream recovery device as follows:

(1) To remove water vapor that would cause icing in a downstream condenser, or

(2) To remove water vapor that would negatively affect the adsorption capacity of carbon in a downstream carbon adsorber, or

(3) To remove high molecular weight organic compounds or other organic compounds that would be difficult to remove during regeneration of a downstream carbon adsorber.

Process tank means a tank or vessel that is used within a process to collect material discharged from a feedstock storage tank or equipment within the process before the material is transferred to other equipment within the process or a product storage tank. A process tank has emissions that are related to the characteristics of the batch cycle, and it does not accumulate product over multiple batches. Surge control vessels and bottoms receivers are not process tanks.

Production-indexed HAP consumption factor (HAP factor) means the result of dividing the annual consumption of total HAP by the annual production rate, per process.

Production-indexed VOC consumption factor (VOC factor) means the result of dividing the annual consumption of total VOC by the annual production rate, per process.

Quaternary ammonium compounds means a type of organic nitrogen compound in which the molecular structure includes a central nitrogen atom joined to four organic groups as well as an acid radical of some sort.

Recovery device means an individual unit of equipment used for the purpose of recovering chemicals from process vent streams and from wastewater streams for fuel value (i.e., net positive heating value), use, reuse, or for sale for fuel value, use, or reuse. For the purposes of meeting requirements in table 2 to this subpart, the recovery device must not be a process condenser and must recover chemicals to be reused in a process on site. Examples of equipment that may be recovery devices include absorbers, carbon adsorbers, condensers, oil-water separators or organic-water separators, or organic removal devices such as decanters, strippers, or thin-film evaporation units. To be a recovery device for a wastewater stream, a decanter and any other equipment based on the operating principle of gravity separation must receive only multi-phase liquid streams.

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

Safety device means a closure device such as a pressure relief valve, frangible disc, fusible plug, or any other type of device which functions exclusively to prevent physical damage or permanent deformation to a unit or its air emission control equipment by venting gases or vapors directly to the atmosphere during unsafe conditions resulting from an unplanned, accidental, or emergency event. For the purposes of this subpart, a safety device is not used for routine venting of gases or vapors from the vapor headspace underneath a cover such as during filling of the unit or to adjust the pressure in response to normal daily diurnal ambient temperature fluctuations. A safety device is designed to remain in a closed position during normal operations and open only when the internal pressure, or another relevant parameter, exceeds the device threshold setting applicable to the air emission control equipment as determined by the owner or operator based on manufacturer recommendations, applicable regulations, fire protection and prevention codes and practices, or other requirements for the safe handling of flammable, combustible, explosive, reactive, or hazardous materials.

Shutdown means the cessation of operation of a continuous operation for any purpose. Shutdown also means the cessation of a batch operation, or any related individual piece of equipment required or used to comply with this subpart, if the steps taken to cease operation differ from those described in a standard batch or nonstandard batch. Shutdown also applies to emptying and degassing storage vessels. Shutdown does not apply to cessation of batch operations at the end of a campaign or between batches within a campaign when the steps taken are routine operations.

Small control device means a control device that controls total HAP emissions of less than 10 tpy, before control.

Standard batch means a batch process operated within a range of operating conditions that are documented in an operating scenario. Emissions from a standard batch are based on the operating conditions that result in highest emissions. The standard batch defines the uncontrolled and controlled emissions for each emission episode defined under the operating scenario.

Startup means the setting in operation of a continuous operation for any purpose; the first time a new or reconstructed batch operation begins production; for new equipment added, including equipment required or used to comply with this subpart, the first time the equipment is put into operation; or for the introduction of a new product/process, the first time the product or process is run in equipment. For batch operations, startup applies to the first time the equipment is put into operation at the start of a campaign to produce a product that has been produced in the past if the steps taken to begin production differ from those specified in a standard batch or nonstandard batch. Startup does not apply when the equipment is put into operation as part of a batch within a campaign when the steps taken are routine operations.

Storage tank means a tank or other vessel that is used to store liquids that contain organic HAP and/or hydrogen halide and halogen HAP and that has been assigned to an MCPU according to the procedures in § 63.2435(d). The following are not considered storage tanks for the purposes of this subpart:

(1) Vessels permanently attached to motor vehicles such as trucks, railcars, barges, or ships;

(2) Pressure vessels designed to operate in excess of 204.9 kilopascals and without emissions to the atmosphere;

(3) Vessels storing organic liquids that contain HAP only as impurities;

(4) Wastewater storage tanks;

(5) Bottoms receivers;

(6) Surge control vessels; and

(7) Process tanks.

Supplemental gases means the air that is added to a vent stream after the vent stream leaves the unit operation. Air that is part of the vent stream as a result of the nature of the unit operation is not considered supplemental gases. Air required to operate combustion device burner(s) is not considered supplemental gases.

Surge control vessel means feed drums, recycle drums, and intermediate vessels as part of any continuous operation. Surge control vessels are used within an MCPU when in-process storage, mixing, or management of flowrates or volumes is needed to introduce material into continuous operations.

Total organic compounds or (TOC) means the total gaseous organic compounds (minus methane and ethane) in a vent stream.

Transfer rack means the collection of loading arms and loading hoses, at a single loading rack, that are assigned to an MCPU according to the procedures specified in § 63.2435(d) and are used to fill tank trucks and/or rail cars with organic liquids that contain one or more of the organic HAP listed in section 112(b) of the CAA of this subpart. Transfer rack includes the associated pumps, meters, shutoff valves, relief valves, and other piping and valves.

Unit operation means those processing steps that occur within distinct equipment that are used, among other things, to prepare reactants, facilitate reactions, separate and purify products, and recycle materials. Equipment used for these purposes includes, but is not limited to, reactors, distillation columns, extraction columns, absorbers, decanters, dryers, condensers, and filtration equipment.

Waste management unit means the equipment, structure(s), and/or device(s) used to convey, store, treat, or dispose of wastewater streams or residuals. Examples of waste management units include wastewater tanks, air flotation units, surface impoundments, containers, oil-water or organic-water separators, individual drain systems, biological wastewater treatment units, waste incinerators, and organic removal devices such as steam and air stripper units, and thin film evaporation units. If such equipment is being operated as a recovery device, then it is part of a miscellaneous organic chemical manufacturing process and is not a waste management unit.

Wastewater means water that is discarded from an MCPU or control device through a POD and that contains either: an annual average concentration of compounds in tables 8 and 9 to this subpart of at least 5 ppmw and has an annual average flowrate of 0.02 liters per minute or greater; or an annual average concentration of compounds in tables 8 and 9 to this subpart of at least 10,000 ppmw at any flowrate. Wastewater means process wastewater or maintenance wastewater. The following are not considered wastewater for the purposes of this subpart:

(1) Stormwater from segregated sewers;

(2) Water from fire-fighting and deluge systems, including testing of such systems;

(3) Spills;

(4) Water from safety showers;

(5) Samples of a size not greater than reasonably necessary for the method of analysis that is used;

(6) Equipment leaks;

(7) Wastewater drips from procedures such as disconnecting hoses after cleaning lines; and

(8) Noncontact cooling water.

Wastewater stream means a stream that contains only wastewater as defined in this paragraph (i).

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.

[68 FR 63888, Nov. 10, 2003, as amended at 70 FR 38560, July 1, 2005; 71 FR 40338, July 14, 2006]

Table 1 to Subpart FFFF of Part 63—Emission Limits and Work Practice Standards for Continuous Process Vents

As required in § 63.2455, you must meet each emission limit and work practice standard in the following table that applies to your continuous process vents:

For each . . .	For which . . .	Then you must . . .
1. Group 1 continuous process vent	a. Not applicable	i. Reduce emissions of total organic HAP by ≥98 percent by weight or to an outlet process concentration ≤20 ppmv as organic HAP or TOC by venting emissions through a closed-vent system to any combination of control devices (except a flare); or
		ii. Reduce emissions of total organic HAP by venting emissions through a closed vent system to a flare; or
		iii. Use a recovery device to maintain the TRE above 1.9 for an existing source or above 5.0 for a new source.
2. Halogenated Group 1 continuous process vent stream	a. You use a combustion control device to control organic HAP emissions	i. Use a halogen reduction device after the combustion device to reduce emissions of hydrogen halide and halogen HAP by ≥99 percent by weight, or to ≤0.45 kg/hr, or to ≤20 ppmv; or ii. Use a halogen reduction device before the combustion device to reduce the halogen atom mass emission rate to ≤0.45 kg/hr or to a concentration ≤20 ppmv.
3. Group 2 continuous process vent at an existing source	You use a recovery device to maintain the TRE level >1.9 but ≤5.0	Comply with the requirements in § 63.993 and the requirements referenced therein.
4. Group 2 continuous process vent at a new source	You use a recovery device to maintain the TRE level >5.0 but ≤8.0	Comply with the requirements in § 63.993 and the requirements referenced therein.

Table 2 to Subpart FFFF of Part 63—Emission Limits and Work Practice Standards for Batch Process Vents

As required in § 63.2460, you must meet each emission limit and work practice standard in the following table that applies to your batch process vents:

For each . . .	Then you must . . .	And you must . . .
1. Process with Group 1 batch process vents	a. Reduce collective uncontrolled organic HAP emissions from the sum of all batch process vents within the process by ≥98 percent by weight by venting emissions from a sufficient number of the vents through one or more closed-vent systems to any combination of control devices (except a flare); or	Not applicable.
	b. Reduce collective uncontrolled organic HAP emissions from the sum of all batch process vents within the process by ≥95 percent by weight by venting emissions from a sufficient number of the	Not applicable.

For each . . .	Then you must . . .	And you must . . .
	vents through one or more closed-vent systems to any combination of recovery devices or a biofilter, except you may elect to comply with the requirements of subpart WW of this part for any process tank; or	
	c. Reduce uncontrolled organic HAP emissions from one or more batch process vents within the process by venting through a closed-vent system to a flare or by venting through one or more closed-vent systems to any combination of control devices (excluding a flare) that reduce organic HAP to an outlet concentration ≤20 ppmv as TOC or total organic HAP.	For all other batch process vents within the process, reduce collective organic HAP emissions as specified in item 1.a and/or item 1.b of this table.
2. Halogenated Group 1 batch process vent for which you use a combustion device to control organic HAP emissions	a. Use a halogen reduction device after the combustion control device; or	i. Reduce overall emissions of hydrogen halide and halogen HAP by ≥99 percent; or ii. Reduce overall emissions of hydrogen halide and halogen HAP to ≤0.45 kg/hr; or iii. Reduce overall emissions of hydrogen halide and halogen HAP to a concentration ≤20 ppmv.
	b. Use a halogen reduction device before the combustion control device	Reduce the halogen atom mass emission rate to ≤0.45 kg/hr or to a concentration ≤20 ppmv.

[68 FR 63888, Nov. 10, 2003, as amended at 71 FR 40339, July 14, 2006]

Table 3 to Subpart FFFF of Part 63—Emission Limits for Hydrogen Halide and Halogen HAP Emissions or HAP Metals Emissions From Process Vents

As required in § 63.2465, you must meet each emission limit in the following table that applies to your process vents that contain hydrogen halide and halogen HAP emissions or PM HAP emissions:

For each . . .	You must . . .
1. Process with uncontrolled hydrogen halide and halogen HAP emissions from process vents ≥1,000 lb/yr	a. Reduce collective hydrogen halide and halogen HAP emissions by ≥99 percent by weight or to an outlet concentration ≤20 ppmv by venting through one or more closed-vent systems to any combination of control devices, or
	b. Reduce the halogen atom mass emission rate from the sum of all batch process vents and each individual continuous process vent to ≤0.45 kg/hr by venting through one or more closed-vent systems to a halogen reduction device.

For each . . .	You must . . .
2. Process at a new source with uncontrolled emissions from process vents ≥150 lb/yr of HAP metals	Reduce overall emissions of HAP metals by ≥97 percent by weight.

[68 FR 63888, Nov. 10, 2003, as amended at 71 FR 40340, July 14, 2006]

Table 4 to Subpart FFFF of Part 63—Emission Limits for Storage Tanks

As required in § 63.2470, you must meet each emission limit in the following table that applies to your storage tanks:

For each . . .	For which . . .	Then you must . . .
1. Group 1 storage tank	a. The maximum true vapor pressure of total HAP at the storage temperature is ≥76.6 kilopascals	i. Reduce total HAP emissions by ≥95 percent by weight or to ≤20 ppmv of TOC or organic HAP and ≤20 ppmv of hydrogen halide and halogen HAP by venting emissions through a closed vent system to any combination of control devices (excluding a flare); or
		ii. Reduce total organic HAP emissions by venting emissions through a closed vent system to a flare; or
		iii. Reduce total HAP emissions by venting emissions to a fuel gas system or process in accordance with § 63.982(d) and the requirements referenced therein.
	b. The maximum true vapor pressure of total HAP at the storage temperature is <76.6 kilopascals	i. Comply with the requirements of subpart WW of this part, except as specified in § 63.2470; or
		ii. Reduce total HAP emissions by ≥95 percent by weight or to ≤20 ppmv of TOC or organic HAP and ≤20 ppmv of hydrogen halide and halogen HAP by venting emissions through a closed vent system to any combination of control devices (excluding a flare); or
		iii. Reduce total organic HAP emissions by venting emissions through a closed vent system to a flare; or
		iv. Reduce total HAP emissions by venting emissions to a fuel gas system or process in accordance with § 63.982(d) and the requirements referenced therein.
2. Halogenated vent stream from a Group 1 storage tank	You use a combustion control device to control organic HAP emissions	Meet one of the emission limit options specified in Item 2.a.i or ii. in Table 1 to this subpart.

[68 FR 63888, Nov. 10, 2003, as amended at 71 FR 40340, July 14, 2006]

Table 5 to Subpart FFFF of Part 63—Emission Limits and Work Practice Standards for Transfer Racks

As required in § 63.2475, you must meet each emission limit and work practice standard in the following table that applies to your transfer racks:

For each . . .	**You must . . .**
1. Group 1 transfer rack	a. Reduce emissions of total organic HAP by ≥98 percent by weight or to an outlet concentration ≤20 ppmv as organic HAP or TOC by venting emissions through a closed-vent system to any combination of control devices (except a flare); or
	b. Reduce emissions of total organic HAP by venting emissions through a closed-vent system to a flare; or
	c. Reduce emissions of total organic HAP by venting emissions to a fuel gas system or process in accordance with § 63.982(d) and the requirements referenced therein; or
	d. Use a vapor balancing system designed and operated to collect organic HAP vapors displaced from tank trucks and railcars during loading and route the collected HAP vapors to the storage tank from which the liquid being loaded originated or to another storage tank connected by a common header.
2. Halogenated Group 1 transfer rack vent stream for which you use a combustion device to control organic HAP emissions	a. Use a halogen reduction device after the combustion device to reduce emissions of hydrogen halide and halogen HAP by ≥99 percent by weight, to ≤0.45 kg/hr, or to ≤20 ppmv; or b. Use a halogen reduction device before the combustion device to reduce the halogen atom mass emission rate to ≤0.45 kg/hr or to a concentration ≤20 ppmv.

[68 FR 63888, Nov. 10, 2003, as amended at 71 FR 40341, July 14, 2006]

Table 6 to Subpart FFFF of Part 63—Requirements for Equipment Leaks

As required in § 63.2480, you must meet each requirement in the following table that applies to your equipment leaks:

For all . . .	**And that is part of . . .**	**You must . . .**
1. Equipment that is in organic HAP service	a. Comply with the requirements of subpart UU of this part 63 and the requirements referenced therein, except as specified in § 63.2480(b) and (d); or	
	b. Comply with the requirements of subpart H of this part 63 and the requirements referenced therein, except as specified in § 63.2480(b) and (d); or	
	c. Comply with the requirements of 40 CFR part 65, subpart F and the requirements referenced therein, except as specified in § 63.2480(c) and (d).	

For all . . .	And that is part of . . .	You must . . .
2. Equipment that is in organic HAP service at a new source	a. Any MCPU	i. Comply with the requirements of subpart UU of this part 63 and the requirements referenced therein; or ii. Comply with the requirements of 40 CFR part 65, subpart F.

[68 FR 63888, Nov. 10, 2003, as amended at 71 FR 40341, July 14, 2006]

Table 7 to Subpart FFFF of Part 63—Requirements for Wastewater Streams and Liquid Streams in Open Systems Within an MCPU

As required in § 63.2485, you must meet each requirement in the following table that applies to your wastewater streams and liquid streams in open systems within an MCPU:

For each . . .	You must . . .
1. Process wastewater stream	Comply with the requirements in §§ 63.132 through 63.148 and the requirements referenced therein, except as specified in § 63.2485.
2. Maintenance wastewater stream	Comply with the requirements in § 63.105 and the requirements referenced therein, except as specified in § 63.2485.
3. Liquid streams in an open system within an MCPU	Comply with the requirements in § 63.149 and the requirements referenced therein, except as specified in § 63.2485.

Table 8 to Subpart FFFF of Part 63—Partially Soluble Hazardous Air Pollutants

As specified in § 63.2485, the partially soluble HAP in wastewater that are subject to management and treatment requirements in this subpart FFFF are listed in the following table:

Chemical name . . .	CAS No.
1. 1,1,1-Trichloroethane (methyl chloroform)	71556
2. 1,1,2,2-Tetrachloroethane	79345
3. 1,1,2-Trichloroethane	79005
4. 1,1-Dichloroethylene (vinylidene chloride)	75354
5. 1,2-Dibromoethane	106934
6. 1,2-Dichloroethane (ethylene dichloride)	107062
7. 1,2-Dichloropropane	78875
8. 1,3-Dichloropropene	542756
9. 2,4,5-Trichlorophenol	95954
10. 1,4-Dichlorobenzene	106467
11. 2-Nitropropane	79469
12. 4-Methyl-2-pentanone (MIBK)	108101
13. Acetaldehyde	75070

Chemical name . . .	**CAS No.**
14. Acrolein	107028
15. Acrylonitrile	107131
16. Allyl chloride	107051
17. Benzene	71432
18. Benzyl chloride	100447
19. Biphenyl	92524
20. Bromoform (tribromomethane)	75252
21. Bromomethane	74839
22. Butadiene	106990
23. Carbon disulfide	75150
24. Chlorobenzene	108907
25. Chloroethane (ethyl chloride)	75003
26. Chloroform	67663
27. Chloromethane	74873
28. Chloroprene	126998
29. Cumene	98828
30. Dichloroethyl ether	111444
31. Dinitrophenol	51285
32. Epichlorohydrin	106898
33. Ethyl acrylate	140885
34. Ethylbenzene	100414
35. Ethylene oxide	75218
36. Ethylidene dichloride	75343
37. Hexachlorobenzene	118741
38. Hexachlorobutadiene	87683
39. Hexachloroethane	67721
40. Methyl methacrylate	80626
41. Methyl-t-butyl ether	1634044
42. Methylene chloride	75092
43. N-hexane	110543
44. N,N-dimethylaniline	121697
45. Naphthalene	91203
46. Phosgene	75445

Chemical name . . .	**CAS No.**
47. Propionaldehyde	123386
48. Propylene oxide	75569
49. Styrene	100425
50. Tetrachloroethylene (perchloroethylene)	127184
51. Tetrachloromethane (carbon tetrachloride)	56235
52. Toluene	108883
53. Trichlorobenzene (1,2,4-)	120821
54. Trichloroethylene	79016
55. Trimethylpentane	540841
56. Vinyl acetate	108054
57. Vinyl chloride	75014
58. Xylene (m)	108383
59. Xylene (o)	95476
60. Xylene (p)	106423

[68 FR 63888, Nov. 10, 2003, as amended at 70 FR 38560, July 1, 2005; 71 FR 40341, July 14, 2006]

Table 9 to Subpart FFFF of Part 63—Soluble Hazardous Air Pollutants

As specified in § 63.2485, the soluble HAP in wastewater that are subject to management and treatment requirements of this subpart FFFF are listed in the following table:

Chemical name . . .	**CAS No.**
1. Acetonitrile	75058
2. Acetophenone	98862
3. Diethyl sulfate	64675
4. Dimethyl hydrazine (1,1)	57147
5. Dimethyl sulfate	77781
6. Dinitrotoluene (2,4)	121142
7. Dioxane (1,4)	123911
8. Ethylene glycol dimethyl ether	110714
9. Ethylene glycol monobutyl ether acetate	112072
10. Ethylene glycol monomethyl ether acetate	110496
11. Isophorone	78591
12. Methanol	67561
13. Nitrobenzene	98953

Chemical name . . .	**CAS No.**
14. Toluidine (o-)	95534
15. Triethylamine	121448

[68 FR 63888, Nov. 10, 2003, as amended at 70 FR 38561, July 1, 2005]

Table 10 to Subpart FFFF of Part 63—Work Practice Standards for Heat Exchange Systems

As required in § 63.2490, you must meet each requirement in the following table that applies to your heat exchange systems:

For each . . .	**You must . . .**
Heat exchange system, as defined in § 63.101	Comply with the requirements of § 63.104 and the requirements referenced therein, except as specified in § 63.2490.

Table 11 to Subpart FFFF of Part 63—Requirements for Reports

As required in § 63.2520(a) and (b), you must submit each report that applies to you on the schedule shown in the following table:

You must submit a(n)	**The report must contain . . .**	**You must submit the report . . .**
1. Precompliance report	The information specified in § 63.2520(c)	At least 6 months prior to the compliance date; or for new sources, with the application for approval of construction or reconstruction.
2. Notification of compliance status report	The information specified in § 63.2520(d)	No later than 150 days after the compliance date specified in § 63.2445.
3. Compliance report	The information specified in § 63.2520(e)	Semiannually according to the requirements in § 63.2520(b).

Table 12 to Subpart FFFF of Part 63—Applicability of General Provisions to Subpart FFFF

As specified in § 63.2540, the parts of the General Provisions that apply to you are shown in the following table:

Citation	**Subject**	**Explanation**
§ 63.1	Applicability	Yes.
§ 63.2	Definitions	Yes.
§ 63.3	Units and Abbreviations	Yes.
§ 63.4	Prohibited Activities	Yes.
§ 63.5	Construction/Reconstruction	Yes.
§ 63.6(a)	Applicability	Yes.

Citation	Subject	Explanation
§ 63.6(b)(1)-(4)	Compliance Dates for New and Reconstructed sources	Yes.
§ 63.6(b)(5)	Notification	Yes.
§ 63.6(b)(6)	[Reserved]	
§ 63.6(b)(7)	Compliance Dates for New and Reconstructed Area Sources That Become Major	Yes.
§ 63.6(c)(1)-(2)	Compliance Dates for Existing Sources	Yes.
§ 63.6(c)(3)-(4)	[Reserved]	
§ 63.6(c)(5)	Compliance Dates for Existing Area Sources That Become Major	Yes
§ 63.6(d)	[Reserved]	
§ 63.6(e)(1)-(2)	Operation & Maintenance	Yes.
§ 63.6(e)(3)(i), (ii), and (v) through (viii)	Startup, Shutdown, Malfunction Plan (SSMP)	Yes, except information regarding Group 2 emission points and equipment leaks is not required in the SSMP, as specified in § 63.2525(j).
§ 63.6(e)(3)(iii) and (iv)	Recordkeeping and Reporting During SSM	No, § 63.998(d)(3) and 63.998(c)(1)(ii)(D) through (G) specify the recordkeeping requirement for SSM events, and § 63.2520(e)(4) specifies reporting requirements.
§ 63.6(e)(3)(ix)	SSMP incorporation into title V permit	Yes.
§ 63.6(f)(1)	Compliance Except During SSM	Yes.
§ 63.6(f)(2)-(3)	Methods for Determining Compliance	Yes.
§ 63.6(g)(1)-(3)	Alternative Standard	Yes.
§ 63.6(h)	Opacity/Visible Emission (VE) Standards	Only for flares for which Method 22 observations are required as part of a flare compliance assessment.
§ 63.6(i)(1)-(14)	Compliance Extension	Yes.
§ 63.6(j)	Presidential Compliance Exemption	Yes.
§ 63.7(a)(1)-(2)	Performance Test Dates	Yes, except substitute 150 days for 180 days.
§ 63.7(a)(3)	Section 114 Authority	Yes, and this paragraph also applies to flare compliance assessments as specified under § 63.997(b)(2).
§ 63.7(b)(1)	Notification of Performance Test	Yes.
§ 63.7(b)(2)	Notification of Rescheduling	Yes.
§ 63.7(c)	Quality Assurance/Test Plan	Yes, except the test plan must be submitted with the notification of the performance test if the

Citation	Subject	Explanation
		control device controls batch process vents.
§ 63.7(d)	Testing Facilities	Yes.
§ 63.7(e)(1)	Conditions for Conducting Performance Tests	Yes, except that performance tests for batch process vents must be conducted under worst-case conditions as specified in § 63.2460.
§ 63.7(e)(2)	Conditions for Conducting Performance Tests	Yes.
§ 63.7(e)(3)	Test Run Duration	Yes.
§ 63.7(f)	Alternative Test Method	Yes.
§ 63.7(g)	Performance Test Data Analysis	Yes.
§ 63.7(h)	Waiver of Tests	Yes.
§ 63.8(a)(1)	Applicability of Monitoring Requirements	Yes.
§ 63.8(a)(2)	Performance Specifications	Yes.
§ 63.8(a)(3)	[Reserved]	
§ 63.8(a)(4)	Monitoring with Flares	Yes.
§ 63.8(b)(1)	Monitoring	Yes.
§ 63.8(b)(2)-(3)	Multiple Effluents and Multiple Monitoring Systems	Yes.
§ 63.8(c)(1)	Monitoring System Operation and Maintenance	Yes.
§ 63.8(c)(1)(i)	Routine and Predictable SSM	Yes.
§ 63.8(c)(1)(ii)	SSM not in SSMP	Yes.
§ 63.8(c)(1)(iii)	Compliance with Operation and Maintenance Requirements	Yes.
§ 63.8(c)(2)-(3)	Monitoring System Installation	Yes.
§ 63.8(c)(4)	CMS Requirements	Only for CEMS. Requirements for CPMS are specified in referenced subparts G and SS of part 63. Requirements for COMS do not apply because subpart FFFF does not require continuous opacity monitoring systems (COMS).
§ 63.8(c)(4)(i)	COMS Measurement and Recording Frequency	No; subpart FFFF does not require COMS.
§ 63.8(c)(4)(ii)	CEMS Measurement and Recording Frequency	Yes.
§ 63.8(c)(5)	COMS Minimum Procedures	No. Subpart FFFF does not contain opacity or VE limits.
§ 63.8(c)(6)	CMS Requirements	Only for CEMS; requirements for CPMS are specified in referenced subparts G and SS of this

Citation	Subject	Explanation
		part 63. Requirements for COMS do not apply because subpart FFFF does not require COMS.
§ 63.8(c)(7)-(8)	CMS Requirements	Only for CEMS. Requirements for CPMS are specified in referenced subparts G and SS of part 63. Requirements for COMS do not apply because subpart FFFF does not require COMS.
§ 63.8(d)	CMS Quality Control	Only for CEMS.
§ 63.8(e)	CMS Performance Evaluation	Only for CEMS. Section 63.8(e)(5)(ii) does not apply because subpart FFFF does not require COMS.
§ 63.8(f)(1)-(5)	Alternative Monitoring Method	Yes, except you may also request approval using the precompliance report.
§ 63.8(f)(6)	Alternative to Relative Accuracy Test	Only applicable when using CEMS to demonstrate compliance, including the alternative standard in § 63.2505.
§ 63.8(g)(1)-(4)	Data Reduction	Only when using CEMS, including for the alternative standard in § 63.2505, except that the requirements for COMS do not apply because subpart FFFF has no opacity or VE limits, and § 63.8(g)(2) does not apply because data reduction requirements for CEMS are specified in § 63.2450(j).
§ 63.8(g)(5)	Data Reduction	No. Requirements for CEMS are specified in § 63.2450(j). Requirements for CPMS are specified in referenced subparts G and SS of this part 63.
§ 63.9(a)	Notification Requirements	Yes.
§ 63.9(b)(1)-(5)	Initial Notifications	Yes.
§ 63.9(c)	Request for Compliance Extension	Yes.
§ 63.9(d)	Notification of Special Compliance Requirements for New Source	Yes.
§ 63.9(e)	Notification of Performance Test	Yes.
§ 63.9(f)	Notification of VE/Opacity Test	No. Subpart FFFF does not contain opacity or VE limits.
§ 63.9(g)	Additional Notifications When Using CMS	Only for CEMS. Section 63.9(g)(2) does not apply because subpart FFFF does not require COMS.
63.9(h)(1)-(6)	Notification of Compliance Status	Yes, except subpart FFFF has no opacity or VE limits, and 63.9(h)(2)(i)(A) through (G) and (ii) do not apply because 63.2520(d) specifies the required contents and due date of the notification of compliance status report.
§ 63.9(i)	Adjustment of Submittal Deadlines	Yes.
§ 63.9(j)	Change in Previous Information	No, § 63.2520(e) specifies reporting requirements for process changes.

Citation	Subject	Explanation
§ 63.10(a)	Recordkeeping/Reporting	Yes.
§ 63.10(b)(1)	Recordkeeping/Reporting	Yes.
§ 63.10(b)(2)(i)-(ii), (iv), (v)	Records related to SSM	No, §§ 63.998(d)(3) and 63.998(c)(1)(ii)(D) through (G) specify recordkeeping requirements for periods of SSM.
§ 63.10(b)(2)(iii)	Records related to maintenance of air pollution control equipment	Yes.
§ 63.10(b)(2)(vi), (x), and (xi)	CMS Records	Only for CEMS; requirements for CPMS are specified in referenced subparts G and SS of this part 63.
§ 63.10(b)(2)(vii)-(ix)	Records	Yes.
§ 63.10(b)(2)(xii)	Records	Yes.
§ 63.10(b)(2)(xiii)	Records	Only for CEMS.
§ 63.10(b)(2)(xiv)	Records	Yes.
§ 63.10(b)(3)	Records	Yes.
§ 63.10(c)(1)-(6),(9)-(15)	Records	Only for CEMS. Recordkeeping requirements for CPMS are specified in referenced subparts G and SS of this part 63.
§ 63.10(c)(7)-(8)	Records	No. Recordkeeping requirements are specified in § 63.2525.
§ 63.10(d)(1)	General Reporting Requirements	Yes.
§ 63.10(d)(2)	Report of Performance Test Results	Yes.
§ 63.10(d)(3)	Reporting Opacity or VE Observations	No. Subpart FFFF does not contain opacity or VE limits.
§ 63.10(d)(4)	Progress Reports	Yes.
§ 63.10(d)(5)(i)	Periodic Startup, Shutdown, and Malfunction Reports	No, § 63.2520(e)(4) and (5) specify the SSM reporting requirements.
§ 63.10(d)(5)(ii)	Immediate SSM Reports	No.
§ 63.10(e)(1)	Additional CEMS Reports	Yes.
§ 63.10(e)(2)(i)	Additional CMS Reports	Only for CEMS.
§ 63.10(e)(2)(ii)	Additional COMS Reports	No. Subpart FFFF does not require COMS.
§ 63.10(e)(3)	Reports	No. Reporting requirements are specified in § 63.2520.
§ 63.10(e)(3)(i)-(iii)	Reports	No. Reporting requirements are specified in § 63.2520.
§ 63.10(e)(3)(iv)-(v)	Excess Emissions Reports	No. Reporting requirements are specified in § 63.2520.

Citation	Subject	Explanation
§ 63.10(e)(3)(iv)-(v)	Excess Emissions Reports	No. Reporting requirements are specified in § 63.2520.
§ 63.10(e)(3)(vi)-(viii)	Excess Emissions Report and Summary Report	No. Reporting requirements are specified in § 63.2520.
§ 63.10(e)(4)	Reporting COMS data	No. Subpart FFFF does not contain opacity or VE limits.
§ 63.10(f)	Waiver for Recordkeeping/Reporting	Yes.
§ 63.11	Control device requirements for flares and work practice requirements for equipment leaks	Yes.
§ 63.12	Delegation	Yes.
§ 63.13	Addresses	Yes.
§ 63.14	Incorporation by Reference	Yes.
§ 63.15	Availability of Information	Yes.

[68 FR 63888, Nov. 10, 2003, as amended at 70 FR 38561, July 1, 2005; 71 FR 20463, Apr. 20, 2006; 71 FR 40341, July 14, 2006; 73 FR 72816, Dec. 22, 2008]

Indiana Department of Environmental Management
Office of Air Quality

Attachment B to a Part 70 Operating Permit

Source Background and Description

Source Name:	Ohio Valley Resources, LLC
Source Location:	300-400 East CR 350 North, Rockport, Indiana 47635
County:	Spencer
SIC Code:	2873
Permit No.:	T 147-32322-00062
Permit Reviewer:	David Matousek

40 CFR 63, Subpart ZZZZ

40 CFR 63, Subpart ZZZZ **National Emissions Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines**

Source: 69 FR 33506, June 15, 2004, unless otherwise noted.

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What This Subpart Covers

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§ 63.6580 What is the purpose of subpart ZZZZ?

Subpart ZZZZ establishes national emission limitations and operating limitations for hazardous air pollutants (HAP) emitted from stationary reciprocating internal combustion engines (RICE) located at major and area sources of HAP emissions. This subpart also establishes requirements to demonstrate initial and continuous compliance with the emission limitations and operating limitations.

[73 FR 3603, Jan. 18, 2008]

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§ 63.6585 Am I subject to this subpart?

You are subject to this subpart if you own or operate a stationary RICE at a major or area source of HAP emissions, except if the stationary RICE is being tested at a stationary RICE test cell/stand.

(a) A stationary RICE is any internal combustion engine which uses reciprocating motion to convert heat energy into mechanical work and which is not mobile. Stationary RICE differ from mobile RICE in that a stationary RICE is not a non-road engine as defined at 40 CFR 1068.30, and is not used to propel a motor vehicle or a vehicle used solely for competition.

(b) 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, except that for oil and gas production facilities, a major source of HAP emissions is determined for each surface site.

(c) An area source of HAP emissions is a source that is not a major source.

(d) If you are an owner or operator of an area source subject to this subpart, your status as an entity subject to a standard or other requirements under this subpart does not subject you to the obligation to obtain a permit under 40 CFR part 70 or 71, provided you are not required to obtain a permit under 40 CFR 70.3(a) or 40 CFR 71.3(a) for a reason other than your status as an area source under this subpart. Notwithstanding the previous sentence, you must continue to comply with the provisions of this subpart as applicable.

(e) If you are an owner or operator of a stationary RICE used for national security purposes, you may be eligible to request an exemption from the requirements of this subpart as described in 40 CFR part 1068, subpart C.

(f) The emergency stationary RICE listed in paragraphs (f)(1) through (3) of this section are not subject to this subpart. The stationary RICE must meet the definition of an emergency stationary RICE in § 63.6675, which includes operating according to the provisions specified in § 63.6640(f).

(1) Existing residential emergency stationary RICE located at an area source of HAP emissions that do not operate or are not contractually obligated to be available for more than 15 hours per calendar year for the purposes specified in § 63.6640(f)(2)(ii) and (iii) and that do not operate for the purpose specified in § 63.6640(f)(4)(ii).

(2) Existing commercial emergency stationary RICE located at an area source of HAP emissions that do not operate or are not contractually obligated to be available for more than 15 hours per calendar year for the purposes specified in § 63.6640(f)(2)(ii) and (iii) and that do not operate for the purpose specified in § 63.6640(f)(4)(ii).

(3) Existing institutional emergency stationary RICE located at an area source of HAP emissions that do not operate or are not contractually obligated to be available for more than 15 hours per calendar year for the purposes specified in § 63.6640(f)(2)(ii) and (iii) and that do not operate for the purpose specified in § 63.6640(f)(4)(ii).

[69 FR 33506, June 15, 2004, as amended at 73 FR 3603, Jan. 18, 2008; 78 FR 6700, Jan. 30, 2013]

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§ 63.6590 What parts of my plant does this subpart cover?

This subpart applies to each affected source.

(a) *Affected source.* An affected source is any existing, new, or reconstructed stationary RICE located at a major or area source of HAP emissions, excluding stationary RICE being tested at a stationary RICE test cell/stand.

(1) *Existing stationary RICE.*

(i) For stationary RICE with a site rating of more than 500 brake horsepower (HP) located at a major source of HAP emissions, a stationary RICE is existing if you commenced construction or reconstruction of the stationary RICE before December 19, 2002.

(ii) For stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions, a stationary RICE is existing if you commenced construction or reconstruction of the stationary RICE before June 12, 2006.

(iii) For stationary RICE located at an area source of HAP emissions, a stationary RICE is existing if you commenced construction or reconstruction of the stationary RICE before June 12, 2006.

(iv) A change in ownership of an existing stationary RICE does not make that stationary RICE a new or reconstructed stationary RICE.

(2) *New stationary RICE.* (i) A stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions is new if you commenced construction of the stationary RICE on or after December 19, 2002.

(ii) A stationary RICE with a site rating of equal to or less than 500 brake HP located at a major source of HAP emissions is new if you commenced construction of the stationary RICE on or after June 12, 2006.

(iii) A stationary RICE located at an area source of HAP emissions is new if you commenced construction of the stationary RICE on or after June 12, 2006.

(3) *Reconstructed stationary RICE.* (i) A stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions is reconstructed if you meet the definition of reconstruction in § 63.2 and reconstruction is commenced on or after December 19, 2002.

(ii) A stationary RICE with a site rating of equal to or less than 500 brake HP located at a major source of HAP emissions is reconstructed if you meet the definition of reconstruction in § 63.2 and reconstruction is commenced on or after June 12, 2006.

(iii) A stationary RICE located at an area source of HAP emissions is reconstructed if you meet the definition of reconstruction in § 63.2 and reconstruction is commenced on or after June 12, 2006.

(b) *Stationary RICE subject to limited requirements.* (1) An affected source which meets either of the criteria in paragraphs (b)(1)(i) through (ii) of this section does not have to meet the requirements of this subpart and of subpart A of this part except for the initial notification requirements of § 63.6645(f).

(i) The stationary RICE is a new or reconstructed emergency stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions that does not operate or is not contractually obligated to be available for more than 15 hours per calendar year for the purposes specified in § 63.6640(f)(2)(ii) and (iii).

(ii) The stationary RICE is a new or reconstructed limited use stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions.

(2) A new or reconstructed stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions which combusts landfill or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis must meet the initial notification requirements of § 63.6645(f) and the requirements of §§ 63.6625(c), 63.6650(g), and 63.6655(c). These stationary RICE do not have to meet the emission limitations and operating limitations of this subpart.

(3) The following stationary RICE do not have to meet the requirements of this subpart and of subpart A of this part, including initial notification requirements:

(i) Existing spark ignition 2 stroke lean burn (2SLB) stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions;

(ii) Existing spark ignition 4 stroke lean burn (4SLB) stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions;

(iii) Existing emergency stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions that does not operate or is not contractually obligated to be available for more than 15 hours per calendar year for the purposes specified in § 63.6640(f)(2)(ii) and (iii).

(iv) Existing limited use stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions;

(v) Existing stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions that combusts landfill gas or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis;

(c) *Stationary RICE subject to Regulations under 40 CFR Part 60.* An affected source that meets any of the criteria in paragraphs (c)(1) through (7) of this section must meet the requirements of this part by meeting the requirements of 40 CFR part 60 subpart IIII, for compression ignition engines or 40 CFR part 60 subpart JJJJ, for spark ignition engines. No further requirements apply for such engines under this part.

(1) A new or reconstructed stationary RICE located at an area source;

(2) A new or reconstructed 2SLB stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions;

(3) A new or reconstructed 4SLB stationary RICE with a site rating of less than 250 brake HP located at a major source of HAP emissions;

(4) A new or reconstructed spark ignition 4 stroke rich burn (4SRB) stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions;

(5) A new or reconstructed stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions which combusts landfill or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis;

(6) A new or reconstructed emergency or limited use stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions;

(7) A new or reconstructed compression ignition (CI) stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions.

[69 FR 33506, June 15, 2004, as amended at 73 FR 3604, Jan. 18, 2008; 75 FR 9674, Mar. 3, 2010; 75 FR 37733, June 30, 2010; 75 FR 51588, Aug. 20, 2010; 78 FR 6700, Jan. 30, 2013]

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§ 63.6595 When do I have to comply with this subpart?

(a) *Affected sources.* (1) If you have an existing stationary RICE, excluding existing non-emergency CI stationary RICE, with a site rating of more than 500 brake HP located at a major source of HAP emissions, you must comply with the applicable emission limitations, operating limitations and other requirements no later than June 15, 2007. If you have an existing non-emergency CI stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions, an existing stationary CI RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions, or an existing stationary CI RICE located at an area source of HAP emissions, you must comply with the applicable emission limitations, operating limitations, and other requirements no later than May 3, 2013. If you have an existing stationary SI RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions, or an existing stationary SI RICE located at an area source of HAP emissions, you must comply with the applicable emission limitations, operating limitations, and other requirements no later than October 19, 2013.

(2) If you start up your new or reconstructed stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions before August 16, 2004, you must comply with the applicable emission limitations and operating limitations in this subpart no later than August 16, 2004.

(3) If you start up your new or reconstructed stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions after August 16, 2004, you must comply with the applicable emission limitations and operating limitations in this subpart upon startup of your affected source.

(4) If you start up your new or reconstructed stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions before January 18, 2008, you must comply with the applicable emission limitations and operating limitations in this subpart no later than January 18, 2008.

(5) If you start up your new or reconstructed stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions after January 18, 2008, you must comply with the applicable emission limitations and operating limitations in this subpart upon startup of your affected source.

(6) If you start up your new or reconstructed stationary RICE located at an area source of HAP emissions before January 18, 2008, you must comply with the applicable emission limitations and operating limitations in this subpart no later than January 18, 2008.

(7) If you start up your new or reconstructed stationary RICE located at an area source of HAP emissions after January 18, 2008, you must comply with the applicable emission limitations and operating limitations in this subpart upon startup of your affected source.

(b) *Area sources that become major sources.* If you have an area source that increases its emissions or its potential to emit such that it becomes a major source of HAP, the compliance dates in paragraphs (b)(1) and (2) of this section apply to you.

(1) Any stationary RICE for which construction or reconstruction is commenced after the date when your area source becomes a major source of HAP must be in compliance with this subpart upon startup of your affected source.

(2) Any stationary RICE for which construction or reconstruction is commenced before your area source becomes a major source of HAP must be in compliance with the provisions of this subpart that are applicable to RICE located at major sources within 3 years after your area source becomes a major source of HAP.

(c) If you own or operate an affected source, you must meet the applicable notification requirements in § 63.6645 and in 40 CFR part 63, subpart A.

[69 FR 33506, June 15, 2004, as amended at 73 FR 3604, Jan. 18, 2008; 75 FR 9675, Mar. 3, 2010; 75 FR 51589, Aug. 20, 2010; 78 FR 6701, Jan. 30, 2013]

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Emission and Operating Limitations

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§ 63.6600 What emission limitations and operating limitations must I meet if I own or operate a stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions?

Compliance with the numerical emission limitations established in this subpart is based on the results of testing the average of three 1-hour runs using the testing requirements and procedures in § 63.6620 and Table 4 to this subpart.

(a) If you own or operate an existing, new, or reconstructed spark ignition 4SRB stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions, you must comply with the emission limitations in Table 1a to this subpart and the operating limitations in Table 1b to this subpart which apply to you.

(b) If you own or operate a new or reconstructed 2SLB stationary RICE with a site rating of more than 500 brake HP located at major source of HAP emissions, a new or reconstructed 4SLB stationary RICE with a site rating of more than 500 brake HP located at major source of HAP emissions, or a new or reconstructed CI stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions, you must comply with the emission limitations in Table 2a to this subpart and the operating limitations in Table 2b to this subpart which apply to you.

(c) If you own or operate any of the following stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions, you do not need to comply with the emission limitations in Tables 1a, 2a, 2c, and 2d to this subpart or operating limitations in Tables 1b and 2b to this subpart: an existing 2SLB stationary RICE; an existing 4SLB stationary RICE; a stationary RICE that combusts landfill gas or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis; an emergency stationary RICE; or a limited use stationary RICE.

(d) If you own or operate an existing non-emergency stationary CI RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions, you must comply with the emission limitations in Table 2c to this subpart and the operating limitations in Table 2b to this subpart which apply to you.

[73 FR 3605, Jan. 18, 2008, as amended at 75 FR 9675, Mar. 3, 2010]

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§ 63.6601 What emission limitations must I meet if I own or operate a new or reconstructed 4SLB stationary RICE with a site rating of greater than or equal to 250 brake HP and less than or equal to 500 brake HP located at a major source of HAP emissions?

Compliance with the numerical emission limitations established in this subpart is based on the results of testing the average of three 1-hour runs using the testing requirements and procedures in § 63.6620 and Table 4 to this subpart. If you own or operate a new or reconstructed 4SLB stationary RICE with a site rating of greater than or equal to 250 and less than or equal to 500 brake HP located at major source of HAP emissions manufactured on or after January 1, 2008, you must comply with the emission limitations in Table 2a to this subpart and the operating limitations in Table 2b to this subpart which apply to you.

[73 FR 3605, Jan. 18, 2008, as amended at 75 FR 9675, Mar. 3, 2010; 75 FR 51589, Aug. 20, 2010]

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§ 63.6602 What emission limitations and other requirements must I meet if I own or operate an existing stationary RICE with a site rating of equal to or less than 500 brake HP located at a major source of HAP emissions?

If you own or operate an existing stationary RICE with a site rating of equal to or less than 500 brake HP located at a major source of HAP emissions, you must comply with the emission limitations and other requirements in Table 2c to this subpart which apply to you. Compliance with the numerical emission limitations established in this subpart is based on the results of testing the average of three 1-hour runs using the testing requirements and procedures in § 63.6620 and Table 4 to this subpart.

[78 FR 6701, Jan. 30, 2013]

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§ 63.6603 What emission limitations, operating limitations, and other requirements must I meet if I own or operate an existing stationary RICE located at an area source of HAP emissions?

Compliance with the numerical emission limitations established in this subpart is based on the results of testing the average of three 1-hour runs using the testing requirements and procedures in § 63.6620 and Table 4 to this subpart.

(a) If you own or operate an existing stationary RICE located at an area source of HAP emissions, you must comply with the requirements in Table 2d to this subpart and the operating limitations in Table 2b to this subpart that apply to you.

(b) If you own or operate an existing stationary non-emergency CI RICE with a site rating of more than 300 HP located at an area source of HAP that meets either paragraph (b)(1) or (2) of this section, you do not have to meet the numerical CO emission limitations specified in Table 2d of this subpart. Existing stationary non-emergency CI RICE with a site rating of more than 300 HP located at an area source of HAP that meet either paragraph (b)(1) or (2) of this section must meet the management practices that are shown for stationary non-emergency CI RICE with a site rating of less than or equal to 300 HP in Table 2d of this subpart.

(1) The area source is located in an area of Alaska that is not accessible by the Federal Aid Highway System (FAHS).

(2) The stationary RICE is located at an area source that meets paragraphs (b)(2)(i), (ii), and (iii) of this section.

(i) The only connection to the FAHS is through the Alaska Marine Highway System (AMHS), or the stationary RICE operation is within an isolated grid in Alaska that is not connected to the statewide electrical grid referred to as the Alaska Railbelt Grid.

(ii) At least 10 percent of the power generated by the stationary RICE on an annual basis is used for residential purposes.

(iii) The generating capacity of the area source is less than 12 megawatts, or the stationary RICE is used exclusively for backup power for renewable energy.

(c) If you own or operate an existing stationary non-emergency CI RICE with a site rating of more than 300 HP located on an offshore vessel that is an area source of HAP and is a nonroad vehicle that is an Outer Continental Shelf (OCS) source as defined in 40 CFR 55.2, you do not have to meet the numerical

CO emission limitations specified in Table 2d of this subpart. You must meet all of the following management practices:

(1) Change oil every 1,000 hours of operation or annually, whichever comes first. Sources have the option to utilize an oil analysis program as described in § 63.6625(i) in order to extend the specified oil change requirement.

(2) Inspect and clean air filters every 750 hours of operation or annually, whichever comes first, and replace as necessary.

(3) Inspect fuel filters and belts, if installed, every 750 hours of operation or annually, whichever comes first, and replace as necessary.

(4) Inspect all flexible hoses every 1,000 hours of operation or annually, whichever comes first, and replace as necessary.

(d) If you own or operate an existing non-emergency CI RICE with a site rating of more than 300 HP located at an area source of HAP emissions that is certified to the Tier 1 or Tier 2 emission standards in Table 1 of 40 CFR 89.112 and that is subject to an enforceable state or local standard that requires the engine to be replaced no later than June 1, 2018, you may until January 1, 2015, or 12 years after the installation date of the engine (whichever is later), but not later than June 1, 2018, choose to comply with the management practices that are shown for stationary non-emergency CI RICE with a site rating of less than or equal to 300 HP in Table 2d of this subpart instead of the applicable emission limitations in Table 2d, operating limitations in Table 2b, and crankcase ventilation system requirements in § 63.6625(g). You must comply with the emission limitations in Table 2d and operating limitations in Table 2b that apply for non-emergency CI RICE with a site rating of more than 300 HP located at an area source of HAP emissions by January 1, 2015, or 12 years after the installation date of the engine (whichever is later), but not later than June 1, 2018. You must also comply with the crankcase ventilation system requirements in § 63.6625(g) by January 1, 2015, or 12 years after the installation date of the engine (whichever is later), but not later than June 1, 2018.

(e) If you own or operate an existing non-emergency CI RICE with a site rating of more than 300 HP located at an area source of HAP emissions that is certified to the Tier 3 (Tier 2 for engines above 560 kilowatt (kW)) emission standards in Table 1 of 40 CFR 89.112, you may comply with the requirements under this part by meeting the requirements for Tier 3 engines (Tier 2 for engines above 560 kW) in 40 CFR part 60 subpart IIII instead of the emission limitations and other requirements that would otherwise apply under this part for existing non-emergency CI RICE with a site rating of more than 300 HP located at an area source of HAP emissions.

(f) An existing non-emergency SI 4SLB and 4SRB stationary RICE with a site rating of more than 500 HP located at area sources of HAP must meet the definition of remote stationary RICE in § 63.6675 on the initial compliance date for the engine, October 19, 2013, in order to be considered a remote stationary RICE under this subpart. Owners and operators of existing non-emergency SI 4SLB and 4SRB stationary RICE with a site rating of more than 500 HP located at area sources of HAP that meet the definition of remote stationary RICE in § 63.6675 of this subpart as of October 19, 2013 must evaluate the status of their stationary RICE every 12 months. Owners and operators must keep records of the initial and annual evaluation of the status of the engine. If the evaluation indicates that the stationary RICE no longer meets the definition of remote stationary RICE in § 63.6675 of this subpart, the owner or operator must comply with all of the requirements for existing non-emergency SI 4SLB and 4SRB stationary RICE with a site rating of more than 500 HP located at area sources of HAP that are not remote stationary RICE within 1 year of the evaluation.

[75 FR 9675, Mar. 3, 2010, as amended at 75 FR 51589, Aug. 20, 2010; 76 FR 12866, Mar. 9, 2011; 78 FR 6701, Jan. 30, 2013]

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§ 63.6604 What fuel requirements must I meet if I own or operate a stationary CI RICE?

(a) If you own or operate an existing non-emergency, non-black start CI stationary RICE with a site rating of more than 300 brake HP with a displacement of less than 30 liters per cylinder that uses diesel fuel, you must use diesel fuel that meets the requirements in 40 CFR 80.510(b) for nonroad diesel fuel.

(b) Beginning January 1, 2015, if you own or operate an existing emergency CI stationary RICE with a site rating of more than 100 brake HP and a displacement of less than 30 liters per cylinder that uses diesel fuel and operates or is contractually obligated to be available for more than 15 hours per calendar year for the purposes specified in § 63.6640(f)(2)(ii) and (iii) or that operates for the purpose specified in § 63.6640(f)(4)(ii), you must use diesel fuel that meets the requirements in 40 CFR 80.510(b) for nonroad diesel fuel, except that any existing diesel fuel purchased (or otherwise obtained) prior to January 1, 2015, may be used until depleted.

(c) Beginning January 1, 2015, if you own or operate a new emergency CI stationary RICE with a site rating of more than 500 brake HP and a displacement of less than 30 liters per cylinder located at a major source of HAP that uses diesel fuel and operates or is contractually obligated to be available for more than 15 hours per calendar year for the purposes specified in § 63.6640(f)(2)(ii) and (iii), you must use diesel fuel that meets the requirements in 40 CFR 80.510(b) for nonroad diesel fuel, except that any existing diesel fuel purchased (or otherwise obtained) prior to January 1, 2015, may be used until depleted.

(d) Existing CI stationary RICE located in Guam, American Samoa, the Commonwealth of the Northern Mariana Islands, at area sources in areas of Alaska that meet either § 63.6603(b)(1) or § 63.6603(b)(2), or are on offshore vessels that meet § 63.6603(c) are exempt from the requirements of this section.

[78 FR 6702, Jan. 30, 2013]

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General Compliance Requirements

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§ 63.6605 What are my general requirements for complying with this subpart?

(a) You must be in compliance with the emission limitations, operating limitations, and other requirements in this subpart that apply to you at all times.

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

[75 FR 9675, Mar. 3, 2010, as amended at 78 FR 6702, Jan. 30, 2013]

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Testing and Initial Compliance Requirements

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§ 63.6610 By what date must I conduct the initial performance tests or other initial compliance demonstrations if I own or operate a stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions?

If you own or operate a stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions you are subject to the requirements of this section.

(a) You must conduct the initial performance test or other initial compliance demonstrations in Table 4 to this subpart that apply to you within 180 days after the compliance date that is specified for your stationary RICE in § 63.6595 and according to the provisions in § 63.7(a)(2).

(b) If you commenced construction or reconstruction between December 19, 2002 and June 15, 2004 and own or operate stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions, you must demonstrate initial compliance with either the proposed emission limitations or the promulgated emission limitations no later than February 10, 2005 or no later than 180 days after startup of the source, whichever is later, according to § 63.7(a)(2)(ix).

(c) If you commenced construction or reconstruction between December 19, 2002 and June 15, 2004 and own or operate stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions, and you chose to comply with the proposed emission limitations when demonstrating initial compliance, you must conduct a second performance test to demonstrate compliance with the promulgated emission limitations by December 13, 2007 or after startup of the source, whichever is later, according to § 63.7(a)(2)(ix).

(d) An owner or operator is not required to conduct an initial performance test on units for which a performance test has been previously conducted, but the test must meet all of the conditions described in paragraphs (d)(1) through (5) of this section.

(1) The test must have been conducted using the same methods specified in this subpart, and these methods must have been followed correctly.

(2) The test must not be older than 2 years.

(3) The test must be reviewed and accepted by the Administrator.

(4) Either no process or equipment changes must have been made since the test was performed, or the owner or operator must be able to demonstrate that the results of the performance test, with or without adjustments, reliably demonstrate compliance despite process or equipment changes.

(5) The test must be conducted at any load condition within plus or minus 10 percent of 100 percent load.

[69 FR 33506, June 15, 2004, as amended at 73 FR 3605, Jan. 18, 2008]

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§ 63.6611 By what date must I conduct the initial performance tests or other initial compliance demonstrations if I own or operate a new or reconstructed 4SLB SI stationary RICE with a site rating of greater than or equal to 250 and less than or equal to 500 brake HP located at a major source of HAP emissions?

If you own or operate a new or reconstructed 4SLB stationary RICE with a site rating of greater than or equal to 250 and less than or equal to 500 brake HP located at a major source of HAP emissions, you must conduct an initial performance test within 240 days after the compliance date that is specified for your stationary RICE in § 63.6595 and according to the provisions specified in Table 4 to this subpart, as appropriate.

[73 FR 3605, Jan. 18, 2008, as amended at 75 FR 51589, Aug. 20, 2010]

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§ 63.6612 By what date must I conduct the initial performance tests or other initial compliance demonstrations if I own or operate an existing stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions or an existing stationary RICE located at an area source of HAP emissions?

If you own or operate an existing stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions or an existing stationary RICE located at an area source of HAP emissions you are subject to the requirements of this section.

(a) You must conduct any initial performance test or other initial compliance demonstration according to Tables 4 and 5 to this subpart that apply to you within 180 days after the compliance date that is specified for your stationary RICE in § 63.6595 and according to the provisions in § 63.7(a)(2).

(b) An owner or operator is not required to conduct an initial performance test on a unit for which a performance test has been previously conducted, but the test must meet all of the conditions described in paragraphs (b)(1) through (4) of this section.

(1) The test must have been conducted using the same methods specified in this subpart, and these methods must have been followed correctly.

(2) The test must not be older than 2 years.

(3) The test must be reviewed and accepted by the Administrator.

(4) Either no process or equipment changes must have been made since the test was performed, or the owner or operator must be able to demonstrate that the results of the performance test, with or without adjustments, reliably demonstrate compliance despite process or equipment changes.

[75 FR 9676, Mar. 3, 2010, as amended at 75 FR 51589, Aug. 20, 2010]

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§ 63.6615 When must I conduct subsequent performance tests?

If you must comply with the emission limitations and operating limitations, you must conduct subsequent performance tests as specified in Table 3 of this subpart.

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§ 63.6620 What performance tests and other procedures must I use?

(a) You must conduct each performance test in Tables 3 and 4 of this subpart that applies to you.

(b) Each performance test must be conducted according to the requirements that this subpart specifies in Table 4 to this subpart. If you own or operate a non-operational stationary RICE that is subject to performance testing, you do not need to start up the engine solely to conduct the performance test. Owners and operators of a non-operational engine can conduct the performance test when the engine is started up again. The test must be conducted at any load condition within plus or minus 10 percent of 100 percent load for the stationary RICE listed in paragraphs (b)(1) through (4) of this section.

(1) Non-emergency 4SRB stationary RICE with a site rating of greater than 500 brake HP located at a major source of HAP emissions.

(2) New non-emergency 4SLB stationary RICE with a site rating of greater than or equal to 250 brake HP located at a major source of HAP emissions.

(3) New non-emergency 2SLB stationary RICE with a site rating of greater than 500 brake HP located at a major source of HAP emissions.

(4) New non-emergency CI stationary RICE with a site rating of greater than 500 brake HP located at a major source of HAP emissions.

(c) [Reserved]

(d) 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, unless otherwise specified in this subpart.

(e)(1) You must use Equation 1 of this section to determine compliance with the percent reduction requirement:

$$\frac{C_i - C_o}{C_i} \times 100 = R \quad (Eq.\ 1)$$

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Where:

C_i = concentration of carbon monoxide (CO), total hydrocarbons (THC), or formaldehyde at the control device inlet,

C_o = concentration of CO, THC, or formaldehyde at the control device outlet, and

R = percent reduction of CO, THC, or formaldehyde emissions.

(2) You must normalize the CO, THC, or formaldehyde concentrations at the inlet and outlet of the control device to a dry basis and to 15 percent oxygen, or an equivalent percent carbon dioxide (CO_2). If pollutant concentrations are to be corrected to 15 percent oxygen and CO_2 concentration is measured in lieu of oxygen concentration measurement, a CO_2 correction factor is needed. Calculate the CO_2 correction factor as described in paragraphs (e)(2)(i) through (iii) of this section.

(i) Calculate the fuel-specific F_o value for the fuel burned during the test using values obtained from Method 19, Section 5.2, and the following equation:

$$F_O = \frac{0.209\ F_d}{F_C} \quad (Eq.\ 2)$$

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Where:

F_o = Fuel factor based on the ratio of oxygen volume to the ultimate CO_2 volume produced by the fuel at zero percent excess air.

0.209 = Fraction of air that is oxygen, percent/100.

F_d = Ratio of the volume of dry effluent gas to the gross calorific value of the fuel from Method 19, dsm^3 /J ($dscf/10^6$ Btu).

F_c = Ratio of the volume of CO_2 produced to the gross calorific value of the fuel from Method 19, dsm^3 /J ($dscf/10^6$ Btu)

(ii) Calculate the CO_2 correction factor for correcting measurement data to 15 percent O_2 , as follows:

$$X_{CO2} = \frac{5.9}{F_O} \quad (Eq.\ 3)$$

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Where:

X_{CO2} = CO_2 correction factor, percent.

5.9 = 20.9 percent O_2 —15 percent O_2 , the defined O_2 correction value, percent.

(iii) Calculate the CO, THC, and formaldehyde gas concentrations adjusted to 15 percent O_2 using CO_2 as follows:

$$C_{adj} = C_d \frac{X_{CO2}}{\%CO_2} \quad (Eq.\ 4)$$

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Where:

C_{adj} = Calculated concentration of CO, THC, or formaldehyde adjusted to 15 percent O_2.

C_d = Measured concentration of CO, THC, or formaldehyde, uncorrected.

X_{CO2} = CO_2 correction factor, percent.

$\%CO_2$ = Measured CO_2 concentration measured, dry basis, percent.

(f) If you comply with the emission limitation to reduce CO and you are not using an oxidation catalyst, if you comply with the emission limitation to reduce formaldehyde and you are not using NSCR, or if you comply with the emission limitation to limit the concentration of formaldehyde in the stationary RICE exhaust and you are not using an oxidation catalyst or NSCR, you must petition the Administrator for operating limitations to be established during the initial performance test and continuously monitored thereafter; or for approval of no operating limitations. You must not conduct the initial performance test until after the petition has been approved by the Administrator.

(g) If you petition the Administrator for approval of operating limitations, your petition must include the information described in paragraphs (g)(1) through (5) of this section.

(1) Identification of the specific parameters you propose to use as operating limitations;

(2) A discussion of the relationship between these parameters and HAP emissions, identifying how HAP emissions change with changes in these parameters, and how limitations on these parameters will serve to limit HAP emissions;

(3) A discussion of how you will establish the upper and/or lower values for these parameters which will establish the limits on these parameters in the operating limitations;

(4) A discussion identifying the methods you will use to measure and the instruments you will use to monitor these parameters, as well as the relative accuracy and precision of these methods and instruments; and

(5) A discussion identifying the frequency and methods for recalibrating the instruments you will use for monitoring these parameters.

(h) If you petition the Administrator for approval of no operating limitations, your petition must include the information described in paragraphs (h)(1) through (7) of this section.

(1) Identification of the parameters associated with operation of the stationary RICE and any emission control device which could change intentionally (*e.g.,* operator adjustment, automatic controller adjustment, etc.) or unintentionally (*e.g.,* wear and tear, error, etc.) on a routine basis or over time;

(2) A discussion of the relationship, if any, between changes in the parameters and changes in HAP emissions;

(3) For the parameters which could change in such a way as to increase HAP emissions, a discussion of whether establishing limitations on the parameters would serve to limit HAP emissions;

(4) For the parameters which could change in such a way as to increase HAP emissions, a discussion of how you could establish upper and/or lower values for the parameters which would establish limits on the parameters in operating limitations;

(5) For the parameters, a discussion identifying the methods you could use to measure them and the instruments you could use to monitor them, as well as the relative accuracy and precision of the methods and instruments;

(6) For the parameters, a discussion identifying the frequency and methods for recalibrating the instruments you could use to monitor them; and

(7) A discussion of why, from your point of view, it is infeasible or unreasonable to adopt the parameters as operating limitations.

(i) The engine percent load during a performance test must be determined by documenting the calculations, assumptions, and measurement devices used to measure or estimate the percent load in a specific application. A written report of the average percent load determination must be included in the notification of compliance status. The following information must be included in the written report: the engine model number, the engine manufacturer, the year of purchase, the manufacturer's site-rated brake horsepower, the ambient temperature, pressure, and humidity during the performance test, and all assumptions that were made to estimate or calculate percent load during the performance test must be clearly explained. If measurement devices such as flow meters, kilowatt meters, beta analyzers, stain gauges, etc. are used, the model number of the measurement device, and an estimate of its accurate in percentage of true value must be provided.

[69 FR 33506, June 15, 2004, as amended at 75 FR 9676, Mar. 3, 2010; 78 FR 6702, Jan. 30, 2013]

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§ 63.6625 What are my monitoring, installation, collection, operation, and maintenance requirements?

(a) If you elect to install a CEMS as specified in Table 5 of this subpart, you must install, operate, and maintain a CEMS to monitor CO and either O_2 or CO_2 according to the requirements in paragraphs (a)(1) through (4) of this section. If you are meeting a requirement to reduce CO emissions, the CEMS must be installed at both the inlet and outlet of the control device. If you are meeting a requirement to limit the concentration of CO, the CEMS must be installed at the outlet of the control device.

(1) Each CEMS must be installed, operated, and maintained according to the applicable performance specifications of 40 CFR part 60, appendix B.

(2) You must conduct an initial performance evaluation and an annual relative accuracy test audit (RATA) of each CEMS according to the requirements in § 63.8 and according to the applicable performance specifications of 40 CFR part 60, appendix B as well as daily and periodic data quality checks in accordance with 40 CFR part 60, appendix F, procedure 1.

(3) As specified in § 63.8(c)(4)(ii), each CEMS must complete a minimum of one cycle of operation (sampling, analyzing, and data recording) for each successive 15-minute period. You must have at least two data points, with each representing a different 15-minute period, to have a valid hour of data.

(4) The CEMS data must be reduced as specified in § 63.8(g)(2) and recorded in parts per million or parts per billion (as appropriate for the applicable limitation) at 15 percent oxygen or the equivalent CO_2 concentration.

(b) If you are required to install a continuous parameter monitoring system (CPMS) as specified in Table 5 of this subpart, you must install, operate, and maintain each CPMS according to the requirements in paragraphs (b)(1) through (6) of this section. For an affected source that is complying with the emission limitations and operating limitations on March 9, 2011, the requirements in paragraph (b) of this section are applicable September 6, 2011.

(1) You must prepare a site-specific monitoring plan that addresses the monitoring system design, data collection, and the quality assurance and quality control elements outlined in paragraphs (b)(1)(i) through (v) of this section and in § 63.8(d). As specified in § 63.8(f)(4), you may request approval of monitoring system quality assurance and quality control procedures alternative to those specified in paragraphs (b)(1) through (5) of this section in your site-specific monitoring plan.

(i) The performance criteria and design specifications for the monitoring system equipment, including the sample interface, detector signal analyzer, and data acquisition and calculations;

(ii) Sampling interface (*e.g.,* thermocouple) location such that the monitoring system will provide representative measurements;

(iii) Equipment performance evaluations, system accuracy audits, or other audit procedures;

(iv) Ongoing operation and maintenance procedures in accordance with provisions in § 63.8(c)(1)(ii) and (c)(3); and

(v) Ongoing reporting and recordkeeping procedures in accordance with provisions in § 63.10(c), (e)(1), and (e)(2)(i).

(2) You must install, operate, and maintain each CPMS in continuous operation according to the procedures in your site-specific monitoring plan.

(3) The CPMS must collect data at least once every 15 minutes (see also § 63.6635).

(4) For a CPMS for measuring temperature range, the temperature sensor must have a minimum tolerance of 2.8 degrees Celsius (5 degrees Fahrenheit) or 1 percent of the measurement range, whichever is larger.

(5) You must conduct the CPMS equipment performance evaluation, system accuracy audits, or other audit procedures specified in your site-specific monitoring plan at least annually.

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

(c) If you are operating a new or reconstructed stationary RICE which fires landfill gas or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis, you must monitor and record your fuel usage daily with separate fuel meters to measure the volumetric flow rate of each fuel. In addition, you must operate your stationary RICE in a manner which reasonably minimizes HAP emissions.

(d) If you are operating a new or reconstructed emergency 4SLB stationary RICE with a site rating of greater than or equal to 250 and less than or equal to 500 brake HP located at a major source of HAP emissions, you must install a non-resettable hour meter prior to the startup of the engine.

(e) If you own or operate any of the following stationary RICE, you must operate and maintain the stationary RICE and after-treatment control device (if any) according to the manufacturer's emission-related written instructions or develop your own maintenance plan which must provide to the extent practicable for the maintenance and operation of the engine in a manner consistent with good air pollution control practice for minimizing emissions:

(1) An existing stationary RICE with a site rating of less than 100 HP located at a major source of HAP emissions;

(2) An existing emergency or black start stationary RICE with a site rating of less than or equal to 500 HP located at a major source of HAP emissions;

(3) An existing emergency or black start stationary RICE located at an area source of HAP emissions;

(4) An existing non-emergency, non-black start stationary CI RICE with a site rating less than or equal to 300 HP located at an area source of HAP emissions;

(5) An existing non-emergency, non-black start 2SLB stationary RICE located at an area source of HAP emissions;

(6) An existing non-emergency, non-black start stationary RICE located at an area source of HAP emissions which combusts landfill or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis.

(7) An existing non-emergency, non-black start 4SLB stationary RICE with a site rating less than or equal to 500 HP located at an area source of HAP emissions;

(8) An existing non-emergency, non-black start 4SRB stationary RICE with a site rating less than or equal to 500 HP located at an area source of HAP emissions;

(9) An existing, non-emergency, non-black start 4SLB stationary RICE with a site rating greater than 500 HP located at an area source of HAP emissions that is operated 24 hours or less per calendar year; and

(10) An existing, non-emergency, non-black start 4SRB stationary RICE with a site rating greater than 500 HP located at an area source of HAP emissions that is operated 24 hours or less per calendar year.

(f) If you own or operate an existing emergency stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions or an existing emergency stationary RICE located at an area source of HAP emissions, you must install a non-resettable hour meter if one is not already installed.

(g) If you own or operate an existing non-emergency, non-black start CI engine greater than or equal to 300 HP that is not equipped with a closed crankcase ventilation system, you must comply with either paragraph (g)(1) or paragraph (2) of this section. Owners and operators must follow the manufacturer's specified maintenance requirements for operating and maintaining the open or closed crankcase ventilation systems and replacing the crankcase filters, or can request the Administrator to approve different maintenance requirements that are as protective as manufacturer requirements. Existing CI engines located at area sources in areas of Alaska that meet either § 63.6603(b)(1) or § 63.6603(b)(2) do not have to meet the requirements of this paragraph (g). Existing CI engines located on offshore vessels that meet § 63.6603(c) do not have to meet the requirements of this paragraph (g).

(1) Install a closed crankcase ventilation system that prevents crankcase emissions from being emitted to the atmosphere, or

(2) Install an open crankcase filtration emission control system that reduces emissions from the crankcase by filtering the exhaust stream to remove oil mist, particulates and metals.

(h) If you operate a new, reconstructed, or existing stationary engine, you must minimize the engine's time spent at idle during startup and minimize the engine's startup time to a period needed for appropriate and safe loading of the engine, not to exceed 30 minutes, after which time the emission standards applicable to all times other than startup in Tables 1a, 2a, 2c, and 2d to this subpart apply.

(i) If you own or operate a stationary CI engine that is subject to the work, operation or management practices in items 1 or 2 of Table 2c to this subpart or in items 1 or 4 of Table 2d to this subpart, you have the option of utilizing an oil analysis program in order to extend the specified oil change requirement in Tables 2c and 2d to this subpart. The oil analysis must be performed at the same frequency specified for changing the oil in Table 2c or 2d to this subpart. The analysis program must at a minimum analyze the following three parameters: Total Base Number, viscosity, and percent water content. The condemning limits for these parameters are as follows: Total Base Number is less than 30 percent of the Total Base Number of the oil when new; viscosity of the oil has changed by more than 20 percent from the viscosity of the oil when new; or percent water content (by volume) is greater than 0.5. If all of these condemning limits are not exceeded, the engine owner or operator is not required to change the oil. If any of the limits are exceeded, the engine owner or operator must change the oil within 2 business days of receiving the results of the analysis; if the engine is not in operation when the results of the analysis are received, the engine owner or operator must change the oil within 2 business days or before commencing operation, whichever is later. The owner or operator must keep records of the parameters that are analyzed as part of the program, the results of the analysis, and the oil changes for the engine. The analysis program must be part of the maintenance plan for the engine.

(j) If you own or operate a stationary SI engine that is subject to the work, operation or management practices in items 6, 7, or 8 of Table 2c to this subpart or in items 5, 6, 7, 9, or 11 of Table 2d to this subpart, you have the option of utilizing an oil analysis program in order to extend the specified oil change requirement in Tables 2c and 2d to this subpart. The oil analysis must be performed at the same frequency specified for changing the oil in Table 2c or 2d to this subpart. The analysis program must at a minimum analyze the following three parameters: Total Acid Number, viscosity, and percent water content. The condemning limits for these parameters are as follows: Total Acid Number increases by more than 3.0 milligrams of potassium hydroxide (KOH) per gram from Total Acid Number of the oil when new; viscosity of the oil has changed by more than 20 percent from the viscosity of the oil when new; or percent water content (by volume) is greater than 0.5. If all of these condemning limits are not exceeded, the engine owner or operator is not required to change the oil. If any of the limits are exceeded, the engine owner or operator must change the oil within 2 business days of receiving the results of the analysis; if the engine is not in operation when the results of the analysis are received, the engine owner or operator must change the oil within 2 business days or before commencing operation, whichever is later. The owner or operator must keep records of the parameters that are analyzed as part of the program, the results of the analysis, and the oil changes for the engine. The analysis program must be part of the maintenance plan for the engine.

[69 FR 33506, June 15, 2004, as amended at 73 FR 3606, Jan. 18, 2008; 75 FR 9676, Mar. 3, 2010; 75 FR 51589, Aug. 20, 2010; 76 FR 12866, Mar. 9, 2011; 78 FR 6703, Jan. 30, 2013]

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§ 63.6630 How do I demonstrate initial compliance with the emission limitations, operating limitations, and other requirements?

(a) You must demonstrate initial compliance with each emission limitation, operating limitation, and other requirement that applies to you according to Table 5 of this subpart.

(b) During the initial performance test, you must establish each operating limitation in Tables 1b and 2b of this subpart that applies to you.

(c) You must submit the Notification of Compliance Status containing the results of the initial compliance demonstration according to the requirements in § 63.6645.

(d) Non-emergency 4SRB stationary RICE complying with the requirement to reduce formaldehyde emissions by 76 percent or more can demonstrate initial compliance with the formaldehyde emission limit by testing for THC instead of formaldehyde. The testing must be conducted according to the requirements in Table 4 of this subpart. The average reduction of emissions of THC determined from the performance test must be equal to or greater than 30 percent.

(e) The initial compliance demonstration required for existing non-emergency 4SLB and 4SRB stationary RICE with a site rating of more than 500 HP located at an area source of HAP that are not remote stationary RICE and that are operated more than 24 hours per calendar year must be conducted according to the following requirements:

(1) The compliance demonstration must consist of at least three test runs.

(2) Each test run must be of at least 15 minute duration, except that each test conducted using the method in appendix A to this subpart must consist of at least one measurement cycle and include at least 2 minutes of test data phase measurement.

(3) If you are demonstrating compliance with the CO concentration or CO percent reduction requirement, you must measure CO emissions using one of the CO measurement methods specified in Table 4 of this subpart, or using appendix A to this subpart.

(4) If you are demonstrating compliance with the THC percent reduction requirement, you must measure THC emissions using Method 25A, reported as propane, of 40 CFR part 60, appendix A.

(5) You must measure O_2 using one of the O_2 measurement methods specified in Table 4 of this subpart. Measurements to determine O_2 concentration must be made at the same time as the measurements for CO or THC concentration.

(6) If you are demonstrating compliance with the CO or THC percent reduction requirement, you must measure CO or THC emissions and O_2 emissions simultaneously at the inlet and outlet of the control device.

[69 FR 33506, June 15, 2004, as amended at 78 FR 6704, Jan. 30, 2013]

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Continuous Compliance Requirements

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§ 63.6635 How do I monitor and collect data to demonstrate continuous compliance?

(a) If you must comply with emission and operating limitations, you must monitor and collect data according to this section.

(b) Except for monitor malfunctions, associated repairs, required performance evaluations, and required quality assurance or control activities, you must monitor continuously at all times that the stationary RICE 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.

(c) You may not use data recorded during monitoring malfunctions, associated repairs, and required quality assurance or control activities in data averages and calculations used to report emission or operating levels. You must, however, use all the valid data collected during all other periods.

[69 FR 33506, June 15, 2004, as amended at 76 FR 12867, Mar. 9, 2011]

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§ 63.6640 How do I demonstrate continuous compliance with the emission limitations, operating limitations, and other requirements?

(a) You must demonstrate continuous compliance with each emission limitation, operating limitation, and other requirements in Tables 1a and 1b, Tables 2a and 2b, Table 2c, and Table 2d to this subpart that apply to you according to methods specified in Table 6 to this subpart.

(b) You must report each instance in which you did not meet each emission limitation or operating limitation in Tables 1a and 1b, Tables 2a and 2b, Table 2c, and Table 2d to this subpart that apply to you. These instances are deviations from the emission and operating limitations in this subpart. These deviations must be reported according to the requirements in § 63.6650. If you change your catalyst, you must reestablish the values of the operating parameters measured during the initial performance test. When you reestablish the values of your operating parameters, you must also conduct a performance test to demonstrate that you are meeting the required emission limitation applicable to your stationary RICE.

(c) The annual compliance demonstration required for existing non-emergency 4SLB and 4SRB stationary RICE with a site rating of more than 500 HP located at an area source of HAP that are not remote stationary RICE and that are operated more than 24 hours per calendar year must be conducted according to the following requirements:

(1) The compliance demonstration must consist of at least one test run.

(2) Each test run must be of at least 15 minute duration, except that each test conducted using the method in appendix A to this subpart must consist of at least one measurement cycle and include at least 2 minutes of test data phase measurement.

(3) If you are demonstrating compliance with the CO concentration or CO percent reduction requirement, you must measure CO emissions using one of the CO measurement methods specified in Table 4 of this subpart, or using appendix A to this subpart.

(4) If you are demonstrating compliance with the THC percent reduction requirement, you must measure THC emissions using Method 25A, reported as propane, of 40 CFR part 60, appendix A.

(5) You must measure O_2 using one of the O_2 measurement methods specified in Table 4 of this subpart. Measurements to determine O_2 concentration must be made at the same time as the measurements for CO or THC concentration.

(6) If you are demonstrating compliance with the CO or THC percent reduction requirement, you must measure CO or THC emissions and O_2 emissions simultaneously at the inlet and outlet of the control device.

(7) If the results of the annual compliance demonstration show that the emissions exceed the levels specified in Table 6 of this subpart, the stationary RICE must be shut down as soon as safely possible, and appropriate corrective action must be taken (e.g., repairs, catalyst cleaning, catalyst replacement). The stationary RICE must be retested within 7 days of being restarted and the emissions must meet the levels specified in Table 6 of this subpart. If the retest shows that the emissions continue to exceed the specified levels, the stationary RICE must again be shut down as soon as safely possible, and the stationary RICE may not operate, except for purposes of startup and testing, until the owner/operator demonstrates through testing that the emissions do not exceed the levels specified in Table 6 of this subpart.

(d) For new, reconstructed, and rebuilt stationary RICE, deviations from the emission or operating limitations that occur during the first 200 hours of operation from engine startup (engine burn-in period) are not violations. Rebuilt stationary RICE means a stationary RICE that has been rebuilt as that term is defined in 40 CFR 94.11(a).

(e) You must also report each instance in which you did not meet the requirements in Table 8 to this subpart that apply to you. If you own or operate a new or reconstructed stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions (except new or reconstructed 4SLB engines greater than or equal to 250 and less than or equal to 500 brake HP), a new or reconstructed stationary RICE located at an area source of HAP emissions, or any of the following RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions, you do not need to comply with the requirements in Table 8 to this subpart: An existing 2SLB stationary RICE, an existing 4SLB stationary RICE, an existing emergency stationary RICE, an existing limited use stationary RICE, or an existing stationary RICE which fires landfill gas or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis. If you own or operate any of the following RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions, you do not need to comply with the requirements in Table 8 to this subpart, except for the initial notification requirements: a new or reconstructed stationary RICE that combusts landfill gas or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis, a new or reconstructed emergency stationary RICE, or a new or reconstructed limited use stationary RICE.

(f) If you own or operate an emergency stationary RICE, you must operate the emergency stationary RICE according to the requirements in paragraphs (f)(1) through (4) of this section. In order for the engine to be considered an emergency stationary RICE under this subpart, any operation other than emergency operation, maintenance and testing, emergency demand response, and operation in non-emergency situations for 50 hours per year, as described in paragraphs (f)(1) through (4) of this section, is prohibited. If you do not operate the engine according to the requirements in paragraphs (f)(1) through (4) of this section, the engine will not be considered an emergency engine under this subpart and must meet all requirements for non-emergency engines.

(1) There is no time limit on the use of emergency stationary RICE in emergency situations.

(2) You may operate your emergency stationary RICE for any combination of the purposes specified in paragraphs (f)(2)(i) through (iii) of this section for a maximum of 100 hours per calendar year. Any operation for non-emergency situations as allowed by paragraphs (f)(3) and (4) of this section counts as part of the 100 hours per calendar year allowed by this paragraph (f)(2).

(i) Emergency stationary RICE may be operated for maintenance checks and readiness testing, provided that the tests are recommended by federal, state or local government, the manufacturer, the vendor, the regional transmission organization or equivalent balancing authority and transmission operator, or the insurance company associated with the engine. The owner or operator may petition the Administrator for approval of additional hours to be used for maintenance checks and readiness testing, but a petition is not required if the owner or operator maintains records indicating that federal, state, or local standards require maintenance and testing of emergency RICE beyond 100 hours per calendar year.

(ii) Emergency stationary RICE may be operated for emergency demand response for periods in which the Reliability Coordinator under the North American Electric Reliability Corporation (NERC) Reliability Standard EOP-002-3, Capacity and Energy Emergencies (incorporated by reference, see § 63.14), or other authorized entity as determined by the Reliability Coordinator, has declared an Energy Emergency Alert Level 2 as defined in the NERC Reliability Standard EOP-002-3.

(iii) Emergency stationary RICE may be operated for periods where there is a deviation of voltage or frequency of 5 percent or greater below standard voltage or frequency.

(3) Emergency stationary RICE located at major sources of HAP may be operated for up to 50 hours per calendar year in non-emergency situations. The 50 hours of operation in non-emergency situations are counted as part of the 100 hours per calendar year for maintenance and testing and emergency demand response provided in paragraph (f)(2) of this section. The 50 hours per year for non-emergency situations cannot be used for peak shaving or non-emergency demand response, or to generate income for a facility to supply power to an electric grid or otherwise supply power as part of a financial arrangement with another entity.

(4) Emergency stationary RICE located at area sources of HAP may be operated for up to 50 hours per calendar year in non-emergency situations. The 50 hours of operation in non-emergency situations are counted as part of the 100 hours per calendar year for maintenance and testing and emergency demand response provided in paragraph (f)(2) of this section. Except as provided in paragraphs (f)(4)(i) and (ii) of this section, the 50 hours per year for non-emergency situations cannot be used for peak shaving or non-emergency demand response, or to generate income for a facility to an electric grid or otherwise supply power as part of a financial arrangement with another entity.

(i) Prior to May 3, 2014, the 50 hours per year for non-emergency situations can be used for peak shaving or non-emergency demand response to generate income for a facility, or to otherwise supply power as part of a financial arrangement with another entity if the engine is operated as part of a peak shaving (load management program) with the local distribution system operator and the power is provided only to the facility itself or to support the local distribution system.

(ii) The 50 hours per year for non-emergency situations can be used to supply power as part of a financial arrangement with another entity if all of the following conditions are met:

(A) The engine is dispatched by the local balancing authority or local transmission and distribution system operator.

(B) The dispatch is intended to mitigate local transmission and/or distribution limitations so as to avert potential voltage collapse or line overloads that could lead to the interruption of power supply in a local area or region.

(C) The dispatch follows reliability, emergency operation or similar protocols that follow specific NERC, regional, state, public utility commission or local standards or guidelines.

(D) The power is provided only to the facility itself or to support the local transmission and distribution system.

(E) The owner or operator identifies and records the entity that dispatches the engine and the specific NERC, regional, state, public utility commission or local standards or guidelines that are being followed for dispatching the engine. The local balancing authority or local transmission and distribution system operator may keep these records on behalf of the engine owner or operator.

[69 FR 33506, June 15, 2004, as amended at 71 FR 20467, Apr. 20, 2006; 73 FR 3606, Jan. 18, 2008; 75 FR 9676, Mar. 3, 2010; 75 FR 51591, Aug. 20, 2010; 78 FR 6704, Jan. 30, 2013]

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Notifications, Reports, and Records

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§ 63.6645 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 (f)(6), 63.9(b) through (e), and (g) and (h) that apply to you by the dates specified if you own or operate any of the following;

(1) An existing stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions.

(2) An existing stationary RICE located at an area source of HAP emissions.

(3) A stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions.

(4) A new or reconstructed 4SLB stationary RICE with a site rating of greater than or equal to 250 HP located at a major source of HAP emissions.

(5) This requirement does not apply if you own or operate an existing stationary RICE less than 100 HP, an existing stationary emergency RICE, or an existing stationary RICE that is not subject to any numerical emission standards.

(b) As specified in § 63.9(b)(2), if you start up your stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions before the effective date of this subpart, you must submit an Initial Notification not later than December 13, 2004.

(c) If you start up your new or reconstructed stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions on or after August 16, 2004, you must submit an Initial Notification not later than 120 days after you become subject to this subpart.

(d) As specified in § 63.9(b)(2), if you start up your stationary RICE with a site rating of equal to or less than 500 brake HP located at a major source of HAP emissions before the effective date of this subpart and you are required to submit an initial notification, you must submit an Initial Notification not later than July 16, 2008.

(e) If you start up your new or reconstructed stationary RICE with a site rating of equal to or less than 500 brake HP located at a major source of HAP emissions on or after March 18, 2008 and you are required to submit an initial notification, you must submit an Initial Notification not later than 120 days after you become subject to this subpart.

(f) If you are required to submit an Initial Notification but are otherwise not affected by the requirements of this subpart, in accordance with § 63.6590(b), your notification should include the information in § 63.9(b)(2)(i) through (v), and a statement that your stationary RICE has no additional requirements and explain the basis of the exclusion (for example, that it operates exclusively as an emergency stationary RICE if it has a site rating of more than 500 brake HP located at a major source of HAP emissions).

(g) If you are required to conduct a performance test, you must submit a Notification of Intent to conduct a performance test at least 60 days before the performance test is scheduled to begin as required in § 63.7(b)(1).

(h) If you are required to conduct a performance test or other initial compliance demonstration as specified in Tables 4 and 5 to this subpart, you must submit a Notification of Compliance Status according to § 63.9(h)(2)(ii).

(1) For each initial compliance demonstration required in Table 5 to this subpart that does not include a performance test, you must submit the Notification of Compliance Status before the close of business on the 30th day following the completion of the initial compliance demonstration.

(2) For each initial compliance demonstration required in Table 5 to this subpart that includes a performance test conducted according to the requirements in Table 3 to this subpart, you must submit the Notification of Compliance Status, including the performance test results, before the close of business on the 60th day following the completion of the performance test according to § 63.10(d)(2).

(i) If you own or operate an existing non-emergency CI RICE with a site rating of more than 300 HP located at an area source of HAP emissions that is certified to the Tier 1 or Tier 2 emission standards in Table 1 of 40 CFR 89.112 and subject to an enforceable state or local standard requiring engine replacement and you intend to meet management practices rather than emission limits, as specified in § 63.6603(d), you must submit a notification by March 3, 2013, stating that you intend to use the provision in § 63.6603(d) and identifying the state or local regulation that the engine is subject to.

[73 FR 3606, Jan. 18, 2008, as amended at 75 FR 9677, Mar. 3, 2010; 75 FR 51591, Aug. 20, 2010; 78 FR 6705, Jan. 30, 2013]

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§ 63.6650 What reports must I submit and when?

(a) You must submit each report in Table 7 of this subpart that applies to you.

(b) Unless the Administrator has approved a different schedule for submission of reports under § 63.10(a), you must submit each report by the date in Table 7 of this subpart and according to the requirements in paragraphs (b)(1) through (b)(9) of this section.

(1) For semiannual Compliance reports, the first Compliance report must cover the period beginning on the compliance date that is specified for your affected source in § 63.6595 and ending on June 30 or December 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 § 63.6595.

(2) For semiannual Compliance reports, the first Compliance report must be postmarked or delivered no later than July 31 or January 31, whichever date follows the end of the first calendar half after the compliance date that is specified for your affected source in § 63.6595.

(3) For semiannual Compliance reports, 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) For semiannual Compliance reports, 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 stationary RICE that is subject to permitting regulations pursuant to 40 CFR part 70 or 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 (b)(4) of this section.

(6) For annual Compliance reports, the first Compliance report must cover the period beginning on the compliance date that is specified for your affected source in § 63.6595 and ending on December 31.

(7) For annual Compliance reports, the first Compliance report must be postmarked or delivered no later than January 31 following the end of the first calendar year after the compliance date that is specified for your affected source in § 63.6595.

(8) For annual Compliance reports, each subsequent Compliance report must cover the annual reporting period from January 1 through December 31.

(9) For annual Compliance reports, each subsequent Compliance report must be postmarked or delivered no later than January 31.

(c) The Compliance report must contain the information in paragraphs (c)(1) through (6) of this section.

(1) Company name and address.

(2) Statement by a responsible official, with that official's name, title, and signature, certifying the accuracy of the content of the report.

(3) Date of report and beginning and ending dates of the reporting period.

(4) If you had a malfunction during the reporting period, the compliance report must include the number, duration, and a brief description for each type of malfunction which occurred during the reporting period and which caused or may have caused any applicable emission limitation to be exceeded. The report must also include a description of actions taken by an owner or operator during a malfunction of an affected source to minimize emissions in accordance with § 63.6605(b), including actions taken to correct a malfunction.

(5) If there are no deviations from any emission or operating limitations that apply to you, a statement that there were no deviations from the emission or operating limitations during the reporting period.

(6) If there were no periods during which the continuous monitoring system (CMS), including CEMS and CPMS, was out-of-control, as specified in § 63.8(c)(7), a statement that there were no periods during which the CMS was out-of-control during the reporting period.

(d) For each deviation from an emission or operating limitation that occurs for a stationary RICE where you are not using a CMS to comply with the emission or operating limitations in this subpart, the Compliance report must contain the information in paragraphs (c)(1) through (4) of this section and the information in paragraphs (d)(1) and (2) of this section.

(1) The total operating time of the stationary RICE at which the deviation occurred during the reporting period.

(2) Information on the number, duration, and cause of deviations (including unknown cause, if applicable), as applicable, and the corrective action taken.

(e) For each deviation from an emission or operating limitation occurring for a stationary RICE where you are using a CMS to comply with the emission and operating limitations in this subpart, you must include information in paragraphs (c)(1) through (4) and (e)(1) through (12) of this section.

(1) The date and time that each malfunction started and stopped.

(2) The date, time, and duration 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 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 control equipment problems, process problems, other known causes, and other unknown causes.

(7) A summary of the total duration of CMS downtime during the reporting period, and the total duration of CMS downtime as a percent of the total operating time of the stationary RICE at which the CMS downtime occurred during that reporting period.

(8) An identification of each parameter and pollutant (CO or formaldehyde) that was monitored at the stationary RICE.

(9) A brief description of the stationary RICE.

(10) A brief description of the CMS.

(11) The date of the latest CMS certification or audit.

(12) A description of any changes in CMS, processes, or controls since the last reporting period.

(f) Each affected source that has obtained a title V operating permit pursuant to 40 CFR part 70 or 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 7 of 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 or operating limitation in this subpart, submission of the Compliance report shall be deemed to satisfy any obligation to report the same deviations in the semiannual monitoring report. However, submission of a Compliance report shall not otherwise affect any obligation the affected source may have to report deviations from permit requirements to the permit authority.

(g) If you are operating as a new or reconstructed stationary RICE which fires landfill gas or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis, you must submit an annual report according to Table 7 of this subpart by the date specified unless the Administrator has approved a different schedule, according to the information described in paragraphs (b)(1) through (b)(5) of this section. You must report the data specified in (g)(1) through (g)(3) of this section.

(1) Fuel flow rate of each fuel and the heating values that were used in your calculations. You must also demonstrate that the percentage of heat input provided by landfill gas or digester gas is equivalent to 10 percent or more of the total fuel consumption on an annual basis.

(2) The operating limits provided in your federally enforceable permit, and any deviations from these limits.

(3) Any problems or errors suspected with the meters.

(h) If you own or operate an emergency stationary RICE with a site rating of more than 100 brake HP that operates or is contractually obligated to be available for more than 15 hours per calendar year for the purposes specified in § 63.6640(f)(2)(ii) and (iii) or that operates for the purpose specified in § 63.6640(f)(4)(ii), you must submit an annual report according to the requirements in paragraphs (h)(1) through (3) of this section.

(1) The report must contain the following information:

(i) Company name and address where the engine is located.

(ii) Date of the report and beginning and ending dates of the reporting period.

(iii) Engine site rating and model year.

(iv) Latitude and longitude of the engine in decimal degrees reported to the fifth decimal place.

(v) Hours operated for the purposes specified in § 63.6640(f)(2)(ii) and (iii), including the date, start time, and end time for engine operation for the purposes specified in § 63.6640(f)(2)(ii) and (iii).

(vi) Number of hours the engine is contractually obligated to be available for the purposes specified in § 63.6640(f)(2)(ii) and (iii).

(vii) Hours spent for operation for the purpose specified in § 63.6640(f)(4)(ii), including the date, start time, and end time for engine operation for the purposes specified in § 63.6640(f)(4)(ii). The report must also identify the entity that dispatched the engine and the situation that necessitated the dispatch of the engine.

(viii) If there were no deviations from the fuel requirements in § 63.6604 that apply to the engine (if any), a statement that there were no deviations from the fuel requirements during the reporting period.

(ix) If there were deviations from the fuel requirements in § 63.6604 that apply to the engine (if any), information on the number, duration, and cause of deviations, and the corrective action taken.

(2) The first annual report must cover the calendar year 2015 and must be submitted no later than March 31, 2016. Subsequent annual reports for each calendar year must be submitted no later than March 31 of the following calendar year.

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

[69 FR 33506, June 15, 2004, as amended at 75 FR 9677, Mar. 3, 2010; 78 FR 6705, Jan. 30, 2013]

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§ 63.6655 What records must I keep?

(a) If you must comply with the emission and operating limitations, you must keep the records described in paragraphs (a)(1) through (a)(5), (b)(1) through (b)(3) and (c) 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 that you submitted, according to the requirement in § 63.10(b)(2)(xiv).

(2) Records of the occurrence and duration of each malfunction of operation (*i.e.,* process equipment) or the air pollution control and monitoring equipment.

(3) Records of performance tests and performance evaluations as required in § 63.10(b)(2)(viii).

(4) Records of all required maintenance performed on the air pollution control and monitoring equipment.

(5) Records of actions taken during periods of malfunction to minimize emissions in accordance with § 63.6605(b), including corrective actions to restore malfunctioning process and air pollution control and monitoring equipment to its normal or usual manner of operation.

(b) For each CEMS or CPMS, you must keep the records listed in paragraphs (b)(1) through (3) of this section.

(1) Records described in § 63.10(b)(2)(vi) through (xi).

(2) Previous (*i.e.,* superseded) versions of the performance evaluation plan as required in § 63.8(d)(3).

(3) Requests for alternatives to the relative accuracy test for CEMS or CPMS as required in § 63.8(f)(6)(i), if applicable.

(c) If you are operating a new or reconstructed stationary RICE which fires landfill gas or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis, you must keep the records of your daily fuel usage monitors.

(d) You must keep the records required in Table 6 of this subpart to show continuous compliance with each emission or operating limitation that applies to you.

(e) You must keep records of the maintenance conducted on the stationary RICE in order to demonstrate that you operated and maintained the stationary RICE and after-treatment control device (if any) according to your own maintenance plan if you own or operate any of the following stationary RICE;

(1) An existing stationary RICE with a site rating of less than 100 brake HP located at a major source of HAP emissions.

(2) An existing stationary emergency RICE.

(3) An existing stationary RICE located at an area source of HAP emissions subject to management practices as shown in Table 2d to this subpart.

(f) If you own or operate any of the stationary RICE in paragraphs (f)(1) through (2) of this section, you must keep records of the hours of operation of the engine that is recorded through the non-resettable hour meter. The owner or operator must document how many hours are spent for emergency operation, including what classified the operation as emergency and how many hours are spent for non-emergency operation. If the engine is used for the purposes specified in § 63.6640(f)(2)(ii) or (iii) or § 63.6640(f)(4)(ii), the owner or operator must keep records of the notification of the emergency situation, and the date, start time, and end time of engine operation for these purposes.

(1) An existing emergency stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions that does not meet the standards applicable to non-emergency engines.

(2) An existing emergency stationary RICE located at an area source of HAP emissions that does not meet the standards applicable to non-emergency engines.

[69 FR 33506, June 15, 2004, as amended at 75 FR 9678, Mar. 3, 2010; 75 FR 51592, Aug. 20, 2010; 78 FR 6706, Jan. 30, 2013]

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§ 63.6660   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 readily accessible in hard copy or electronic form for at least 5 years after the date of each occurrence, measurement, maintenance, corrective action, report, or record, according to § 63.10(b)(1).

[69 FR 33506, June 15, 2004, as amended at 75 FR 9678, Mar. 3, 2010]

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Other Requirements and Information

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§ 63.6665   What parts of the General Provisions apply to me?

Table 8 to this subpart shows which parts of the General Provisions in §§ 63.1 through 63.15 apply to you. If you own or operate a new or reconstructed stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions (except new or reconstructed 4SLB engines greater than or equal to 250 and less than or equal to 500 brake HP), a new or reconstructed stationary RICE located at an area source of HAP emissions, or any of the following RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions, you do not need to comply with any of the requirements of the General Provisions specified in Table 8: An existing 2SLB stationary RICE, an existing 4SLB stationary RICE, an existing stationary RICE that combusts landfill or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis, an existing emergency stationary RICE, or an existing limited use stationary RICE. If you own or operate any of the following

RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions, you do not need to comply with the requirements in the General Provisions specified in Table 8 except for the initial notification requirements: A new stationary RICE that combusts landfill gas or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis, a new emergency stationary RICE, or a new limited use stationary RICE.

[75 FR 9678, Mar. 3, 2010]

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§ 63.6670 Who implements and enforces this subpart?

(a) This subpart is implemented and enforced by 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 whether this subpart is delegated to your State, local, or tribal agency.

(b) In delegating implementation and enforcement authority of this subpart to a State, local, or tribal agency under 40 CFR part 63, subpart E, the authorities contained in 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:

(1) Approval of alternatives to the non-opacity emission limitations and operating limitations in § 63.6600 under § 63.6(g).

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

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

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

(5) Approval of a performance test which was conducted prior to the effective date of the rule, as specified in § 63.6610(b).

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§ 63.6675 What definitions apply to this subpart?

Terms used in this subpart are defined in the Clean Air Act (CAA); in 40 CFR 63.2, the General Provisions of this part; and in this section as follows:

Alaska Railbelt Grid means the service areas of the six regulated public utilities that extend from Fairbanks to Anchorage and the Kenai Peninsula. These utilities are Golden Valley Electric Association; Chugach Electric Association; Matanuska Electric Association; Homer Electric Association; Anchorage Municipal Light & Power; and the City of Seward Electric System.

Area source means any stationary source of HAP that is not a major source as defined in part 63.

Associated equipment as used in this subpart and as referred to in section 112(n)(4) of the CAA, means equipment associated with an oil or natural gas exploration or production well, and includes all equipment from the well bore to the point of custody transfer, except glycol dehydration units, storage vessels with potential for flash emissions, combustion turbines, and stationary RICE.

Backup power for renewable energy means an engine that provides backup power to a facility that generates electricity from renewable energy resources, as that term is defined in Alaska Statute 42.45.045(l)(5) (incorporated by reference, see § 63.14).

Black start engine means an engine whose only purpose is to start up a combustion turbine.

CAA means the Clean Air Act (42 U.S.C. 7401 *et seq.,* as amended by Public Law 101-549, 104 Stat. 2399).

Commercial emergency stationary RICE means an emergency stationary RICE used in commercial establishments such as office buildings, hotels, stores, telecommunications facilities, restaurants, financial institutions such as banks, doctor's offices, and sports and performing arts facilities.

Compression ignition means relating to a type of stationary internal combustion engine that is not a spark ignition engine.

Custody transfer means the transfer of hydrocarbon liquids or natural gas: After processing and/or treatment in the producing operations, or from storage vessels or automatic transfer facilities or other such equipment, including product loading racks, to pipelines or any other forms of transportation. For the purposes of this subpart, the point at which such liquids or natural gas enters a natural gas processing plant is a point of custody transfer.

Deviation means any instance in which an affected source subject to this subpart, or an owner or operator of such a source:

(1) Fails to meet any requirement or obligation established by this subpart, including but not limited to any emission limitation or operating limitation;

(2) 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

(3) Fails to meet any emission limitation or operating limitation in this subpart during malfunction, regardless or whether or not such failure is permitted by this subpart.

(4) Fails to satisfy the general duty to minimize emissions established by § 63.6(e)(1)(i).

Diesel engine means any stationary RICE in which a high boiling point liquid fuel injected into the combustion chamber ignites when the air charge has been compressed to a temperature sufficiently high for auto-ignition. This process is also known as compression ignition.

Diesel fuel means any liquid obtained from the distillation of petroleum with a boiling point of approximately 150 to 360 degrees Celsius. One commonly used form is fuel oil number 2. Diesel fuel also includes any non-distillate fuel with comparable physical and chemical properties (*e.g.* biodiesel) that is suitable for use in compression ignition engines.

Digester gas means any gaseous by-product of wastewater treatment typically formed through the anaerobic decomposition of organic waste materials and composed principally of methane and CO_2 .

Dual-fuel engine means any stationary RICE in which a liquid fuel (typically diesel fuel) is used for compression ignition and gaseous fuel (typically natural gas) is used as the primary fuel.

Emergency stationary RICE means any stationary reciprocating internal combustion engine that meets all of the criteria in paragraphs (1) through (3) of this definition. All emergency stationary RICE must comply with the requirements specified in § 63.6640(f) in order to be considered emergency stationary RICE. If the engine does not comply with the requirements specified in § 63.6640(f), then it is not considered to be an emergency stationary RICE under this subpart.

(1) The stationary RICE is operated to provide electrical power or mechanical work during an emergency situation. Examples include stationary RICE used to produce power for critical networks or equipment (including power supplied to portions of a facility) when electric power from the local utility (or the normal power source, if the facility runs on its own power production) is interrupted, or stationary RICE used to pump water in the case of fire or flood, etc.

(2) The stationary RICE is operated under limited circumstances for situations not included in paragraph (1) of this definition, as specified in § 63.6640(f).

(3) The stationary RICE operates as part of a financial arrangement with another entity in situations not included in paragraph (1) of this definition only as allowed in § 63.6640(f)(2)(ii) or (iii) and § 63.6640(f)(4)(i) or (ii).

Engine startup means the time from initial start until applied load and engine and associated equipment reaches steady state or normal operation. For stationary engine with catalytic controls, engine startup means the time from initial start until applied load and engine and associated equipment, including the catalyst, reaches steady state or normal operation.

Four-stroke engine means any type of engine which completes the power cycle in two crankshaft revolutions, with intake and compression strokes in the first revolution and power and exhaust strokes in the second revolution.

Gaseous fuel means a material used for combustion which is in the gaseous state at standard atmospheric temperature and pressure conditions.

Gasoline means any fuel sold in any State for use in motor vehicles and motor vehicle engines, or nonroad or stationary engines, and commonly or commercially known or sold as gasoline.

Glycol dehydration unit means a device in which a liquid glycol (including, but not limited to, ethylene glycol, diethylene glycol, or triethylene glycol) absorbent directly contacts a natural gas stream and absorbs water in a contact tower or absorption column (absorber). The glycol contacts and absorbs water vapor and other gas stream constituents from the natural gas and becomes “rich” glycol. This glycol is then regenerated in the glycol dehydration unit reboiler. The “lean” glycol is then recycled.

Hazardous air pollutants (HAP) means any air pollutants listed in or pursuant to section 112(b) of the CAA.

Institutional emergency stationary RICE means an emergency stationary RICE used in institutional establishments such as medical centers, nursing homes, research centers, institutions of higher education, correctional facilities, elementary and secondary schools, libraries, religious establishments, police stations, and fire stations.

ISO standard day conditions means 288 degrees Kelvin (15 degrees Celsius), 60 percent relative humidity and 101.3 kilopascals pressure.

Landfill gas means a gaseous by-product of the land application of municipal refuse typically formed through the anaerobic decomposition of waste materials and composed principally of methane and CO_2 .

Lean burn engine means any two-stroke or four-stroke spark ignited engine that does not meet the definition of a rich burn engine.

Limited use stationary RICE means any stationary RICE that operates less than 100 hours per year.

Liquefied petroleum gas means any liquefied hydrocarbon gas obtained as a by-product in petroleum refining of natural gas production.

Liquid fuel means any fuel in liquid form at standard temperature and pressure, including but not limited to diesel, residual/crude oil, kerosene/naphtha (jet fuel), and gasoline.

Major Source, as used in this subpart, shall have the same meaning as in § 63.2, except that:

(1) Emissions from any oil or gas exploration or production well (with its associated equipment (as defined in this section)) and emissions from any pipeline compressor station or pump station shall not be aggregated with emissions from other similar units, to determine whether such emission points or stations are major sources, even when emission points are in a contiguous area or under common control;

(2) For oil and gas production facilities, emissions from processes, operations, or equipment that are not part of the same oil and gas production facility, as defined in § 63.1271 of subpart HHH of this part, shall not be aggregated;

(3) For production field facilities, only HAP emissions from glycol dehydration units, storage vessel with the potential for flash emissions, combustion turbines and reciprocating internal combustion engines shall be aggregated for a major source determination; and

(4) Emissions from processes, operations, and equipment that are not part of the same natural gas transmission and storage facility, as defined in § 63.1271 of subpart HHH of this part, shall not be aggregated.

Malfunction means any sudden, infrequent, and not reasonably preventable failure of air pollution control equipment, process equipment, or a process to operate in a normal or usual manner which causes, or has the potential to cause, the emission limitations in an applicable standard to be exceeded. Failures that are caused in part by poor maintenance or careless operation are not malfunctions.

Natural gas means a naturally occurring mixture of hydrocarbon and non-hydrocarbon gases found in geologic formations beneath the Earth's surface, of which the principal constituent is methane. Natural gas may be field or pipeline quality.

Non-selective catalytic reduction (NSCR) means an add-on catalytic nitrogen oxides (NO_X) control device for rich burn engines that, in a two-step reaction, promotes the conversion of excess oxygen, NO_X , CO, and volatile organic compounds (VOC) into CO_2 , nitrogen, and water.

Oil and gas production facility as used in this subpart means any grouping of equipment where hydrocarbon liquids are processed, upgraded (*i.e.,* remove impurities or other constituents to meet contract specifications), or stored prior to the point of custody transfer; or where natural gas is processed, upgraded, or stored prior to entering the natural gas transmission and storage source category. For purposes of a major source determination, facility (including a building, structure, or installation) means oil and natural gas production and processing equipment that is located within the boundaries of an individual surface site as defined in this section. Equipment that is part of a facility will typically be located within close proximity to other equipment located at the same facility. Pieces of production equipment or groupings of equipment located on different oil and gas leases, mineral fee tracts, lease tracts, subsurface or surface unit areas, surface fee tracts, surface lease tracts, or separate surface sites, whether or not connected by a road, waterway, power line or pipeline, shall not be considered part of the same facility. Examples of facilities in the oil and natural gas production source category include, but are not limited to, well sites, satellite tank batteries, central tank batteries, a compressor station that transports natural gas to a natural gas processing plant, and natural gas processing plants.

Oxidation catalyst means an add-on catalytic control device that controls CO and VOC by oxidation.

Peaking unit or engine means any standby engine intended for use during periods of high demand that are not emergencies.

Percent load means the fractional power of an engine compared to its maximum manufacturer's design capacity at engine site conditions. Percent load may range between 0 percent to above 100 percent.

Potential to emit means the maximum capacity of a stationary source to emit a pollutant under its physical and operational design. Any physical or operational limitation on the capacity of the stationary source to emit a pollutant, including air pollution control equipment and restrictions on hours of operation or on the type or amount of material combusted, stored, or processed, shall be treated as part of its design if the limitation or the effect it would have on emissions is federally enforceable. For oil and natural gas production facilities subject to subpart HH of this part, the potential to emit provisions in § 63.760(a) may be used. For natural gas transmission and storage facilities subject to subpart HHH of this part, the maximum annual facility gas throughput for storage facilities may be determined according to § 63.1270(a)(1) and the maximum annual throughput for transmission facilities may be determined according to § 63.1270(a)(2).

Production field facility means those oil and gas production facilities located prior to the point of custody transfer.

Production well means any hole drilled in the earth from which crude oil, condensate, or field natural gas is extracted.

Propane means a colorless gas derived from petroleum and natural gas, with the molecular structure C_3H_8 .

Remote stationary RICE means stationary RICE meeting any of the following criteria:

(1) Stationary RICE located in an offshore area that is beyond the line of ordinary low water along that portion of the coast of the United States that is in direct contact with the open seas and beyond the line marking the seaward limit of inland waters.

(2) Stationary RICE located on a pipeline segment that meets both of the criteria in paragraphs (2)(i) and (ii) of this definition.

(i) A pipeline segment with 10 or fewer buildings intended for human occupancy and no buildings with four or more stories within 220 yards (200 meters) on either side of the centerline of any continuous 1-mile (1.6 kilometers) length of pipeline. Each separate dwelling unit in a multiple dwelling unit building is counted as a separate building intended for human occupancy.

(ii) The pipeline segment does not lie within 100 yards (91 meters) of either a building or a small, well-defined outside area (such as a playground, recreation area, outdoor theater, or other place of public assembly) that is occupied by 20 or more persons on at least 5 days a week for 10 weeks in any 12-month period. The days and weeks need not be consecutive. The building or area is considered occupied for a full day if it is occupied for any portion of the day.

(iii) For purposes of this paragraph (2), the term pipeline segment means all parts of those physical facilities through which gas moves in transportation, including but not limited to pipe, valves, and other appurtenance attached to pipe, compressor units, metering stations, regulator stations, delivery stations, holders, and fabricated assemblies. Stationary RICE located within 50 yards (46 meters) of the pipeline segment providing power for equipment on a pipeline segment are part of the pipeline segment. Transportation of gas means the gathering, transmission, or distribution of gas by pipeline, or the storage of gas. A building is intended for human occupancy if its primary use is for a purpose involving the presence of humans.

(3) Stationary RICE that are not located on gas pipelines and that have 5 or fewer buildings intended for human occupancy and no buildings with four or more stories within a 0.25 mile radius around the engine. A building is intended for human occupancy if its primary use is for a purpose involving the presence of humans.

Residential emergency stationary RICE means an emergency stationary RICE used in residential establishments such as homes or apartment buildings.

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

Rich burn engine means any four-stroke spark ignited engine where the manufacturer's recommended operating air/fuel ratio divided by the stoichiometric air/fuel ratio at full load conditions is less than or equal to 1.1. Engines originally manufactured as rich burn engines, but modified prior to December 19, 2002 with passive emission control technology for NO_X (such as pre-combustion chambers) will be considered lean burn engines. Also, existing engines where there are no manufacturer's recommendations regarding air/fuel ratio will be considered a rich burn engine if the excess oxygen content of the exhaust at full load conditions is less than or equal to 2 percent.

Site-rated HP means the maximum manufacturer's design capacity at engine site conditions.

Spark ignition means relating to either: A gasoline-fueled engine; or any other type of engine with a spark plug (or other sparking device) and with operating characteristics significantly similar to the theoretical Otto combustion cycle. Spark ignition engines usually use a throttle to regulate intake air flow to control power during normal operation. Dual-fuel engines in which a liquid fuel (typically diesel fuel) is used for CI and gaseous fuel (typically natural gas) is used as the primary fuel at an annual average ratio of less than 2 parts diesel fuel to 100 parts total fuel on an energy equivalent basis are spark ignition engines.

Stationary reciprocating internal combustion engine (RICE) means any reciprocating internal combustion engine which uses reciprocating motion to convert heat energy into mechanical work and which is not mobile. Stationary RICE differ from mobile RICE in that a stationary RICE is not a non-road engine as defined at 40 CFR 1068.30, and is not used to propel a motor vehicle or a vehicle used solely for competition.

Stationary RICE test cell/stand means an engine test cell/stand, as defined in subpart PPPPP of this part, that tests stationary RICE.

Stoichiometric means the theoretical air-to-fuel ratio required for complete combustion.

Storage vessel with the potential for flash emissions means any storage vessel that contains a hydrocarbon liquid with a stock tank gas-to-oil ratio equal to or greater than 0.31 cubic meters per liter and an American Petroleum Institute gravity equal to or greater than 40 degrees and an actual annual average hydrocarbon liquid throughput equal to or greater than 79,500 liters per day. Flash emissions occur when dissolved hydrocarbons in the fluid evolve from solution when the fluid pressure is reduced.

Subpart means 40 CFR part 63, subpart ZZZZ.

Surface site means any combination of one or more graded pad sites, gravel pad sites, foundations, platforms, or the immediate physical location upon which equipment is physically affixed.

Two-stroke engine means a type of engine which completes the power cycle in single crankshaft revolution by combining the intake and compression operations into one stroke and the power and exhaust operations into a second stroke. This system requires auxiliary scavenging and inherently runs lean of stoichiometric.

[69 FR 33506, June 15, 2004, as amended at 71 FR 20467, Apr. 20, 2006; 73 FR 3607, Jan. 18, 2008; 75 FR 9679, Mar. 3, 2010; 75 FR 51592, Aug. 20, 2010; 76 FR 12867, Mar. 9, 2011; 78 FR 6706, Jan. 30, 2013]

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Table 1 a to Subpart ZZZZ of Part 63—Emission Limitations for Existing, New, and Reconstructed Spark Ignition, 4SRB Stationary RICE > 500 HP Located at a Major Source of HAP Emissions

As stated in §§ 63.6600 and 63.6640, you must comply with the following emission limitations at 100 percent load plus or minus 10 percent for existing, new and reconstructed 4SRB stationary RICE >500 HP located at a major source of HAP emissions:

For each . . .	You must meet the following emission limitation, except during periods of startup . . .	During periods of startup you must . . .
1. 4SRB stationary RICE	a. Reduce formaldehyde emissions by 76 percent or more. If you commenced construction or reconstruction between December 19, 2002 and June 15, 2004, you may reduce formaldehyde emissions by 75 percent or more until June 15, 2007 or	Minimize the engine's time spent at idle and minimize the engine's startup time at startup to a period needed for appropriate and safe loading of the engine, not to exceed 30 minutes, after which time the non-startup emission limitations apply.[1]
	b. Limit the concentration of formaldehyde in the stationary RICE exhaust to 350 ppbvd or less at 15 percent O_2	

[1] Sources can petition the Administrator pursuant to the requirements of 40 CFR 63.6(g) for alternative work practices.

[75 FR 9679, Mar. 3, 2010, as amended at 75 FR 51592, Aug. 20, 2010]

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Table 1 b to Subpart ZZZZ of Part 63—Operating Limitations for Existing, New, and Reconstructed SI 4SRB Stationary RICE >500 HP Located at a Major Source of HAP Emissions

As stated in §§ 63.6600, 63.6603, 63.6630 and 63.6640, you must comply with the following operating limitations for existing, new and reconstructed 4SRB stationary RICE >500 HP located at a major source of HAP emissions:

Table 1b to Subpart ZZZZ of Part 63—Operating Limitations for Existing, New, and Reconstructed SI 4SRB Stationary RICE >500 HP Located at a Major Source of HAP Emissions

For each . . .	You must meet the following operating limitation, except during periods of startup . . .
1. existing, new and reconstructed 4SRB stationary RICE >500 HP located at a major source of HAP emissions complying with the requirement to reduce formaldehyde emissions by 76 percent or more (or by 75 percent or more, if applicable) and using NSCR; or existing, new and reconstructed 4SRB stationary RICE >500 HP located at a major source of HAP emissions complying with the requirement to limit the concentration of formaldehyde in the stationary RICE exhaust to 350 ppbvd or less at 15 percent $O_2$and using NSCR;	a. maintain your catalyst so that the pressure drop across the catalyst does not change by more than 2 inches of water at 100 percent load plus or minus 10 percent from the pressure drop across the catalyst measured during the initial performance test; and b. maintain the temperature of your stationary RICE exhaust so that the catalyst inlet temperature is greater than or equal to 750 °F and less than or equal to 1250 °F.[1]
2. existing, new and reconstructed 4SRB stationary RICE >500 HP located at a major source of HAP emissions complying with the requirement to reduce formaldehyde emissions by 76 percent or more (or by 75 percent or more, if applicable) and not using NSCR; or	Comply with any operating limitations approved by the Administrator.
existing, new and reconstructed 4SRB stationary RICE >500 HP located at a major source of HAP emissions complying with the requirement to limit the concentration of formaldehyde in the stationary RICE exhaust to 350 ppbvd or less at 15 percent $O_2$and not using NSCR.	

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[1] Sources can petition the Administrator pursuant to the requirements of 40 CFR 63.8(f) for a different temperature range.

[78 FR 6706, Jan. 30, 2013]

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Table 2 a to Subpart ZZZZ of Part 63—Emission Limitations for New and Reconstructed 2SLB and Compression Ignition Stationary RICE >500 HP and New and Reconstructed 4SLB Stationary RICE ≥250 HP Located at a Major Source of HAP Emissions

As stated in §§ 63.6600 and 63.6640, you must comply with the following emission limitations for new and reconstructed lean burn and new and reconstructed compression ignition stationary RICE at 100 percent load plus or minus 10 percent:

For each . . .	You must meet the following emission limitation, except during periods of startup . . .	During periods of startup you must . . .
1. 2SLB stationary RICE	a. Reduce CO emissions by 58 percent or more; or b. Limit concentration of formaldehyde in the stationary RICE exhaust to 12 ppmvd or less at 15 percent O_2. If you commenced construction or reconstruction between December 19, 2002 and June 15, 2004, you may limit concentration of formaldehyde to 17 ppmvd or less at 15 percent O_2until June 15, 2007	Minimize the engine's time spent at idle and minimize the engine's startup time at startup to a period needed for appropriate and safe loading of the engine, not to exceed 30 minutes, after which time the non-startup emission limitations apply.[1]
2. 4SLB stationary RICE	a. Reduce CO emissions by 93 percent or more; or	
	b. Limit concentration of formaldehyde in the stationary RICE exhaust to 14 ppmvd or less at 15 percent O_2	
3. CI stationary RICE	a. Reduce CO emissions by 70 percent or more; or	
	b. Limit concentration of formaldehyde in the stationary RICE exhaust to 580 ppbvd or less at 15 percent O_2	

[1] Sources can petition the Administrator pursuant to the requirements of 40 CFR 63.6(g) for alternative work practices.

[75 FR 9680, Mar. 3, 2010]

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Table 2 b to Subpart ZZZZ of Part 63—Operating Limitations for New and Reconstructed 2SLB and CI Stationary RICE >500 HP Located at a Major Source of HAP Emissions, New and Reconstructed 4SLB Stationary RICE ≥250 HP Located at a Major Source of HAP Emissions, Existing CI Stationary RICE >500 HP

As stated in §§ 63.6600, 63.6601, 63.6603, 63.6630, and 63.6640, you must comply with the following operating limitations for new and reconstructed 2SLB and CI stationary RICE >500 HP located at a major source of HAP emissions; new and reconstructed 4SLB stationary RICE ≥250 HP located at a major source of HAP emissions; and existing CI stationary RICE >500 HP:

Table 2b to Subpart ZZZZ of Part 63—Operating Limitations for New and Reconstructed 2SLB and CI Stationary RICE >500 HP Located at a Major Source of HAP Emissions, New and Reconstructed 4SLB Stationary RICE ≥250 HP Located at a Major Source of HAP Emissions, Existing CI Stationary RICE >500 HP

For each . . .	You must meet the following operating limitation, except during periods of startup . . .
1. New and reconstructed 2SLB and CI stationary RICE >500 HP located at a major source of HAP emissions and new and reconstructed 4SLB stationary RICE ≥250 HP located at a major source of HAP emissions complying with the requirement to reduce CO emissions and using an oxidation catalyst; and New and reconstructed 2SLB and CI stationary RICE >500 HP located at a major source of HAP emissions and new and reconstructed 4SLB stationary RICE ≥250 HP located at a major source of HAP emissions complying with the requirement to limit the concentration of formaldehyde in the stationary RICE exhaust and using an oxidation catalyst.	a. maintain your catalyst so that the pressure drop across the catalyst does not change by more than 2 inches of water at 100 percent load plus or minus 10 percent from the pressure drop across the catalyst that was measured during the initial performance test; and b. maintain the temperature of your stationary RICE exhaust so that the catalyst inlet temperature is greater than or equal to 450 °F and less than or equal to 1350 °F.[1]
2. Existing CI stationary RICE >500 HP complying with the requirement to limit or reduce the concentration of CO in the stationary RICE exhaust and using an oxidation catalyst	a. maintain your catalyst so that the pressure drop across the catalyst does not change by more than 2 inches of water from the pressure drop across the catalyst that was measured during the initial performance test; and
	b. maintain the temperature of your stationary RICE exhaust so that the catalyst inlet temperature is greater than or equal to 450 °F and less than or equal to 1350 °F.[1]
3. New and reconstructed 2SLB and CI stationary RICE >500 HP located at a major source of HAP emissions and new and reconstructed 4SLB stationary RICE ≥250 HP located at a major source of HAP emissions complying with the requirement to reduce CO emissions and not using an oxidation catalyst; and	Comply with any operating limitations approved by the Administrator.
New and reconstructed 2SLB and CI stationary RICE >500 HP located at a major source of HAP emissions and new and reconstructed 4SLB stationary RICE ≥250 HP located at a major source of HAP emissions complying with the requirement to limit the concentration of formaldehyde in the stationary RICE exhaust and not using an oxidation catalyst; and	
existing CI stationary RICE >500 HP complying with the requirement to limit or reduce the concentration of CO in the stationary RICE exhaust and not using an oxidation catalyst.	

[1] Sources can petition the Administrator pursuant to the requirements of 40 CFR 63.8(f) for a different temperature range.

[78 FR 6707, Jan. 30, 2013]

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Requirements for Existing Compression Ignition Stationary RICE Located at a Major Source of HAP Emissions and Existing Spark Ignition Stationary RICE ≤500 HP Located at a Major Source of HAP Emissions

As stated in §§ 63.6600, 63.6602, and 63.6640, you must comply with the following requirements for existing compression ignition stationary RICE located at a major source of HAP emissions and existing spark ignition stationary RICE ≤500 HP located at a major source of HAP emissions:

Table 2c to Subpart ZZZZ of Part 63—Requirements for Existing Compression Ignition Stationary RICE Located at a Major Source of HAP Emissions and Existing Spark Ignition Stationary RICE ≤500 HP Located at a Major Source of HAP Emissions

For each . . .	You must meet the following requirement, except during periods of startup . . .	During periods of startup you must . . .
1. Emergency stationary CI RICE and black start stationary CI RICE [1]	a. Change oil and filter every 500 hours of operation or annually, whichever comes first.[2] b. Inspect air cleaner every 1,000 hours of operation or annually, whichever comes first, and replace as necessary; c. Inspect all hoses and belts every 500 hours of operation or annually, whichever comes first, and replace as necessary.[3]	Minimize the engine's time spent at idle and minimize the engine's startup time at startup to a period needed for appropriate and safe loading of the engine, not to exceed 30 minutes, after which time the non-startup emission limitations apply.[3]
2. Non-Emergency, non-black start stationary CI RICE <100 HP	a. Change oil and filter every 1,000 hours of operation or annually, whichever comes first.[2] b. Inspect air cleaner every 1,000 hours of operation or annually, whichever comes first, and replace as necessary; c. Inspect all hoses and belts every 500 hours of operation or annually, whichever comes first, and replace as necessary.[3]	
3. Non-Emergency, non-black start CI stationary RICE 100≤HP≤300 HP	Limit concentration of CO in the stationary RICE exhaust to 230 ppmvd or less at 15 percent O_2.	

For each . . .	You must meet the following requirement, except during periods of startup . . .	During periods of startup you must . . .
4. Non-Emergency, non-black start CI stationary RICE 300>HP≤500.” is corrected to read “4. Non-Emergency, non-black start CI stationary RICE 300<HP≤500.	a. Limit concentration of CO in the stationary RICE exhaust to 49 ppmvd or less at 15 percent O_2; or b. Reduce CO emissions by 70 percent or more.	
5. Non-Emergency, non-black start stationary CI RICE >500 HP	a. Limit concentration of CO in the stationary RICE exhaust to 23 ppmvd or less at 15 percent O_2; or b. Reduce CO emissions by 70 percent or more.	
6. Emergency stationary SI RICE and black start stationary SI RICE.[1]	a. Change oil and filter every 500 hours of operation or annually, whichever comes first;[2] b. Inspect spark plugs every 1,000 hours of operation or annually, whichever comes first, and replace as necessary; c. Inspect all hoses and belts every 500 hours of operation or annually, whichever comes first, and replace as necessary.[3]	
7. Non-Emergency, non-black start stationary SI RICE <100 HP that are not 2SLB stationary RICE	a. Change oil and filter every 1,440 hours of operation or annually, whichever comes first;[2] b. Inspect spark plugs every 1,440 hours of operation or annually, whichever comes first, and replace as necessary;	
	c. Inspect all hoses and belts every 1,440 hours of operation or annually, whichever comes first, and replace as necessary.[3]	

For each . . .	You must meet the following requirement, except during periods of startup . . .	During periods of startup you must . . .
8. Non-Emergency, non-black start 2SLB stationary SI RICE <100 HP	a. Change oil and filter every 4,320 hours of operation or annually, whichever comes first;[2] b. Inspect spark plugs every 4,320 hours of operation or annually, whichever comes first, and replace as necessary;	
	c. Inspect all hoses and belts every 4,320 hours of operation or annually, whichever comes first, and replace as necessary.[3]	
9. Non-emergency, non-black start 2SLB stationary RICE 100≤HP≤500	Limit concentration of CO in the stationary RICE exhaust to 225 ppmvd or less at 15 percent O_2.	
10. Non-emergency, non-black start 4SLB stationary RICE 100≤HP≤500	Limit concentration of CO in the stationary RICE exhaust to 47 ppmvd or less at 15 percent O_2.	
11. Non-emergency, non-black start 4SRB stationary RICE 100≤HP≤500	Limit concentration of formaldehyde in the stationary RICE exhaust to 10.3 ppmvd or less at 15 percent O_2.	
12. Non-emergency, non-black start stationary RICE 100≤HP≤500 which combusts landfill or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis	Limit concentration of CO in the stationary RICE exhaust to 177 ppmvd or less at 15 percent O_2.	

[1] If an emergency engine is operating during an emergency and it is not possible to shut down the engine in order to perform the work practice requirements on the schedule required in Table 2c of this subpart, or if performing the work practice on the required schedule would otherwise pose an unacceptable risk under federal, state, or local law, the work practice can be delayed until the emergency is over or the unacceptable risk under federal, state, or local law has abated. The work practice should be performed as soon as practicable after the emergency has ended or the unacceptable risk under federal, state, or local law has abated. Sources must report any failure to perform the work practice on the schedule required and the federal, state or local law under which the risk was deemed unacceptable.

[2] Sources have the option to utilize an oil analysis program as described in § 63.6625(i) or (j) in order to extend the specified oil change requirement in Table 2c of this subpart.

[3] Sources can petition the Administrator pursuant to the requirements of 40 CFR 63.6(g) for alternative work practices.

[78 FR 6708, Jan. 30, 2013, as amended at 78 FR 14457, Mar. 6, 2013]

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Requirements for Existing Stationary RICE Located at Area Sources of HAP Emissions

As stated in §§ 63.6603 and 63.6640, you must comply with the following requirements for existing stationary RICE located at area sources of HAP emissions:

Table 2d to Subpart ZZZZ of Part 63—Requirements for Existing Stationary RICE Located at Area Sources of HAP Emissions

For each . . .	You must meet the following requirement, except during periods of startup . . .	During periods of startup you must . . .
1. Non-Emergency, non-black start CI stationary RICE ≤300 HP	a. Change oil and filter every 1,000 hours of operation or annually, whichever comes first;[1] b. Inspect air cleaner every 1,000 hours of operation or annually, whichever comes first, and replace as necessary; c. Inspect all hoses and belts every 500 hours of operation or annually, whichever comes first, and replace as necessary.	Minimize the engine's time spent at idle and minimize the engine's startup time at startup to a period needed for appropriate and safe loading of the engine, not to exceed 30 minutes, after which time the non-startup emission limitations apply.
2. Non-Emergency, non-black start CI stationary RICE 300<HP≤500	a. Limit concentration of CO in the stationary RICE exhaust to 49 ppmvd at 15 percent O_2; or	
	b. Reduce CO emissions by 70 percent or more.	
3. Non-Emergency, non-black start CI stationary RICE >500 HP	a. Limit concentration of CO in the stationary RICE exhaust to 23 ppmvd at 15 percent O_2; or	
	b. Reduce CO emissions by 70 percent or more.	

For each . . .	You must meet the following requirement, except during periods of startup . . .	During periods of startup you must . . .
4. Emergency stationary CI RICE and black start stationary CI RICE.[2]	a. Change oil and filter every 500 hours of operation or annually, whichever comes first;[1]	
	b. Inspect air cleaner every 1,000 hours of operation or annually, whichever comes first, and replace as necessary; and	
	c. Inspect all hoses and belts every 500 hours of operation or annually, whichever comes first, and replace as necessary.	
5. Emergency stationary SI RICE; black start stationary SI RICE; non-emergency, non-black start 4SLB stationary RICE >500 HP that operate 24 hours or less per calendar year; non-emergency, non-black start 4SRB stationary RICE >500 HP that operate 24 hours or less per calendar year.[2]	a. Change oil and filter every 500 hours of operation or annually, whichever comes first;[1]; b. Inspect spark plugs every 1,000 hours of operation or annually, whichever comes first, and replace as necessary; and c. Inspect all hoses and belts every 500 hours of operation or annually, whichever comes first, and replace as necessary.	
6. Non-emergency, non-black start 2SLB stationary RICE	a. Change oil and filter every 4,320 hours of operation or annually, whichever comes first;[1]	
	b. Inspect spark plugs every 4,320 hours of operation or annually, whichever comes first, and replace as necessary; and	

For each . . .	You must meet the following requirement, except during periods of startup . . .	During periods of startup you must . . .
	c. Inspect all hoses and belts every 4,320 hours of operation or annually, whichever comes first, and replace as necessary.	
7. Non-emergency, non-black start 4SLB stationary RICE ≤500 HP	a. Change oil and filter every 1,440 hours of operation or annually, whichever comes first;[1]	
	b. Inspect spark plugs every 1,440 hours of operation or annually, whichever comes first, and replace as necessary; and	
	c. Inspect all hoses and belts every 1,440 hours of operation or annually, whichever comes first, and replace as necessary.	
8. Non-emergency, non-black start 4SLB remote stationary RICE >500 HP	a. Change oil and filter every 2,160 hours of operation or annually, whichever comes first;[1]	
	b. Inspect spark plugs every 2,160 hours of operation or annually, whichever comes first, and replace as necessary; and	
	c. Inspect all hoses and belts every 2,160 hours of operation or annually, whichever comes first, and replace as necessary.	
9. Non-emergency, non-black start 4SLB stationary RICE >500 HP that are not remote stationary RICE and that operate more than 24 hours per calendar year	Install an oxidation catalyst to reduce HAP emissions from the stationary RICE.	

For each . . .	**You must meet the following requirement, except during periods of startup . . .**	**During periods of startup you must . . .**
10. Non-emergency, non-black start 4SRB stationary RICE ≤500 HP	a. Change oil and filter every 1,440 hours of operation or annually, whichever comes first;[1]	
	b. Inspect spark plugs every 1,440 hours of operation or annually, whichever comes first, and replace as necessary; and	
	c. Inspect all hoses and belts every 1,440 hours of operation or annually, whichever comes first, and replace as necessary.	
11. Non-emergency, non-black start 4SRB remote stationary RICE >500 HP	a. Change oil and filter every 2,160 hours of operation or annually, whichever comes first;[1]	
	b. Inspect spark plugs every 2,160 hours of operation or annually, whichever comes first, and replace as necessary; and	
	c. Inspect all hoses and belts every 2,160 hours of operation or annually, whichever comes first, and replace as necessary.	
12. Non-emergency, non-black start 4SRB stationary RICE >500 HP that are not remote stationary RICE and that operate more than 24 hours per calendar year	Install NSCR to reduce HAP emissions from the stationary RICE.	
13. Non-emergency, non-black start stationary RICE which combusts landfill or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis	a. Change oil and filter every 1,440 hours of operation or annually, whichever comes first;[1] b. Inspect spark plugs every 1,440 hours of operation or annually, whichever comes first, and replace as necessary; and	

For each . . .	You must meet the following requirement, except during periods of startup . . .	During periods of startup you must . . .
	c. Inspect all hoses and belts every 1,440 hours of operation or annually, whichever comes first, and replace as necessary.	

[1] Sources have the option to utilize an oil analysis program as described in § 63.6625(i) or (j) in order to extend the specified oil change requirement in Table 2d of this subpart.

[2] If an emergency engine is operating during an emergency and it is not possible to shut down the engine in order to perform the management practice requirements on the schedule required in Table 2d of this subpart, or if performing the management practice on the required schedule would otherwise pose an unacceptable risk under federal, state, or local law, the management practice can be delayed until the emergency is over or the unacceptable risk under federal, state, or local law has abated. The management practice should be performed as soon as practicable after the emergency has ended or the unacceptable risk under federal, state, or local law has abated. Sources must report any failure to perform the management practice on the schedule required and the federal, state or local law under which the risk was deemed unacceptable.

[78 FR 6709, Jan. 30, 2013]

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Subsequent Performance Tests

As stated in §§ 63.6615 and 63.6620, you must comply with the following subsequent performance test requirements:

Table 3 to Subpart ZZZZ of Part 63—Subsequent Performance Tests

For each . . .	Complying with the requirement to . . .	You must . . .
1. New or reconstructed 2SLB stationary RICE >500 HP located at major sources; new or reconstructed 4SLB stationary RICE ≥250 HP located at major sources; and new or reconstructed CI stationary RICE >500 HP located at major sources	Reduce CO emissions and not using a CEMS	Conduct subsequent performance tests semiannually.[1]
2. 4SRB stationary RICE ≥5,000 HP located at major sources	Reduce formaldehyde emissions	Conduct subsequent performance tests semiannually.[1]
3. Stationary RICE >500 HP located at major sources and new or reconstructed 4SLB stationary RICE 250≤HP≤500 located at major sources	Limit the concentration of formaldehyde in the stationary RICE exhaust	Conduct subsequent performance tests semiannually.[1]

For each . . .	Complying with the requirement to . . .	You must . . .
4. Existing non-emergency, non-black start CI stationary RICE >500 HP that are not limited use stationary RICE	Limit or reduce CO emissions and not using a CEMS	Conduct subsequent performance tests every 8,760 hours or 3 years, whichever comes first.
5. Existing non-emergency, non-black start CI stationary RICE >500 HP that are limited use stationary RICE	Limit or reduce CO emissions and not using a CEMS	Conduct subsequent performance tests every 8,760 hours or 5 years, whichever comes first.

[1] After you have demonstrated compliance for two consecutive tests, you may reduce the frequency of subsequent performance tests to annually. If the results of any subsequent annual performance test indicate the stationary RICE is not in compliance with the CO or formaldehyde emission limitation, or you deviate from any of your operating limitations, you must resume semiannual performance tests.

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Table 4 to Subpart ZZZZ of Part 63—Requirements for Performance Tests

As stated in §§ 63.6610, 63.6611, 63.6612, 63.6620, and 63.6640, you must comply with the following requirements for performance tests for stationary RICE:

Table 4 to Subpart ZZZZ of Part 63. Requirements for Performance Tests

For each . . .	Complying with the requirement to . . .	You must . . .	Using . . .	According to the following requirements . . .
1. 2SLB, 4SLB, and CI stationary RICE	a. reduce CO emissions	i. Measure the O_2 at the inlet and outlet of the control device; and	(1) Method 3 or 3A or 3B of 40 CFR part 60, appendix A, or ASTM Method D6522-00 (Reapproved 2005).[a] [c]	(a) Measurements to determine O_2 must be made at the same time as the measurements for CO concentration.
		ii. Measure the CO at the inlet and the outlet of the control device	(1) ASTM D6522-00 (Reapproved 2005) [a] [b] [c] or Method 10 of 40 CFR part 60, appendix A	(a) The CO concentration must be at 15 percent O_2, dry basis.
2. 4SRB stationary RICE	a. reduce formaldehyde emissions	i. Select the sampling port location and the number of traverse points; and	(1) Method 1 or 1A of 40 CFR part 60, appendix A § 63.7(d)(1)(i)	(a) sampling sites must be located at the inlet and outlet of the control device.

For each . . .	Complying with the requirement to . . .	You must . . .	Using . . .	According to the following requirements . . .
		ii. Measure O_2 at the inlet and outlet of the control device; and	(1) Method 3 or 3A or 3B of 40 CFR part 60, appendix A, or ASTM Method D6522-00 (Reapproved 2005).[a]	(a) measurements to determine O_2 concentration must be made at the same time as the measurements for formaldehyde or THC concentration.
		iii. Measure moisture content at the inlet and outlet of the control device; and	(1) Method 4 of 40 CFR part 60, appendix A, or Test Method 320 of 40 CFR part 63, appendix A, or ASTM D 6348-03.[a]	(a) measurements to determine moisture content must be made at the same time and location as the measurements for formaldehyde or THC concentration.
		iv. If demonstrating compliance with the formaldehyde percent reduction requirement, measure formaldehyde at the inlet and the outlet of the control device	(1) Method 320 or 323 of 40 CFR part 63, appendix A; or ASTM D6348-03,[a] provided in ASTM D6348-03 Annex A5 (Analyte Spiking Technique), the percent R must be greater than or equal to 70 and less than or equal to 130	(a) formaldehyde concentration must be at 15 percent O_2, dry basis. Results of this test consist of the average of the three 1-hour or longer runs.
		v. If demonstrating compliance with the THC percent reduction requirement, measure THC at the inlet and the outlet of the control device	(1) Method 25A, reported as propane, of 40 CFR part 60, appendix A	(a) THC concentration must be at 15 percent O_2, dry basis. Results of this test consist of the average of the three 1-hour or longer runs.
3. Stationary RICE	a. limit the concentration of formaldehyde or CO in the stationary RICE exhaust	i. Select the sampling port location and the number of traverse points; and	(1) Method 1 or 1A of 40 CFR part 60, appendix A § 63.7(d)(1)(i)	(a) if using a control device, the sampling site must be located at the outlet of the control device.
		ii. Determine the O_2 concentration of the stationary RICE exhaust at the sampling port location; and	(1) Method 3 or 3A or 3B of 40 CFR part 60, appendix A, or ASTM Method D6522-00 (Reapproved 2005).[a]	(a) measurements to determine O_2 concentration must be made at the same time and location as the measurements for formaldehyde or CO concentration.

For each . . .	Complying with the requirement to . . .	You must . . .	Using . . .	According to the following requirements . . .
		iii. Measure moisture content of the stationary RICE exhaust at the sampling port location; and	(1) Method 4 of 40 CFR part 60, appendix A, or Test Method 320 of 40 CFR part 63, appendix A, or ASTM D 6348-03.[a]	(a) measurements to determine moisture content must be made at the same time and location as the measurements for formaldehyde or CO concentration.
		iv. Measure formaldehyde at the exhaust of the stationary RICE; or	(1) Method 320 or 323 of 40 CFR part 63, appendix A; or ASTM D6348-03,[a]provided in ASTM D6348-03 Annex A5 (Analyte Spiking Technique), the percent R must be greater than or equal to 70 and less than or equal to 130	(a) Formaldehyde concentration must be at 15 percent O_2, dry basis. Results of this test consist of the average of the three 1-hour or longer runs.
		v. measure CO at the exhaust of the stationary RICE.	(1) Method 10 of 40 CFR part 60, appendix A, ASTM Method D6522-00 (2005),[a] [c]Method 320 of 40 CFR part 63, appendix A, or ASTM D6348-03.[a]	(a) CO concentration must be at 15 percent O_2, dry basis. Results of this test consist of the average of the three 1-hour or longer runs.

[a] Incorporated by reference, see 40 CFR 63.14. You may also obtain copies from University Microfilms International, 300 North Zeeb Road, Ann Arbor, MI 48106.

[b] You may also use Method 320 of 40 CFR part 63, appendix A, or ASTM D6348-03.

[c] ASTM-D6522-00 (2005) may be used to test both CI and SI stationary RICE.

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Table 5 to Subpart ZZZZ of Part 63—Initial Compliance With Emission Limitations, Operating Limitations, and Other Requirements

As stated in §§ 63.6612, 63.6625 and 63.6630, you must initially comply with the emission and operating limitations as required by the following:

Table 5 to Subpart ZZZZ of Part 63—Initial Compliance With Emission Limitations, Operating Limitations, and Other Requirements

For each . . .	Complying with the requirement to . . .	You have demonstrated initial compliance if . . .
1. New or reconstructed non-emergency 2SLB stationary RICE >500 HP located at a major source of HAP, new or reconstructed non-emergency 4SLB stationary RICE ≥250 HP located at a major source of HAP, non-emergency stationary CI RICE >500 HP located at a major source of HAP, and existing non-emergency stationary CI RICE >500 HP located at an area source of HAP	a. Reduce CO emissions and using oxidation catalyst, and using a CPMS	i. The average reduction of emissions of CO determined from the initial performance test achieves the required CO percent reduction; and ii. You have installed a CPMS to continuously monitor catalyst inlet temperature according to the requirements in § 63.6625(b); and iii. You have recorded the catalyst pressure drop and catalyst inlet temperature during the initial performance test.
2. Non-emergency stationary CI RICE >500 HP located at a major source of HAP, and existing non-emergency stationary CI RICE >500 HP located at an area source of HAP	a. Limit the concentration of CO, using oxidation catalyst, and using a CPMS	i. The average CO concentration determined from the initial performance test is less than or equal to the CO emission limitation; and
		ii. You have installed a CPMS to continuously monitor catalyst inlet temperature according to the requirements in § 63.6625(b); and
		iii. You have recorded the catalyst pressure drop and catalyst inlet temperature during the initial performance test.
3. New or reconstructed non-emergency 2SLB stationary RICE >500 HP located at a major source of HAP, new or reconstructed non-emergency 4SLB stationary RICE ≥250 HP located at a major source of HAP, non-emergency stationary CI RICE >500 HP located at a major source of HAP, and existing non-emergency stationary CI RICE >500 HP located at an area source of HAP	a. Reduce CO emissions and not using oxidation catalyst	i. The average reduction of emissions of CO determined from the initial performance test achieves the required CO percent reduction; and ii. You have installed a CPMS to continuously monitor operating parameters approved by the Administrator (if any) according to the requirements in § 63.6625(b); and iii. You have recorded the approved operating parameters (if any) during the initial performance test.

For each . . .	Complying with the requirement to . . .	You have demonstrated initial compliance if . . .
4. Non-emergency stationary CI RICE >500 HP located at a major source of HAP, and existing non-emergency stationary CI RICE >500 HP located at an area source of HAP	a. Limit the concentration of CO, and not using oxidation catalyst	i. The average CO concentration determined from the initial performance test is less than or equal to the CO emission limitation; and ii. You have installed a CPMS to continuously monitor operating parameters approved by the Administrator (if any) according to the requirements in § 63.6625(b); and
		iii. You have recorded the approved operating parameters (if any) during the initial performance test.
5. New or reconstructed non-emergency 2SLB stationary RICE >500 HP located at a major source of HAP, new or reconstructed non-emergency 4SLB stationary RICE ≥250 HP located at a major source of HAP, non-emergency stationary CI RICE >500 HP located at a major source of HAP, and existing non-emergency stationary CI RICE >500 HP located at an area source of HAP	a. Reduce CO emissions, and using a CEMS	i. You have installed a CEMS to continuously monitor CO and either O_2or CO_2at both the inlet and outlet of the oxidation catalyst according to the requirements in § 63.6625(a); and ii. You have conducted a performance evaluation of your CEMS using PS 3 and 4A of 40 CFR part 60, appendix B; and
		iii. The average reduction of CO calculated using § 63.6620 equals or exceeds the required percent reduction. The initial test comprises the first 4-hour period after successful validation of the CEMS. Compliance is based on the average percent reduction achieved during the 4-hour period.
6. Non-emergency stationary CI RICE >500 HP located at a major source of HAP, and existing non-emergency stationary CI RICE >500 HP located at an area source of HAP	a. Limit the concentration of CO, and using a CEMS	i. You have installed a CEMS to continuously monitor CO and either O_2or CO_2at the outlet of the oxidation catalyst according to the requirements in § 63.6625(a); and
		ii. You have conducted a performance evaluation of your CEMS using PS 3 and 4A of 40 CFR part 60, appendix B; and
		iii. The average concentration of CO calculated using § 63.6620 is less than or equal to the CO emission limitation. The initial test comprises the first 4-hour period after successful validation of the CEMS. Compliance is based on the average concentration measured during the 4-hour period.

For each . . .	**Complying with the requirement to . . .**	**You have demonstrated initial compliance if . . .**
7. Non-emergency 4SRB stationary RICE >500 HP located at a major source of HAP	a. Reduce formaldehyde emissions and using NSCR	i. The average reduction of emissions of formaldehyde determined from the initial performance test is equal to or greater than the required formaldehyde percent reduction, or the average reduction of emissions of THC determined from the initial performance test is equal to or greater than 30 percent; and
		ii. You have installed a CPMS to continuously monitor catalyst inlet temperature according to the requirements in § 63.6625(b); and
		iii. You have recorded the catalyst pressure drop and catalyst inlet temperature during the initial performance test.
8. Non-emergency 4SRB stationary RICE >500 HP located at a major source of HAP	a. Reduce formaldehyde emissions and not using NSCR	i. The average reduction of emissions of formaldehyde determined from the initial performance test is equal to or greater than the required formaldehyde percent reduction or the average reduction of emissions of THC determined from the initial performance test is equal to or greater than 30 percent; and
		ii. You have installed a CPMS to continuously monitor operating parameters approved by the Administrator (if any) according to the requirements in § 63.6625(b); and
		iii. You have recorded the approved operating parameters (if any) during the initial performance test.
9. New or reconstructed non-emergency stationary RICE >500 HP located at a major source of HAP, new or reconstructed non-emergency 4SLB stationary RICE 250≤HP≤500 located at a major source of HAP, and existing non-emergency 4SRB stationary RICE >500 HP located at a major source of HAP	a. Limit the concentration of formaldehyde in the stationary RICE exhaust and using oxidation catalyst or NSCR	i. The average formaldehyde concentration, corrected to 15 percent O_2, dry basis, from the three test runs is less than or equal to the formaldehyde emission limitation; and ii. You have installed a CPMS to continuously monitor catalyst inlet temperature according to the requirements in § 63.6625(b); and
		iii. You have recorded the catalyst pressure drop and catalyst inlet temperature during the initial performance test.

For each . . .	**Complying with the requirement to . . .**	**You have demonstrated initial compliance if . . .**
10. New or reconstructed non-emergency stationary RICE >500 HP located at a major source of HAP, new or reconstructed non-emergency 4SLB stationary RICE 250≤HP≤500 located at a major source of HAP, and existing non-emergency 4SRB stationary RICE >500 HP located at a major source of HAP	a. Limit the concentration of formaldehyde in the stationary RICE exhaust and not using oxidation catalyst or NSCR	i. The average formaldehyde concentration, corrected to 15 percent O_2, dry basis, from the three test runs is less than or equal to the formaldehyde emission limitation; and ii. You have installed a CPMS to continuously monitor operating parameters approved by the Administrator (if any) according to the requirements in § 63.6625(b); and
		iii. You have recorded the approved operating parameters (if any) during the initial performance test.
11. Existing non-emergency stationary RICE 100≤HP≤500 located at a major source of HAP, and existing non-emergency stationary CI RICE 300<HP≤500 located at an area source of HAP	a. Reduce CO emissions	i. The average reduction of emissions of CO or formaldehyde, as applicable determined from the initial performance test is equal to or greater than the required CO or formaldehyde, as applicable, percent reduction.
12. Existing non-emergency stationary RICE 100≤HP≤500 located at a major source of HAP, and existing non-emergency stationary CI RICE 300<HP≤500 located at an area source of HAP	a. Limit the concentration of formaldehyde or CO in the stationary RICE exhaust	i. The average formaldehyde or CO concentration, as applicable, corrected to 15 percent O_2, dry basis, from the three test runs is less than or equal to the formaldehyde or CO emission limitation, as applicable.
13. Existing non-emergency 4SLB stationary RICE >500 HP located at an area source of HAP that are not remote stationary RICE and that are operated more than 24 hours per calendar year	a. Install an oxidation catalyst	i. You have conducted an initial compliance demonstration as specified in § 63.6630(e) to show that the average reduction of emissions of CO is 93 percent or more, or the average CO concentration is less than or equal to 47 ppmvd at 15 percent O_2;
		ii. You have installed a CPMS to continuously monitor catalyst inlet temperature according to the requirements in § 63.6625(b), or you have installed equipment to automatically shut down the engine if the catalyst inlet temperature exceeds 1350 °F.

For each . . .	Complying with the requirement to . . .	You have demonstrated initial compliance if . . .
14. Existing non-emergency 4SRB stationary RICE >500 HP located at an area source of HAP that are not remote stationary RICE and that are operated more than 24 hours per calendar year	a. Install NSCR	i. You have conducted an initial compliance demonstration as specified in § 63.6630(e) to show that the average reduction of emissions of CO is 75 percent or more, the average CO concentration is less than or equal to 270 ppmvd at 15 percent O_2, or the average reduction of emissions of THC is 30 percent or more;
		ii. You have installed a CPMS to continuously monitor catalyst inlet temperature according to the requirements in § 63.6625(b), or you have installed equipment to automatically shut down the engine if the catalyst inlet temperature exceeds 1250 °F.

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Table 6 to Subpart ZZZZ of Part 63—Continuous Compliance With Emission Limitations, and Other Requirements

As stated in § 63.6640, you must continuously comply with the emissions and operating limitations and work or management practices as required by the following:

Table 6 to Subpart ZZZZ of Part 63—Continuous Compliance With Emission Limitations, and Other Requirements

For each . . .	Complying with the requirement to . . .	You must demonstrate continuous compliance by . . .
1. New or reconstructed non-emergency 2SLB stationary RICE >500 HP located at a major source of HAP, new or reconstructed non-emergency 4SLB stationary RICE ≥250 HP located at a major source of HAP, and new or reconstructed non-emergency CI stationary RICE >500 HP located at a major source of HAP	a. Reduce CO emissions and using an oxidation catalyst, and using a CPMS	i. Conducting semiannual performance tests for CO to demonstrate that the required CO percent reduction is achieved [a]; and ii. Collecting the catalyst inlet temperature data according to § 63.6625(b); and iii. Reducing these data to 4-hour rolling averages; and
		iv. Maintaining the 4-hour rolling averages within the operating limitations for the catalyst inlet temperature; and

For each . . .	Complying with the requirement to . . .	You must demonstrate continuous compliance by . . .
		v. Measuring the pressure drop across the catalyst once per month and demonstrating that the pressure drop across the catalyst is within the operating limitation established during the performance test.
2. New or reconstructed non-emergency 2SLB stationary RICE >500 HP located at a major source of HAP, new or reconstructed non-emergency 4SLB stationary RICE ≥250 HP located at a major source of HAP, and new or reconstructed non-emergency CI stationary RICE >500 HP located at a major source of HAP	a. Reduce CO emissions and not using an oxidation catalyst, and using a CPMS	i. Conducting semiannual performance tests for CO to demonstrate that the required CO percent reduction is achieved [a]; and ii. Collecting the approved operating parameter (if any) data according to § 63.6625(b); and iii. Reducing these data to 4-hour rolling averages; and
		iv. Maintaining the 4-hour rolling averages within the operating limitations for the operating parameters established during the performance test.
3. New or reconstructed non-emergency 2SLB stationary RICE >500 HP located at a major source of HAP, new or reconstructed non-emergency 4SLB stationary RICE ≥250 HP located at a major source of HAP, new or reconstructed non-emergency stationary CI RICE >500 HP located at a major source of HAP, and existing non-emergency stationary CI RICE >500 HP	a. Reduce CO emissions or limit the concentration of CO in the stationary RICE exhaust, and using a CEMS	i. Collecting the monitoring data according to § 63.6625(a), reducing the measurements to 1-hour averages, calculating the percent reduction or concentration of CO emissions according to § 63.6620; and ii. Demonstrating that the catalyst achieves the required percent reduction of CO emissions over the 4-hour averaging period, or that the emission remain at or below the CO concentration limit; and
		iii. Conducting an annual RATA of your CEMS using PS 3 and 4A of 40 CFR part 60, appendix B, as well as daily and periodic data quality checks in accordance with 40 CFR part 60, appendix F, procedure 1.
4. Non-emergency 4SRB stationary RICE >500 HP located at a major source of HAP	a. Reduce formaldehyde emissions and using NSCR	i. Collecting the catalyst inlet temperature data according to § 63.6625(b); and
		ii. Reducing these data to 4-hour rolling averages; and
		iii. Maintaining the 4-hour rolling averages within the operating limitations for the catalyst inlet temperature; and

For each . . .	Complying with the requirement to . . .	You must demonstrate continuous compliance by . . .
		iv. Measuring the pressure drop across the catalyst once per month and demonstrating that the pressure drop across the catalyst is within the operating limitation established during the performance test.
5. Non-emergency 4SRB stationary RICE >500 HP located at a major source of HAP	a. Reduce formaldehyde emissions and not using NSCR	i. Collecting the approved operating parameter (if any) data according to § 63.6625(b); and
		ii. Reducing these data to 4-hour rolling averages; and
		iii. Maintaining the 4-hour rolling averages within the operating limitations for the operating parameters established during the performance test.
6. Non-emergency 4SRB stationary RICE with a brake HP ≥5,000 located at a major source of HAP	a. Reduce formaldehyde emissions	Conducting semiannual performance tests for formaldehyde to demonstrate that the required formaldehyde percent reduction is achieved, or to demonstrate that the average reduction of emissions of THC determined from the performance test is equal to or greater than 30 percent.[a]
7. New or reconstructed non-emergency stationary RICE >500 HP located at a major source of HAP and new or reconstructed non-emergency 4SLB stationary RICE 250≤HP≤500 located at a major source of HAP	a. Limit the concentration of formaldehyde in the stationary RICE exhaust and using oxidation catalyst or NSCR	i. Conducting semiannual performance tests for formaldehyde to demonstrate that your emissions remain at or below the formaldehyde concentration limit [a]; and ii. Collecting the catalyst inlet temperature data according to § 63.6625(b); and
		iii. Reducing these data to 4-hour rolling averages; and
		iv. Maintaining the 4-hour rolling averages within the operating limitations for the catalyst inlet temperature; and
		v. Measuring the pressure drop across the catalyst once per month and demonstrating that the pressure drop across the catalyst is within the operating limitation established during the performance test.

For each . . .	Complying with the requirement to . . .	You must demonstrate continuous compliance by . . .
8. New or reconstructed non-emergency stationary RICE >500 HP located at a major source of HAP and new or reconstructed non-emergency 4SLB stationary RICE 250≤HP≤500 located at a major source of HAP	a. Limit the concentration of formaldehyde in the stationary RICE exhaust and not using oxidation catalyst or NSCR	i. Conducting semiannual performance tests for formaldehyde to demonstrate that your emissions remain at or below the formaldehyde concentration limit [a]; and ii. Collecting the approved operating parameter (if any) data according to § 63.6625(b); and
		iii. Reducing these data to 4-hour rolling averages; and
		iv. Maintaining the 4-hour rolling averages within the operating limitations for the operating parameters established during the performance test.
9. Existing emergency and black start stationary RICE ≤500 HP located at a major source of HAP, existing non-emergency stationary RICE <100 HP located at a major source of HAP, existing emergency and black start stationary RICE located at an area source of HAP, existing non-emergency stationary CI RICE ≤300 HP located at an area source of HAP, existing non-emergency 2SLB stationary RICE located at an area source of HAP, existing non-emergency stationary SI RICE located at an area source of HAP which combusts landfill or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis, existing non-emergency 4SLB and 4SRB stationary RICE ≤500 HP located at an area source of HAP, existing non-emergency 4SLB and 4SRB stationary RICE >500 HP located at an area source of HAP that operate 24 hours or less per calendar year, and existing non-emergency 4SLB and 4SRB stationary RICE >500 HP located at an area source of HAP that are remote stationary RICE	a. Work or Management practices	i. Operating and maintaining the stationary RICE according to the manufacturer's emission-related operation and maintenance instructions; or ii. Develop and follow your own maintenance plan which must provide to the extent practicable for the maintenance and operation of the engine in a manner consistent with good air pollution control practice for minimizing emissions.

For each . . .	**Complying with the requirement to . . .**	**You must demonstrate continuous compliance by . . .**
10. Existing stationary CI RICE >500 HP that are not limited use stationary RICE	a. Reduce CO emissions, or limit the concentration of CO in the stationary RICE exhaust, and using oxidation catalyst	i. Conducting performance tests every 8,760 hours or 3 years, whichever comes first, for CO or formaldehyde, as appropriate, to demonstrate that the required CO or formaldehyde, as appropriate, percent reduction is achieved or that your emissions remain at or below the CO or formaldehyde concentration limit; and
		ii. Collecting the catalyst inlet temperature data according to § 63.6625(b); and
		iii. Reducing these data to 4-hour rolling averages; and
		iv. Maintaining the 4-hour rolling averages within the operating limitations for the catalyst inlet temperature; and
		v. Measuring the pressure drop across the catalyst once per month and demonstrating that the pressure drop across the catalyst is within the operating limitation established during the performance test.
11. Existing stationary CI RICE >500 HP that are not limited use stationary RICE	a. Reduce CO emissions, or limit the concentration of CO in the stationary RICE exhaust, and not using oxidation catalyst	i. Conducting performance tests every 8,760 hours or 3 years, whichever comes first, for CO or formaldehyde, as appropriate, to demonstrate that the required CO or formaldehyde, as appropriate, percent reduction is achieved or that your emissions remain at or below the CO or formaldehyde concentration limit; and
		ii. Collecting the approved operating parameter (if any) data according to § 63.6625(b); and
		iii. Reducing these data to 4-hour rolling averages; and
		iv. Maintaining the 4-hour rolling averages within the operating limitations for the operating parameters established during the performance test.

For each . . .	**Complying with the requirement to . . .**	**You must demonstrate continuous compliance by . . .**
12. Existing limited use CI stationary RICE >500 HP	a. Reduce CO emissions or limit the concentration of CO in the stationary RICE exhaust, and using an oxidation catalyst	i. Conducting performance tests every 8,760 hours or 5 years, whichever comes first, for CO or formaldehyde, as appropriate, to demonstrate that the required CO or formaldehyde, as appropriate, percent reduction is achieved or that your emissions remain at or below the CO or formaldehyde concentration limit; and
		ii. Collecting the catalyst inlet temperature data according to § 63.6625(b); and
		iii. Reducing these data to 4-hour rolling averages; and
		iv. Maintaining the 4-hour rolling averages within the operating limitations for the catalyst inlet temperature; and
		v. Measuring the pressure drop across the catalyst once per month and demonstrating that the pressure drop across the catalyst is within the operating limitation established during the performance test.
13. Existing limited use CI stationary RICE >500 HP	a. Reduce CO emissions or limit the concentration of CO in the stationary RICE exhaust, and not using an oxidation catalyst	i. Conducting performance tests every 8,760 hours or 5 years, whichever comes first, for CO or formaldehyde, as appropriate, to demonstrate that the required CO or formaldehyde, as appropriate, percent reduction is achieved or that your emissions remain at or below the CO or formaldehyde concentration limit; and
		ii. Collecting the approved operating parameter (if any) data according to § 63.6625(b); and
		iii. Reducing these data to 4-hour rolling averages; and
		iv. Maintaining the 4-hour rolling averages within the operating limitations for the operating parameters established during the performance test.

For each . . .	Complying with the requirement to . . .	You must demonstrate continuous compliance by . . .
14. Existing non-emergency 4SLB stationary RICE >500 HP located at an area source of HAP that are not remote stationary RICE and that are operated more than 24 hours per calendar year	a. Install an oxidation catalyst	i. Conducting annual compliance demonstrations as specified in § 63.6640(c) to show that the average reduction of emissions of CO is 93 percent or more, or the average CO concentration is less than or equal to 47 ppmvd at 15 percent O_2; and either ii. Collecting the catalyst inlet temperature data according to § 63.6625(b), reducing these data to 4-hour rolling averages; and maintaining the 4-hour rolling averages within the limitation of greater than 450 °F and less than or equal to 1350 °F for the catalyst inlet temperature; or iii. Immediately shutting down the engine if the catalyst inlet temperature exceeds 1350 °F.
15. Existing non-emergency 4SRB stationary RICE >500 HP located at an area source of HAP that are not remote stationary RICE and that are operated more than 24 hours per calendar year	a. Install NSCR	i. Conducting annual compliance demonstrations as specified in § 63.6640(c) to show that the average reduction of emissions of CO is 75 percent or more, the average CO concentration is less than or equal to 270 ppmvd at 15 percent $O_{2,}$ or the average reduction of emissions of THC is 30 percent or more; and either ii. Collecting the catalyst inlet temperature data according to § 63.6625(b), reducing these data to 4-hour rolling averages; and maintaining the 4-hour rolling averages within the limitation of greater than or equal to 750 °F and less than or equal to 1250 °F for the catalyst inlet temperature; or iii. Immediately shutting down the engine if the catalyst inlet temperature exceeds 1250 °F.

[a] After you have demonstrated compliance for two consecutive tests, you may reduce the frequency of subsequent performance tests to annually. If the results of any subsequent annual performance test indicate the stationary RICE is not in compliance with the CO or formaldehyde emission limitation, or you deviate from any of your operating limitations, you must resume semiannual performance tests.

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Table 7 to Subpart ZZZZ of Part 63—Requirements for Reports

As stated in § 63.6650, you must comply with the following requirements for reports:

Table 7 to Subpart ZZZZ of Part 63—Requirements for Reports

For each . . .	You must submit a . . .	The report must contain . . .	You must submit the report . . .
1. Existing non-emergency, non-black start stationary RICE 100≤HP≤500 located at a major source of HAP; existing non-emergency, non-black start stationary CI RICE >500 HP located at a major source of HAP; existing non-emergency 4SRB stationary RICE >500 HP located at a major source of HAP; existing non-emergency, non-black start stationary CI RICE >300 HP located at an area source of HAP; new or reconstructed non-emergency stationary RICE >500 HP located at a major source of HAP; and new or reconstructed non-emergency 4SLB stationary RICE 250≤HP≤500 located at a major source of HAP	Compliance report	a. If there are no deviations from any emission limitations or operating limitations that apply to you, a statement that there were no deviations from the emission limitations or operating limitations during the reporting period. If there were no periods during which the CMS, including CEMS and CPMS, was out-of-control, as specified in § 63.8(c)(7), a statement that there were not periods during which the CMS was out-of-control during the reporting period; or	i. Semiannually according to the requirements in § 63.6650(b)(1)-(5) for engines that are not limited use stationary RICE subject to numerical emission limitations; and ii. Annually according to the requirements in § 63.6650(b)(6)-(9) for engines that are limited use stationary RICE subject to numerical emission limitations.
		b. If you had a deviation from any emission limitation or operating limitation during the reporting period, the information in § 63.6650(d). If there were periods during which the CMS, including CEMS and CPMS, was out-of-control, as specified in § 63.8(c)(7), the information in § 63.6650(e); or	i. Semiannually according to the requirements in § 63.6650(b).
		c. If you had a malfunction during the reporting period, the information in § 63.6650(c)(4).	i. Semiannually according to the requirements in § 63.6650(b).
2. New or reconstructed non-emergency stationary RICE that combusts landfill gas or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis	Report	a. The fuel flow rate of each fuel and the heating values that were used in your calculations, and you must demonstrate that the percentage of heat input provided by landfill gas or digester gas, is equivalent to 10 percent or more of the gross heat input on an annual basis; and	i. Annually, according to the requirements in § 63.6650.

For each . . .	You must submit a . . .	The report must contain . . .	You must submit the report . . .
		b. The operating limits provided in your federally enforceable permit, and any deviations from these limits; and	i. See item 2.a.i.
		c. Any problems or errors suspected with the meters.	i. See item 2.a.i.
3. Existing non-emergency, non-black start 4SLB and 4SRB stationary RICE >500 HP located at an area source of HAP that are not remote stationary RICE and that operate more than 24 hours per calendar year	Compliance report	a. The results of the annual compliance demonstration, if conducted during the reporting period.	i. Semiannually according to the requirements in § 63.6650(b)(1)-(5).
4. Emergency stationary RICE that operate or are contractually obligated to be available for more than 15 hours per year for the purposes specified in § 63.6640(f)(2)(ii) and (iii) or that operate for the purposes specified in § 63.6640(f)(4)(ii)	Report	a. The information in § 63.6650(h)(1)	i. annually according to the requirements in § 63.6650(h)(2)-(3).

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Table 8 to Subpart ZZZZ of Part 63—Applicability of General Provisions to Subpart ZZZZ.

As stated in § 63.6665, you must comply with the following applicable general provisions.

General provisions citation	Subject of citation	Applies to subpart	Explanation
§ 63.1	General applicability of the General Provisions	Yes.	
§ 63.2	Definitions	Yes	Additional terms defined in § 63.6675.
§ 63.3	Units and abbreviations	Yes.	
§ 63.4	Prohibited activities and circumvention	Yes.	
§ 63.5	Construction and reconstruction	Yes.	
§ 63.6(a)	Applicability	Yes.	

§ 63.6(b)(1)-(4)	Compliance dates for new and reconstructed sources	Yes.	
§ 63.6(b)(5)	Notification	Yes.	
§ 63.6(b)(6)	[Reserved]		
§ 63.6(b)(7)	Compliance dates for new and reconstructed area sources that become major sources	Yes.	
§ 63.6(c)(1)-(2)	Compliance dates for existing sources	Yes.	
§ 63.6(c)(3)-(4)	[Reserved]		
§ 63.6(c)(5)	Compliance dates for existing area sources that become major sources	Yes.	
§ 63.6(d)	[Reserved]		
§ 63.6(e)	Operation and maintenance	No.	
§ 63.6(f)(1)	Applicability of standards	No.	
§ 63.6(f)(2)	Methods for determining compliance	Yes.	
§ 63.6(f)(3)	Finding of compliance	Yes.	
§ 63.6(g)(1)-(3)	Use of alternate standard	Yes.	
§ 63.6(h)	Opacity and visible emission standards	No	Subpart ZZZZ does not contain opacity or visible emission standards.
§ 63.6(i)	Compliance extension procedures and criteria	Yes.	
§ 63.6(j)	Presidential compliance exemption	Yes.	
§ 63.7(a)(1)-(2)	Performance test dates	Yes	Subpart ZZZZ contains performance test dates at §§ 63.6610, 63.6611, and 63.6612.
§ 63.7(a)(3)	CAA section 114 authority	Yes.	
§ 63.7(b)(1)	Notification of performance test	Yes	Except that § 63.7(b)(1) only applies as specified in § 63.6645.
§ 63.7(b)(2)	Notification of rescheduling	Yes	Except that § 63.7(b)(2) only applies as specified in § 63.6645.
§ 63.7(c)	Quality assurance/test plan	Yes	Except that § 63.7(c) only applies as specified in § 63.6645.
§ 63.7(d)	Testing facilities	Yes.	

§ 63.7(e)(1)	Conditions for conducting performance tests	No.	Subpart ZZZZ specifies conditions for conducting performance tests at § 63.6620.
§ 63.7(e)(2)	Conduct of performance tests and reduction of data	Yes	Subpart ZZZZ specifies test methods at § 63.6620.
§ 63.7(e)(3)	Test run duration	Yes.	
§ 63.7(e)(4)	Administrator may require other testing under section 114 of the CAA	Yes.	
§ 63.7(f)	Alternative test method provisions	Yes.	
§ 63.7(g)	Performance test data analysis, recordkeeping, and reporting	Yes.	
§ 63.7(h)	Waiver of tests	Yes.	
§ 63.8(a)(1)	Applicability of monitoring requirements	Yes	Subpart ZZZZ contains specific requirements for monitoring at § 63.6625.
§ 63.8(a)(2)	Performance specifications	Yes.	
§ 63.8(a)(3)	[Reserved]		
§ 63.8(a)(4)	Monitoring for control devices	No.	
§ 63.8(b)(1)	Monitoring	Yes.	
§ 63.8(b)(2)-(3)	Multiple effluents and multiple monitoring systems	Yes.	
§ 63.8(c)(1)	Monitoring system operation and maintenance	Yes.	
§ 63.8(c)(1)(i)	Routine and predictable SSM	No	
§ 63.8(c)(1)(ii)	SSM not in Startup Shutdown Malfunction Plan	Yes.	
§ 63.8(c)(1)(iii)	Compliance with operation and maintenance requirements	No	
§ 63.8(c)(2)-(3)	Monitoring system installation	Yes.	
§ 63.8(c)(4)	Continuous monitoring system (CMS) requirements	Yes	Except that subpart ZZZZ does not require Continuous Opacity Monitoring System (COMS).
§ 63.8(c)(5)	COMS minimum procedures	No	Subpart ZZZZ does not require COMS.
§ 63.8(c)(6)-(8)	CMS requirements	Yes	Except that subpart ZZZZ does not require COMS.
§ 63.8(d)	CMS quality control	Yes.	

§ 63.8(e)	CMS performance evaluation	Yes	Except for § 63.8(e)(5)(ii), which applies to COMS.
		Except that § 63.8(e) only applies as specified in § 63.6645.	
§ 63.8(f)(1)-(5)	Alternative monitoring method	Yes	Except that § 63.8(f)(4) only applies as specified in § 63.6645.
§ 63.8(f)(6)	Alternative to relative accuracy test	Yes	Except that § 63.8(f)(6) only applies as specified in § 63.6645.
§ 63.8(g)	Data reduction	Yes	Except that provisions for COMS are not applicable. Averaging periods for demonstrating compliance are specified at §§ 63.6635 and 63.6640.
§ 63.9(a)	Applicability and State delegation of notification requirements	Yes.	
§ 63.9(b)(1)-(5)	Initial notifications	Yes	Except that § 63.9(b)(3) is reserved.
		Except that § 63.9(b) only applies as specified in § 63.6645.	
§ 63.9(c)	Request for compliance extension	Yes	Except that § 63.9(c) only applies as specified in § 63.6645.
§ 63.9(d)	Notification of special compliance requirements for new sources	Yes	Except that § 63.9(d) only applies as specified in § 63.6645.
§ 63.9(e)	Notification of performance test	Yes	Except that § 63.9(e) only applies as specified in § 63.6645.
§ 63.9(f)	Notification of visible emission (VE)/opacity test	No	Subpart ZZZZ does not contain opacity or VE standards.
§ 63.9(g)(1)	Notification of performance evaluation	Yes	Except that § 63.9(g) only applies as specified in § 63.6645.
§ 63.9(g)(2)	Notification of use of COMS data	No	Subpart ZZZZ does not contain opacity or VE standards.
§ 63.9(g)(3)	Notification that criterion for alternative to RATA is exceeded	Yes	If alternative is in use.

		Except that § 63.9(g) only applies as specified in § 63.6645.	
§ 63.9(h)(1)-(6)	Notification of compliance status	Yes	Except that notifications for sources using a CEMS are due 30 days after completion of performance evaluations. § 63.9(h)(4) is reserved.
			Except that § 63.9(h) only applies as specified in § 63.6645.
§ 63.9(i)	Adjustment of submittal deadlines	Yes.	
§ 63.9(j)	Change in previous information	Yes.	
§ 63.10(a)	Administrative provisions for recordkeeping/reporting	Yes.	
§ 63.10(b)(1)	Record retention	Yes	Except that the most recent 2 years of data do not have to be retained on site.
§ 63.10(b)(2)(i)-(v)	Records related to SSM	No.	
§ 63.10(b)(2)(vi)-(xi)	Records	Yes.	
§ 63.10(b)(2)(xii)	Record when under waiver	Yes.	
§ 63.10(b)(2)(xiii)	Records when using alternative to RATA	Yes	For CO standard if using RATA alternative.
§ 63.10(b)(2)(xiv)	Records of supporting documentation	Yes.	
§ 63.10(b)(3)	Records of applicability determination	Yes.	
§ 63.10(c)	Additional records for sources using CEMS	Yes	Except that § 63.10(c)(2)-(4) and (9) are reserved.
§ 63.10(d)(1)	General reporting requirements	Yes.	
§ 63.10(d)(2)	Report of performance test results	Yes.	
§ 63.10(d)(3)	Reporting opacity or VE observations	No	Subpart ZZZZ does not contain opacity or VE standards.
§ 63.10(d)(4)	Progress reports	Yes.	
§ 63.10(d)(5)	Startup, shutdown, and malfunction reports	No.	
§ 63.10(e)(1) and (2)(i)	Additional CMS Reports	Yes.	

§ 63.10(e)(2)(ii)	COMS-related report	No	Subpart ZZZZ does not require COMS.
§ 63.10(e)(3)	Excess emission and parameter exceedances reports	Yes.	Except that § 63.10(e)(3)(i) (C) is reserved.
§ 63.10(e)(4)	Reporting COMS data	No	Subpart ZZZZ does not require COMS.
§ 63.10(f)	Waiver for recordkeeping/reporting	Yes.	
§ 63.11	Flares	No.	
§ 63.12	State authority and delegations	Yes.	
§ 63.13	Addresses	Yes.	
§ 63.14	Incorporation by reference	Yes.	
§ 63.15	Availability of information	Yes.	

[75 FR 9688, Mar. 3, 2010, as amended at 78 FR 6720, Jan. 30, 2013]

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Appendix A—Protocol for Using an Electrochemical Analyzer to Determine Oxygen and Carbon Monoxide Concentrations From Certain Engines

1.0 SCOPE AND APPLICATION. WHAT IS THIS PROTOCOL?

This protocol is a procedure for using portable electrochemical (EC) cells for measuring carbon monoxide (CO) and oxygen (O_2) concentrations in controlled and uncontrolled emissions from existing stationary 4-stroke lean burn and 4-stroke rich burn reciprocating internal combustion engines as specified in the applicable rule.

1.1 Analytes. What does this protocol determine?

This protocol measures the engine exhaust gas concentrations of carbon monoxide (CO) and oxygen (O_2).

Analyte	**CAS No.**	**Sensitivity**
Carbon monoxide (CO)	630-08-0	Minimum detectable limit should be 2 percent of the nominal range or 1 ppm, whichever is less restrictive.
Oxygen (O_2)	*7782-44-7*	

1.2 Applicability. When is this protocol acceptable?

This protocol is applicable to 40 CFR part 63, subpart ZZZZ. Because of inherent cross sensitivities of EC cells, you must not apply this protocol to other emissions sources without specific instruction to that effect.

1.3 Data Quality Objectives. How good must my collected data be?

Refer to Section 13 to verify and document acceptable analyzer performance.

1.4 Range. What is the targeted analytical range for this protocol?

The measurement system and EC cell design(s) conforming to this protocol will determine the analytical range for each gas component. The nominal ranges are defined by choosing up-scale calibration gas concentrations near the maximum anticipated flue gas concentrations for CO and O_2 , or no more than twice the permitted CO level.

1.5 Sensitivity. What minimum detectable limit will this protocol yield for a particular gas component?

The minimum detectable limit depends on the nominal range and resolution of the specific EC cell used, and the signal to noise ratio of the measurement system. The minimum detectable limit should be 2 percent of the nominal range or 1 ppm, whichever is less restrictive.

2.0 SUMMARY OF PROTOCOL

In this protocol, a gas sample is extracted from an engine exhaust system and then conveyed to a portable EC analyzer for measurement of CO and O_2 gas concentrations. This method provides measurement system performance specifications and sampling protocols to ensure reliable data. You may use additions to, or modifications of vendor supplied measurement systems (e.g., heated or unheated sample lines, thermocouples, flow meters, selective gas scrubbers, etc.) to meet the design specifications of this protocol. Do not make changes to the measurement system from the as-verified configuration (Section 3.12).

3.0 DEFINITIONS

3.1 Measurement System. The total equipment required for the measurement of CO and O_2 concentrations. The measurement system consists of the following major subsystems:

3.1.1 Data Recorder. A strip chart recorder, computer or digital recorder for logging measurement data from the analyzer output. You may record measurement data from the digital data display manually or electronically.

3.1.2 Electrochemical (EC) Cell. A device, similar to a fuel cell, used to sense the presence of a specific analyte and generate an electrical current output proportional to the analyte concentration.

3.1.3 Interference Gas Scrubber. A device used to remove or neutralize chemical compounds that may interfere with the selective operation of an EC cell.

3.1.4 Moisture Removal System. Any device used to reduce the concentration of moisture in the sample stream so as to protect the EC cells from the damaging effects of condensation and to minimize errors in measurements caused by the scrubbing of soluble gases.

3.1.5 Sample Interface. The portion of the system used for one or more of the following: sample acquisition; sample transport; sample conditioning or protection of the EC cell from any degrading effects of the engine exhaust effluent; removal of particulate matter and condensed moisture.

3.2 Nominal Range. The range of analyte concentrations over which each EC cell is operated (normally 25 percent to 150 percent of up-scale calibration gas value). Several nominal ranges can be used for any given cell so long as the calibration and repeatability checks for that range remain within specifications.

3.3 Calibration Gas. A vendor certified concentration of a specific analyte in an appropriate balance gas.

3.4 Zero Calibration Error. The analyte concentration output exhibited by the EC cell in response to zero-level calibration gas.

3.5 Up-Scale Calibration Error. The mean of the difference between the analyte concentration exhibited by the EC cell and the certified concentration of the up-scale calibration gas.

3.6 Interference Check. A procedure for quantifying analytical interference from components in the engine exhaust gas other than the targeted analytes.

3.7 Repeatability Check. A protocol for demonstrating that an EC cell operated over a given nominal analyte concentration range provides a stable and consistent response and is not significantly affected by repeated exposure to that gas.

3.8 Sample Flow Rate. The flow rate of the gas sample as it passes through the EC cell. In some situations, EC cells can experience drift with changes in flow rate. The flow rate must be monitored and documented during all phases of a sampling run.

3.9 Sampling Run. A timed three-phase event whereby an EC cell's response rises and plateaus in a sample conditioning phase, remains relatively constant during a measurement data phase, then declines during a refresh phase. The sample conditioning phase exposes the EC cell to the gas sample for a length of time sufficient to reach a constant response. The measurement data phase is the time interval during which gas sample measurements can be made that meet the acceptance criteria of this protocol. The refresh phase then purges the EC cells with CO-free air. The refresh phase replenishes requisite O_2 and moisture in the electrolyte reserve and provides a mechanism to de-gas or desorb any interference gas scrubbers or filters so as to enable a stable CO EC cell response. There are four primary types of sampling runs: pre- sampling calibrations; stack gas sampling; post-sampling calibration checks; and measurement system repeatability checks. Stack gas sampling runs can be chained together for extended evaluations, providing all other procedural specifications are met.

3.10 Sampling Day. A time not to exceed twelve hours from the time of the pre-sampling calibration to the post-sampling calibration check. During this time, stack gas sampling runs can be repeated without repeated recalibrations, providing all other sampling specifications have been met.

3.11 Pre-Sampling Calibration/Post-Sampling Calibration Check. The protocols executed at the beginning and end of each sampling day to bracket measurement readings with controlled performance checks.

3.12 Performance-Established Configuration. The EC cell and sampling system configuration that existed at the time that it initially met the performance requirements of this protocol.

4.0 INTERFERENCES.

When present in sufficient concentrations, NO and NO_2 are two gas species that have been reported to interfere with CO concentration measurements. In the likelihood of this occurrence, it is the protocol user's responsibility to employ and properly maintain an appropriate CO EC cell filter or scrubber for removal of these gases, as described in Section 6.2.12.

5.0 SAFETY. [RESERVED]

6.0 EQUIPMENT AND SUPPLIES.

6.1 What equipment do I need for the measurement system?

The system must maintain the gas sample at conditions that will prevent moisture condensation in the sample transport lines, both before and as the sample gas contacts the EC cells. The essential components of the measurement system are described below.

6.2 Measurement System Components.

6.2.1 Sample Probe. A single extraction-point probe constructed of glass, stainless steel or other non-reactive material, and of length sufficient to reach any designated sampling point. The sample probe must be designed to prevent plugging due to condensation or particulate matter.

6.2.2 Sample Line. Non-reactive tubing to transport the effluent from the sample probe to the EC cell.

6.2.3 Calibration Assembly (optional). A three-way valve assembly or equivalent to introduce calibration gases at ambient pressure at the exit end of the sample probe during calibration checks. The assembly must be designed such that only stack gas or calibration gas flows in the sample line and all gases flow through any gas path filters.

6.2.4 Particulate Filter (optional). Filters before the inlet of the EC cell to prevent accumulation of particulate material in the measurement system and extend the useful life of the components. All filters must be fabricated of materials that are non-reactive to the gas mixtures being sampled.

6.2.5 Sample Pump. A leak-free pump to provide undiluted sample gas to the system at a flow rate sufficient to minimize the response time of the measurement system. If located upstream of the EC cells, the pump must be constructed of a material that is non-reactive to the gas mixtures being sampled.

6.2.8 Sample Flow Rate Monitoring. An adjustable rotameter or equivalent device used to adjust and maintain the sample flow rate through the analyzer as prescribed.

6.2.9 Sample Gas Manifold (optional). A manifold to divert a portion of the sample gas stream to the analyzer and the remainder to a by-pass discharge vent. The sample gas manifold may also include provisions for introducing calibration gases directly to the analyzer. The manifold must be constructed of a material that is non-reactive to the gas mixtures being sampled.

6.2.10 EC cell. A device containing one or more EC cells to determine the CO and O_2 concentrations in the sample gas stream. The EC cell(s) must meet the applicable performance specifications of Section 13 of this protocol.

6.2.11 Data Recorder. A strip chart recorder, computer or digital recorder to make a record of analyzer output data. The data recorder resolution (i.e., readability) must be no greater than 1 ppm for CO; 0.1 percent for O_2 ; and one degree (either °C or °F) for temperature. Alternatively, you may use a digital or analog meter having the same resolution to observe and manually record the analyzer responses.

6.2.12 Interference Gas Filter or Scrubber. A device to remove interfering compounds upstream of the CO EC cell. Specific interference gas filters or scrubbers used in the performance-established configuration of the analyzer must continue to be used. Such a filter or scrubber must have a means to determine when the removal agent is exhausted. Periodically replace or replenish it in accordance with the manufacturer's recommendations.

7.0 REAGENTS AND STANDARDS. WHAT CALIBRATION GASES ARE NEEDED?

7.1 Calibration Gases. CO calibration gases for the EC cell must be CO in nitrogen or CO in a mixture of nitrogen and O_2. Use CO calibration gases with labeled concentration values certified by the manufacturer to be within ± 5 percent of the label value. Dry ambient air (20.9 percent O_2) is acceptable for calibration of the O_2 cell. If needed, any lower percentage O_2 calibration gas must be a mixture of O_2 in nitrogen.

7.1.1 Up-Scale CO Calibration Gas Concentration. Choose one or more up-scale gas concentrations such that the average of the stack gas measurements for each stack gas sampling run are between 25 and 150 percent of those concentrations. Alternatively, choose an up-scale gas that does not exceed twice the concentration of the applicable outlet standard. If a measured gas value exceeds 150 percent of the up-scale CO calibration gas value at any time during the stack gas sampling run, the run must be discarded and repeated.

7.1.2 Up-Scale O_2 Calibration Gas Concentration.

Select an O_2 gas concentration such that the difference between the gas concentration and the average stack gas measurement or reading for each sample run is less than 15 percent O_2 . When the average exhaust gas O_2 readings are above 6 percent, you may use dry ambient air (20.9 percent O_2) for the up-scale O_2 calibration gas.

7.1.3 Zero Gas. Use an inert gas that contains less than 0.25 percent of the up-scale CO calibration gas concentration. You may use dry air that is free from ambient CO and other combustion gas products (e.g., CO_2).

8.0 SAMPLE COLLECTION AND ANALYSIS

8.1 Selection of Sampling Sites.

8.1.1 Control Device Inlet. Select a sampling site sufficiently downstream of the engine so that the combustion gases should be well mixed. Use a single sampling extraction point near the center of the duct (e.g., within the 10 percent centroidal area), unless instructed otherwise.

8.1.2 Exhaust Gas Outlet. Select a sampling site located at least two stack diameters downstream of any disturbance (e.g., turbocharger exhaust, crossover junction or recirculation take-off) and at least one-half stack diameter upstream of the gas discharge to the atmosphere. Use a single sampling extraction point near the center of the duct (e.g., within the 10 percent centroidal area), unless instructed otherwise.

8.2 Stack Gas Collection and Analysis. Prior to the first stack gas sampling run, conduct that the pre-sampling calibration in accordance with Section 10.1. Use Figure 1 to record all data. Zero the analyzer with zero gas. Confirm and record that the scrubber media color is correct and not exhausted. Then position the probe at the sampling point and begin the sampling run at the same flow rate used during the up-scale calibration. Record the start time. Record all EC cell output responses and the flow rate during the “sample conditioning phase” once per minute until constant readings are obtained. Then begin the “measurement data phase” and record readings every 15 seconds for at least two minutes (or eight readings), or as otherwise required to achieve two continuous minutes of data that meet the specification given in Section 13.1. Finally, perform the “refresh phase” by introducing dry air, free from CO and other combustion gases, until several minute-to-minute readings of consistent value have been obtained. For each run use the “measurement data phase” readings to calculate the average stack gas CO and O_2 concentrations.

8.3 EC Cell Rate. Maintain the EC cell sample flow rate so that it does not vary by more than ± 10 percent throughout the pre-sampling calibration, stack gas sampling and post-sampling calibration check. Alternatively, the EC cell sample flow rate can be maintained within a tolerance range that does not affect the gas concentration readings by more than ± 3 percent, as instructed by the EC cell manufacturer.

9.0 QUALITY CONTROL (RESERVED)

10.0 CALIBRATION AND STANDARDIZATION

10.1 Pre-Sampling Calibration. Conduct the following protocol once for each nominal range to be used on each EC cell before performing a stack gas sampling run on each field sampling day. Repeat the calibration if you replace an EC cell before completing all of the sampling runs. There is no prescribed order for calibration of the EC cells; however, each cell must complete the measurement data phase during calibration. Assemble the measurement system by following the manufacturer's recommended protocols including for preparing and preconditioning the EC cell. Assure the measurement system has no leaks and verify the gas scrubbing agent is not depleted. Use Figure 1 to record all data.

10.1.1 Zero Calibration. For both the O_2 and CO cells, introduce zero gas to the measurement system (e.g., at the calibration assembly) and record the concentration reading every minute until readings are constant for at least two consecutive minutes. Include the time and sample flow rate. Repeat the steps in this section at least once to verify the zero calibration for each component gas.

10.1.2 Zero Calibration Tolerance. For each zero gas introduction, the zero level output must be less than or equal to ± 3 percent of the up-scale gas value or ± 1 ppm, whichever is less restrictive, for the CO channel and less than or equal to ± 0.3 percent O_2 for the O_2 channel.

10.1.3 Up-Scale Calibration. Individually introduce each calibration gas to the measurement system (e.g., at the calibration assembly) and record the start time. Record all EC cell output responses and the flow rate during this “sample conditioning phase” once per minute until readings are constant for at least two minutes. Then begin the “measurement data phase” and record readings every 15 seconds for a total of two minutes, or as otherwise required. Finally, perform the “refresh phase” by introducing dry air, free from CO and other combustion gases, until readings are constant for at least two consecutive minutes. Then repeat the steps in this section at least once to verify the calibration for each component gas. Introduce all gases to flow through the entire sample handling system (i.e., at the exit end of the sampling probe or the calibration assembly).

10.1.4 Up-Scale Calibration Error. The mean of the difference of the “measurement data phase” readings from the reported standard gas value must be less than or equal to ± 5 percent or ± 1 ppm for CO or ± 0.5 percent O_2 , whichever is less restrictive, respectively. The maximum allowable deviation from the mean measured value of any single “measurement data phase” reading must be less than or equal to ± 2 percent or ± 1 ppm for CO or ± 0.5 percent O_2 , whichever is less restrictive, respectively.

10.2 Post-Sampling Calibration Check. Conduct a stack gas post-sampling calibration check after the stack gas sampling run or set of runs and within 12 hours of the initial calibration. Conduct up-scale and zero calibration checks using the protocol in Section 10.1. Make no changes to the sampling system or EC cell calibration until all post-sampling calibration checks have been recorded. If either the zero or up-scale calibration error exceeds the respective specification in Sections 10.1.2 and 10.1.4 then all measurement data collected since the previous successful calibrations are invalid and re-calibration and re-sampling are required. If the sampling system is disassembled or the EC cell calibration is adjusted, repeat the calibration check before conducting the next analyzer sampling run.

11.0 ANALYTICAL PROCEDURE

The analytical procedure is fully discussed in Section 8.

12.0 CALCULATIONS AND DATA ANALYSIS

Determine the CO and O_2 concentrations for each stack gas sampling run by calculating the mean gas concentrations of the data recorded during the "measurement data phase".

13.0 PROTOCOL PERFORMANCE

Use the following protocols to verify consistent analyzer performance during each field sampling day.

13.1 Measurement Data Phase Performance Check. Calculate the mean of the readings from the "measurement data phase". The maximum allowable deviation from the mean for each of the individual readings is ± 2 percent, or ± 1 ppm, whichever is less restrictive. Record the mean value and maximum deviation for each gas monitored. Data must conform to Section 10.1.4. The EC cell flow rate must conform to the specification in Section 8.3.

Example: A measurement data phase is invalid if the maximum deviation of any single reading comprising that mean is greater than ± 2 percent *or ± 1 ppm (the default criteria). For example, if the mean = 30 ppm, single readings of below 29 ppm and above 31 ppm are disallowed*).

13.2 Interference Check. Before the initial use of the EC cell and interference gas scrubber in the field, and semi-annually thereafter, challenge the interference gas scrubber with NO and NO_2 gas standards that are generally recognized as representative of diesel-fueled engine NO and NO_2 emission values. Record the responses displayed by the CO EC cell and other pertinent data on Figure 1 or a similar form.

13.2.1 Interference Response. The combined NO and NO_2 interference response should be less than or equal to ± 5 percent of the up-scale CO calibration gas concentration.

13.3 Repeatability Check. Conduct the following check once for each nominal range that is to be used on the CO EC cell within 5 days prior to each field sampling program. If a field sampling program lasts longer than 5 days, repeat this check every 5 days. Immediately repeat the check if the EC cell is replaced or if the EC cell is exposed to gas concentrations greater than 150 percent of the highest up-scale gas concentration.

13.3.1 Repeatability Check Procedure. Perform a complete EC cell sampling run (all three phases) by introducing the CO calibration gas to the measurement system and record the response. Follow Section 10.1.3. Use Figure 1 to record all data. Repeat the run three times for a total of four complete runs. During the four repeatability check runs, do not adjust the system except where necessary to achieve the correct calibration gas flow rate at the analyzer.

13.3.2 Repeatability Check Calculations. Determine the highest and lowest average "measurement data phase" CO concentrations from the four repeatability check runs and record the results on Figure 1 or a similar form. The absolute value of the difference between the maximum and minimum average values recorded must not vary more than ± 3 percent or ± 1 ppm of the up-scale gas value, whichever is less restrictive.

14.0 Pollution Prevention (Reserved)

15.0 Waste Management (Reserved)

16.0 Alternative Procedures (Reserved)

17.0 References

(1) “Development of an Electrochemical Cell Emission Analyzer Test Protocol”, Topical Report, Phil Juneau, Emission Monitoring, Inc., July 1997.

(2) “Determination of Nitrogen Oxides, Carbon Monoxide, and Oxygen Emissions from Natural Gas-Fired Engines, Boilers, and Process Heaters Using Portable Analyzers”, EMC Conditional Test Protocol 30 (CTM-30), Gas Research Institute Protocol GRI-96/0008, Revision 7, October 13, 1997.

(3) “ICAC Test Protocol for Periodic Monitoring”, EMC Conditional Test Protocol 34 (CTM-034), The Institute of Clean Air Companies, September 8, 1999.

(4) “Code of Federal Regulations”, Protection of Environment, 40 CFR, Part 60, Appendix A, Methods 1-4; 10.

Table 1: Appendix A—Sampling Run Data.

Facility__________ Engine I.D.__________ Date______				
Run Type:	(_)	(_)	(_)	(_)
(X)	Pre-Sample Calibration	Stack Gas Sample	Post-Sample Cal. Check	Repeatability Check

.

Run #	1	1	2	2	3	3	4	4	Time	Scrub. OK	Flow- Rate
Gas	O_2	CO	O_2	CO	O_2	CO	O_2	CO			
Sample Cond. Phase											
″											
″											
″											
″											
Measurement Data Phase											
″											
″											
″											

Run #	1	1	2	2	3	3	4	4	Time	Scrub. OK	Flow- Rate
Gas	O_2	CO	O_2	CO	O_2	CO	O_2	CO			
″											
″											
″											
″											
″											
″											
″											
Mean											
Refresh Phase											
″											
″											
″											
″											

[78 FR 6721, Jan. 30, 2013]

Indiana Department of Environmental Management
Office of Air Quality

Attachment C to a Part 70 Operating Permit

Source Background and Description

Source Name:	Ohio Valley Resources, LLC
Source Location:	300-400 East CR 350 North, Rockport, Indiana 47635
County:	Spencer
SIC Code:	2873
Permit No.:	T 147-32322-00062
Permit Reviewer:	David Matousek

40 CFR 60, Subpart VVA

40 CFR 60, Subpart VVA **Standards of Performance for Equipment Leaks of VOC in the Synthetic Organic Chemicals Manufacturing Industry for Which Construction, Reconstruction, or Modification Commenced After November 7, 2006**

Source: 72 FR 64883, Nov. 16, 2007, unless otherwise noted.

§ 60.480a Applicability and designation of affected facility.

(a)(1) The provisions of this subpart apply to affected facilities in the synthetic organic chemicals manufacturing industry.

(2) The group of all equipment (defined in § 60.481a) within a process unit is an affected facility.

(b) Any affected facility under paragraph (a) of this section that commences construction, reconstruction, or modification after November 7, 2006, shall be subject to the requirements of this subpart.

(c) Addition or replacement of equipment for the purpose of process improvement which is accomplished without a capital expenditure shall not by itself be considered a modification under this subpart.

(d)(1) If an owner or operator applies for one or more of the exemptions in this paragraph, then the owner or operator shall maintain records as required in § 60.486a(i).

(2) Any affected facility that has the design capacity to produce less than 1,000 Mg/yr (1,102 ton/yr) of a chemical listed in § 60.489 is exempt from §§ 60.482-1a through 60.482-11a.

(3) If an affected facility produces heavy liquid chemicals only from heavy liquid feed or raw materials, then it is exempt from §§ 60.482-1a through 60.482-11a.

(4) Any affected facility that produces beverage alcohol is exempt from §§ 60.482-1a through 60.482-11a.

(5) Any affected facility that has no equipment in volatile organic compounds (VOC) service is exempt from §§ 60.482-1a through 60.482-11a.

(e) *Alternative means of compliance* —(1) *Option to comply with part 65.* (i) Owners or operators may choose to comply with the provisions of 40 CFR part 65, subpart F, to satisfy the requirements of §§

60.482-1a through 60.487a for an affected facility. When choosing to comply with 40 CFR part 65, subpart F, the requirements of §§ 60.485a(d), (e), and (f), and 60.486a(i) and (j) still apply. Other provisions applying to an owner or operator who chooses to comply with 40 CFR part 65 are provided in 40 CFR 65.1.

(ii) *Part 60, subpart A.* Owners or operators who choose to comply with 40 CFR part 65, subpart F must also comply with §§ 60.1, 60.2, 60.5, 60.6, 60.7(a)(1) and (4), 60.14, 60.15, and 60.16 for that equipment. All sections and paragraphs of subpart A of this part that are not mentioned in this paragraph (e)(1)(ii) do not apply to owners or operators of equipment subject to this subpart complying with 40 CFR part 65, subpart F, except that provisions required to be met prior to implementing 40 CFR part 65 still apply. Owners and operators who choose to comply with 40 CFR part 65, subpart F, must comply with 40 CFR part 65, subpart A.

(2) *Part 63, subpart H.* (i) Owners or operators may choose to comply with the provisions of 40 CFR part 63, subpart H, to satisfy the requirements of §§ 60.482-1a through 60.487a for an affected facility. When choosing to comply with 40 CFR part 63, subpart H, the requirements of § 60.485a(d), (e), and (f), and § 60.486a(i) and (j) still apply.

(ii) *Part 60, subpart A.* Owners or operators who choose to comply with 40 CFR part 63, subpart H must also comply with §§ 60.1, 60.2, 60.5, 60.6, 60.7(a)(1) and (4), 60.14, 60.15, and 60.16 for that equipment. All sections and paragraphs of subpart A of this part that are not mentioned in this paragraph (e)(2)(ii) do not apply to owners or operators of equipment subject to this subpart complying with 40 CFR part 63, subpart H, except that provisions required to be met prior to implementing 40 CFR part 63 still apply. Owners and operators who choose to comply with 40 CFR part 63, subpart H, must comply with 40 CFR part 63, subpart A.

(f) *Stay of standards.* (1) Owners or operators that start a new, reconstructed, or modified affected source prior to November 16, 2007 are not required to comply with the requirements in this paragraph until EPA takes final action to require compliance and publishes a document in the FEDERAL REGISTER .

(i) The definition of “capital expenditure” in § 60.481a of this subpart. While the definition of “capital expenditure” is stayed, owners or operators should use the definition found in § 60.481 of subpart VV of this part.

(ii) [Reserved]

(2) Owners or operators are not required to comply with the requirements in this paragraph until EPA takes final action to require compliance and publishes a document in the FEDERAL REGISTER .

(i) The definition of “process unit” in § 60.481a of this subpart. While the definition of “process unit” is stayed, owners or operators should use the following definition:

Process unit means components assembled to produce, as intermediate or final products, one or more of the chemicals listed in § 60.489 of this part. A process unit can operate independently if supplied with sufficient feed or raw materials and sufficient storage facilities for the product.

(ii) The method of allocation of shared storage vessels in § 60.482-1a(g) of this subpart.

(iii) The standards for connectors in gas/vapor service and in light liquid service in § 60.482-11a of this subpart.

[72 FR 64883, Nov. 16, 2007, as amended at 73 FR 31375, June 2, 2008]

§ 60.481a Definitions.

As used in this subpart, all terms not defined herein shall have the meaning given them in the Clean Air Act (CAA) or in subpart A of part 60, and the following terms shall have the specific meanings given them.

Capital expenditure means, in addition to the definition in 40 CFR 60.2, an expenditure for a physical or operational change to an existing facility that:

(a) Exceeds P, the product of the facility's replacement cost, R, and an adjusted annual asset guideline repair allowance, A, as reflected by the following equation: $P = R \times A$, where:

(1) The adjusted annual asset guideline repair allowance, A, is the product of the percent of the replacement cost, Y, and the applicable basic annual asset guideline repair allowance, B, divided by 100 as reflected by the following equation:

$A = Y \times (B \div 100)$;

(2) The percent Y is determined from the following equation: $Y = 1.0 - 0.575 \log X$, where X is 2006 minus the year of construction; and

(3) The applicable basic annual asset guideline repair allowance, B, is selected from the following table consistent with the applicable subpart:

Table for Determining Applicable Value for B

Subpart applicable to facility	**Value of B to be used in equation**
VVa	12.5
GGGa	7.0

Closed-loop system means an enclosed system that returns process fluid to the process.

Closed-purge system means a system or combination of systems and portable containers to capture purged liquids. Containers for purged liquids must be covered or closed when not being filled or emptied.

Closed vent system means a system that is not open to the atmosphere and that is composed of hard-piping, ductwork, connections, and, if necessary, flow-inducing devices that transport gas or vapor from a piece or pieces of equipment to a control device or back to a process.

Connector means flanged, screwed, or other joined fittings used to connect two pipe lines or a pipe line and a piece of process equipment or that close an opening in a pipe that could be connected to another pipe. Joined fittings welded completely around the circumference of the interface are not considered connectors for the purpose of this regulation.

Control device means an enclosed combustion device, vapor recovery system, or flare.

Distance piece means an open or enclosed casing through which the piston rod travels, separating the compressor cylinder from the crankcase.

Double block and bleed system means two block valves connected in series with a bleed valve or line that can vent the line between the two block valves.

Duct work means a conveyance system such as those commonly used for heating and ventilation systems. It is often made of sheet metal and often has sections connected by screws or crimping. Hard-piping is not ductwork.

Equipment means each pump, compressor, pressure relief device, sampling connection system, open-ended valve or line, valve, and flange or other connector in VOC service and any devices or systems required by this subpart.

First attempt at repair means to take action for the purpose of stopping or reducing leakage of organic material to the atmosphere using best practices.

Fuel gas means gases that are combusted to derive useful work or heat.

Fuel gas system means the offsite and onsite piping and flow and pressure control system that gathers gaseous stream(s) generated by onsite operations, may blend them with other sources of gas, and transports the gaseous stream for use as fuel gas in combustion devices or in-process combustion equipment, such as furnaces and gas turbines, either singly or in combination.

Hard-piping means pipe or tubing that is manufactured and properly installed using good engineering judgment and standards such as ASME B31.3, Process Piping (available from the American Society of Mechanical Engineers, P.O. Box 2300, Fairfield, NJ 07007-2300).

In gas/vapor service means that the piece of equipment contains process fluid that is in the gaseous state at operating conditions.

In heavy liquid service means that the piece of equipment is not in gas/vapor service or in light liquid service.

In light liquid service means that the piece of equipment contains a liquid that meets the conditions specified in § 60.485a(e).

In-situ sampling systems means nonextractive samplers or in-line samplers.

In vacuum service means that equipment is operating at an internal pressure which is at least 5 kilopascals (kPa) (0.7 psia) below ambient pressure.

In VOC service means that the piece of equipment contains or contacts a process fluid that is at least 10 percent VOC by weight. (The provisions of § 60.485a(d) specify how to determine that a piece of equipment is not in VOC service.)

Initial calibration value means the concentration measured during the initial calibration at the beginning of each day required in § 60.485a(b)(1), or the most recent calibration if the instrument is recalibrated during the day (i.e., the calibration is adjusted) after a calibration drift assessment.

Liquids dripping means any visible leakage from the seal including spraying, misting, clouding, and ice formation.

Open-ended valve or line means any valve, except safety relief valves, having one side of the valve seat in contact with process fluid and one side open to the atmosphere, either directly or through open piping.

Pressure release means the emission of materials resulting from system pressure being greater than set pressure of the pressure relief device.

Process improvement means routine changes made for safety and occupational health requirements, for energy savings, for better utility, for ease of maintenance and operation, for correction of design deficiencies, for bottleneck removal, for changing product requirements, or for environmental control.

Process unit means the components assembled and connected by pipes or ducts to process raw materials and to produce, as intermediate or final products, one or more of the chemicals listed in § 60.489. A process unit can operate independently if supplied with sufficient feed or raw materials and sufficient storage facilities for the product. For the purpose of this subpart, process unit includes any feed, intermediate and final product storage vessels (except as specified in § 60.482-1a(g)), product transfer racks, and connected ducts and piping. A process unit includes all equipment as defined in this subpart.

Process unit shutdown means a work practice or operational procedure that stops production from a process unit or part of a process unit during which it is technically feasible to clear process material from a process unit or part of a process unit consistent with safety constraints and during which repairs can be accomplished. The following are not considered process unit shutdowns:

(1) An unscheduled work practice or operational procedure that stops production from a process unit or part of a process unit for less than 24 hours.

(2) An unscheduled work practice or operational procedure that would stop production from a process unit or part of a process unit for a shorter period of time than would be required to clear the process unit or part of the process unit of materials and start up the unit, and would result in greater emissions than delay of repair of leaking components until the next scheduled process unit shutdown.

(3) The use of spare equipment and technically feasible bypassing of equipment without stopping production.

Quarter means a 3-month period; the first quarter concludes on the last day of the last full month during the 180 days following initial startup.

Repaired means that equipment is adjusted, or otherwise altered, in order to eliminate a leak as defined in the applicable sections of this subpart and, except for leaks identified in accordance with §§ 60.482-2a(b)(2)(ii) and (d)(6)(ii) and (d)(6)(iii), 60.482-3a(f), and 60.482-10a(f)(1)(ii), is re-monitored as specified in § 60.485a(b) to verify that emissions from the equipment are below the applicable leak definition.

Replacement cost means the capital needed to purchase all the depreciable components in a facility.

Sampling connection system means an assembly of equipment within a process unit used during periods of representative operation to take samples of the process fluid. Equipment used to take nonroutine grab samples is not considered a sampling connection system.

Sensor means a device that measures a physical quantity or the change in a physical quantity such as temperature, pressure, flow rate, pH, or liquid level.

Storage vessel means a tank or other vessel that is used to store organic liquids that are used in the process as raw material feedstocks, produced as intermediates or final products, or generated as wastes. Storage vessel does not include vessels permanently attached to motor vehicles, such as trucks, railcars, barges or ships.

Synthetic organic chemicals manufacturing industry means the industry that produces, as intermediates or final products, one or more of the chemicals listed in § 60.489.

Transfer rack means the collection of loading arms and loading hoses, at a single loading rack, that are used to fill tank trucks and/or railcars with organic liquids.

Volatile organic compounds or VOC means, for the purposes of this subpart, any reactive organic compounds as defined in § 60.2 Definitions.

EFFECTIVE DATE NOTE: At 73 FR 31376, June 2, 2008, in § 60.481a, the definitions of "capital expenditure" and "process unit" were stayed until further notice.

§ 60.482-1a Standards: General.

(a) Each owner or operator subject to the provisions of this subpart shall demonstrate compliance with the requirements of §§ 60.482-1a through 60.482-10a or § 60.480a(e) for all equipment within 180 days of initial startup.

(b) Compliance with §§ 60.482-1a to 60.482-10a will be determined by review of records and reports, review of performance test results, and inspection using the methods and procedures specified in § 60.485a.

(c)(1) An owner or operator may request a determination of equivalence of a means of emission limitation to the requirements of §§ 60.482-2a, 60.482-3a, 60.482-5a, 60.482-6a, 60.482-7a, 60.482-8a, and 60.482-10a as provided in § 60.484a.

(2) If the Administrator makes a determination that a means of emission limitation is at least equivalent to the requirements of §§ 60.482-2a, 60.482-3a, 60.482-5a, 60.482-6a, 60.482-7a, 60.482-8a, or 60.482-10a, an owner or operator shall comply with the requirements of that determination.

(d) Equipment that is in vacuum service is excluded from the requirements of §§ 60.482-2a through 60.482-10a if it is identified as required in § 60.486a(e)(5).

(e) Equipment that an owner or operator designates as being in VOC service less than 300 hr/yr is excluded from the requirements of §§ 60.482-2a through 60.482-11a if it is identified as required in § 60.486a(e)(6) and it meets any of the conditions specified in paragraphs (e)(1) through (3) of this section.

(1) The equipment is in VOC service only during startup and shutdown, excluding startup and shutdown between batches of the same campaign for a batch process.

(2) The equipment is in VOC service only during process malfunctions or other emergencies.

(3) The equipment is backup equipment that is in VOC service only when the primary equipment is out of service.

(f)(1) If a dedicated batch process unit operates less than 365 days during a year, an owner or operator may monitor to detect leaks from pumps, valves, and open-ended valves or lines at the frequency specified in the following table instead of monitoring as specified in §§ 60.482-2a, 60.482-7a, and 60.483.2a:

	Equivalent monitoring frequency time in use		
Operating time (percent of hours during year)	**Monthly**	**Quarterly**	**Semiannually**
0 to <25	Quarterly	Annually	Annually.
25 to <50	Quarterly	Semiannually	Annually.
50 to <75	Bimonthly	Three quarters	Semiannually.
75 to 100	Monthly	Quarterly	Semiannually.

(2) Pumps and valves that are shared among two or more batch process units that are subject to this subpart may be monitored at the frequencies specified in paragraph (f)(1) of this section, provided the operating time of all such process units is considered.

(3) The monitoring frequencies specified in paragraph (f)(1) of this section are not requirements for monitoring at specific intervals and can be adjusted to accommodate process operations. An owner or operator may monitor at any time during the specified monitoring period (e.g., month, quarter, year), provided the monitoring is conducted at a reasonable interval after completion of the last monitoring campaign. Reasonable intervals are defined in paragraphs (f)(3)(i) through (iv) of this section.

(i) When monitoring is conducted quarterly, monitoring events must be separated by at least 30 calendar days.

(ii) When monitoring is conducted semiannually (*i.e.* , once every 2 quarters), monitoring events must be separated by at least 60 calendar days.

(iii) When monitoring is conducted in 3 quarters per year, monitoring events must be separated by at least 90 calendar days.

(iv) When monitoring is conducted annually, monitoring events must be separated by at least 120 calendar days.

(g) If the storage vessel is shared with multiple process units, the process unit with the greatest annual amount of stored materials (predominant use) is the process unit the storage vessel is assigned to. If the storage vessel is shared equally among process units, and one of the process units has equipment subject to this subpart, the storage vessel is assigned to that process unit. If the storage vessel is shared equally among process units, none of which have equipment subject to this subpart of this part, the storage vessel is assigned to any process unit subject to subpart VV of this part. If the predominant use of the storage vessel varies from year to year, then the owner or operator must estimate the predominant use initially and reassess every 3 years. The owner or operator must keep records of the information and supporting calculations that show how predominant use is determined. All equipment on the storage vessel must be monitored when in VOC service.

EFFECTIVE DATE NOTE: At 73 FR 31376, June 2, 2008, in § 60.482-1a, paragraph (g) was stayed until further notice.

§ 60.482-2a Standards: Pumps in light liquid service.

(a)(1) Each pump in light liquid service shall be monitored monthly to detect leaks by the methods specified in § 60.485a(b), except as provided in § 60.482-1a(c) and (f) and paragraphs (d), (e), and (f) of this section. A pump that begins operation in light liquid service after the initial startup date for the process unit must be monitored for the first time within 30 days after the end of its startup period, except for a pump that replaces a leaking pump and except as provided in § 60.482-1a(c) and paragraphs (d), (e), and (f) of this section.

(2) Each pump in light liquid service shall be checked by visual inspection each calendar week for indications of liquids dripping from the pump seal, except as provided in § 60.482-1a(f).

(b)(1) The instrument reading that defines a leak is specified in paragraphs (b)(1)(i) and (ii) of this section.

(i) 5,000 parts per million (ppm) or greater for pumps handling polymerizing monomers;

(ii) 2,000 ppm or greater for all other pumps.

(2) If there are indications of liquids dripping from the pump seal, the owner or operator shall follow the procedure specified in either paragraph (b)(2)(i) or (ii) of this section. This requirement does not apply to a pump that was monitored after a previous weekly inspection and the instrument reading was less than the concentration specified in paragraph (b)(1)(i) or (ii) of this section, whichever is applicable.

(i) Monitor the pump within 5 days as specified in § 60.485a(b). A leak is detected if the instrument reading measured during monitoring indicates a leak as specified in paragraph (b)(1)(i) or (ii) of this section, whichever is applicable. The leak shall be repaired using the procedures in paragraph (c) of this section.

(ii) Designate the visual indications of liquids dripping as a leak, and repair the leak using either the procedures in paragraph (c) of this section or by eliminating the visual indications of liquids dripping.

(c)(1) When a leak is detected, it shall be repaired as soon as practicable, but not later than 15 calendar days after it is detected, except as provided in § 60.482-9a.

(2) A first attempt at repair shall be made no later than 5 calendar days after each leak is detected. First attempts at repair include, but are not limited to, the practices described in paragraphs (c)(2)(i) and (ii) of this section, where practicable.

(i) Tightening the packing gland nuts;

(ii) Ensuring that the seal flush is operating at design pressure and temperature.

(d) Each pump equipped with a dual mechanical seal system that includes a barrier fluid system is exempt from the requirements of paragraph (a) of this section, provided the requirements specified in paragraphs (d)(1) through (6) of this section are met.

(1) Each dual mechanical seal system is:

(i) Operated with the barrier fluid at a pressure that is at all times greater than the pump stuffing box pressure; or

(ii) Equipped with a barrier fluid degassing reservoir that is routed to a process or fuel gas system or connected by a closed vent system to a control device that complies with the requirements of § 60.482-10a; or

(iii) Equipped with a system that purges the barrier fluid into a process stream with zero VOC emissions to the atmosphere.

(2) The barrier fluid system is in heavy liquid service or is not in VOC service.

(3) Each barrier fluid system is equipped with a sensor that will detect failure of the seal system, the barrier fluid system, or both.

(4)(i) Each pump is checked by visual inspection, each calendar week, for indications of liquids dripping from the pump seals.

(ii) If there are indications of liquids dripping from the pump seal at the time of the weekly inspection, the owner or operator shall follow the procedure specified in either paragraph (d)(4)(ii)(A) or (B) of this section prior to the next required inspection.

(A) Monitor the pump within 5 days as specified in § 60.485a(b) to determine if there is a leak of VOC in the barrier fluid. If an instrument reading of 2,000 ppm or greater is measured, a leak is detected.

(B) Designate the visual indications of liquids dripping as a leak.

(5)(i) Each sensor as described in paragraph (d)(3) is checked daily or is equipped with an audible alarm.

(ii) The owner or operator determines, based on design considerations and operating experience, a criterion that indicates failure of the seal system, the barrier fluid system, or both.

(iii) If the sensor indicates failure of the seal system, the barrier fluid system, or both, based on the criterion established in paragraph (d)(5)(ii) of this section, a leak is detected.

(6)(i) When a leak is detected pursuant to paragraph (d)(4)(ii)(A) of this section, it shall be repaired as specified in paragraph (c) of this section.

(ii) A leak detected pursuant to paragraph (d)(5)(iii) of this section shall be repaired within 15 days of detection by eliminating the conditions that activated the sensor.

(iii) A designated leak pursuant to paragraph (d)(4)(ii)(B) of this section shall be repaired within 15 days of detection by eliminating visual indications of liquids dripping.

(e) Any pump that is designated, as described in § 60.486a(e)(1) and (2), for no detectable emissions, as indicated by an instrument reading of less than 500 ppm above background, is exempt from the requirements of paragraphs (a), (c), and (d) of this section if the pump:

(1) Has no externally actuated shaft penetrating the pump housing;

(2) Is demonstrated to be operating with no detectable emissions as indicated by an instrument reading of less than 500 ppm above background as measured by the methods specified in § 60.485a(c); and

(3) Is tested for compliance with paragraph (e)(2) of this section initially upon designation, annually, and at other times requested by the Administrator.

(f) If any pump is equipped with a closed vent system capable of capturing and transporting any leakage from the seal or seals to a process or to a fuel gas system or to a control device that complies with the requirements of § 60.482-10a, it is exempt from paragraphs (a) through (e) of this section.

(g) Any pump that is designated, as described in § 60.486a(f)(1), as an unsafe-to-monitor pump is exempt from the monitoring and inspection requirements of paragraphs (a) and (d)(4) through (6) of this section if:

(1) The owner or operator of the pump demonstrates that the pump is unsafe-to-monitor because monitoring personnel would be exposed to an immediate danger as a consequence of complying with paragraph (a) of this section; and

(2) The owner or operator of the pump has a written plan that requires monitoring of the pump as frequently as practicable during safe-to-monitor times, but not more frequently than the periodic monitoring schedule otherwise applicable, and repair of the equipment according to the procedures in paragraph (c) of this section if a leak is detected.

(h) Any pump that is located within the boundary of an unmanned plant site is exempt from the weekly visual inspection requirement of paragraphs (a)(2) and (d)(4) of this section, and the daily requirements of paragraph (d)(5) of this section, provided that each pump is visually inspected as often as practicable and at least monthly.

§ 60.482-3a Standards: Compressors.

(a) Each compressor shall be equipped with a seal system that includes a barrier fluid system and that prevents leakage of VOC to the atmosphere, except as provided in § 60.482-1a(c) and paragraphs (h), (i), and (j) of this section.

(b) Each compressor seal system as required in paragraph (a) of this section shall be:

(1) Operated with the barrier fluid at a pressure that is greater than the compressor stuffing box pressure; or

(2) Equipped with a barrier fluid system degassing reservoir that is routed to a process or fuel gas system or connected by a closed vent system to a control device that complies with the requirements of § 60.482-10a; or

(3) Equipped with a system that purges the barrier fluid into a process stream with zero VOC emissions to the atmosphere.

(c) The barrier fluid system shall be in heavy liquid service or shall not be in VOC service.

(d) Each barrier fluid system as described in paragraph (a) shall be equipped with a sensor that will detect failure of the seal system, barrier fluid system, or both.

(e)(1) Each sensor as required in paragraph (d) of this section shall be checked daily or shall be equipped with an audible alarm.

(2) The owner or operator shall determine, based on design considerations and operating experience, a criterion that indicates failure of the seal system, the barrier fluid system, or both.

(f) If the sensor indicates failure of the seal system, the barrier system, or both based on the criterion determined under paragraph (e)(2) of this section, a leak is detected.

(g)(1) When a leak is detected, it shall be repaired as soon as practicable, but not later than 15 calendar days after it is detected, except as provided in § 60.482-9a.

(2) A first attempt at repair shall be made no later than 5 calendar days after each leak is detected.

(h) A compressor is exempt from the requirements of paragraphs (a) and (b) of this section, if it is equipped with a closed vent system to capture and transport leakage from the compressor drive shaft back to a process or fuel gas system or to a control device that complies with the requirements of § 60.482-10a, except as provided in paragraph (i) of this section.

(i) Any compressor that is designated, as described in § 60.486a(e)(1) and (2), for no detectable emissions, as indicated by an instrument reading of less than 500 ppm above background, is exempt from the requirements of paragraphs (a) through (h) of this section if the compressor:

(1) Is demonstrated to be operating with no detectable emissions, as indicated by an instrument reading of less than 500 ppm above background, as measured by the methods specified in § 60.485a(c); and

(2) Is tested for compliance with paragraph (i)(1) of this section initially upon designation, annually, and at other times requested by the Administrator.

(j) Any existing reciprocating compressor in a process unit which becomes an affected facility under provisions of § 60.14 or § 60.15 is exempt from paragraphs (a) through (e) and (h) of this section, provided the owner or operator demonstrates that recasting the distance piece or replacing the compressor are the only options available to bring the compressor into compliance with the provisions of paragraphs (a) through (e) and (h) of this section.

§ 60.482-4a Standards: Pressure relief devices in gas/vapor service.

(a) Except during pressure releases, each pressure relief device in gas/vapor service shall be operated with no detectable emissions, as indicated by an instrument reading of less than 500 ppm above background, as determined by the methods specified in § 60.485a(c).

(b)(1) After each pressure release, the pressure relief device shall be returned to a condition of no detectable emissions, as indicated by an instrument reading of less than 500 ppm above background, as soon as practicable, but no later than 5 calendar days after the pressure release, except as provided in § 60.482-9a.

(2) No later than 5 calendar days after the pressure release, the pressure relief device shall be monitored to confirm the conditions of no detectable emissions, as indicated by an instrument reading of less than 500 ppm above background, by the methods specified in § 60.485a(c).

(c) Any pressure relief device that is routed to a process or fuel gas system or equipped with a closed vent system capable of capturing and transporting leakage through the pressure relief device to a control device as described in § 60.482-10a is exempted from the requirements of paragraphs (a) and (b) of this section.

(d)(1) Any pressure relief device that is equipped with a rupture disk upstream of the pressure relief device is exempt from the requirements of paragraphs (a) and (b) of this section, provided the owner or operator complies with the requirements in paragraph (d)(2) of this section.

(2) After each pressure release, a new rupture disk shall be installed upstream of the pressure relief device as soon as practicable, but no later than 5 calendar days after each pressure release, except as provided in § 60.482-9a.

§ 60.482-5a Standards: Sampling connection systems.

(a) Each sampling connection system shall be equipped with a closed-purge, closed-loop, or closed-vent system, except as provided in § 60.482-1a(c) and paragraph (c) of this section.

(b) Each closed-purge, closed-loop, or closed-vent system as required in paragraph (a) of this section shall comply with the requirements specified in paragraphs (b)(1) through (4) of this section.

(1) Gases displaced during filling of the sample container are not required to be collected or captured.

(2) Containers that are part of a closed-purge system must be covered or closed when not being filled or emptied.

(3) Gases remaining in the tubing or piping between the closed-purge system valve(s) and sample container valve(s) after the valves are closed and the sample container is disconnected are not required to be collected or captured.

(4) Each closed-purge, closed-loop, or closed-vent system shall be designed and operated to meet requirements in either paragraph (b)(4)(i), (ii), (iii), or (iv) of this section.

(i) Return the purged process fluid directly to the process line.

(ii) Collect and recycle the purged process fluid to a process.

(iii) Capture and transport all the purged process fluid to a control device that complies with the requirements of § 60.482-10a.

(iv) Collect, store, and transport the purged process fluid to any of the following systems or facilities:

(A) A waste management unit as defined in 40 CFR 63.111, if the waste management unit is subject to and operated in compliance with the provisions of 40 CFR part 63, subpart G, applicable to Group 1 wastewater streams;

(B) A treatment, storage, or disposal facility subject to regulation under 40 CFR part 262, 264, 265, or 266;

(C) A facility permitted, licensed, or registered by a state to manage municipal or industrial solid waste, if the process fluids are not hazardous waste as defined in 40 CFR part 261;

(D) A waste management unit subject to and operated in compliance with the treatment requirements of 40 CFR 61.348(a), provided all waste management units that collect, store, or transport the purged process fluid to the treatment unit are subject to and operated in compliance with the management requirements of 40 CFR 61.343 through 40 CFR 61.347; or

(E) A device used to burn off-specification used oil for energy recovery in accordance with 40 CFR part 279, subpart G, provided the purged process fluid is not hazardous waste as defined in 40 CFR part 261.

(c) In-situ sampling systems and sampling systems without purges are exempt from the requirements of paragraphs (a) and (b) of this section.

§ 60.482-6a Standards: Open-ended valves or lines.

(a)(1) Each open-ended valve or line shall be equipped with a cap, blind flange, plug, or a second valve, except as provided in § 60.482-1a(c) and paragraphs (d) and (e) of this section.

(2) The cap, blind flange, plug, or second valve shall seal the open end at all times except during operations requiring process fluid flow through the open-ended valve or line.

(b) Each open-ended valve or line equipped with a second valve shall be operated in a manner such that the valve on the process fluid end is closed before the second valve is closed.

(c) When a double block-and-bleed system is being used, the bleed valve or line may remain open during operations that require venting the line between the block valves but shall comply with paragraph (a) of this section at all other times.

(d) Open-ended valves or lines in an emergency shutdown system which are designed to open automatically in the event of a process upset are exempt from the requirements of paragraphs (a), (b), and (c) of this section.

(e) Open-ended valves or lines containing materials which would autocatalytically polymerize or would present an explosion, serious overpressure, or other safety hazard if capped or equipped with a double block and bleed system as specified in paragraphs (a) through (c) of this section are exempt from the requirements of paragraphs (a) through (c) of this section.

§ 60.482-7a Standards: Valves in gas/vapor service and in light liquid service.

(a)(1) Each valve shall be monitored monthly to detect leaks by the methods specified in § 60.485a(b) and shall comply with paragraphs (b) through (e) of this section, except as provided in paragraphs (f), (g), and (h) of this section, § 60.482-1a(c) and (f), and §§ 60.483-1a and 60.483-2a.

(2) A valve that begins operation in gas/vapor service or light liquid service after the initial startup date for the process unit must be monitored according to paragraphs (a)(2)(i) or (ii), except for a valve that replaces a leaking valve and except as provided in paragraphs (f), (g), and (h) of this section, § 60.482-1a(c), and §§ 60.483-1a and 60.483-2a.

(i) Monitor the valve as in paragraph (a)(1) of this section. The valve must be monitored for the first time within 30 days after the end of its startup period to ensure proper installation.

(ii) If the existing valves in the process unit are monitored in accordance with § 60.483-1a or § 60.483-2a, count the new valve as leaking when calculating the percentage of valves leaking as described in § 60.483-2a(b)(5). If less than 2.0 percent of the valves are leaking for that process unit, the valve must be monitored for the first time during the next scheduled monitoring event for existing valves in the process unit or within 90 days, whichever comes first.

(b) If an instrument reading of 500 ppm or greater is measured, a leak is detected.

(c)(1)(i) Any valve for which a leak is not detected for 2 successive months may be monitored the first month of every quarter, beginning with the next quarter, until a leak is detected.

(ii) As an alternative to monitoring all of the valves in the first month of a quarter, an owner or operator may elect to subdivide the process unit into two or three subgroups of valves and monitor each subgroup in a different month during the quarter, provided each subgroup is monitored every 3 months. The owner or operator must keep records of the valves assigned to each subgroup.

(2) If a leak is detected, the valve shall be monitored monthly until a leak is not detected for 2 successive months.

(d)(1) When a leak is detected, it shall be repaired as soon as practicable, but no later than 15 calendar days after the leak is detected, except as provided in § 60.482-9a.

(2) A first attempt at repair shall be made no later than 5 calendar days after each leak is detected.

(e) First attempts at repair include, but are not limited to, the following best practices where practicable:

(1) Tightening of bonnet bolts;

(2) Replacement of bonnet bolts;

(3) Tightening of packing gland nuts;

(4) Injection of lubricant into lubricated packing.

(f) Any valve that is designated, as described in § 60.486a(e)(2), for no detectable emissions, as indicated by an instrument reading of less than 500 ppm above background, is exempt from the requirements of paragraph (a) of this section if the valve:

(1) Has no external actuating mechanism in contact with the process fluid,

(2) Is operated with emissions less than 500 ppm above background as determined by the method specified in § 60.485a(c), and

(3) Is tested for compliance with paragraph (f)(2) of this section initially upon designation, annually, and at other times requested by the Administrator.

(g) Any valve that is designated, as described in § 60.486a(f)(1), as an unsafe-to-monitor valve is exempt from the requirements of paragraph (a) of this section if:

(1) The owner or operator of the valve demonstrates that the valve is unsafe to monitor because monitoring personnel would be exposed to an immediate danger as a consequence of complying with paragraph (a) of this section, and

(2) The owner or operator of the valve adheres to a written plan that requires monitoring of the valve as frequently as practicable during safe-to-monitor times.

(h) Any valve that is designated, as described in § 60.486a(f)(2), as a difficult-to-monitor valve is exempt from the requirements of paragraph (a) of this section if:

(1) The owner or operator of the valve demonstrates that the valve cannot be monitored without elevating the monitoring personnel more than 2 meters above a support surface.

(2) The process unit within which the valve is located either:

(i) Becomes an affected facility through § 60.14 or § 60.15 and was constructed on or before January 5, 1981; or

(ii) Has less than 3.0 percent of its total number of valves designated as difficult-to-monitor by the owner or operator.

(3) The owner or operator of the valve follows a written plan that requires monitoring of the valve at least once per calendar year.

§ 60.482-8a Standards: Pumps, valves, and connectors in heavy liquid service and pressure relief devices in light liquid or heavy liquid service.

(a) If evidence of a potential leak is found by visual, audible, olfactory, or any other detection method at pumps, valves, and connectors in heavy liquid service and pressure relief devices in light liquid or heavy liquid service, the owner or operator shall follow either one of the following procedures:

(1) The owner or operator shall monitor the equipment within 5 days by the method specified in § 60.485a(b) and shall comply with the requirements of paragraphs (b) through (d) of this section.

(2) The owner or operator shall eliminate the visual, audible, olfactory, or other indication of a potential leak within 5 calendar days of detection.

(b) If an instrument reading of 10,000 ppm or greater is measured, a leak is detected.

(c)(1) When a leak is detected, it shall be repaired as soon as practicable, but not later than 15 calendar days after it is detected, except as provided in § 60.482-9a.

(2) The first attempt at repair shall be made no later than 5 calendar days after each leak is detected.

(d) First attempts at repair include, but are not limited to, the best practices described under §§ 60.482-2a(c)(2) and 60.482-7a(e).

§ 60.482-9a Standards: Delay of repair.

(a) Delay of repair of equipment for which leaks have been detected will be allowed if repair within 15 days is technically infeasible without a process unit shutdown. Repair of this equipment shall occur before the end of the next process unit shutdown. Monitoring to verify repair must occur within 15 days after startup of the process unit.

(b) Delay of repair of equipment will be allowed for equipment which is isolated from the process and which does not remain in VOC service.

(c) Delay of repair for valves and connectors will be allowed if:

(1) The owner or operator demonstrates that emissions of purged material resulting from immediate repair are greater than the fugitive emissions likely to result from delay of repair, and

(2) When repair procedures are effected, the purged material is collected and destroyed or recovered in a control device complying with § 60.482-10a.

(d) Delay of repair for pumps will be allowed if:

(1) Repair requires the use of a dual mechanical seal system that includes a barrier fluid system, and

(2) Repair is completed as soon as practicable, but not later than 6 months after the leak was detected.

(e) Delay of repair beyond a process unit shutdown will be allowed for a valve, if valve assembly replacement is necessary during the process unit shutdown, valve assembly supplies have been depleted, and valve assembly supplies had been sufficiently stocked before the supplies were depleted. Delay of repair beyond the next process unit shutdown will not be allowed unless the next process unit shutdown occurs sooner than 6 months after the first process unit shutdown.

(f) When delay of repair is allowed for a leaking pump, valve, or connector that remains in service, the pump, valve, or connector may be considered to be repaired and no longer subject to delay of repair requirements if two consecutive monthly monitoring instrument readings are below the leak definition.

§ 60.482-10a Standards: Closed vent systems and control devices.

(a) Owners or operators of closed vent systems and control devices used to comply with provisions of this subpart shall comply with the provisions of this section.

(b) Vapor recovery systems (for example, condensers and absorbers) shall be designed and operated to recover the VOC emissions vented to them with an efficiency of 95 percent or greater, or to an exit concentration of 20 parts per million by volume (ppmv), whichever is less stringent.

(c) Enclosed combustion devices shall be designed and operated to reduce the VOC emissions vented to them with an efficiency of 95 percent or greater, or to an exit concentration of 20 ppmv, on a dry basis, corrected to 3 percent oxygen, whichever is less stringent or to provide a minimum residence time of 0.75 seconds at a minimum temperature of 816 °C.

(d) Flares used to comply with this subpart shall comply with the requirements of § 60.18.

(e) Owners or operators of control devices used to comply with the provisions of this subpart shall monitor these control devices to ensure that they are operated and maintained in conformance with their designs.

(f) Except as provided in paragraphs (i) through (k) of this section, each closed vent system shall be inspected according to the procedures and schedule specified in paragraphs (f)(1) and (2) of this section.

(1) If the vapor collection system or closed vent system is constructed of hard-piping, the owner or operator shall comply with the requirements specified in paragraphs (f)(1)(i) and (ii) of this section:

(i) Conduct an initial inspection according to the procedures in § 60.485a(b); and

(ii) Conduct annual visual inspections for visible, audible, or olfactory indications of leaks.

(2) If the vapor collection system or closed vent system is constructed of ductwork, the owner or operator shall:

(i) Conduct an initial inspection according to the procedures in § 60.485a(b); and

(ii) Conduct annual inspections according to the procedures in § 60.485a(b).

(g) Leaks, as indicated by an instrument reading greater than 500 ppmv above background or by visual inspections, shall be repaired as soon as practicable except as provided in paragraph (h) of this section.

(1) A first attempt at repair shall be made no later than 5 calendar days after the leak is detected.

(2) Repair shall be completed no later than 15 calendar days after the leak is detected.

(h) Delay of repair of a closed vent system for which leaks have been detected is allowed if the repair is technically infeasible without a process unit shutdown or if the owner or operator determines that emissions resulting from immediate repair would be greater than the fugitive emissions likely to result from delay of repair. Repair of such equipment shall be complete by the end of the next process unit shutdown.

(i) If a vapor collection system or closed vent system is operated under a vacuum, it is exempt from the inspection requirements of paragraphs (f)(1)(i) and (f)(2) of this section.

(j) Any parts of the closed vent system that are designated, as described in paragraph (l)(1) of this section, as unsafe to inspect are exempt from the inspection requirements of paragraphs (f)(1)(i) and (f)(2) of this section if they comply with the requirements specified in paragraphs (j)(1) and (2) of this section:

(1) The owner or operator determines that the equipment is unsafe to inspect because inspecting personnel would be exposed to an imminent or potential danger as a consequence of complying with paragraphs (f)(1)(i) or (f)(2) of this section; and

(2) The owner or operator has a written plan that requires inspection of the equipment as frequently as practicable during safe-to-inspect times.

(k) Any parts of the closed vent system that are designated, as described in paragraph (l)(2) of this section, as difficult to inspect are exempt from the inspection requirements of paragraphs (f)(1)(i) and (f)(2) of this section if they comply with the requirements specified in paragraphs (k)(1) through (3) of this section:

(1) The owner or operator determines that the equipment cannot be inspected without elevating the inspecting personnel more than 2 meters above a support surface; and

(2) The process unit within which the closed vent system is located becomes an affected facility through §§ 60.14 or 60.15, or the owner or operator designates less than 3.0 percent of the total number of closed vent system equipment as difficult to inspect; and

(3) The owner or operator has a written plan that requires inspection of the equipment at least once every 5 years. A closed vent system is exempt from inspection if it is operated under a vacuum.

(l) The owner or operator shall record the information specified in paragraphs (l)(1) through (5) of this section.

(1) Identification of all parts of the closed vent system that are designated as unsafe to inspect, an explanation of why the equipment is unsafe to inspect, and the plan for inspecting the equipment.

(2) Identification of all parts of the closed vent system that are designated as difficult to inspect, an explanation of why the equipment is difficult to inspect, and the plan for inspecting the equipment.

(3) For each inspection during which a leak is detected, a record of the information specified in § 60.486a(c).

(4) For each inspection conducted in accordance with § 60.485a(b) during which no leaks are detected, a record that the inspection was performed, the date of the inspection, and a statement that no leaks were detected.

(5) For each visual inspection conducted in accordance with paragraph (f)(1)(ii) of this section during which no leaks are detected, a record that the inspection was performed, the date of the inspection, and a statement that no leaks were detected.

(m) Closed vent systems and control devices used to comply with provisions of this subpart shall be operated at all times when emissions may be vented to them.

§ 60.482-11a Standards: Connectors in gas/vapor service and in light liquid service.

(a) The owner or operator shall initially monitor all connectors in the process unit for leaks by the later of either 12 months after the compliance date or 12 months after initial startup. If all connectors in the process unit have been monitored for leaks prior to the compliance date, no initial monitoring is required provided either no process changes have been made since the monitoring or the owner or operator can determine that the results of the monitoring, with or without adjustments, reliably demonstrate compliance despite process changes. If required to monitor because of a process change, the owner or operator is required to monitor only those connectors involved in the process change.

(b) Except as allowed in § 60.482-1a(c), § 60.482-10a, or as specified in paragraph (e) of this section, the owner or operator shall monitor all connectors in gas and vapor and light liquid service as specified in paragraphs (a) and (b)(3) of this section.

(1) The connectors shall be monitored to detect leaks by the method specified in § 60.485a(b) and, as applicable, § 60.485a(c).

(2) If an instrument reading greater than or equal to 500 ppm is measured, a leak is detected.

(3) The owner or operator shall perform monitoring, subsequent to the initial monitoring required in paragraph (a) of this section, as specified in paragraphs (b)(3)(i) through (iii) of this section, and shall comply with the requirements of paragraphs (b)(3)(iv) and (v) of this section. The required period in which monitoring must be conducted shall be determined from paragraphs (b)(3)(i) through (iii) of this section using the monitoring results from the preceding monitoring period. The percent leaking connectors shall be calculated as specified in paragraph (c) of this section.

(i) If the percent leaking connectors in the process unit was greater than or equal to 0.5 percent, then monitor within 12 months (1 year).

(ii) If the percent leaking connectors in the process unit was greater than or equal to 0.25 percent but less than 0.5 percent, then monitor within 4 years. An owner or operator may comply with the requirements of this paragraph by monitoring at least 40 percent of the connectors within 2 years of the start of the monitoring period, provided all connectors have been monitored by the end of the 4-year monitoring period.

(iii) If the percent leaking connectors in the process unit was less than 0.25 percent, then monitor as provided in paragraph (b)(3)(iii)(A) of this section and either paragraph (b)(3)(iii)(B) or (b)(3)(iii)(C) of this section, as appropriate.

(A) An owner or operator shall monitor at least 50 percent of the connectors within 4 years of the start of the monitoring period.

(B) If the percent of leaking connectors calculated from the monitoring results in paragraph (b)(3)(iii)(A) of this section is greater than or equal to 0.35 percent of the monitored connectors, the owner or operator shall monitor as soon as practical, but within the next 6 months, all connectors that have not yet been monitored during the monitoring period. At the conclusion of monitoring, a new monitoring period shall be started pursuant to paragraph (b)(3) of this section, based on the percent of leaking connectors within the total monitored connectors.

(C) If the percent of leaking connectors calculated from the monitoring results in paragraph (b)(3)(iii)(A) of this section is less than 0.35 percent of the monitored connectors, the owner or operator shall monitor all connectors that have not yet been monitored within 8 years of the start of the monitoring period.

(iv) If, during the monitoring conducted pursuant to paragraphs (b)(3)(i) through (iii) of this section, a connector is found to be leaking, it shall be re-monitored once within 90 days after repair to confirm that it is not leaking.

(v) The owner or operator shall keep a record of the start date and end date of each monitoring period under this section for each process unit.

(c) For use in determining the monitoring frequency, as specified in paragraphs (a) and (b)(3) of this section, the percent leaking connectors as used in paragraphs (a) and (b)(3) of this section shall be calculated by using the following equation:

$\%C_L = C_L / C_t * 100$

Where:

$\%C_L$ = Percent of leaking connectors as determined through periodic monitoring required in paragraphs (a) and (b)(3)(i) through (iii) of this section.

C_L = Number of connectors measured at 500 ppm or greater, by the method specified in § 60.485a(b).

C_t = Total number of monitored connectors in the process unit or affected facility.

(d) When a leak is detected pursuant to paragraphs (a) and (b) of this section, it shall be repaired as soon as practicable, but not later than 15 calendar days after it is detected, except as provided in § 60.482-9a. A first attempt at repair as defined in this subpart shall be made no later than 5 calendar days after the leak is detected.

(e) Any connector that is designated, as described in § 60.486a(f)(1), as an unsafe-to-monitor connector is exempt from the requirements of paragraphs (a) and (b) of this section if:

(1) The owner or operator of the connector demonstrates that the connector is unsafe-to-monitor because monitoring personnel would be exposed to an immediate danger as a consequence of complying with paragraphs (a) and (b) of this section; and

(2) The owner or operator of the connector has a written plan that requires monitoring of the connector as frequently as practicable during safe-to-monitor times but not more frequently than the periodic monitoring schedule otherwise applicable, and repair of the equipment according to the procedures in paragraph (d) of this section if a leak is detected.

(f) *Inaccessible, ceramic, or ceramic-lined connectors* . (1) Any connector that is inaccessible or that is ceramic or ceramic-lined (e.g., porcelain, glass, or glass-lined), is exempt from the monitoring requirements of paragraphs (a) and (b) of this section, from the leak repair requirements of paragraph (d) of this section, and from the recordkeeping and reporting requirements of §§ 63.1038 and 63.1039. An inaccessible connector is one that meets any of the provisions specified in paragraphs (f)(1)(i) through (vi) of this section, as applicable:

(i) Buried;

(ii) Insulated in a manner that prevents access to the connector by a monitor probe;

(iii) Obstructed by equipment or piping that prevents access to the connector by a monitor probe;

(iv) Unable to be reached from a wheeled scissor-lift or hydraulic-type scaffold that would allow access to connectors up to 7.6 meters (25 feet) above the ground;

(v) Inaccessible because it would require elevating the monitoring personnel more than 2 meters (7 feet) above a permanent support surface or would require the erection of scaffold; or

(vi) Not able to be accessed at any time in a safe manner to perform monitoring. Unsafe access includes, but is not limited to, the use of a wheeled scissor-lift on unstable or uneven terrain, the use of a motorized man-lift basket in areas where an ignition potential exists, or access would require near proximity to hazards such as electrical lines, or would risk damage to equipment.

(2) If any inaccessible, ceramic, or ceramic-lined connector is observed by visual, audible, olfactory, or other means to be leaking, the visual, audible, olfactory, or other indications of a leak to the atmosphere shall be eliminated as soon as practical.

(g) Except for instrumentation systems and inaccessible, ceramic, or ceramic-lined connectors meeting the provisions of paragraph (f) of this section, identify the connectors subject to the requirements of this subpart. Connectors need not be individually identified if all connectors in a designated area or length of pipe subject to the provisions of this subpart are identified as a group, and the number of connectors subject is indicated.

EFFECTIVE DATE NOTE: At 73 FR 31376, June 2, 2008, § 60.482-11a was stayed until further notice.

§ 60.483-1a Alternative standards for valves—allowable percentage of valves leaking.

(a) An owner or operator may elect to comply with an allowable percentage of valves leaking of equal to or less than 2.0 percent.

(b) The following requirements shall be met if an owner or operator wishes to comply with an allowable percentage of valves leaking:

(1) An owner or operator must notify the Administrator that the owner or operator has elected to comply with the allowable percentage of valves leaking before implementing this alternative standard, as specified in § 60.487a(d).

(2) A performance test as specified in paragraph (c) of this section shall be conducted initially upon designation, annually, and at other times requested by the Administrator.

(3) If a valve leak is detected, it shall be repaired in accordance with § 60.482-7a(d) and (e).

(c) Performance tests shall be conducted in the following manner:

(1) All valves in gas/vapor and light liquid service within the affected facility shall be monitored within 1 week by the methods specified in § 60.485a(b).

(2) If an instrument reading of 500 ppm or greater is measured, a leak is detected.

(3) The leak percentage shall be determined by dividing the number of valves for which leaks are detected by the number of valves in gas/vapor and light liquid service within the affected facility.

(d) Owners and operators who elect to comply with this alternative standard shall not have an affected facility with a leak percentage greater than 2.0 percent, determined as described in § 60.485a(h).

§ 60.483-2a Alternative standards for valves—skip period leak detection and repair.

(a)(1) An owner or operator may elect to comply with one of the alternative work practices specified in paragraphs (b)(2) and (3) of this section.

(2) An owner or operator must notify the Administrator before implementing one of the alternative work practices, as specified in § 60.487(d)a.

(b)(1) An owner or operator shall comply initially with the requirements for valves in gas/vapor service and valves in light liquid service, as described in § 60.482-7a.

(2) After 2 consecutive quarterly leak detection periods with the percent of valves leaking equal to or less than 2.0, an owner or operator may begin to skip 1 of the quarterly leak detection periods for the valves in gas/vapor and light liquid service.

(3) After 5 consecutive quarterly leak detection periods with the percent of valves leaking equal to or less than 2.0, an owner or operator may begin to skip 3 of the quarterly leak detection periods for the valves in gas/vapor and light liquid service.

(4) If the percent of valves leaking is greater than 2.0, the owner or operator shall comply with the requirements as described in § 60.482-7a but can again elect to use this section.

(5) The percent of valves leaking shall be determined as described in § 60.485a(h).

(6) An owner or operator must keep a record of the percent of valves found leaking during each leak detection period.

(7) A valve that begins operation in gas/vapor service or light liquid service after the initial startup date for a process unit following one of the alternative standards in this section must be monitored in accordance with § 60.482-7a(a)(2)(i) or (ii) before the provisions of this section can be applied to that valve.

§ 60.484a Equivalence of means of emission limitation.

(a) Each owner or operator subject to the provisions of this subpart may apply to the Administrator for determination of equivalence for any means of emission limitation that achieves a reduction in emissions of VOC at least equivalent to the reduction in emissions of VOC achieved by the controls required in this subpart.

(b) Determination of equivalence to the equipment, design, and operational requirements of this subpart will be evaluated by the following guidelines:

(1) Each owner or operator applying for an equivalence determination shall be responsible for collecting and verifying test data to demonstrate equivalence of means of emission limitation.

(2) The Administrator will compare test data for demonstrating equivalence of the means of emission limitation to test data for the equipment, design, and operational requirements.

(3) The Administrator may condition the approval of equivalence on requirements that may be necessary to assure operation and maintenance to achieve the same emission reduction as the equipment, design, and operational requirements.

(c) Determination of equivalence to the required work practices in this subpart will be evaluated by the following guidelines:

(1) Each owner or operator applying for a determination of equivalence shall be responsible for collecting and verifying test data to demonstrate equivalence of an equivalent means of emission limitation.

(2) For each affected facility for which a determination of equivalence is requested, the emission reduction achieved by the required work practice shall be demonstrated.

(3) For each affected facility, for which a determination of equivalence is requested, the emission reduction achieved by the equivalent means of emission limitation shall be demonstrated.

(4) Each owner or operator applying for a determination of equivalence shall commit in writing to work practice(s) that provide for emission reductions equal to or greater than the emission reductions achieved by the required work practice.

(5) The Administrator will compare the demonstrated emission reduction for the equivalent means of emission limitation to the demonstrated emission reduction for the required work practices and will consider the commitment in paragraph (c)(4) of this section.

(6) The Administrator may condition the approval of equivalence on requirements that may be necessary to assure operation and maintenance to achieve the same emission reduction as the required work practice.

(d) An owner or operator may offer a unique approach to demonstrate the equivalence of any equivalent means of emission limitation.

(e)(1) After a request for determination of equivalence is received, the Administrator will publish a notice in the FEDERAL REGISTER and provide the opportunity for public hearing if the Administrator judges that the request may be approved.

(2) After notice and opportunity for public hearing, the Administrator will determine the equivalence of a means of emission limitation and will publish the determination in the FEDERAL REGISTER .

(3) Any equivalent means of emission limitations approved under this section shall constitute a required work practice, equipment, design, or operational standard within the meaning of section 111(h)(1) of the CAA.

(f)(1) Manufacturers of equipment used to control equipment leaks of VOC may apply to the Administrator for determination of equivalence for any equivalent means of emission limitation that achieves a reduction in emissions of VOC achieved by the equipment, design, and operational requirements of this subpart.

(2) The Administrator will make an equivalence determination according to the provisions of paragraphs (b), (c), (d), and (e) of this section.

§ 60.485a Test methods and procedures.

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

(b) The owner or operator shall determine compliance with the standards in §§ 60.482-1a through 60.482-11a, 60.483a, and 60.484a as follows:

(1) Method 21 shall be used to determine the presence of leaking sources. The instrument shall be calibrated before use each day of its use by the procedures specified in Method 21 of appendix A-7 of this part. The following calibration gases shall be used:

(i) Zero air (less than 10 ppm of hydrocarbon in air); and

(ii) A mixture of methane or n-hexane and air at a concentration no more than 2,000 ppm greater than the leak definition concentration of the equipment monitored. If the monitoring instrument's design allows for multiple calibration scales, then the lower scale shall be calibrated with a calibration gas that is no higher than 2,000 ppm above the concentration specified as a leak, and the highest scale shall be calibrated with a calibration gas that is approximately equal to 10,000 ppm. If only one scale on an instrument will be used during monitoring, the owner or operator need not calibrate the scales that will not be used during that day's monitoring.

(2) A calibration drift assessment shall be performed, at a minimum, at the end of each monitoring day. Check the instrument using the same calibration gas(es) that were used to calibrate the instrument before use. Follow the procedures specified in Method 21 of appendix A-7 of this part, Section 10.1, except do not adjust the meter readout to correspond to the calibration gas value. Record the instrument reading for each scale used as specified in § 60.486a(e)(7). Calculate the average algebraic difference between the three meter readings and the most recent calibration value. Divide this algebraic difference by the initial calibration value and multiply by 100 to express the calibration drift as a percentage. If any calibration drift assessment shows a negative drift of more than 10 percent from the initial calibration value, then all equipment monitored since the last calibration with instrument readings below the appropriate leak definition and above the leak definition multiplied by (100 minus the percent of negative drift/divided by 100) must be re-monitored. If any calibration drift assessment shows a positive drift of more than 10 percent from the initial calibration value, then, at the owner/operator's discretion, all equipment since the last calibration with instrument readings above the appropriate leak definition and below the leak definition multiplied by (100 plus the percent of positive drift/divided by 100) may be re-monitored.

(c) The owner or operator shall determine compliance with the no-detectable-emission standards in §§ 60.482-2a(e), 60.482-3a(i), 60.482-4a, 60.482-7a(f), and 60.482-10a(e) as follows:

(1) The requirements of paragraph (b) shall apply.

(2) Method 21 of appendix A-7 of this part shall be used to determine the background level. All potential leak interfaces shall be traversed as close to the interface as possible. The arithmetic difference between the maximum concentration indicated by the instrument and the background level is compared with 500 ppm for determining compliance.

(d) The owner or operator shall test each piece of equipment unless he demonstrates that a process unit is not in VOC service, i.e., that the VOC content would never be reasonably expected to exceed 10 percent by weight. For purposes of this demonstration, the following methods and procedures shall be used:

(1) Procedures that conform to the general methods in ASTM E260-73, 91, or 96, E168-67, 77, or 92, E169-63, 77, or 93 (incorporated by reference—see § 60.17) shall be used to determine the percent VOC content in the process fluid that is contained in or contacts a piece of equipment.

(2) Organic compounds that are considered by the Administrator to have negligible photochemical reactivity may be excluded from the total quantity of organic compounds in determining the VOC content of the process fluid.

(3) Engineering judgment may be used to estimate the VOC content, if a piece of equipment had not been shown previously to be in service. If the Administrator disagrees with the judgment, paragraphs (d)(1) and (2) of this section shall be used to resolve the disagreement.

(e) The owner or operator shall demonstrate that a piece of equipment is in light liquid service by showing that all the following conditions apply:

(1) The vapor pressure of one or more of the organic components is greater than 0.3 kPa at 20 °C (1.2 in. H_2 O at 68 °F). Standard reference texts or ASTM D2879-83, 96, or 97 (incorporated by reference—see § 60.17) shall be used to determine the vapor pressures.

(2) The total concentration of the pure organic components having a vapor pressure greater than 0.3 kPa at 20 °C (1.2 in. H_2 O at 68 °F) is equal to or greater than 20 percent by weight.

(3) The fluid is a liquid at operating conditions.

(f) Samples used in conjunction with paragraphs (d), (e), and (g) of this section shall be representative of the process fluid that is contained in or contacts the equipment or the gas being combusted in the flare.

(g) The owner or operator shall determine compliance with the standards of flares as follows:

(1) Method 22 of appendix A-7 of this part shall be used to determine visible emissions.

(2) A thermocouple or any other equivalent device shall be used to monitor the presence of a pilot flame in the flare.

(3) The maximum permitted velocity for air assisted flares shall be computed using the following equation:

$$V_{max} = K_1 + K_2 H_T$$

Where:

V_{max} = Maximum permitted velocity, m/sec (ft/sec).

H_T = Net heating value of the gas being combusted, MJ/scm (Btu/scf).

K_1 = 8.706 m/sec (metric units) = 28.56 ft/sec (English units).

K_2 = 0.7084 m^4 /(MJ-sec) (metric units) = 0.087 ft^4 /(Btu-sec) (English units).

(4) The net heating value (HT) of the gas being combusted in a flare shall be computed using the following equation:

$$H_T = K \sum_{i=1}^{n} C_i H_i$$

Where:

K = Conversion constant, 1.740×10^{-7} (g-mole)(MJ)/(ppm-scm-kcal) (metric units) = 4.674×10^{-6} [(g-mole)(Btu)/(ppm-scf-kcal)] (English units).

C_i = Concentration of sample component "i," ppm

H_i = net heat of combustion of sample component "i" at 25 °C and 760 mm Hg (77 °F and 14.7 psi), kcal/g-mole.

(5) Method 18 of appendix A-6 of this part or ASTM D6420-99 (2004) (where the target compound(s) are those listed in Section 1.1 of ASTM D6420-99, and the target concentration is between 150 parts per billion by volume and 100 ppmv) and ASTM D2504-67, 77, or 88 (Reapproved 1993) (incorporated by reference-see § 60.17) shall be used to determine the concentration of sample component "i."

(6) ASTM D2382-76 or 88 or D4809-95 (incorporated by reference-see § 60.17) shall be used to determine the net heat of combustion of component "i" if published values are not available or cannot be calculated.

(7) Method 2, 2A, 2C, or 2D of appendix A-7 of this part, as appropriate, shall be used to determine the actual exit velocity of a flare. If needed, the unobstructed (free) cross-sectional area of the flare tip shall be used.

(h) The owner or operator shall determine compliance with § 60.483-1a or § 60.483-2a as follows:

(1) The percent of valves leaking shall be determined using the following equation:

$$\%V_L = (V_L / V_T) * 100$$

Where:

$\%V_L$ = Percent leaking valves.

V_L = Number of valves found leaking.

V_T = The sum of the total number of valves monitored.

(2) The total number of valves monitored shall include difficult-to-monitor and unsafe-to-monitor valves only during the monitoring period in which those valves are monitored.

(3) The number of valves leaking shall include valves for which repair has been delayed.

(4) Any new valve that is not monitored within 30 days of being placed in service shall be included in the number of valves leaking and the total number of valves monitored for the monitoring period in which the valve is placed in service.

(5) If the process unit has been subdivided in accordance with § 60.482-7a(c)(1)(ii), the sum of valves found leaking during a monitoring period includes all subgroups.

(6) The total number of valves monitored does not include a valve monitored to verify repair.

§ 60.486a Recordkeeping requirements.

(a)(1) Each owner or operator subject to the provisions of this subpart shall comply with the recordkeeping requirements of this section.

(2) An owner or operator of more than one affected facility subject to the provisions of this subpart may comply with the recordkeeping requirements for these facilities in one recordkeeping system if the system identifies each record by each facility.

(3) The owner or operator shall record the information specified in paragraphs (a)(3)(i) through (v) of this section for each monitoring event required by §§ 60.482-2a, 60.482-3a, 60.482-7a, 60.482-8a, 60.482-11a, and 60.483-2a.

(i) Monitoring instrument identification.

(ii) Operator identification.

(iii) Equipment identification.

(iv) Date of monitoring.

(v) Instrument reading.

(b) When each leak is detected as specified in §§ 60.482-2a, 60.482-3a, 60.482-7a, 60.482-8a, 60.482-11a, and 60.483-2a, the following requirements apply:

(1) A weatherproof and readily visible identification, marked with the equipment identification number, shall be attached to the leaking equipment.

(2) The identification on a valve may be removed after it has been monitored for 2 successive months as specified in § 60.482-7a(c) and no leak has been detected during those 2 months.

(3) The identification on a connector may be removed after it has been monitored as specified in § 60.482-11a(b)(3)(iv) and no leak has been detected during that monitoring.

(4) The identification on equipment, except on a valve or connector, may be removed after it has been repaired.

(c) When each leak is detected as specified in §§ 60.482-2a, 60.482-3a, 60.482-7a, 60.482-8a, 60.482-11a, and 60.483-2a, the following information shall be recorded in a log and shall be kept for 2 years in a readily accessible location:

(1) The instrument and operator identification numbers and the equipment identification number, except when indications of liquids dripping from a pump are designated as a leak.

(2) The date the leak was detected and the dates of each attempt to repair the leak.

(3) Repair methods applied in each attempt to repair the leak.

(4) Maximum instrument reading measured by Method 21 of appendix A-7 of this part at the time the leak is successfully repaired or determined to be nonrepairable, except when a pump is repaired by eliminating indications of liquids dripping.

(5) “Repair delayed” and the reason for the delay if a leak is not repaired within 15 calendar days after discovery of the leak.

(6) The signature of the owner or operator (or designate) whose decision it was that repair could not be effected without a process shutdown.

(7) The expected date of successful repair of the leak if a leak is not repaired within 15 days.

(8) Dates of process unit shutdowns that occur while the equipment is unrepaired.

(9) The date of successful repair of the leak.

(d) The following information pertaining to the design requirements for closed vent systems and control devices described in § 60.482-10a shall be recorded and kept in a readily accessible location:

(1) Detailed schematics, design specifications, and piping and instrumentation diagrams.

(2) The dates and descriptions of any changes in the design specifications.

(3) A description of the parameter or parameters monitored, as required in § 60.482-10a(e), to ensure that control devices are operated and maintained in conformance with their design and an explanation of why that parameter (or parameters) was selected for the monitoring.

(4) Periods when the closed vent systems and control devices required in §§ 60.482-2a, 60.482-3a, 60.482-4a, and 60.482-5a are not operated as designed, including periods when a flare pilot light does not have a flame.

(5) Dates of startups and shutdowns of the closed vent systems and control devices required in §§ 60.482-2a, 60.482-3a, 60.482-4a, and 60.482-5a.

(e) The following information pertaining to all equipment subject to the requirements in §§ 60.482-1a to 60.482-11a shall be recorded in a log that is kept in a readily accessible location:

(1) A list of identification numbers for equipment subject to the requirements of this subpart.

(2)(i) A list of identification numbers for equipment that are designated for no detectable emissions under the provisions of §§ 60.482-2a(e), 60.482-3a(i), and 60.482-7a(f).

(ii) The designation of equipment as subject to the requirements of § 60.482-2a(e), § 60.482-3a(i), or § 60.482-7a(f) shall be signed by the owner or operator. Alternatively, the owner or operator may establish a mechanism with their permitting authority that satisfies this requirement.

(3) A list of equipment identification numbers for pressure relief devices required to comply with § 60.482-4a.

(4)(i) The dates of each compliance test as required in §§ 60.482-2a(e), 60.482-3a(i), 60.482-4a, and 60.482-7a(f).

(ii) The background level measured during each compliance test.

(iii) The maximum instrument reading measured at the equipment during each compliance test.

(5) A list of identification numbers for equipment in vacuum service.

(6) A list of identification numbers for equipment that the owner or operator designates as operating in VOC service less than 300 hr/yr in accordance with § 60.482-1a(e), a description of the conditions under which the equipment is in VOC service, and rationale supporting the designation that it is in VOC service less than 300 hr/yr.

(7) The date and results of the weekly visual inspection for indications of liquids dripping from pumps in light liquid service.

(8) Records of the information specified in paragraphs (e)(8)(i) through (vi) of this section for monitoring instrument calibrations conducted according to sections 8.1.2 and 10 of Method 21 of appendix A-7 of this part and § 60.485a(b).

(i) Date of calibration and initials of operator performing the calibration.

(ii) Calibration gas cylinder identification, certification date, and certified concentration.

(iii) Instrument scale(s) used.

(iv) A description of any corrective action taken if the meter readout could not be adjusted to correspond to the calibration gas value in accordance with section 10.1 of Method 21 of appendix A-7 of this part.

(v) Results of each calibration drift assessment required by § 60.485a(b)(2) (i.e., instrument reading for calibration at end of monitoring day and the calculated percent difference from the initial calibration value).

(vi) If an owner or operator makes their own calibration gas, a description of the procedure used.

(9) The connector monitoring schedule for each process unit as specified in § 60.482-11a(b)(3)(v).

(10) Records of each release from a pressure relief device subject to § 60.482-4a.

(f) The following information pertaining to all valves subject to the requirements of § 60.482-7a(g) and (h), all pumps subject to the requirements of § 60.482-2a(g), and all connectors subject to the requirements of § 60.482-11a(e) shall be recorded in a log that is kept in a readily accessible location:

(1) A list of identification numbers for valves, pumps, and connectors that are designated as unsafe-to-monitor, an explanation for each valve, pump, or connector stating why the valve, pump, or connector is unsafe-to-monitor, and the plan for monitoring each valve, pump, or connector.

(2) A list of identification numbers for valves that are designated as difficult-to-monitor, an explanation for each valve stating why the valve is difficult-to-monitor, and the schedule for monitoring each valve.

(g) The following information shall be recorded for valves complying with § 60.483-2a:

(1) A schedule of monitoring.

(2) The percent of valves found leaking during each monitoring period.

(h) The following information shall be recorded in a log that is kept in a readily accessible location:

(1) Design criterion required in §§ 60.482-2a(d)(5) and 60.482-3a(e)(2) and explanation of the design criterion; and

(2) Any changes to this criterion and the reasons for the changes.

(i) The following information shall be recorded in a log that is kept in a readily accessible location for use in determining exemptions as provided in § 60.480a(d):

(1) An analysis demonstrating the design capacity of the affected facility,

(2) A statement listing the feed or raw materials and products from the affected facilities and an analysis demonstrating whether these chemicals are heavy liquids or beverage alcohol, and

(3) An analysis demonstrating that equipment is not in VOC service.

(j) Information and data used to demonstrate that a piece of equipment is not in VOC service shall be recorded in a log that is kept in a readily accessible location.

(k) The provisions of § 60.7(b) and (d) do not apply to affected facilities subject to this subpart.

§ 60.487a Reporting requirements.

(a) Each owner or operator subject to the provisions of this subpart shall submit semiannual reports to the Administrator beginning 6 months after the initial startup date.

(b) The initial semiannual report to the Administrator shall include the following information:

(1) Process unit identification.

(2) Number of valves subject to the requirements of § 60.482-7a, excluding those valves designated for no detectable emissions under the provisions of § 60.482-7a(f).

(3) Number of pumps subject to the requirements of § 60.482-2a, excluding those pumps designated for no detectable emissions under the provisions of § 60.482-2a(e) and those pumps complying with § 60.482-2a(f).

(4) Number of compressors subject to the requirements of § 60.482-3a, excluding those compressors designated for no detectable emissions under the provisions of § 60.482-3a(i) and those compressors complying with § 60.482-3a(h).

(5) Number of connectors subject to the requirements of § 60.482-11a.

(c) All semiannual reports to the Administrator shall include the following information, summarized from the information in § 60.486a:

(1) Process unit identification.

(2) For each month during the semiannual reporting period,

(i) Number of valves for which leaks were detected as described in § 60.482-7a(b) or § 60.483-2a,

(ii) Number of valves for which leaks were not repaired as required in § 60.482-7a(d)(1),

(iii) Number of pumps for which leaks were detected as described in § 60.482-2a(b), (d)(4)(ii)(A) or (B), or (d)(5)(iii),

(iv) Number of pumps for which leaks were not repaired as required in § 60.482-2a(c)(1) and (d)(6),

(v) Number of compressors for which leaks were detected as described in § 60.482-3a(f),

(vi) Number of compressors for which leaks were not repaired as required in § 60.482-3a(g)(1),

(vii) Number of connectors for which leaks were detected as described in § 60.482-11a(b)

(viii) Number of connectors for which leaks were not repaired as required in § 60.482-11a(d), and

(ix)-(x) [Reserved]

(xi) The facts that explain each delay of repair and, where appropriate, why a process unit shutdown was technically infeasible.

(3) Dates of process unit shutdowns which occurred within the semiannual reporting period.

(4) Revisions to items reported according to paragraph (b) of this section if changes have occurred since the initial report or subsequent revisions to the initial report.

(d) An owner or operator electing to comply with the provisions of §§ 60.483-1a or 60.483-2a shall notify the Administrator of the alternative standard selected 90 days before implementing either of the provisions.

(e) An owner or operator shall report the results of all performance tests in accordance with § 60.8 of the General Provisions. The provisions of § 60.8(d) do not apply to affected facilities subject to the provisions of this subpart except that an owner or operator must notify the Administrator of the schedule for the initial performance tests at least 30 days before the initial performance tests.

(f) The requirements of paragraphs (a) through (c) of this section remain in force until and unless EPA, in delegating enforcement authority to a state under section 111(c) of the CAA, approves reporting requirements or an alternative means of compliance surveillance adopted by such state. In that event, affected sources within the state will be relieved of the obligation to comply with the requirements of paragraphs (a) through (c) of this section, provided that they comply with the requirements established by the state.

§ 60.488a Reconstruction.

For the purposes of this subpart:

(a) The cost of the following frequently replaced components of the facility shall not be considered in calculating either the “fixed capital cost of the new components” or the “fixed capital costs that would be required to construct a comparable new facility” under § 60.15: Pump seals, nuts and bolts, rupture disks, and packings.

(b) Under § 60.15, the “fixed capital cost of new components” includes the fixed capital cost of all depreciable components (except components specified in § 60.488a(a)) which are or will be replaced pursuant to all continuous programs of component replacement which are commenced within any 2-year period following the applicability date for the appropriate subpart. (See the “Applicability and designation of affected facility” section of the appropriate subpart.) For purposes of this paragraph, “commenced” means that an owner or operator has undertaken a continuous program of component replacement or that an owner or operator has entered into a contractual obligation to undertake and complete, within a reasonable time, a continuous program of component replacement.

§ 60.489a List of chemicals produced by affected facilities.

Process units that produce, as intermediates or final products, chemicals listed in § 60.489 are covered under this subpart. The applicability date for process units producing one or more of these chemicals is November 8, 2006.

Indiana Department of Environmental Management
Office of Air Quality

Attachment D to a Part 70 Operating Permit

Source Background and Description

Source Name:	Ohio Valley Resources, LLC
Source Location:	300-400 East CR 350 North, Rockport, Indiana 47635
County:	Spencer
SIC Code:	2873
Permit No.:	T 147-32322-00062
Permit Reviewer:	David Matousek

40 CFR 60, Subpart GA

40 CFR 60, Subpart GA **Standards of Performance for Nitric Acid Plants for Which Construction, Reconstruction, or Modification Commenced after October 14, 2011**

Source: 77 FR 48445, Aug. 14, 2012, unless otherwise noted.

§ 60.70a Applicability and designation of affected facility.

(a) The provisions of this subpart are applicable to each nitric acid production unit, which is the affected facility.

(b) This subpart applies to any nitric acid production unit that commences construction or modification after October 14, 2011.

§ 60.71a 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.

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

Monitoring system malfunction means a sudden, infrequent, not reasonably preventable failure of the monitoring system to provide valid data. Monitoring system failures that are caused in part by poor maintenance or careless operation are not malfunctions. You are required to implement monitoring system repairs in response to monitoring system malfunctions or out-of-control periods, and to return the monitoring system to operation as expeditiously as practicable.

Nitric acid production unit means any facility producing weak nitric acid by either the pressure or atmospheric pressure process.

Operating day means a 24-hour period beginning at 12:00 a.m. during which the nitric acid production unit operated at any time during this period.

Weak nitric acid means acid which is 30 to 70 percent in strength.

§ 60.72a Standards.

Nitrogen oxides. On and after the date on which the performance test required to be conducted by § 60.73a(e) is completed, you may not discharge into the atmosphere from any affected facility any gases which contain NO_X , expressed as NO_2 , in excess of 0.50 pounds (lb) per ton of nitric acid produced, as a 30-day emission rate calculated based on 30 consecutive operating days, the production being expressed as 100 percent nitric acid. The emission standard applies at all times.

§ 60.73a Emissions testing and monitoring.

(a) *General emissions monitoring requirements.* You must install and operate a NO_X concentration (ppmv) continuous emissions monitoring system (CEMS). You must also install and operate a stack gas flow rate monitoring system. With measurements of stack gas NO_X concentration and stack gas flow rate, you will determine hourly NO_X emissions rate (e.g., lb/hr) and with measured data of the hourly nitric acid production (tons), calculate emissions in units of the applicable emissions limit (lb/ton of 100 percent acid produced). You must operate the monitoring system and report emissions during all operating periods including unit startup and shutdown, and malfunction.

(b) *Nitrogen oxides concentration continuous emissions monitoring system.* (1) You must install, calibrate, maintain, and operate a CEMS for measuring and recording the concentration of NO_X emissions in accordance with the provisions of § 60.13 and Performance Specification 2 of Appendix B and Procedure 1 of Appendix F of this part. You must use cylinder gas audits to fulfill the quarterly auditing requirement at section 5.1 of Procedure 1 of Appendix F of this part for the NO_X concentration CEMS.

(2) For the NO_X concentration CEMS, use a span value, as defined in Performance Specification 2, section 3.11, of Appendix B of this part, of 500 ppmv (as NO_2). If you emit NO_X at concentrations higher than 600 ppmv (e.g., during startup or shutdown periods), you must apply a second CEMS or dual range CEMS and a second span value equal to 125 percent of the maximum estimated NO_X emission concentration to apply to the second CEMS or to the higher of the dual analyzer ranges during such periods.

(3) For conducting the relative accuracy test audits, per Performance Specification 2, section 8.4, of Appendix B of this part and Procedure 1, section 5.1.1, of Appendix F of this part, use either EPA Reference Method 7, 7A, 7C, 7D, or 7E of Appendix A-4 of this part; EPA Reference Method 320 of Appendix A of part 63 of this chapter; or ASTM D6348-03 (incorporated by reference, see § 60.17). To verify the operation of the second CEMS or the higher range of a dual analyzer CEMS described in paragraph (b)(2) of this section, you need not conduct a relative accuracy test audit but only the calibration drift test initially (found in Performance Specification 2, section 8.3.1, of Appendix B of this part) and the cylinder gas audit thereafter (found in Procedure 1, section 5.1.2, of Appendix F of this part).

(4) If you use EPA Reference Method 7E of Appendix A-4 of this part, you must mitigate loss of NO_2 in water according to the requirements in paragraphs (b)(4)(i), (ii), or (iii) of this section and verify performance by conducting the system bias checks required in EPA Reference Method 7E, section 8, of Appendix A-4 of this part according to (b)(4)(iv) of this section, or follow the dynamic spike procedure according to paragraph (b)(4)(v) of this section.

(i) For a wet-basis measurement system, you must measure and report temperature of sample line and components (up to analyzer inlet) to demonstrate that the temperatures remain above the sample gas dew point at all times during the sampling.

(ii) You may use a dilution probe to reduce the dew point of the sample gas.

(iii) You may use a refrigerated-type condenser or similar device (e.g., permeation dryer) to remove condensate continuously from sample gas while maintaining minimal contact between condensate and sample gas.

(iv) If your analyzer measures nitric oxide (NO) and nitrogen dioxide (NO_2) separately, you must use both NO and NO_2 calibration gases. Otherwise, you must substitute NO_2 calibration gas for NO calibration gas in the performance of system bias checks.

(v) You must conduct dynamic spiking according to EPA Reference Method 7E, section 16.1, of Appendix A-4 of this part using NO_2 as the spike gas.

(5) Instead of a NO_X concentration CEMS meeting Performance Specification 2, you may apply an FTIR CEMS meeting the requirements of Performance Specification 15 of Appendix B of this part to measure NO_X concentrations. Should you use an FTIR CEMS, you must replace the Relative Accuracy Test Audit requirements of Procedure 1 of appendix F of this part with the validation requirements and criteria of Performance Specification 15, sections 11.1.1 and 12.0, of Appendix B of this part.

(c) *Determining NO_X mass emissions rate values.* You must use the NO_X concentration CEMS, acid production, gas flow rate monitor and other monitoring data to calculate emissions data in units of the applicable limit (lb NO_X /ton of acid produced expressed as 100 percent nitric acid).

(1) You must install, calibrate, maintain, and operate a CEMS for measuring and recording the stack gas flow rates to use in combination with data from the CEMS for measuring emissions concentrations of NO_X to produce data in units of mass rate (e.g., lb/hr) of NO_X on an hourly basis. You will operate and certify the continuous emissions rate monitoring system (CERMS) in accordance with the provisions of § 60.13 and Performance Specification 6 of Appendix B of this part. You must comply with the following provisions in (c)(1)(i) through (iii) of this section.

(i) You must use a stack gas flow rate sensor with a full scale output of at least 125 percent of the maximum expected exhaust volumetric flow rate (see Performance Specification 6, section 8, of Appendix B of this part).

(ii) For conducting the relative accuracy test audits, per Performance Specification 6, section 8.2 of Appendix B of this part and Procedure 1, section 5.1.1, of Appendix F of this part, you must use either EPA Reference Method 2, 2F, or 2G of Appendix A-4 of this part. You may also apply Method 2H in conjunction with other velocity measurements.

(iii) You must verify that the CERMS complies with the quality assurance requirements in Procedure 1 of Appendix F of this part. You must conduct relative accuracy testing to provide for calculating the relative accuracy for RATA and RAA determinations in units of lb/hour.

(2) You must determine the nitric acid production parameters (production rate and concentration) by installing, calibrating, maintaining, and operating a permanent monitoring system (e.g., weigh scale, volume flow meter, mass flow meter, tank volume) to measure and record the weight rates of nitric acid produced in tons per hour. If your nitric acid production rate measurements are for periods longer than hourly (e.g., daily values), you will determine average hourly production values, tons acid/hr, by dividing the total acid production by the number of hours of process operation for the subject measurement period. You must comply with the following provisions in (c)(2)(i) through (iv) of this section.

(i) You must verify that each component of the monitoring system has an accuracy and precision of no more than ±5 percent of full scale.

(ii) You must analyze product concentration via titration or by determining the temperature and specific gravity of the nitric acid. You may also use ASTM E1584-11 (incorporated by reference, see § 60.17), for determining the concentration of nitric acid in percent. You must determine product concentration daily.

(iii) You must use the acid concentration to express the nitric acid production as 100 percent nitric acid.

(iv) You must record the nitric acid production, expressed as 100 percent nitric acid, and the hours of operation.

(3) You must calculate hourly NO_X emissions rates in units of the standard (lb/ton acid) for each hour of process operation. For process operating periods for which there is little or no acid production (e.g., startup or shutdown), you must use the average hourly acid production rate determined from the data collected over the previous 30 days of normal acid production periods (see § 60.75a).

(d) *Continuous monitoring system.* For each continuous monitoring system, including NO_X concentration measurement, volumetric flow rate measurement, and nitric acid production measurement equipment, you must meet the requirements in paragraphs (d)(1) through (3) of this section.

(1) You must operate the monitoring system and collect data at all required intervals at all times the affected facility is operating except for periods of monitoring system malfunctions or out-of-control periods as defined in Appendix F, sections 4 and 5, of this part, repairs associated with monitoring system malfunctions or out-of-control periods, and required monitoring system quality assurance or quality control activities including, as applicable, calibration checks and required zero and span adjustments.

(2) You may not use data recorded during monitoring system malfunctions or out-of-control periods, repairs associated with monitoring system malfunctions or out-of-control periods, or required monitoring system quality assurance or control activities in calculations used to report emissions or operating levels. You must use all the data collected during all other periods in calculating emissions and the status of compliance with the applicable emissions limit in accordance with § 60.72a(a).

(e) *Initial performance testing.* You must conduct an initial performance test to demonstrate compliance with the NO_X emissions limit under § 60.72a(a) beginning in the calendar month following initial certification of the NO_X and flow rate monitoring CEMS. The initial performance test consists of collection of hourly NO_X average concentration, mass flow rate recorded with the certified NO_X concentration and flow rate CEMS and the corresponding acid generation (tons) data for all of the hours of operation for the first 30 days beginning on the first day of the first month following completion of the CEMS installation and certification as described above. You must assure that the CERMS meets all of the data quality assurance requirements as per § 60.13 and Appendix F, Procedure 1, of this part and you must use the data from the CERMS for this compliance determination.

§ 60.74a Affirmative defense for violations of emission standards during malfunction.

In response to an action to enforce the standards set forth in § 60.72a, you may assert an affirmative defense to a claim for civil penalties for violations of such standards that are caused by malfunction, as defined at 40 CFR 60.2. Appropriate penalties may be assessed, however, if you fail to meet your burden of proving all of the requirements in the affirmative defense. The affirmative defense shall not be available for claims for injunctive relief.

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

(1) The violation:

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

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

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

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

(2) Repairs were made as expeditiously as possible when a violation occurred. Off-shift and overtime labor were used, to the extent practicable to make these repairs; and

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

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

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

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

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

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

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

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

§ 60.75a Calculations.

(a) You must calculate the 30 operating day rolling arithmetic average emissions rate in units of the applicable emissions standard (lb NO_X /ton 100 percent acid produced) at the end of each operating day using all of the quality assured hourly average CEMS data for the previous 30 operating days.

(b) You must calculate the 30 operating day average emissions rate according to Equation 1:

$$\frac{E_{30} = k\frac{1}{n}\sum_{i=1}^{n} C_i\, Q_i}{P_i} \qquad \text{(Eq. 1)}$$

Where:

E_{30} = 30 operating day average emissions rate of NO_X , lb NO_X /ton of 100 percent HNO_3 ;

C_i = concentration of NO_X for hour i, ppmv;

Q_i = volumetric flow rate of effluent gas for hour i, where C_i and Q_i are on the same basis (either wet or dry), scf/hr;

P_i = total acid produced during production hour i, tons 100 percent HNO_3 ;

k = conversion factor, 1.194×10^{-7} for NO_X ; and

n = number of operating hours in the 30 operating day period, i.e., n is between 30 and 720.

§ 60.76a Recordkeeping.

(a) For the NO_X emissions rate, you must keep records for and results of the performance evaluations of the continuous emissions monitoring systems.

(b) You must maintain records of the following information for each 30 operating day period:

(1) Hours of operation.

(2) Production rate of nitric acid, expressed as 100 percent nitric acid.

(3) 30 operating day average NO_X emissions rate values.

(c) You must maintain records of the following time periods:

(1) Times when you were not in compliance with the emissions standards.

(2) Times when the pollutant concentration exceeded full span of the NO_X monitoring equipment.

(3) Times when the volumetric flow rate exceeded the high value of the volumetric flow rate monitoring equipment.

(d) You must maintain records of the reasons for any periods of noncompliance and description of corrective actions taken.

(e) You must maintain records of any modifications to CEMS which could affect the ability of the CEMS to comply with applicable performance specifications.

(f) For each malfunction, you must maintain records of the following information:

(1) Records of the occurrence and duration of each malfunction of operation (i.e., process equipment) or the air pollution control and monitoring equipment.

(2) Records of actions taken during periods of malfunction to minimize emissions in accordance with § 60.11(d), including corrective actions to restore malfunctioning process and air pollution control and monitoring equipment to its normal or usual manner of operation.

§ 60.77a Reporting.

(a) The performance test data from the initial and subsequent performance tests and from the performance evaluations of the continuous monitors must be submitted to the Administrator at the appropriate address as shown in 40 CFR 60.4.

(b) The following information must be reported to the Administrator for each 30 operating day period where you were not in compliance with the emissions standard:

(1) Time period;

(2) NO_X emission rates (lb/ton of acid produced);

(3) Reasons for noncompliance with the emissions standard; and

(4) Description of corrective actions taken.

(c) You must also report the following whenever they occur:

(1) Times when the pollutant concentration exceeded full span of the NO_X pollutant monitoring equipment.

(2) Times when the volumetric flow rate exceeded the high value of the volumetric flow rate monitoring equipment.

(d) You must report any modifications to CERMS which could affect the ability of the CERMS to comply with applicable performance specifications.

(e) Within 60 days of completion of the relative accuracy test audit (RATA) required by this subpart, you must submit the data from that audit to EPA's WebFIRE database by using the Compliance and Emissions Data Reporting Interface (CEDRI) that is accessed through EPA's Central Data Exchange (CDX) (*https://cdx.epa.gov/SSL/cdx/EPA_Home.asp*). You must submit performance test data in the file format generated through use of EPA's Electronic Reporting Tool (ERT) (*http://www.epa.gov/ttn/chief/ert/index.html*). Only data collected using test methods listed on the ERT Web site are subject to this requirement for submitting reports electronically to WebFIRE. Owners or operators who claim that some of the information being submitted for performance tests is confidential business information (CBI) must submit a complete ERT file including information claimed to be CBI on a compact disk or other commonly used electronic storage media (including, but not limited to, flash drives) by registered letter to EPA and the same ERT file with the CBI omitted to EPA via CDX as described earlier in this paragraph. Mark the compact disk or other commonly used electronic storage media clearly as CBI and mail to U.S. EPA/OAPQS/CORE CBI Office, Attention: WebFIRE Administrator, MD C404-02, 4930 Old Page Rd., Durham, NC 27703. At the discretion of the delegated authority, you must also submit these reports to the delegated authority in the format specified by the delegated authority. You must submit the other information as required in the performance evaluation as described in § 60.2 and as required in this chapter.

(f) If a malfunction occurred during the reporting period, you must submit a report that contains the following:

(1) The number, duration, and a brief description for each type of malfunction which occurred during the reporting period and which caused or may have caused any applicable emission limitation to be exceeded.

(2) A description of actions taken by an owner or operator during a malfunction of an affected facility to minimize emissions in accordance with § 60.11(d), including actions taken to correct a malfunction.

Indiana Department of Environmental Management
Office of Air Quality

Attachment E to a Part 70 Operating Permit

Source Background and Description

Source Name:	Ohio Valley Resources, LLC
Source Location:	300-400 East CR 350 North, Rockport, Indiana 47635
County:	Spencer
SIC Code:	2873
Permit No.:	T 147-32322-00062
Permit Reviewer:	David Matousek

40 CFR 60, Subpart IIII

40 CFR 60, Subpart IIII **Standards of Performance for Stationary Compression Ignition Internal Combustion Engines**

Source: 71 FR 39172, July 11, 2006, unless otherwise noted.

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What This Subpart Covers

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§ 60.4200 Am I subject to this subpart?

(a) The provisions of this subpart are applicable to manufacturers, owners, and operators of stationary compression ignition (CI) internal combustion engines (ICE) and other persons as specified in paragraphs (a)(1) through (4) of this section. For the purposes of this subpart, the date that construction commences is the date the engine is ordered by the owner or operator.

(1) Manufacturers of stationary CI ICE with a displacement of less than 30 liters per cylinder where the model year is:

(i) 2007 or later, for engines that are not fire pump engines;

(ii) The model year listed in Table 3 to this subpart or later model year, for fire pump engines.

(2) Owners and operators of stationary CI ICE that commence construction after July 11, 2005, where the stationary CI ICE are:

(i) Manufactured after April 1, 2006, and are not fire pump engines, or

(ii) Manufactured as a certified National Fire Protection Association (NFPA) fire pump engine after July 1, 2006.

(3) Owners and operators of any stationary CI ICE that are modified or reconstructed after July 11, 2005 and any person that modifies or reconstructs any stationary CI ICE after July 11, 2005.

(4) The provisions of § 60.4208 of this subpart are applicable to all owners and operators of stationary CI ICE that commence construction after July 11, 2005.

(b) The provisions of this subpart are not applicable to stationary CI ICE being tested at a stationary CI ICE test cell/stand.

(c) If you are an owner or operator of an area source subject to this subpart, you are exempt from the obligation to obtain a permit under 40 CFR part 70 or 40 CFR part 71, provided you are not required to obtain a permit under 40 CFR 70.3(a) or 40 CFR 71.3(a) for a reason other than your status as an area source under this subpart. Notwithstanding the previous sentence, you must continue to comply with the provisions of this subpart applicable to area sources.

(d) Stationary CI ICE may be eligible for exemption from the requirements of this subpart as described in 40 CFR part 1068, subpart C (or the exemptions described in 40 CFR part 89, subpart J and 40 CFR part 94, subpart J, for engines that would need to be certified to standards in those parts), except that owners and operators, as well as manufacturers, may be eligible to request an exemption for national security.

(e) Owners and operators of facilities with CI ICE that are acting as temporary replacement units and that are located at a stationary source for less than 1 year and that have been properly certified as meeting the standards that would be applicable to such engine under the appropriate nonroad engine provisions, are not required to meet any other provisions under this subpart with regard to such engines.

[71 FR 39172, July 11, 2006, as amended at 76 FR 37967, June 28, 2011]

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Emission Standards for Manufacturers

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§ 60.4201 What emission standards must I meet for non-emergency engines if I am a stationary CI internal combustion engine manufacturer?

(a) Stationary CI internal combustion engine manufacturers must certify their 2007 model year and later non-emergency stationary CI ICE with a maximum engine power less than or equal to 2,237 kilowatt (KW) (3,000 horsepower (HP)) and a displacement of less than 10 liters per cylinder to the certification emission standards for new nonroad CI engines in 40 CFR 89.112, 40 CFR 89.113, 40 CFR 1039.101, 40 CFR 1039.102, 40 CFR 1039.104, 40 CFR 1039.105, 40 CFR 1039.107, and 40 CFR 1039.115, as applicable, for all pollutants, for the same model year and maximum engine power.

(b) Stationary CI internal combustion engine manufacturers must certify their 2007 through 2010 model year non-emergency stationary CI ICE with a maximum engine power greater than 2,237 KW (3,000 HP) and a displacement of less than 10 liters per cylinder to the emission standards in table 1 to this subpart, for all pollutants, for the same maximum engine power.

(c) Stationary CI internal combustion engine manufacturers must certify their 2011 model year and later non-emergency stationary CI ICE with a maximum engine power greater than 2,237 KW (3,000 HP) and a displacement of less than 10 liters per cylinder to the certification emission standards for new nonroad CI engines in 40 CFR 1039.101, 40 CFR 1039.102, 40 CFR 1039.104, 40 CFR 1039.105, 40 CFR 1039.107, and 40 CFR 1039.115, as applicable, for all pollutants, for the same maximum engine power.

(d) Stationary CI internal combustion engine manufacturers must certify the following non-emergency stationary CI ICE to the certification emission standards for new marine CI engines in 40 CFR 94.8, as applicable, for all pollutants, for the same displacement and maximum engine power:

(1) Their 2007 model year through 2012 non-emergency stationary CI ICE with a displacement of greater than or equal to 10 liters per cylinder and less than 30 liters per cylinder;

(2) Their 2013 model year non-emergency stationary CI ICE with a maximum engine power greater than or equal to 3,700 KW (4,958 HP) and a displacement of greater than or equal to 10 liters per cylinder and less than 15 liters per cylinder; and

(3) Their 2013 model year non-emergency stationary CI ICE with a displacement of greater than or equal to 15 liters per cylinder and less than 30 liters per cylinder.

(e) Stationary CI internal combustion engine manufacturers must certify the following non-emergency stationary CI ICE to the certification emission standards and other requirements for new marine CI engines in 40 CFR 1042.101, 40 CFR 1042.107, 40 CFR 1042.110, 40 CFR 1042.115, 40 CFR 1042.120, and 40 CFR 1042.145, as applicable, for all pollutants, for the same displacement and maximum engine power:

(1) Their 2013 model year non-emergency stationary CI ICE with a maximum engine power less than 3,700 KW (4,958 HP) and a displacement of greater than or equal to 10 liters per cylinder and less than 15 liters per cylinder; and

(2) Their 2014 model year and later non-emergency stationary CI ICE with a displacement of greater than or equal to 10 liters per cylinder and less than 30 liters per cylinder.

(f) Notwithstanding the requirements in paragraphs (a) through (c) of this section, stationary non-emergency CI ICE identified in paragraphs (a) and (c) may be certified to the provisions of 40 CFR part 94 or, if Table 1 to 40 CFR 1042.1 identifies 40 CFR part 1042 as being applicable, 40 CFR part 1042, if the engines will be used solely in either or both of the following locations:

(1) Areas of Alaska not accessible by the Federal Aid Highway System (FAHS); and

(2) Marine offshore installations.

(g) Notwithstanding the requirements in paragraphs (a) through (f) of this section, stationary CI internal combustion engine manufacturers are not required to certify reconstructed engines; however manufacturers may elect to do so. The reconstructed engine must be certified to the emission standards specified in paragraphs (a) through (e) of this section that are applicable to the model year, maximum engine power, and displacement of the reconstructed stationary CI ICE.

[71 FR 39172, July 11, 2006, as amended at 76 FR 37967, June 28, 2011]

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§ 60.4202 What emission standards must I meet for emergency engines if I am a stationary CI internal combustion engine manufacturer?

(a) Stationary CI internal combustion engine manufacturers must certify their 2007 model year and later emergency stationary CI ICE with a maximum engine power less than or equal to 2,237 KW (3,000 HP) and a displacement of less than 10 liters per cylinder that are not fire pump engines to the emission standards specified in paragraphs (a)(1) through (2) of this section.

(1) For engines with a maximum engine power less than 37 KW (50 HP):

(i) The certification emission standards for new nonroad CI engines for the same model year and maximum engine power in 40 CFR 89.112 and 40 CFR 89.113 for all pollutants for model year 2007 engines, and

(ii) The certification emission standards for new nonroad CI engines in 40 CFR 1039.104, 40 CFR 1039.105, 40 CFR 1039.107, 40 CFR 1039.115, and table 2 to this subpart, for 2008 model year and later engines.

(2) For engines with a maximum engine power greater than or equal to 37 KW (50 HP), the certification emission standards for new nonroad CI engines for the same model year and maximum engine power in 40 CFR 89.112 and 40 CFR 89.113 for all pollutants beginning in model year 2007.

(b) Stationary CI internal combustion engine manufacturers must certify their 2007 model year and later emergency stationary CI ICE with a maximum engine power greater than 2,237 KW (3,000 HP) and a displacement of less than 10 liters per cylinder that are not fire pump engines to the emission standards specified in paragraphs (b)(1) through (2) of this section.

(1) For 2007 through 2010 model years, the emission standards in table 1 to this subpart, for all pollutants, for the same maximum engine power.

(2) For 2011 model year and later, the certification emission standards for new nonroad CI engines for engines of the same model year and maximum engine power in 40 CFR 89.112 and 40 CFR 89.113 for all pollutants.

(c) [Reserved]

(d) Beginning with the model years in table 3 to this subpart, stationary CI internal combustion engine manufacturers must certify their fire pump stationary CI ICE to the emission standards in table 4 to this subpart, for all pollutants, for the same model year and NFPA nameplate power.

(e) Stationary CI internal combustion engine manufacturers must certify the following emergency stationary CI ICE that are not fire pump engines to the certification emission standards for new marine CI engines in 40 CFR 94.8, as applicable, for all pollutants, for the same displacement and maximum engine power:

(1) Their 2007 model year through 2012 emergency stationary CI ICE with a displacement of greater than or equal to 10 liters per cylinder and less than 30 liters per cylinder;

(2) Their 2013 model year and later emergency stationary CI ICE with a maximum engine power greater than or equal to 3,700 KW (4,958 HP) and a displacement of greater than or equal to 10 liters per cylinder and less than 15 liters per cylinder;

(3) Their 2013 model year emergency stationary CI ICE with a displacement of greater than or equal to 15 liters per cylinder and less than 30 liters per cylinder; and

(4) Their 2014 model year and later emergency stationary CI ICE with a maximum engine power greater than or equal to 2,000 KW (2,682 HP) and a displacement of greater than or equal to 15 liters per cylinder and less than 30 liters per cylinder.

(f) Stationary CI internal combustion engine manufacturers must certify the following emergency stationary CI ICE to the certification emission standards and other requirements applicable to Tier 3 new marine CI engines in 40 CFR 1042.101, 40 CFR 1042.107, 40 CFR 1042.115, 40 CFR 1042.120, and 40 CFR 1042.145, for all pollutants, for the same displacement and maximum engine power:

(1) Their 2013 model year and later emergency stationary CI ICE with a maximum engine power less than 3,700 KW (4,958 HP) and a displacement of greater than or equal to 10 liters per cylinder and less than 15 liters per cylinder; and

(2) Their 2014 model year and later emergency stationary CI ICE with a maximum engine power less than 2,000 KW (2,682 HP) and a displacement of greater than or equal to 15 liters per cylinder and less than 30 liters per cylinder.

(g) Notwithstanding the requirements in paragraphs (a) through (d) of this section, stationary emergency CI internal combustion engines identified in paragraphs (a) and (c) may be certified to the provisions of 40 CFR part 94 or, if Table 2 to 40 CFR 1042.101 identifies Tier 3 standards as being applicable, the requirements applicable to Tier 3 engines in 40 CFR part 1042, if the engines will be used solely in either or both of the following locations:

(1) Areas of Alaska not accessible by the FAHS; and

(2) Marine offshore installations.

(h) Notwithstanding the requirements in paragraphs (a) through (f) of this section, stationary CI internal combustion engine manufacturers are not required to certify reconstructed engines; however manufacturers may elect to do so. The reconstructed engine must be certified to the emission standards specified in paragraphs (a) through (f) of this section that are applicable to the model year, maximum engine power and displacement of the reconstructed emergency stationary CI ICE.

[71 FR 39172, July 11, 2006, as amended at 76 FR 37968, June 28, 2011]

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§ 60.4203 How long must my engines meet the emission standards if I am a manufacturer of stationary CI internal combustion engines?

Engines manufactured by stationary CI internal combustion engine manufacturers must meet the emission standards as required in §§ 60.4201 and 60.4202 during the certified emissions life of the engines.

[76 FR 37968, June 28, 2011]

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Emission Standards for Owners and Operators

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§ 60.4204 What emission standards must I meet for non-emergency engines if I am an owner or operator of a stationary CI internal combustion engine?

(a) Owners and operators of pre-2007 model year non-emergency stationary CI ICE with a displacement of less than 10 liters per cylinder must comply with the emission standards in table 1 to this subpart. Owners and operators of pre-2007 model year non-emergency stationary CI ICE with a displacement of greater than or equal to 10 liters per cylinder and less than 30 liters per cylinder must comply with the emission standards in 40 CFR 94.8(a)(1).

(b) Owners and operators of 2007 model year and later non-emergency stationary CI ICE with a displacement of less than 30 liters per cylinder must comply with the emission standards for new CI engines in § 60.4201 for their 2007 model year and later stationary CI ICE, as applicable.

(c) Owners and operators of non-emergency stationary CI engines with a displacement of greater than or equal to 30 liters per cylinder must meet the following requirements:

(1) For engines installed prior to January 1, 2012, limit the emissions of NO_X in the stationary CI internal combustion engine exhaust to the following:

(i) 17.0 grams per kilowatt-hour (g/KW-hr) (12.7 grams per horsepower-hr (g/HP-hr)) when maximum engine speed is less than 130 revolutions per minute (rpm);

(ii) $45 \cdot n^{-0.2}$ g/KW-hr ($34 \cdot n^{-0.2}$ g/HP-hr) when maximum engine speed is 130 or more but less than 2,000 rpm, where n is maximum engine speed; and

(iii) 9.8 g/KW-hr (7.3 g/HP-hr) when maximum engine speed is 2,000 rpm or more.

(2) For engines installed on or after January 1, 2012 and before January 1, 2016, limit the emissions of NO_X in the stationary CI internal combustion engine exhaust to the following:

(i) 14.4 g/KW-hr (10.7 g/HP-hr) when maximum engine speed is less than 130 rpm;

(ii) $44 \cdot n^{-0.23}$ g/KW-hr ($33 \cdot n^{-0.23}$ g/HP-hr) when maximum engine speed is greater than or equal to 130 but less than 2,000 rpm and where n is maximum engine speed; and

(iii) 7.7 g/KW-hr (5.7 g/HP-hr) when maximum engine speed is greater than or equal to 2,000 rpm.

(3) For engines installed on or after January 1, 2016, limit the emissions of NO_X in the stationary CI internal combustion engine exhaust to the following:

(i) 3.4 g/KW-hr (2.5 g/HP-hr) when maximum engine speed is less than 130 rpm;

(ii) $9.0 \cdot n^{-0.20}$ g/KW-hr ($6.7 \cdot n^{-0.20}$ g/HP-hr) where n (maximum engine speed) is 130 or more but less than 2,000 rpm; and

(iii) 2.0 g/KW-hr (1.5 g/HP-hr) where maximum engine speed is greater than or equal to 2,000 rpm.

(4) Reduce particulate matter (PM) emissions by 60 percent or more, or limit the emissions of PM in the stationary CI internal combustion engine exhaust to 0.15 g/KW-hr (0.11 g/HP-hr).

(d) Owners and operators of non-emergency stationary CI ICE with a displacement of less than 30 liters per cylinder who conduct performance tests in-use must meet the not-to-exceed (NTE) standards as indicated in § 60.4212.

(e) Owners and operators of any modified or reconstructed non-emergency stationary CI ICE subject to this subpart must meet the emission standards applicable to the model year, maximum engine power, and displacement of the modified or reconstructed non-emergency stationary CI ICE that are specified in paragraphs (a) through (d) of this section.

[71 FR 39172, July 11, 2006, as amended at 76 FR 37968, June 28, 2011]

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§ 60.4205 What emission standards must I meet for emergency engines if I am an owner or operator of a stationary CI internal combustion engine?

(a) Owners and operators of pre-2007 model year emergency stationary CI ICE with a displacement of less than 10 liters per cylinder that are not fire pump engines must comply with the emission standards in Table 1 to this subpart. Owners and operators of pre-2007 model year emergency stationary CI ICE with a displacement of greater than or equal to 10 liters per cylinder and less than 30 liters per cylinder that are not fire pump engines must comply with the emission standards in 40 CFR 94.8(a)(1).

(b) Owners and operators of 2007 model year and later emergency stationary CI ICE with a displacement of less than 30 liters per cylinder that are not fire pump engines must comply with the emission standards for new nonroad CI engines in § 60.4202, for all pollutants, for the same model year and maximum engine power for their 2007 model year and later emergency stationary CI ICE.

(c) Owners and operators of fire pump engines with a displacement of less than 30 liters per cylinder must comply with the emission standards in table 4 to this subpart, for all pollutants.

(d) Owners and operators of emergency stationary CI engines with a displacement of greater than or equal to 30 liters per cylinder must meet the requirements in this section.

(1) For engines installed prior to January 1, 2012, limit the emissions of NO_X in the stationary CI internal combustion engine exhaust to the following:

(i) 17.0 g/KW-hr (12.7 g/HP-hr) when maximum engine speed is less than 130 rpm;

(ii) $45 \cdot n^{-0.2}$ g/KW-hr ($34 \cdot n^{-0.2}$ g/HP-hr) when maximum engine speed is 130 or more but less than 2,000 rpm, where n is maximum engine speed; and

(iii) 9.8 g/kW-hr (7.3 g/HP-hr) when maximum engine speed is 2,000 rpm or more.

(2) For engines installed on or after January 1, 2012, limit the emissions of NO_X in the stationary CI internal combustion engine exhaust to the following:

(i) 14.4 g/KW-hr (10.7 g/HP-hr) when maximum engine speed is less than 130 rpm;

(ii) $44 \cdot n^{-0.23}$ g/KW-hr ($33 \cdot n^{-0.23}$ g/HP-hr) when maximum engine speed is greater than or equal to 130 but less than 2,000 rpm and where n is maximum engine speed; and

(iii) 7.7 g/KW-hr (5.7 g/HP-hr) when maximum engine speed is greater than or equal to 2,000 rpm.

(3) Limit the emissions of PM in the stationary CI internal combustion engine exhaust to 0.40 g/KW-hr (0.30 g/HP-hr).

(e) Owners and operators of emergency stationary CI ICE with a displacement of less than 30 liters per cylinder who conduct performance tests in-use must meet the NTE standards as indicated in § 60.4212.

(f) Owners and operators of any modified or reconstructed emergency stationary CI ICE subject to this subpart must meet the emission standards applicable to the model year, maximum engine power, and displacement of the modified or reconstructed CI ICE that are specified in paragraphs (a) through (e) of this section.

[71 FR 39172, July 11, 2006, as amended at 76 FR 37969, June 28, 2011]

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§ 60.4206 How long must I meet the emission standards if I am an owner or operator of a stationary CI internal combustion engine?

Owners and operators of stationary CI ICE must operate and maintain stationary CI ICE that achieve the emission standards as required in §§ 60.4204 and 60.4205 over the entire life of the engine.

[76 FR 37969, June 28, 2011]

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Fuel Requirements for Owners and Operators

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§ 60.4207 What fuel requirements must I meet if I am an owner or operator of a stationary CI internal combustion engine subject to this subpart?

(a) Beginning October 1, 2007, owners and operators of stationary CI ICE subject to this subpart that use diesel fuel must use diesel fuel that meets the requirements of 40 CFR 80.510(a).

(b) Beginning October 1, 2010, owners and operators of stationary CI ICE subject to this subpart with a displacement of less than 30 liters per cylinder that use diesel fuel must use diesel fuel that meets the requirements of 40 CFR 80.510(b) for nonroad diesel fuel, except that any existing diesel fuel purchased (or otherwise obtained) prior to October 1, 2010, may be used until depleted.

(c) [Reserved]

(d) Beginning June 1, 2012, owners and operators of stationary CI ICE subject to this subpart with a displacement of greater than or equal to 30 liters per cylinder are no longer subject to the requirements of paragraph (a) of this section, and must use fuel that meets a maximum per-gallon sulfur content of 1,000 parts per million (ppm).

(e) Stationary CI ICE that have a national security exemption under § 60.4200(d) are also exempt from the fuel requirements in this section.

[71 FR 39172, July 11, 2006, as amended at 76 FR 37969, June 28, 2011; 78 FR 6695, Jan. 30, 2013]

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Other Requirements for Owners and Operators

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§ 60.4208 What is the deadline for importing or installing stationary CI ICE produced in previous model years?

(a) After December 31, 2008, owners and operators may not install stationary CI ICE (excluding fire pump engines) that do not meet the applicable requirements for 2007 model year engines.

(b) After December 31, 2009, owners and operators may not install stationary CI ICE with a maximum engine power of less than 19 KW (25 HP) (excluding fire pump engines) that do not meet the applicable requirements for 2008 model year engines.

(c) After December 31, 2014, owners and operators may not install non-emergency stationary CI ICE with a maximum engine power of greater than or equal to 19 KW (25 HP) and less than 56 KW (75 HP) that do not meet the applicable requirements for 2013 model year non-emergency engines.

(d) After December 31, 2013, owners and operators may not install non-emergency stationary CI ICE with a maximum engine power of greater than or equal to 56 KW (75 HP) and less than 130 KW (175 HP) that do not meet the applicable requirements for 2012 model year non-emergency engines.

(e) After December 31, 2012, owners and operators may not install non-emergency stationary CI ICE with a maximum engine power of greater than or equal to 130 KW (175 HP), including those above 560 KW (750 HP), that do not meet the applicable requirements for 2011 model year non-emergency engines.

(f) After December 31, 2016, owners and operators may not install non-emergency stationary CI ICE with a maximum engine power of greater than or equal to 560 KW (750 HP) that do not meet the applicable requirements for 2015 model year non-emergency engines.

(g) After December 31, 2018, owners and operators may not install non-emergency stationary CI ICE with a maximum engine power greater than or equal to 600 KW (804 HP) and less than 2,000 KW (2,680 HP) and a displacement of greater than or equal to 10 liters per cylinder and less than 30 liters per cylinder that do not meet the applicable requirements for 2017 model year non-emergency engines.

(h) In addition to the requirements specified in §§ 60.4201, 60.4202, 60.4204, and 60.4205, it is prohibited to import stationary CI ICE with a displacement of less than 30 liters per cylinder that do not meet the applicable requirements specified in paragraphs (a) through (g) of this section after the dates specified in paragraphs (a) through (g) of this section.

(i) The requirements of this section do not apply to owners or operators of stationary CI ICE that have been modified, reconstructed, and do not apply to engines that were removed from one existing location and reinstalled at a new location.

[71 FR 39172, July 11, 2006, as amended at 76 FR 37969, June 28, 2011]

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§ 60.4209 What are the monitoring requirements if I am an owner or operator of a stationary CI internal combustion engine?

If you are an owner or operator, you must meet the monitoring requirements of this section. In addition, you must also meet the monitoring requirements specified in § 60.4211.

(a) If you are an owner or operator of an emergency stationary CI internal combustion engine that does not meet the standards applicable to non-emergency engines, you must install a non-resettable hour meter prior to startup of the engine.

(b) If you are an owner or operator of a stationary CI internal combustion engine equipped with a diesel particulate filter to comply with the emission standards in § 60.4204, the diesel particulate filter must be installed with a backpressure monitor that notifies the owner or operator when the high backpressure limit of the engine is approached.

[71 FR 39172, July 11, 2006, as amended at 76 FR 37969, June 28, 2011]

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Compliance Requirements

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§ 60.4210 What are my compliance requirements if I am a stationary CI internal combustion engine manufacturer?

(a) Stationary CI internal combustion engine manufacturers must certify their stationary CI ICE with a displacement of less than 10 liters per cylinder to the emission standards specified in § 60.4201(a) through (c) and § 60.4202(a), (b) and (d) using the certification procedures required in 40 CFR part 89, subpart B, or 40 CFR part 1039, subpart C, as applicable, and must test their engines as specified in those parts. For the purposes of this subpart, engines certified to the standards in table 1 to this subpart shall be subject to the same requirements as engines certified to the standards in 40 CFR part 89. For the purposes of this subpart, engines certified to the standards in table 4 to this subpart shall be subject to the same requirements as engines certified to the standards in 40 CFR part 89, except that engines with NFPA nameplate power of less than 37 KW (50 HP) certified to model year 2011 or later standards shall be subject to the same requirements as engines certified to the standards in 40 CFR part 1039.

(b) Stationary CI internal combustion engine manufacturers must certify their stationary CI ICE with a displacement of greater than or equal to 10 liters per cylinder and less than 30 liters per cylinder to the emission standards specified in § 60.4201(d) and (e) and § 60.4202(e) and (f) using the certification procedures required in 40 CFR part 94, subpart C, or 40 CFR part 1042, subpart C, as applicable, and must test their engines as specified in 40 CFR part 94 or 1042, as applicable.

(c) Stationary CI internal combustion engine manufacturers must meet the requirements of 40 CFR 1039.120, 1039.125, 1039.130, and 1039.135, and 40 CFR part 1068 for engines that are certified to the emission standards in 40 CFR part 1039. Stationary CI internal combustion engine manufacturers must meet the corresponding provisions of 40 CFR part 89, 40 CFR part 94 or 40 CFR part 1042 for engines that would be covered by that part if they were nonroad (including marine) engines. Labels on such engines must refer to stationary engines, rather than or in addition to nonroad or marine engines, as appropriate. Stationary CI internal combustion engine manufacturers must label their engines according to paragraphs (c)(1) through (3) of this section.

(1) Stationary CI internal combustion engines manufactured from January 1, 2006 to March 31, 2006 (January 1, 2006 to June 30, 2006 for fire pump engines), other than those that are part of certified engine families under the nonroad CI engine regulations, must be labeled according to 40 CFR 1039.20.

(2) Stationary CI internal combustion engines manufactured from April 1, 2006 to December 31, 2006 (or, for fire pump engines, July 1, 2006 to December 31 of the year preceding the year listed in table 3 to this subpart) must be labeled according to paragraphs (c)(2)(i) through (iii) of this section:

(i) Stationary CI internal combustion engines that are part of certified engine families under the nonroad regulations must meet the labeling requirements for nonroad CI engines, but do not have to meet the labeling requirements in 40 CFR 1039.20.

(ii) Stationary CI internal combustion engines that meet Tier 1 requirements (or requirements for fire pumps) under this subpart, but do not meet the requirements applicable to nonroad CI engines must be labeled according to 40 CFR 1039.20. The engine manufacturer may add language to the label clarifying that the engine meets Tier 1 requirements (or requirements for fire pumps) of this subpart.

(iii) Stationary CI internal combustion engines manufactured after April 1, 2006 that do not meet Tier 1 requirements of this subpart, or fire pumps engines manufactured after July 1, 2006 that do not meet the requirements for fire pumps under this subpart, may not be used in the U.S. If any such engines are manufactured in the U.S. after April 1, 2006 (July 1, 2006 for fire pump engines), they must be exported or must be brought into compliance with the appropriate standards prior to initial operation. The export provisions of 40 CFR 1068.230 would apply to engines for export and the manufacturers must label such engines according to 40 CFR 1068.230.

(3) Stationary CI internal combustion engines manufactured after January 1, 2007 (for fire pump engines, after January 1 of the year listed in table 3 to this subpart, as applicable) must be labeled according to paragraphs (c)(3)(i) through (iii) of this section.

(i) Stationary CI internal combustion engines that meet the requirements of this subpart and the corresponding requirements for nonroad (including marine) engines of the same model year and HP must be labeled according to the provisions in 40 CFR parts 89, 94, 1039 or 1042, as appropriate.

(ii) Stationary CI internal combustion engines that meet the requirements of this subpart, but are not certified to the standards applicable to nonroad (including marine) engines of the same model year and HP must be labeled according to the provisions in 40 CFR parts 89, 94, 1039 or 1042, as appropriate, but the words “stationary” must be included instead of “nonroad” or “marine” on the label. In addition, such engines must be labeled according to 40 CFR 1039.20.

(iii) Stationary CI internal combustion engines that do not meet the requirements of this subpart must be labeled according to 40 CFR 1068.230 and must be exported under the provisions of 40 CFR 1068.230.

(d) An engine manufacturer certifying an engine family or families to standards under this subpart that are identical to standards applicable under 40 CFR parts 89, 94, 1039 or 1042 for that model year may certify any such family that contains both nonroad (including marine) and stationary engines as a single engine family and/or may include any such family containing stationary engines in the averaging, banking and trading provisions applicable for such engines under those parts.

(e) Manufacturers of engine families discussed in paragraph (d) of this section may meet the labeling requirements referred to in paragraph (c) of this section for stationary CI ICE by either adding a separate label containing the information required in paragraph (c) of this section or by adding the words “and stationary” after the word “nonroad” or “marine,” as appropriate, to the label.

(f) Starting with the model years shown in table 5 to this subpart, stationary CI internal combustion engine manufacturers must add a permanent label stating that the engine is for stationary emergency use only to each new emergency stationary CI internal combustion engine greater than or equal to 19 KW (25 HP) that meets all the emission standards for emergency engines in § 60.4202 but does not meet all the emission standards for non-emergency engines in § 60.4201. The label must be added according to the labeling requirements specified in 40 CFR 1039.135(b). Engine manufacturers must specify in the owner's manual that operation of emergency engines is limited to emergency operations and required maintenance and testing.

(g) Manufacturers of fire pump engines may use the test cycle in table 6 to this subpart for testing fire pump engines and may test at the NFPA certified nameplate HP, provided that the engine is labeled as “Fire Pump Applications Only”.

(h) Engine manufacturers, including importers, may introduce into commerce uncertified engines or engines certified to earlier standards that were manufactured before the new or changed standards took effect until inventories are depleted, as long as such engines are part of normal inventory. For example, if the engine manufacturers' normal industry practice is to keep on hand a one-month supply of engines based on its projected sales, and a new tier of standards starts to apply for the 2009 model year, the engine manufacturer may manufacture engines based on the normal inventory requirements late in the 2008 model year, and sell those engines for installation. The engine manufacturer may not circumvent the provisions of §§ 60.4201 or 60.4202 by stockpiling engines that are built before new or changed standards take effect. Stockpiling of such engines beyond normal industry practice is a violation of this subpart.

(i) The replacement engine provisions of 40 CFR 89.1003(b)(7), 40 CFR 94.1103(b)(3), 40 CFR 94.1103(b)(4) and 40 CFR 1068.240 are applicable to stationary CI engines replacing existing equipment that is less than 15 years old.

[71 FR 39172, July 11, 2006, as amended at 76 FR 37969, June 28, 2011]

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§ 60.4211 What are my compliance requirements if I am an owner or operator of a stationary CI internal combustion engine?

(a) If you are an owner or operator and must comply with the emission standards specified in this subpart, you must do all of the following, except as permitted under paragraph (g) of this section:

(1) Operate and maintain the stationary CI internal combustion engine and control device according to the manufacturer's emission-related written instructions;

(2) Change only those emission-related settings that are permitted by the manufacturer; and

(3) Meet the requirements of 40 CFR parts 89, 94 and/or 1068, as they apply to you.

(b) If you are an owner or operator of a pre-2007 model year stationary CI internal combustion engine and must comply with the emission standards specified in §§ 60.4204(a) or 60.4205(a), or if you are an owner or operator of a CI fire pump engine that is manufactured prior to the model years in table 3 to this subpart and must comply with the emission standards specified in § 60.4205(c), you must demonstrate compliance according to one of the methods specified in paragraphs (b)(1) through (5) of this section.

(1) Purchasing an engine certified according to 40 CFR part 89 or 40 CFR part 94, as applicable, for the same model year and maximum engine power. The engine must be installed and configured according to the manufacturer's specifications.

(2) Keeping records of performance test results for each pollutant for a test conducted on a similar engine. The test must have been conducted using the same methods specified in this subpart and these methods must have been followed correctly.

(3) Keeping records of engine manufacturer data indicating compliance with the standards.

(4) Keeping records of control device vendor data indicating compliance with the standards.

(5) Conducting an initial performance test to demonstrate compliance with the emission standards according to the requirements specified in § 60.4212, as applicable.

(c) If you are an owner or operator of a 2007 model year and later stationary CI internal combustion engine and must comply with the emission standards specified in § 60.4204(b) or § 60.4205(b), or if you are an owner or operator of a CI fire pump engine that is manufactured during or after the model year that applies to your fire pump engine power rating in table 3 to this subpart and must comply with the emission standards specified in § 60.4205(c), you must comply by purchasing an engine certified to the emission standards in § 60.4204(b), or § 60.4205(b) or (c), as applicable, for the same model year and maximum (or in the case of fire pumps, NFPA nameplate) engine power. The engine must be installed and configured according to the manufacturer's emission-related specifications, except as permitted in paragraph (g) of this section.

(d) If you are an owner or operator and must comply with the emission standards specified in § 60.4204(c) or § 60.4205(d), you must demonstrate compliance according to the requirements specified in paragraphs (d)(1) through (3) of this section.

(1) Conducting an initial performance test to demonstrate initial compliance with the emission standards as specified in § 60.4213.

(2) Establishing operating parameters to be monitored continuously to ensure the stationary internal combustion engine continues to meet the emission standards. The owner or operator must petition the Administrator for approval of operating parameters to be monitored continuously. The petition must include the information described in paragraphs (d)(2)(i) through (v) of this section.

(i) Identification of the specific parameters you propose to monitor continuously;

(ii) A discussion of the relationship between these parameters and NO_X and PM emissions, identifying how the emissions of these pollutants change with changes in these parameters, and how limitations on these parameters will serve to limit NO_X and PM emissions;

(iii) A discussion of how you will establish the upper and/or lower values for these parameters which will establish the limits on these parameters in the operating limitations;

(iv) A discussion identifying the methods and the instruments you will use to monitor these parameters, as well as the relative accuracy and precision of these methods and instruments; and

(v) A discussion identifying the frequency and methods for recalibrating the instruments you will use for monitoring these parameters.

(3) For non-emergency engines with a displacement of greater than or equal to 30 liters per cylinder, conducting annual performance tests to demonstrate continuous compliance with the emission standards as specified in § 60.4213.

(e) If you are an owner or operator of a modified or reconstructed stationary CI internal combustion engine and must comply with the emission standards specified in § 60.4204(e) or § 60.4205(f), you must demonstrate compliance according to one of the methods specified in paragraphs (e)(1) or (2) of this section.

(1) Purchasing, or otherwise owning or operating, an engine certified to the emission standards in § 60.4204(e) or § 60.4205(f), as applicable.

(2) Conducting a performance test to demonstrate initial compliance with the emission standards according to the requirements specified in § 60.4212 or § 60.4213, as appropriate. The test must be conducted within 60 days after the engine commences operation after the modification or reconstruction.

(f) If you own or operate an emergency stationary ICE, you must operate the emergency stationary ICE according to the requirements in paragraphs (f)(1) through (3) of this section. In order for the engine to be considered an emergency stationary ICE under this subpart, any operation other than emergency operation, maintenance and testing, emergency demand response, and operation in non-emergency situations for 50 hours per year, as described in paragraphs (f)(1) through (3) of this section, is prohibited. If you do not operate the engine according to the requirements in paragraphs (f)(1) through (3) of this section, the engine will not be considered an emergency engine under this subpart and must meet all requirements for non-emergency engines.

(1) There is no time limit on the use of emergency stationary ICE in emergency situations.

(2) You may operate your emergency stationary ICE for any combination of the purposes specified in paragraphs (f)(2)(i) through (iii) of this section for a maximum of 100 hours per calendar year. Any operation for non-emergency situations as allowed by paragraph (f)(3) of this section counts as part of the 100 hours per calendar year allowed by this paragraph (f)(2).

(i) Emergency stationary ICE may be operated for maintenance checks and readiness testing, provided that the tests are recommended by federal, state or local government, the manufacturer, the vendor, the regional transmission organization or equivalent balancing authority and transmission operator, or the insurance company associated with the engine. The owner or operator may petition the Administrator for approval of additional hours to be used for maintenance checks and readiness testing, but a petition is not required if the owner or operator maintains records indicating that federal, state, or local standards require maintenance and testing of emergency ICE beyond 100 hours per calendar year.

(ii) Emergency stationary ICE may be operated for emergency demand response for periods in which the Reliability Coordinator under the North American Electric Reliability Corporation (NERC) Reliability Standard EOP-002-3, Capacity and Energy Emergencies (incorporated by reference, see § 60.17), or other authorized entity as determined by the Reliability Coordinator, has declared an Energy Emergency Alert Level 2 as defined in the NERC Reliability Standard EOP-002-3.

(iii) Emergency stationary ICE may be operated for periods where there is a deviation of voltage or frequency of 5 percent or greater below standard voltage or frequency.

(3) Emergency stationary ICE may be operated for up to 50 hours per calendar year in non-emergency situations. The 50 hours of operation in non-emergency situations are counted as part of the 100 hours per calendar year for maintenance and testing and emergency demand response provided in paragraph (f)(2) of this section. Except as provided in paragraph (f)(3)(i) of this section, the 50 hours per calendar year for non-emergency situations cannot be used for peak shaving or non-emergency demand

response, or to generate income for a facility to an electric grid or otherwise supply power as part of a financial arrangement with another entity.

(i) The 50 hours per year for non-emergency situations can be used to supply power as part of a financial arrangement with another entity if all of the following conditions are met:

(A) The engine is dispatched by the local balancing authority or local transmission and distribution system operator;

(B) The dispatch is intended to mitigate local transmission and/or distribution limitations so as to avert potential voltage collapse or line overloads that could lead to the interruption of power supply in a local area or region.

(C) The dispatch follows reliability, emergency operation or similar protocols that follow specific NERC, regional, state, public utility commission or local standards or guidelines.

(D) The power is provided only to the facility itself or to support the local transmission and distribution system.

(E) The owner or operator identifies and records the entity that dispatches the engine and the specific NERC, regional, state, public utility commission or local standards or guidelines that are being followed for dispatching the engine. The local balancing authority or local transmission and distribution system operator may keep these records on behalf of the engine owner or operator.

(ii) [Reserved]

(g) If you do not install, configure, operate, and maintain your engine and control device according to the manufacturer's emission-related written instructions, or you change emission-related settings in a way that is not permitted by the manufacturer, you must demonstrate compliance as follows:

(1) If you are an owner or operator of a stationary CI internal combustion engine with maximum engine power less than 100 HP, you must keep a maintenance plan and records of conducted maintenance to demonstrate compliance and must, to the extent practicable, maintain and operate the engine in a manner consistent with good air pollution control practice for minimizing emissions. In addition, if you do not install and configure the engine and control device according to the manufacturer's emission-related written instructions, or you change the emission-related settings in a way that is not permitted by the manufacturer, you must conduct an initial performance test to demonstrate compliance with the applicable emission standards within 1 year of such action.

(2) If you are an owner or operator of a stationary CI internal combustion engine greater than or equal to 100 HP and less than or equal to 500 HP, you must keep a maintenance plan and records of conducted maintenance and must, to the extent practicable, maintain and operate the engine in a manner consistent with good air pollution control practice for minimizing emissions. In addition, you must conduct an initial performance test to demonstrate compliance with the applicable emission standards within 1 year of startup, or within 1 year after an engine and control device is no longer installed, configured, operated, and maintained in accordance with the manufacturer's emission-related written instructions, or within 1 year after you change emission-related settings in a way that is not permitted by the manufacturer.

(3) If you are an owner or operator of a stationary CI internal combustion engine greater than 500 HP, you must keep a maintenance plan and records of conducted maintenance and must, to the extent practicable, maintain and operate the engine in a manner consistent with good air pollution control practice for minimizing emissions. In addition, you must conduct an initial performance test to demonstrate compliance with the applicable emission standards within 1 year of startup, or within 1 year

after an engine and control device is no longer installed, configured, operated, and maintained in accordance with the manufacturer's emission-related written instructions, or within 1 year after you change emission-related settings in a way that is not permitted by the manufacturer. You must conduct subsequent performance testing every 8,760 hours of engine operation or 3 years, whichever comes first, thereafter to demonstrate compliance with the applicable emission standards.

[71 FR 39172, July 11, 2006, as amended at 76 FR 37970, June 28, 2011; 78 FR 6695, Jan. 30, 2013]

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Testing Requirements for Owners and Operators

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§ 60.4212 What test methods and other procedures must I use if I am an owner or operator of a stationary CI internal combustion engine with a displacement of less than 30 liters per cylinder?

Owners and operators of stationary CI ICE with a displacement of less than 30 liters per cylinder who conduct performance tests pursuant to this subpart must do so according to paragraphs (a) through (e) of this section.

(a) The performance test must be conducted according to the in-use testing procedures in 40 CFR part 1039, subpart F, for stationary CI ICE with a displacement of less than 10 liters per cylinder, and according to 40 CFR part 1042, subpart F, for stationary CI ICE with a displacement of greater than or equal to 10 liters per cylinder and less than 30 liters per cylinder.

(b) Exhaust emissions from stationary CI ICE that are complying with the emission standards for new CI engines in 40 CFR part 1039 must not exceed the not-to-exceed (NTE) standards for the same model year and maximum engine power as required in 40 CFR 1039.101(e) and 40 CFR 1039.102(g)(1), except as specified in 40 CFR 1039.104(d). This requirement starts when NTE requirements take effect for nonroad diesel engines under 40 CFR part 1039.

(c) Exhaust emissions from stationary CI ICE that are complying with the emission standards for new CI engines in 40 CFR 89.112 or 40 CFR 94.8, as applicable, must not exceed the NTE numerical requirements, rounded to the same number of decimal places as the applicable standard in 40 CFR 89.112 or 40 CFR 94.8, as applicable, determined from the following equation:

$$\text{NTE requirement for each pollutant} = (1.25) \times (\text{STD}) \qquad \text{(Eq. 1)}$$

Where:

STD = The standard specified for that pollutant in 40 CFR 89.112 or 40 CFR 94.8, as applicable.

Alternatively, stationary CI ICE that are complying with the emission standards for new CI engines in 40 CFR 89.112 or 40 CFR 94.8 may follow the testing procedures specified in § 60.4213 of this subpart, as appropriate.

(d) Exhaust emissions from stationary CI ICE that are complying with the emission standards for pre-2007 model year engines in § 60.4204(a), § 60.4205(a), or § 60.4205(c) must not exceed the NTE numerical requirements, rounded to the same number of decimal places as the applicable standard in § 60.4204(a), § 60.4205(a), or § 60.4205(c), determined from the equation in paragraph (c) of this section.

Where:

STD = The standard specified for that pollutant in § 60.4204(a), § 60.4205(a), or § 60.4205(c).

Alternatively, stationary CI ICE that are complying with the emission standards for pre-2007 model year engines in § 60.4204(a), § 60.4205(a), or § 60.4205(c) may follow the testing procedures specified in § 60.4213, as appropriate.

(e) Exhaust emissions from stationary CI ICE that are complying with the emission standards for new CI engines in 40 CFR part 1042 must not exceed the NTE standards for the same model year and maximum engine power as required in 40 CFR 1042.101(c).

[71 FR 39172, July 11, 2006, as amended at 76 FR 37971, June 28, 2011]

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§ 60.4213 What test methods and other procedures must I use if I am an owner or operator of a stationary CI internal combustion engine with a displacement of greater than or equal to 30 liters per cylinder?

Owners and operators of stationary CI ICE with a displacement of greater than or equal to 30 liters per cylinder must conduct performance tests according to paragraphs (a) through (f) of this section.

(a) Each performance test must be conducted according to the requirements in § 60.8 and under the specific conditions that this subpart specifies in table 7. The test must be conducted within 10 percent of 100 percent peak (or the highest achievable) load.

(b) You may not conduct performance tests during periods of startup, shutdown, or malfunction, as specified in § 60.8(c).

(c) You must conduct three separate test runs for each performance test required in this section, as specified in § 60.8(f). Each test run must last at least 1 hour.

(d) To determine compliance with the percent reduction requirement, you must follow the requirements as specified in paragraphs (d)(1) through (3) of this section.

(1) You must use Equation 2 of this section to determine compliance with the percent reduction requirement:

$$\frac{C_i - C_o}{C_i} \times 100 = R \qquad \text{(Eq. 2)}$$

Where:

C_i = concentration of NO_X or PM at the control device inlet,

C_o = concentration of NO_X or PM at the control device outlet, and

R = percent reduction of NO_X or PM emissions.

(2) You must normalize the NO_X or PM concentrations at the inlet and outlet of the control device to a dry basis and to 15 percent oxygen (O_2) using Equation 3 of this section, or an equivalent percent carbon dioxide (CO_2) using the procedures described in paragraph (d)(3) of this section.

$$C_{adj} = C_d \frac{5.9}{20.9 - \% O_2} \qquad \text{(Eq. 3)}$$

Where:

C_{adj} = Calculated NO_X or PM concentration adjusted to 15 percent O_2 .

C_d = Measured concentration of NO_X or PM, uncorrected.

5.9 = 20.9 percent O_2 −15 percent O_2 , the defined O_2 correction value, percent.

$\%O_2$ = Measured O_2 concentration, dry basis, percent.

(3) If pollutant concentrations are to be corrected to 15 percent O_2 and CO_2 concentration is measured in lieu of O_2 concentration measurement, a CO_2 correction factor is needed. Calculate the CO_2 correction factor as described in paragraphs (d)(3)(i) through (iii) of this section.

(i) Calculate the fuel-specific F_o value for the fuel burned during the test using values obtained from Method 19, Section 5.2, and the following equation:

$$F_o = \frac{0.209 F_d}{F_c} \qquad \text{(Eq. 4)}$$

Where:

F_o = Fuel factor based on the ratio of O_2 volume to the ultimate CO_2 volume produced by the fuel at zero percent excess air.

0.209 = Fraction of air that is O_2 , percent/100.

F_d = Ratio of the volume of dry effluent gas to the gross calorific value of the fuel from Method 19, dsm^3 /J (dscf/10^6 Btu).

F_c = Ratio of the volume of CO_2 produced to the gross calorific value of the fuel from Method 19, dsm^3 /J (dscf/10^6 Btu).

(ii) Calculate the CO_2 correction factor for correcting measurement data to 15 percent O_2 , as follows:

$$X_{CO_2} = \frac{5.9}{F_o} \qquad \text{(Eq. 5)}$$

Where:

X_{CO2} = CO_2 correction factor, percent.

5.9 = 20.9 percent O_2 −15 percent O_2 , the defined O_2 correction value, percent.

(iii) Calculate the NO_X and PM gas concentrations adjusted to 15 percent O_2 using CO_2 as follows:

$$C_{adj} = C_d \frac{X_{CO_2}}{\%CO_2} \qquad \text{(Eq. 6)}$$

Where:

C_{adj} = Calculated NO_X or PM concentration adjusted to 15 percent O_2 .

C_d = Measured concentration of NO_X or PM, uncorrected.

$\%CO_2$ = Measured CO_2 concentration, dry basis, percent.

(e) To determine compliance with the NO_X mass per unit output emission limitation, convert the concentration of NO_X in the engine exhaust using Equation 7 of this section:

$$ER = \frac{C_d \times 1.912 \times 10^{-3} \times Q \times T}{\text{KW-hour}} \qquad \text{(Eq. 7)}$$

Where:

ER = Emission rate in grams per KW-hour.

C_d = Measured NO_X concentration in ppm.

1.912×10^{-3} = Conversion constant for ppm NO_X to grams per standard cubic meter at 25 degrees Celsius.

Q = Stack gas volumetric flow rate, in standard cubic meter per hour.

T = Time of test run, in hours.

KW-hour = Brake work of the engine, in KW-hour.

(f) To determine compliance with the PM mass per unit output emission limitation, convert the concentration of PM in the engine exhaust using Equation 8 of this section:

$$ER = \frac{C_{adj} \times Q \times T}{\text{KW-hour}} \qquad \text{(Eq. 8)}$$

Where:

ER = Emission rate in grams per KW-hour.

C_{adj} = Calculated PM concentration in grams per standard cubic meter.

Q = Stack gas volumetric flow rate, in standard cubic meter per hour.

T = Time of test run, in hours.

KW-hour = Energy output of the engine, in KW.

[71 FR 39172, July 11, 2006, as amended at 76 FR 37971, June 28, 2011]

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Notification, Reports, and Records for Owners and Operators

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§ 60.4214 What are my notification, reporting, and recordkeeping requirements if I am an owner or operator of a stationary CI internal combustion engine?

(a) Owners and operators of non-emergency stationary CI ICE that are greater than 2,237 KW (3,000 HP), or have a displacement of greater than or equal to 10 liters per cylinder, or are pre-2007 model year engines that are greater than 130 KW (175 HP) and not certified, must meet the requirements of paragraphs (a)(1) and (2) of this section.

(1) Submit an initial notification as required in § 60.7(a)(1). The notification must include the information in paragraphs (a)(1)(i) through (v) of this section.

(i) Name and address of the owner or operator;

(ii) The address of the affected source;

(iii) Engine information including make, model, engine family, serial number, model year, maximum engine power, and engine displacement;

(iv) Emission control equipment; and

(v) Fuel used.

(2) Keep records of the information in paragraphs (a)(2)(i) through (iv) of this section.

(i) All notifications submitted to comply with this subpart and all documentation supporting any notification.

(ii) Maintenance conducted on the engine.

(iii) If the stationary CI internal combustion is a certified engine, documentation from the manufacturer that the engine is certified to meet the emission standards.

(iv) If the stationary CI internal combustion is not a certified engine, documentation that the engine meets the emission standards.

(b) If the stationary CI internal combustion engine is an emergency stationary internal combustion engine, the owner or operator is not required to submit an initial notification. Starting with the model years in table 5 to this subpart, if the emergency engine does not meet the standards applicable to non-emergency engines in the applicable model year, the owner or operator must keep records of the operation of the engine in emergency and non-emergency service that are recorded through the non-resettable hour meter. The owner must record the time of operation of the engine and the reason the engine was in operation during that time.

(c) If the stationary CI internal combustion engine is equipped with a diesel particulate filter, the owner or operator must keep records of any corrective action taken after the backpressure monitor has notified the owner or operator that the high backpressure limit of the engine is approached.

(d) If you own or operate an emergency stationary CI ICE with a maximum engine power more than 100 HP that operates or is contractually obligated to be available for more than 15 hours per calendar year for the purposes specified in § 60.4211(f)(2)(ii) and (iii) or that operates for the purposes specified in § 60.4211(f)(3)(i), you must submit an annual report according to the requirements in paragraphs (d)(1) through (3) of this section.

(1) The report must contain the following information:

(i) Company name and address where the engine is located.

(ii) Date of the report and beginning and ending dates of the reporting period.

(iii) Engine site rating and model year.

(iv) Latitude and longitude of the engine in decimal degrees reported to the fifth decimal place.

(v) Hours operated for the purposes specified in § 60.4211(f)(2)(ii) and (iii), including the date, start time, and end time for engine operation for the purposes specified in § 60.4211(f)(2)(ii) and (iii).

(vi) Number of hours the engine is contractually obligated to be available for the purposes specified in § 60.4211(f)(2)(ii) and (iii).

(vii) Hours spent for operation for the purposes specified in § 60.4211(f)(3)(i), including the date, start time, and end time for engine operation for the purposes specified in § 60.4211(f)(3)(i). The report must also identify the entity that dispatched the engine and the situation that necessitated the dispatch of the engine.

(2) The first annual report must cover the calendar year 2015 and must be submitted no later than March 31, 2016. Subsequent annual reports for each calendar year must be submitted no later than March 31 of the following calendar year.

(3) The annual report must be submitted electronically using the subpart specific reporting form in the Compliance and Emissions Data Reporting Interface (CEDRI) that is accessed through EPA's Central Data Exchange (CDX) (*www.epa.gov/cdx*). However, if the reporting form specific to this subpart is not available in CEDRI at the time that the report is due, the written report must be submitted to the Administrator at the appropriate address listed in § 60.4.

[71 FR 39172, July 11, 2006, as amended at 78 FR 6696, Jan. 30, 2013]

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Special Requirements

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§ 60.4215 What requirements must I meet for engines used in Guam, American Samoa, or the Commonwealth of the Northern Mariana Islands?

(a) Stationary CI ICE with a displacement of less than 30 liters per cylinder that are used in Guam, American Samoa, or the Commonwealth of the Northern Mariana Islands are required to meet the applicable emission standards in §§ 60.4202 and 60.4205.

(b) Stationary CI ICE that are used in Guam, American Samoa, or the Commonwealth of the Northern Mariana Islands are not required to meet the fuel requirements in § 60.4207.

(c) Stationary CI ICE with a displacement of greater than or equal to 30 liters per cylinder that are used in Guam, American Samoa, or the Commonwealth of the Northern Mariana Islands are required to meet the following emission standards:

(1) For engines installed prior to January 1, 2012, limit the emissions of NO_X in the stationary CI internal combustion engine exhaust to the following:

(i) 17.0 g/KW-hr (12.7 g/HP-hr) when maximum engine speed is less than 130 rpm;

(ii) $45 \cdot n^{-0.2}$ g/KW-hr ($34 \cdot n^{-0.2}$ g/HP-hr) when maximum engine speed is 130 or more but less than 2,000 rpm, where n is maximum engine speed; and

(iii) 9.8 g/KW-hr (7.3 g/HP-hr) when maximum engine speed is 2,000 rpm or more.

(2) For engines installed on or after January 1, 2012, limit the emissions of NO_X in the stationary CI internal combustion engine exhaust to the following:

(i) 14.4 g/KW-hr (10.7 g/HP-hr) when maximum engine speed is less than 130 rpm;

(ii) $44 \cdot n^{-0.23}$ g/KW-hr ($33 \cdot n^{-0.23}$ g/HP-hr) when maximum engine speed is greater than or equal to 130 but less than 2,000 rpm and where n is maximum engine speed; and

(iii) 7.7 g/KW-hr (5.7 g/HP-hr) when maximum engine speed is greater than or equal to 2,000 rpm.

(3) Limit the emissions of PM in the stationary CI internal combustion engine exhaust to 0.40 g/KW-hr (0.30 g/HP-hr).

[71 FR 39172, July 11, 2006, as amended at 76 FR 37971, June 28, 2011]

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§ 60.4216 What requirements must I meet for engines used in Alaska?

(a) Prior to December 1, 2010, owners and operators of stationary CI ICE with a displacement of less than 30 liters per cylinder located in areas of Alaska not accessible by the FAHS should refer to 40 CFR part 69 to determine the diesel fuel requirements applicable to such engines.

(b) Except as indicated in paragraph (c) of this section, manufacturers, owners and operators of stationary CI ICE with a displacement of less than 10 liters per cylinder located in areas of Alaska not accessible by the FAHS may meet the requirements of this subpart by manufacturing and installing engines meeting the requirements of 40 CFR parts 94 or 1042, as appropriate, rather than the otherwise applicable requirements of 40 CFR parts 89 and 1039, as indicated in sections §§ 60.4201(f) and 60.4202(g) of this subpart.

(c) Manufacturers, owners and operators of stationary CI ICE that are located in areas of Alaska not accessible by the FAHS may choose to meet the applicable emission standards for emergency engines in § 60.4202 and § 60.4205, and not those for non-emergency engines in § 60.4201 and § 60.4204, except that for 2014 model year and later non-emergency CI ICE, the owner or operator of any such engine that was not certified as meeting Tier 4 PM standards, must meet the applicable requirements for PM in

§ 60.4201 and § 60.4204 or install a PM emission control device that achieves PM emission reductions of 85 percent, or 60 percent for engines with a displacement of greater than or equal to 30 liters per cylinder, compared to engine-out emissions.

(d) The provisions of § 60.4207 do not apply to owners and operators of pre-2014 model year stationary CI ICE subject to this subpart that are located in areas of Alaska not accessible by the FAHS.

(e) The provisions of § 60.4208(a) do not apply to owners and operators of stationary CI ICE subject to this subpart that are located in areas of Alaska not accessible by the FAHS until after December 31, 2009.

(f) The provisions of this section and § 60.4207 do not prevent owners and operators of stationary CI ICE subject to this subpart that are located in areas of Alaska not accessible by the FAHS from using fuels mixed with used lubricating oil, in volumes of up to 1.75 percent of the total fuel. The sulfur content of the used lubricating oil must be less than 200 parts per million. The used lubricating oil must meet the on-specification levels and properties for used oil in 40 CFR 279.11.

[76 FR 37971, June 28, 2011]

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§ 60.4217 What emission standards must I meet if I am an owner or operator of a stationary internal combustion engine using special fuels?

Owners and operators of stationary CI ICE that do not use diesel fuel may petition the Administrator for approval of alternative emission standards, if they can demonstrate that they use a fuel that is not the fuel on which the manufacturer of the engine certified the engine and that the engine cannot meet the applicable standards required in § 60.4204 or § 60.4205 using such fuels and that use of such fuel is appropriate and reasonably necessary, considering cost, energy, technical feasibility, human health and environmental, and other factors, for the operation of the engine.

[76 FR 37972, June 28, 2011]

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General Provisions

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§ 60.4218 What parts of the General Provisions apply to me?

Table 8 to this subpart shows which parts of the General Provisions in §§ 60.1 through 60.19 apply to you.

DEFINITIONS

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§ 60.4219 What definitions apply to this subpart?

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

Certified emissions life means the period during which the engine is designed to properly function in terms of reliability and fuel consumption, without being remanufactured, specified as a number of hours of operation or calendar years, whichever comes first. The values for certified emissions life for stationary CI ICE with a displacement of less than 10 liters per cylinder are given in 40 CFR 1039.101(g). The values for certified emissions life for stationary CI ICE with a displacement of greater than or equal to 10 liters per cylinder and less than 30 liters per cylinder are given in 40 CFR 94.9(a).

Combustion turbine means all equipment, including but not limited to the turbine, the fuel, air, lubrication and exhaust gas systems, control systems (except emissions control equipment), and any ancillary components and sub-components comprising any simple cycle combustion turbine, any regenerative/recuperative cycle combustion turbine, the combustion turbine portion of any cogeneration cycle combustion system, or the combustion turbine portion of any combined cycle steam/electric generating system.

Compression ignition means relating to a type of stationary internal combustion engine that is not a spark ignition engine.

Date of manufacture means one of the following things:

(1) For freshly manufactured engines and modified engines, date of manufacture means the date the engine is originally produced.

(2) For reconstructed engines, date of manufacture means the date the engine was originally produced, except as specified in paragraph (3) of this definition.

(3) Reconstructed engines are assigned a new date of manufacture if the fixed capital cost of the new and refurbished components exceeds 75 percent of the fixed capital cost of a comparable entirely new facility. An engine that is produced from a previously used engine block does not retain the date of manufacture of the engine in which the engine block was previously used if the engine is produced using all new components except for the engine block. In these cases, the date of manufacture is the date of reconstruction or the date the new engine is produced.

Diesel fuel means any liquid obtained from the distillation of petroleum with a boiling point of approximately 150 to 360 degrees Celsius. One commonly used form is number 2 distillate oil.

Diesel particulate filter means an emission control technology that reduces PM emissions by trapping the particles in a flow filter substrate and periodically removes the collected particles by either physical action or by oxidizing (burning off) the particles in a process called regeneration.

Emergency stationary internal combustion engine means any stationary reciprocating internal combustion engine that meets all of the criteria in paragraphs (1) through (3) of this definition. All emergency stationary ICE must comply with the requirements specified in § 60.4211(f) in order to be considered emergency stationary ICE. If the engine does not comply with the requirements specified in § 60.4211(f), then it is not considered to be an emergency stationary ICE under this subpart.

(1) The stationary ICE is operated to provide electrical power or mechanical work during an emergency situation. Examples include stationary ICE used to produce power for critical networks or equipment (including power supplied to portions of a facility) when electric power from the local utility (or the normal power source, if the facility runs on its own power production) is interrupted, or stationary ICE used to pump water in the case of fire or flood, etc.

(2) The stationary ICE is operated under limited circumstances for situations not included in paragraph (1) of this definition, as specified in § 60.4211(f).

(3) The stationary ICE operates as part of a financial arrangement with another entity in situations not included in paragraph (1) of this definition only as allowed in § 60.4211(f)(2)(ii) or (iii) and § 60.4211(f)(3)(i).

Engine manufacturer means the manufacturer of the engine. See the definition of “manufacturer” in this section.

Fire pump engine means an emergency stationary internal combustion engine certified to NFPA requirements that is used to provide power to pump water for fire suppression or protection.

Freshly manufactured engine means an engine that has not been placed into service. An engine becomes freshly manufactured when it is originally produced.

Installed means the engine is placed and secured at the location where it is intended to be operated.

Manufacturer has the meaning given in section 216(1) of the Act. In general, this term includes any person who manufactures a stationary engine for sale in the United States or otherwise introduces a new stationary engine into commerce in the United States. This includes importers who import stationary engines for sale or resale.

Maximum engine power means maximum engine power as defined in 40 CFR 1039.801.

Model year means the calendar year in which an engine is manufactured (see “date of manufacture”), except as follows:

(1) Model year means the annual new model production period of the engine manufacturer in which an engine is manufactured (see “date of manufacture”), if the annual new model production period is different than the calendar year and includes January 1 of the calendar year for which the model year is named. It may not begin before January 2 of the previous calendar year and it must end by December 31 of the named calendar year.

(2) For an engine that is converted to a stationary engine after being placed into service as a nonroad or other non-stationary engine, model year means the calendar year or new model production period in which the engine was manufactured (see “date of manufacture”).

Other internal combustion engine means any internal combustion engine, except combustion turbines, which is not a reciprocating internal combustion engine or rotary internal combustion engine.

Reciprocating internal combustion engine means any internal combustion engine which uses reciprocating motion to convert heat energy into mechanical work.

Rotary internal combustion engine means any internal combustion engine which uses rotary motion to convert heat energy into mechanical work.

Spark ignition means relating to a gasoline, natural gas, or liquefied petroleum gas fueled engine or any other type of engine with a spark plug (or other sparking device) and with operating characteristics significantly similar to the theoretical Otto combustion cycle. Spark ignition engines usually use a throttle to regulate intake air flow to control power during normal operation. Dual-fuel engines in which a liquid fuel (typically diesel fuel) is used for CI and gaseous fuel (typically natural gas) is used as the primary fuel at an annual average ratio of less than 2 parts diesel fuel to 100 parts total fuel on an energy equivalent basis are spark ignition engines.

Stationary internal combustion engine means any internal combustion engine, except combustion turbines, that converts heat energy into mechanical work and is not mobile. Stationary ICE differ from mobile ICE in that a stationary internal combustion engine is not a nonroad engine as defined at 40 CFR 1068.30 (excluding paragraph (2)(ii) of that definition), and is not used to propel a motor vehicle, aircraft, or a vehicle used solely for competition. Stationary ICE include reciprocating ICE, rotary ICE, and other ICE, except combustion turbines.

Subpart means 40 CFR part 60, subpart IIII.

[71 FR 39172, July 11, 2006, as amended at 76 FR 37972, June 28, 2011; 78 FR 6696, Jan. 30, 2013]

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Table 1 to Subpart IIII of Part 60—Emission Standards for Stationary Pre-2007 Model Year Engines With a Displacement of <10 Liters per Cylinder and 2007-2010 Model Year Engines >2,237 KW (3,000 HP) and With a Displacement of <10 Liters per Cylinder

[As stated in §§ 60.4201(b), 60.4202(b), 60.4204(a), and 60.4205(a), you must comply with the following emission standards]

Maximum engine power	**Emission standards for stationary pre-2007 model year engines with a displacement of <10 liters per cylinder and 2007-2010 model year engines >2,237 KW (3,000 HP) and with a displacement of <10 liters per cylinder in g/KW-hr (g/HP-hr)**				
	NMHC + NO_X	**HC**	**NO_X**	**CO**	**PM**
KW<8 (HP<11)	10.5 (7.8)			8.0 (6.0)	1.0 (0.75)
8≤KW<19 (11≤HP<25)	9.5 (7.1)			6.6 (4.9)	0.80 (0.60)
19≤KW<37 (25≤HP<50)	9.5 (7.1)			5.5 (4.1)	0.80 (0.60)
37≤KW<56 (50≤HP<75)			9.2 (6.9)		
56≤KW<75 (75≤HP<100)			9.2 (6.9)		
75≤KW<130 (100≤HP<175)			9.2 (6.9)		
130≤KW<225 (175≤HP<300)		1.3 (1.0)	9.2 (6.9)	11.4 (8.5)	0.54 (0.40)
225≤KW<450 (300≤HP<600)		1.3 (1.0)	9.2 (6.9)	11.4 (8.5)	0.54 (0.40)
450≤KW≤560 (600≤HP≤750)		1.3 (1.0)	9.2 (6.9)	11.4 (8.5)	0.54 (0.40)
KW>560 (HP>750)		1.3 (1.0)	9.2 (6.9)	11.4 (8.5)	0.54 (0.40)

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Table 2 to Subpart IIII of Part 60—Emission Standards for 2008 Model Year and Later Emergency Stationary CI ICE <37 KW (50 HP) With a Displacement of <10 Liters per Cylinder

[As stated in § 60.4202(a)(1), you must comply with the following emission standards]

	Emission standards for 2008 model year and later emergency stationary CI ICE <37 KW (50 HP) with a displacement of <10 liters per cylinder in g/KW-hr (g/HP-hr)			
Engine power	**Model year(s)**	**NO_X+ NMHC**	**CO**	**PM**
KW<8 (HP<11)	2008+	7.5 (5.6)	8.0 (6.0)	0.40 (0.30)
8≤KW<19 (11≤HP<25)	2008+	7.5 (5.6)	6.6 (4.9)	0.40 (0.30)
19≤KW<37 (25≤HP<50)	2008+	7.5 (5.6)	5.5 (4.1)	0.30 (0.22)

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Table 3 to Subpart IIII of Part 60—Certification Requirements for Stationary Fire Pump Engines

As stated in § 60.4202(d), you must certify new stationary fire pump engines beginning with the following model years:

Engine power	**Starting model year engine manufacturers must certify new stationary fire pump engines according to § 60.4202(d)[1]**
KW<75 (HP<100)	2011
75≤KW<130 (100≤HP<175)	2010
130≤KW≤560 (175≤HP≤750)	2009
KW>560 (HP>750)	2008

[1] Manufacturers of fire pump stationary CI ICE with a maximum engine power greater than or equal to 37 kW (50 HP) and less than 450 KW (600 HP) and a rated speed of greater than 2,650 revolutions per minute (rpm) are not required to certify such engines until three model years following the model year indicated in this Table 3 for engines in the applicable engine power category.

[71 FR 39172, July 11, 2006, as amended at 76 FR 37972, June 28, 2011]

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Table 4 to Subpart IIII of Part 60—Emission Standards for Stationary Fire Pump Engines

[As stated in §§ 60.4202(d) and 60.4205(c), you must comply with the following emission standards for stationary fire pump engines]

Maximum engine power	Model year(s)	NMHC + NO_X	CO	PM
KW<8 (HP<11)	2010 and earlier	10.5 (7.8)	8.0 (6.0)	1.0 (0.75)
	2011+	7.5 (5.6)		0.40 (0.30)
8≤KW<19 (11≤HP<25)	2010 and earlier	9.5 (7.1)	6.6 (4.9)	0.80 (0.60)
	2011+	7.5 (5.6)		0.40 (0.30)
19≤KW<37 (25≤HP<50)	2010 and earlier	9.5 (7.1)	5.5 (4.1)	0.80 (0.60)
	2011+	7.5 (5.6)		0.30 (0.22)
37≤KW<56 (50≤HP<75)	2010 and earlier	10.5 (7.8)	5.0 (3.7)	0.80 (0.60)
	2011+ [1]	4.7 (3.5)		0.40 (0.30)
56≤KW<75 (75≤HP<100)	2010 and earlier	10.5 (7.8)	5.0 (3.7)	0.80 (0.60)
	2011+ [1]	4.7 (3.5)		0.40 (0.30)
75≤KW<130 (100≤HP<175)	2009 and earlier	10.5 (7.8)	5.0 (3.7)	0.80 (0.60)
	2010+ [2]	4.0 (3.0)		0.30 (0.22)
130≤KW<225 (175≤HP<300)	2008 and earlier	10.5 (7.8)	3.5 (2.6)	0.54 (0.40)
	2009+ [3]	4.0 (3.0)		0.20 (0.15)
225≤KW<450 (300≤HP<600)	2008 and earlier	10.5 (7.8)	3.5 (2.6)	0.54 (0.40)
	2009+ [3]	4.0 (3.0)		0.20 (0.15)
450≤KW≤560 (600≤HP≤750)	2008 and earlier	10.5 (7.8)	3.5 (2.6)	0.54 (0.40)
	2009+	4.0 (3.0)		0.20 (0.15)
KW>560 (HP>750)	2007 and earlier	10.5 (7.8)	3.5 (2.6)	0.54 (0.40)
	2008+	6.4 (4.8)		0.20 (0.15)

[1] For model years 2011-2013, manufacturers, owners and operators of fire pump stationary CI ICE in this engine power category with a rated speed of greater than 2,650 revolutions per minute (rpm) may comply with the emission limitations for 2010 model year engines.

[2] For model years 2010-2012, manufacturers, owners and operators of fire pump stationary CI ICE in this engine power category with a rated speed of greater than 2,650 rpm may comply with the emission limitations for 2009 model year engines.

[3] In model years 2009-2011, manufacturers of fire pump stationary CI ICE in this engine power category with a rated speed of greater than 2,650 rpm may comply with the emission limitations for 2008 model year engines.

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Table 5 to Subpart IIII of Part 60—Labeling and Recordkeeping Requirements for New Stationary Emergency Engines

[You must comply with the labeling requirements in § 60.4210(f) and the recordkeeping requirements in § 60.4214(b) for new emergency stationary CI ICE beginning in the following model years:]

Engine power	**Starting model year**
19≤KW<56 (25≤HP<75)	2013
56≤KW<130 (75≤HP<175)	2012
KW≥130 (HP≥175)	2011

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Table 6 to Subpart IIII of Part 60—Optional 3-Mode Test Cycle for Stationary Fire Pump Engines

[As stated in § 60.4210(g), manufacturers of fire pump engines may use the following test cycle for testing fire pump engines:]

Mode No.	**Engine speed** [1]	**Torque (percent)** [2]	**Weighting factors**
1	Rated	100	0.30
2	Rated	75	0.50
3	Rated	50	0.20

[1] Engine speed: ±2 percent of point.

[2] Torque: NFPA certified nameplate HP for 100 percent point. All points should be ±2 percent of engine percent load value.

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Table 7 to Subpart IIII of Part 60—Requirements for Performance Tests for Stationary CI ICE With a Displacement of ≥30 Liters per Cylinder

[As stated in § 60.4213, you must comply with the following requirements for performance tests for stationary CI ICE with a displacement of ≥30 liters per cylinder:]

For each	**Complying with the requirement to**	**You must**	**Using**	**According to the following requirements**
1. Stationary CI internal combustion engine with a displacement of ≥30 liters per cylinder	a. Reduce NO_X emissions by 90 percent or more	i. Select the sampling port location and the number of traverse points;	(1) Method 1 or 1A of 40 CFR part 60, appendix A	(a) Sampling sites must be located at the inlet and outlet of the control device.

For each	**Complying with the requirement to**	**You must**	**Using**	**According to the following requirements**
		ii. Measure O_2 at the inlet and outlet of the control device;	(2) Method 3, 3A, or 3B of 40 CFR part 60, appendix A	(b) Measurements to determine O_2 concentration must be made at the same time as the measurements for NO_X concentration.
		iii. If necessary, measure moisture content at the inlet and outlet of the control device; and,	(3) Method 4 of 40 CFR part 60, appendix A, Method 320 of 40 CFR part 63, appendix A, or ASTM D 6348-03 (incorporated by reference, see § 60.17)	(c) Measurements to determine moisture content must be made at the same time as the measurements for NO_X concentration.
		iv. Measure NO_X at the inlet and outlet of the control device	(4) Method 7E of 40 CFR part 60, appendix A, Method 320 of 40 CFR part 63, appendix A, or ASTM D 6348-03 (incorporated by reference, see § 60.17)	(d) NO_X concentration must be at 15 percent O_2, dry basis. Results of this test consist of the average of the three 1-hour or longer runs.
	b. Limit the concentration of NO_X in the stationary CI internal combustion engine exhaust.	i. Select the sampling port location and the number of traverse points;	(1) Method 1 or 1A of 40 CFR part 60, appendix A	(a) If using a control device, the sampling site must be located at the outlet of the control device.
		ii. Determine the O_2 concentration of the stationary internal combustion engine exhaust at the sampling port location; and,	(2) Method 3, 3A, or 3B of 40 CFR part 60, appendix A	(b) Measurements to determine O_2 concentration must be made at the same time as the measurement for NO_X concentration.
		iii. If necessary, measure moisture content of the stationary internal combustion engine exhaust at the sampling port location; and,	(3) Method 4 of 40 CFR part 60, appendix A, Method 320 of 40 CFR part 63, appendix A, or ASTM D 6348-03 (incorporated by reference, see § 60.17)	(c) Measurements to determine moisture content must be made at the same time as the measurement for NO_X concentration.

For each	Complying with the requirement to	You must	Using	According to the following requirements
		iv. Measure NO_X at the exhaust of the stationary internal combustion engine	(4) Method 7E of 40 CFR part 60, appendix A, Method 320 of 40 CFR part 63, appendix A, or ASTM D 6348-03 (incorporated by reference, see § 60.17)	(d) NO_X concentration must be at 15 percent O_2, dry basis. Results of this test consist of the average of the three 1-hour or longer runs.
	c. Reduce PM emissions by 60 percent or more	i. Select the sampling port location and the number of traverse points;	(1) Method 1 or 1A of 40 CFR part 60, appendix A	(a) Sampling sites must be located at the inlet and outlet of the control device.
		ii. Measure O_2 at the inlet and outlet of the control device;	(2) Method 3, 3A, or 3B of 40 CFR part 60, appendix A	(b) Measurements to determine O_2 concentration must be made at the same time as the measurements for PM concentration.
		iii. If necessary, measure moisture content at the inlet and outlet of the control device; and	(3) Method 4 of 40 CFR part 60, appendix A	(c) Measurements to determine and moisture content must be made at the same time as the measurements for PM concentration.
		iv. Measure PM at the inlet and outlet of the control device	(4) Method 5 of 40 CFR part 60, appendix A	(d) PM concentration must be at 15 percent O_2, dry basis. Results of this test consist of the average of the three 1-hour or longer runs.
	d. Limit the concentration of PM in the stationary CI internal combustion engine exhaust	i. Select the sampling port location and the number of traverse points;	(1) Method 1 or 1A of 40 CFR part 60, appendix A	(a) If using a control device, the sampling site must be located at the outlet of the control device.
		ii. Determine the O_2 concentration of the stationary internal combustion engine exhaust at the sampling port location; and	(2) Method 3, 3A, or 3B of 40 CFR part 60, appendix A	(b) Measurements to determine O_2 concentration must be made at the same time as the measurements for PM concentration.

For each	Complying with the requirement to	You must	Using	According to the following requirements
		iii. If necessary, measure moisture content of the stationary internal combustion engine exhaust at the sampling port location; and	(3) Method 4 of 40 CFR part 60, appendix A	(c) Measurements to determine moisture content must be made at the same time as the measurements for PM concentration.
		iv. Measure PM at the exhaust of the stationary internal combustion engine	(4) Method 5 of 40 CFR part 60, appendix A	(d) PM concentration must be at 15 percent O_2, dry basis. Results of this test consist of the average of the three 1-hour or longer runs.

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Table 8 to Subpart IIII of Part 60—Applicability of General Provisions to Subpart IIII

[As stated in § 60.4218, you must comply with the following applicable General Provisions:]

General Provisions citation	Subject of citation	Applies to subpart	Explanation
§ 60.1	General applicability of the General Provisions	Yes	
§ 60.2	Definitions	Yes	Additional terms defined in § 60.4219.
§ 60.3	Units and abbreviations	Yes	
§ 60.4	Address	Yes	
§ 60.5	Determination of construction or modification	Yes	
§ 60.6	Review of plans	Yes	
§ 60.7	Notification and Recordkeeping	Yes	Except that § 60.7 only applies as specified in § 60.4214(a).
§ 60.8	Performance tests	Yes	Except that § 60.8 only applies to stationary CI ICE with a displacement of (≥30 liters per cylinder and engines that are not certified.
§ 60.9	Availability of information	Yes	
§ 60.10	State Authority	Yes	
§ 60.11	Compliance with standards and maintenance requirements	No	Requirements are specified in subpart IIII.

§ 60.12	Circumvention	Yes	
§ 60.13	Monitoring requirements	Yes	Except that § 60.13 only applies to stationary CI ICE with a displacement of (≥30 liters per cylinder.
§ 60.14	Modification	Yes	
§ 60.15	Reconstruction	Yes	
§ 60.16	Priority list	Yes	
§ 60.17	Incorporations by reference	Yes	
§ 60.18	General control device requirements	No	
§ 60.19	General notification and reporting requirements	Yes	

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Indiana Department of Environmental Management
Office of Air Quality

Attachment F to a Part 70 Operating Permit

Source Background and Description

Source Name:	Ohio Valley Resources, LLC
Source Location:	300-400 East CR 350 North, Rockport, Indiana 47635
County:	Spencer
SIC Code:	2873
Permit No.:	T 147-32322-00062
Permit Reviewer:	David Matousek

40 CFR 60, Subpart Db

40 CFR 60, Subpart Db **Standards of Performance for Industrial-Commercial-Institutional Steam Generating Units**

Source: 72 FR 32742, June 13, 2007, unless otherwise noted.

§ 60.40b Applicability and delegation of authority.

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

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

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

(2) Coal-fired affected facilities having a heat input capacity greater than 73 MW (250 MMBtu/hr) and meeting the applicability requirements under subpart D (Standards of performance for fossil-fuel-fired steam generators; § 60.40) are subject to the PM and NO_X standards under this subpart and to the sulfur dioxide (SO_2) standards under subpart D (§ 60.43).

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

(4) Oil-fired affected facilities having a heat input capacity greater than 73 MW (250 MMBtu/hr) and meeting the applicability requirements under subpart D (Standards of performance for fossil-fuel-fired steam generators; § 60.40) are also subject to the NO_X standards under this subpart and the PM and SO_2 standards under subpart D (§ 60.42 and § 60.43).

(c) Affected facilities that also meet the applicability requirements under subpart J or subpart Ja of this part are subject to the PM and NO_X standards under this subpart and the SO_2 standards under subpart J or subpart Ja of this part, as applicable.

(d) Affected facilities that also meet the applicability requirements under subpart E (Standards of performance for incinerators; § 60.50) are subject to the NO_X and PM standards under this subpart.

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

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

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

(1) Section 60.44b(f).

(2) Section 60.44b(g).

(3) Section 60.49b(a)(4).

(h) Any affected facility that meets the applicability requirements and is subject to subpart Ea, subpart Eb, subpart AAAA, or subpart CCCC of this part is not subject to this subpart.

(i) Affected facilities (*i.e.,* heat recovery steam generators) that are associated with stationary combustion turbines and that meet the applicability requirements of subpart KKKK of this part are not subject to this subpart. This subpart will continue to apply to all other affected facilities (*i.e.* heat recovery steam generators with duct burners) that are capable of combusting more than 29 MW (100 MMBtu/h) heat input of fossil fuel. If the affected facility (*i.e.* 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 stationary combustion turbine emissions are subject to subpart GG or KKKK, as applicable, of this part.)

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

(k) Any affected facility that meets the applicability requirements and is subject to an EPA approved State or Federal section 111(d)/129 plan implementing subpart Cb or subpart BBBB of this part is not covered by this subpart.

(l) Affected facilities that also meet the applicability requirements under subpart BB of this part (Standards of Performance for Kraft Pulp Mills) are subject to the SO_2 and NO_X standards under this subpart and the PM standards under subpart BB.

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

[72 FR 32742, June 13, 2007, as amended at 74 FR 5084, Jan. 28, 2009; 77 FR 9459, Feb. 16, 2012]

§ 60.41b 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 the fuels listed in § 60.42b(a), § 60.43b(a), or § 60.44b(a), as applicable, during a calendar year and the potential heat input to the steam generating unit had it been operated for 8,760 hours during a calendar year at the maximum steady state design heat input capacity. In the case of steam generating units that are rented or leased, the actual heat input shall be determined based on the combined heat input from all operations of the affected facility in a calendar year.

Byproduct/waste means any liquid or gaseous substance produced at chemical manufacturing plants, petroleum refineries, or pulp and paper mills (except natural gas, distillate oil, or residual oil) and combusted in a steam generating unit for heat recovery or for disposal. Gaseous substances with carbon dioxide (CO_2) levels greater than 50 percent or carbon monoxide levels greater than 10 percent are not byproduct/waste for the purpose of this subpart.

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

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

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

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

Coke oven gas means the volatile constituents generated in the gaseous exhaust during the carbonization of bituminous coal to form coke.

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

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

Distillate oil means fuel oils that contain 0.05 weight percent nitrogen or less and comply with the specifications for fuel oil numbers 1 and 2, as defined by the American Society of Testing and Materials in ASTM D396 (incorporated by reference, see § 60.17), diesel fuel oil numbers 1 and 2, as defined by the American Society for Testing and Materials in ASTM D975 (incorporated by reference, see § 60.17), kerosine, as defined by the American Society of Testing and Materials in ASTM D3699 (incorporated by reference, see § 60.17), biodiesel as defined by the American Society of Testing and Materials in ASTM D6751 (incorporated by reference, see § 60.17), or biodiesel blends as defined by the American Society of Testing and Materials in ASTM D7467 (incorporated by reference, see § 60.17).

Dry flue gas desulfurization technology means a SO_2 control system that is located downstream of the steam generating unit and removes sulfur oxides from the combustion gases of the steam generating unit by contacting the combustion gases with an alkaline 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 slurries or solutions used in dry flue gas desulfurization technology include but are not limited to lime and sodium.

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

Emerging technology means any SO_2 control system that is not defined as a conventional technology under this section, and for which the owner or operator of the facility has applied to the Administrator and received approval to operate as an emerging technology under § 60.49b(a)(4).

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

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

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

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

Gaseous fuel means any fuel that is a gas at ISO conditions. This includes, but is not limited to, natural gas and gasified coal (including coke oven gas).

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

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 gas turbines, internal combustion engines, kilns, etc.

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

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

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

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

Lignite means a type of coal classified as lignite A or lignite B by the American Society of Testing and Materials in ASTM D388 (incorporated by reference, see § 60.17).

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

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

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

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

Natural gas means:

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

(2) Liquefied petroleum 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 and residual oil.

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

Potential sulfur dioxide emission rate means the theoretical SO_2 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. For gasified coal or oil that is desulfurized prior to combustion, the *Potential sulfur dioxide emission rate* is the theoretical SO_2 emissions (ng/J or lb/MMBtu heat input) that would result from combusting fuel in a cleaned state without using any post combustion emission control systems.

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

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

Pulverized coal-fired steam generating unit means a steam generating unit in which pulverized coal is introduced into an air stream that carries the coal to the combustion chamber of the steam generating unit where it is fired in suspension. This includes both conventional pulverized coal-fired and micropulverized coal-fired steam generating units. Residual oil means crude oil, fuel oil numbers 1 and 2 that have a nitrogen content greater than 0.05 weight percent, and all fuel oil numbers 4, 5 and 6, as defined by the American Society of Testing and Materials in ASTM D396 (incorporated by reference, see § 60.17).

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

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

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

Temporary boiler means any gaseous or liquid fuel-fired steam generating unit that is designed to, and is capable of, being carried or moved from one location to another by means of, for example, wheels, skids, carrying handles, dollies, trailers, or platforms. A steam generating unit is not a temporary boiler if any one of the following conditions exists:

(1) The equipment is attached to a foundation.

(2) The steam generating unit or a replacement remains at a location for more than 180 consecutive days. Any temporary boiler that replaces a temporary boiler at a location and performs the same or similar function will be included in calculating the consecutive time period.

(3) The equipment is located at a seasonal facility and operates during the full annual operating period of the seasonal facility, remains at the facility for at least 2 years, and operates at that facility for at least 3 months each year.

(4) The equipment is moved from one location to another in an attempt to circumvent the residence time requirements of this definition.

Very low sulfur oil means for units constructed, reconstructed, or modified on or before February 28, 2005, oil that contains no more than 0.5 weight percent sulfur or that, when combusted without SO_2 emission control, has a SO_2 emission rate equal to or less than 215 ng/J (0.5 lb/MMBtu) heat input. For units constructed, reconstructed, or modified after February 28, 2005 and not located in a noncontinental area, *very low sulfur oil* means oil that contains no more than 0.30 weight percent sulfur or that, when combusted without SO_2 emission control, has a SO_2 emission rate equal to or less than 140 ng/J (0.32 lb/MMBtu) heat input. For units constructed, reconstructed, or modified after February 28, 2005 and located in a noncontinental area, *very low sulfur oil* means oil that contains no more than 0.5 weight percent sulfur or that, when combusted without SO_2 emission control, has a SO_2 emission rate equal to or less than 215 ng/J (0.50 lb/MMBtu) heat input.

Wet flue gas desulfurization technology means a SO_2 control system that is located downstream of the steam generating unit and removes sulfur oxides from the combustion gases of the steam generating unit by contacting the combustion gas with an alkaline slurry or solution and forming a liquid material. This definition applies to devices where the aqueous liquid material product of this contact is subsequently converted to other forms. Alkaline reagents used in wet flue gas desulfurization technology include, but are not limited to, lime, limestone, and sodium.

Wet scrubber system means any emission control device that mixes an aqueous stream or slurry with the exhaust gases from a steam generating unit to control emissions of PM or SO_2 .

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

[72 FR 32742, June 13, 2007, as amended at 74 FR 5084, Jan. 28, 2009; 77 FR 9459, Feb. 16, 2012]

§ 60.42b Standard for sulfur dioxide (SO_2).

(a) Except as provided in paragraphs (b), (c), (d), or (j) of this section, on and after the date on which the performance test is completed or required to be completed under § 60.8, whichever comes first, no owner or operator of an affected facility that commenced construction, reconstruction, or modification on or before February 28, 2005, that combusts coal or oil shall cause to be discharged into the atmosphere any gases that contain SO_2 in excess of 87 ng/J (0.20 lb/MMBtu) or 10 percent (0.10) of the potential SO_2 emission rate (90 percent reduction) and the emission limit determined according to the following formula:

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

Where:

E_s = SO_2 emission limit, in ng/J or lb/MMBtu heat input;

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

K_b = 340 ng/J (or 0.80 lb/MMBtu);

H_a = Heat input from the combustion of coal, in J (MMBtu); and

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

For 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 in this paragraph. No credit is provided for the heat input to the affected facility from the combustion of natural gas, wood, municipal-type solid waste, or other fuels or heat derived from exhaust gases from other sources, such as gas turbines, internal combustion engines, kilns, etc.

(b) On and after the date on which the performance test is completed or required to be completed under § 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 refuse alone in a fluidized bed combustion steam generating unit shall cause to be discharged into the atmosphere any gases that contain SO_2 in excess of 87 ng/J (0.20 lb/MMBtu) or 20 percent (0.20) of the potential SO_2 emission rate (80 percent reduction) and 520 ng/J (1.2 lb/MMBtu) heat input. If coal or oil is fired with coal refuse, the affected facility is subject to paragraph (a) or (d) of this section, as applicable. For 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 in this paragraph. No credit is provided for the heat input to the affected facility from the combustion of natural gas, wood, municipal-type solid waste, or other fuels or heat derived from exhaust gases from other sources, such as gas turbines, internal combustion engines, kilns, etc.

(c) On and after the date on which the performance test is completed or is required to be completed under § 60.8, whichever comes first, no owner or operator of an affected facility that combusts coal or oil, either alone or in combination with any other fuel, and that uses an emerging technology for the control of SO_2 emissions, shall cause to be discharged into the atmosphere any gases that contain SO_2 in excess of 50 percent of the potential SO_2 emission rate (50 percent reduction) and that contain SO_2 in excess of the emission limit determined according to the following formula:

$$E_s = \frac{(K_c H_c + K_d H_d)}{(H_c + H_d)}$$

Where:

E_s = SO2 emission limit, in ng/J or lb/MM Btu heat input;

K_c = 260 ng/J (or 0.60 lb/MMBtu);

K_d = 170 ng/J (or 0.40 lb/MMBtu);

H_c = Heat input from the combustion of coal, in J (MMBtu); and

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

For 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 in this paragraph. No credit is provided for the heat input to the affected facility from the combustion of natural gas, wood, municipal-type solid waste, or other fuels, or from the heat input derived from exhaust gases from other sources, such as gas turbines, internal combustion engines, kilns, etc.

(d) On and after the date on which the performance test is completed or required to be completed under § 60.8, whichever comes first, no owner or operator of an affected facility that commenced construction, reconstruction, or modification on or before February 28, 2005 and listed in paragraphs (d)(1), (2), (3), or (4) of this section shall cause to be discharged into the atmosphere any gases that contain SO_2 in excess of 520 ng/J (1.2 lb/MMBtu) heat input if the affected facility combusts coal, or 215 ng/J (0.5 lb/MMBtu) heat input if the affected facility combusts oil other than very low sulfur oil. Percent reduction requirements are not applicable to affected facilities under paragraphs (d)(1), (2), (3) or (4) of this section. For facilities complying with paragraphs (d)(1), (2), or (3) of this section, only the heat input supplied to the affected facility from the combustion of coal and oil is counted in this paragraph. No credit is provided for the heat input to the affected facility from the combustion of natural gas, wood, municipal-type solid waste, or other fuels or heat derived from exhaust gases from other sources, such as gas turbines, internal combustion engines, kilns, etc.

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

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

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

(4) The affected facility burns coke oven gas alone or in combination with natural gas or very low sulfur distillate oil.

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

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

(g) Except as provided in paragraph (i) of this section and § 60.45b(a), the SO_2 emission limits and percent reduction requirements under this section apply at all times, including periods of startup, shutdown, and malfunction.

(h) Reductions in the potential SO_2 emission rate through fuel pretreatment are not credited toward the percent reduction requirement under paragraph (c) of this section unless:

(1) Fuel pretreatment results in a 50 percent or greater reduction in potential SO_2 emissions and

(2) Emissions from the pretreated fuel (without combustion or post-combustion SO_2 control) are equal to or less than the emission limits specified in paragraph (c) of this section.

(i) An affected facility subject to paragraph (a), (b), or (c) of this section may combust very low sulfur oil or natural gas when the SO_2 control system is not being operated because of malfunction or maintenance of the SO_2 control system.

(j) Percent reduction requirements are not applicable to affected facilities combusting only very low sulfur oil. The owner or operator of an affected facility combusting very low sulfur oil shall demonstrate that the oil meets the definition of very low sulfur oil by: (1) Following the performance testing procedures as described in § 60.45b(c) or § 60.45b(d), and following the monitoring procedures as described in § 60.47b(a) or § 60.47b(b) to determine SO_2 emission rate or fuel oil sulfur content; or (2) maintaining fuel records as described in § 60.49b(r).

(k)(1) Except as provided in paragraphs (k)(2), (k)(3), and (k)(4) of this section, on and after the date on which the initial performance test is completed or is required to be completed under § 60.8, 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, natural gas, a mixture of these fuels, or a mixture of these fuels with any other fuels shall cause to be discharged into the atmosphere any gases that contain SO_2 in excess of 87 ng/J (0.20 lb/MMBtu) heat input or 8 percent (0.08) of the potential SO_2 emission rate (92 percent reduction) and 520 ng/J (1.2 lb/MMBtu) heat input. For facilities complying with the percent reduction standard and paragraph (k)(3) of this section, only the heat input supplied to the affected facility from the combustion of coal and oil is counted in paragraph (k) of this section. No credit is provided for the heat input to the affected facility from the combustion of natural gas, wood, municipal-type solid waste, or other fuels or heat derived from exhaust gases from other sources, such as gas turbines, internal combustion engines, kilns, etc.

(2) Units firing only very low sulfur oil, gaseous fuel, a mixture of these fuels, or a mixture of these fuels with any other fuels with a potential SO_2 emission rate of 140 ng/J (0.32 lb/MMBtu) heat input or less are exempt from the SO_2 emissions limit in paragraph (k)(1) of this section.

(3) Units that are located in a noncontinental area and that combust coal, oil, or natural gas shall not discharge any gases that contain SO_2 in excess of 520 ng/J (1.2 lb/MMBtu) heat input if the affected facility combusts coal, or 215 ng/J (0.50 lb/MMBtu) heat input if the affected facility combusts oil or natural gas.

(4) As an alternative to meeting the requirements under paragraph (k)(1) of this section, modified facilities that combust coal or a mixture of coal with other fuels shall not cause to be discharged into the atmosphere any gases that contain SO_2 in excess of 87 ng/J (0.20 lb/MMBtu) heat input or 10 percent (0.10) of the potential SO_2 emission rate (90 percent reduction) and 520 ng/J (1.2 lb/MMBtu) heat input.

[72 FR 32742, June 13, 2007, as amended at 74 FR 5084, Jan. 28, 2009; 76 FR 3523, Jan. 20, 2011]

§ 60.43b Standard for particulate matter (PM).

(a) On and after the date on which the initial performance test is completed or is required to be completed under § 60.8, whichever 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, 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, (i) If the affected facility combusts only coal, or

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

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

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

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

(ii) Has a maximum heat input capacity of 73 MW (250 MMBtu/hr) or less,

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

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

(4) An affected facility burning coke oven gas alone or in combination with other fuels not subject to a PM standard under § 60.43b and not using a post-combustion technology (except a wet scrubber) for reducing PM or SO_2 emissions is not subject to the PM limits under § 60.43b(a).

(b) On and after the date on which the performance test is completed or required to be completed under § 60.8, whichever comes first, no owner or operator of an affected facility that commenced construction, reconstruction, or modification on or before February 28, 2005, and that combusts oil (or mixtures of oil with other fuels) and uses a conventional or emerging technology to reduce SO_2 emissions 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.

(c) On and after the date on which the initial performance test is completed or is required to be completed under § 60.8, whichever comes first, no owner or operator of an affected facility that commenced construction, reconstruction, or modification on or before February 28, 2005, and that combusts wood, or wood with other fuels, except coal, shall cause to be discharged from that affected facility any gases that contain PM in excess of the following emission limits:

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

(2) 86 ng/J (0.20 lb/MMBtu) heat input if (i) The affected facility has an annual capacity factor of 30 percent (0.30) or less for wood;

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

(iii) Has a maximum heat input capacity of 73 MW (250 MMBtu/hr) or less.

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

(1) 43 ng/J (0.10 lb/MMBtu) heat input;

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

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

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

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

(ii) Has a maximum heat input capacity of 73 MW (250 MMBtu/hr) or less;

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

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

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

(f) On and after the date on which the initial performance test is completed or is required to be completed under § 60.8, whichever date comes first, no owner or operator of an affected facility that combusts coal, oil, wood, or mixtures of these fuels with any other fuels shall cause to be discharged into the atmosphere any gases that exhibit greater than 20 percent opacity (6-minute average), except for one 6-minute period per hour of not more than 27 percent opacity. An owner or operator of an affected facility that elects to install, calibrate, maintain, and operate a continuous emissions monitoring system (CEMS) for measuring PM emissions according to the requirements of this subpart and is subject to a federally enforceable PM limit of 0.030 lb/MMBtu or less is exempt from the opacity standard specified in this paragraph.

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

(h)(1) Except as provided in paragraphs (h)(2), (h)(3), (h)(4), (h)(5), and (h)(6) of this section, on and after the date on which the initial performance test is completed or is required to be completed under § 60.8, whichever date comes first, no owner or operator of an affected facility that commenced 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 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,

(2) As an alternative to meeting the requirements of paragraph (h)(1) of this section, the owner or operator of an affected facility for which modification commenced after February 28, 2005, may elect to meet the requirements of this paragraph. On and after the date on which the initial performance test is completed or required to be completed under § 60.8, 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 maximum heat input capacity of 73 MW (250 MMBtu/h) or less shall cause to be discharged into the atmosphere from that affected facility any gases that contain 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, no owner or operator of an affected facility that commences modification after February 28, 2005, and that combusts over 30 percent wood (by heat input) on an annual basis and has a maximum heat input capacity greater than 73 MW (250 MMBtu/h) shall cause to be discharged into the atmosphere from that affected facility any gases that contain PM in excess of 37 ng/J (0.085 lb/MMBtu) heat input.

(5) 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 not located in a noncontinental area that commences construction, reconstruction, or modification after February 28, 2005, and that combusts only oil that contains no more than 0.30 weight percent sulfur, coke oven gas, a mixture of these fuels, or either fuel (or a mixture of these fuels) in combination with other fuels not subject to a PM standard in § 60.43b and not using a post-combustion technology (except a wet scrubber) to reduce SO_2 or PM emissions is not subject to the PM limits in (h)(1) of this section.

(6) 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 located in a noncontinental area that commences construction, reconstruction, or modification after February 28, 2005, and that combusts only oil that contains no more than 0.5 weight percent sulfur, coke oven gas, a mixture of these fuels, or either fuel (or a mixture of these fuels) in combination with other fuels not subject to a PM standard in § 60.43b and not using a post-combustion technology (except a wet scrubber) to reduce SO_2 or PM emissions is not subject to the PM limits in (h)(1) of this section.

[72 FR 32742, June 13, 2007, as amended at 74 FR 5084, Jan. 28, 2009; 77 FR 9459, Feb. 16, 2012]

§ 60.44b Standard for nitrogen oxides (NO_X).

(a) Except as provided under paragraphs (k) and (l) of this section, on and after the date on which the initial performance test is completed or is required to be completed under § 60.8, whichever date comes first, no owner or operator of an affected facility that is subject to the provisions of this section and that combusts only coal, oil, or natural gas shall cause to be discharged into the atmosphere from that affected facility any gases that contain NO_X (expressed as NO_2) in excess of the following emission limits:

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

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

$$E_n = \frac{(EL_{go}H_{go}) + (EL_{ro}H_{ro}) + (EL_cH_c)}{(H_{go} + H_{ro} + H_c)}$$

Where:

E_n = NO_X emission limit (expressed as NO_2), ng/J (lb/MMBtu);

EL_{go} = Appropriate emission limit from paragraph (a)(1) for combustion of natural gas or distillate oil, ng/J (lb/MMBtu);

H_{go} = Heat input from combustion of natural gas or distillate oil, J (MMBtu);

EL_{ro} = Appropriate emission limit from paragraph (a)(2) for combustion of residual oil, ng/J (lb/MMBtu);

H_{ro} = Heat input from combustion of residual oil, J (MMBtu);

EL_c = Appropriate emission limit from paragraph (a)(3) for combustion of coal, ng/J (lb/MMBtu); and

H_c = Heat input from combustion of coal, J (MMBtu).

(c) Except as provided under paragraph (d) and (l) of this section, on and after the date on which the initial performance test is completed or is required to be completed under § 60.8, whichever date comes first, no owner or operator of an affected facility that simultaneously combusts coal or oil, natural gas (or any combination of the three), and wood, or any other fuel shall cause to be discharged into the atmosphere any gases that contain NO_X in excess of the emission limit for the coal, oil, natural gas (or any combination of the three), combusted in the affected facility, as determined pursuant to paragraph (a) or (b) of this section. This standard does not apply to an affected facility that is subject to and in compliance with a federally enforceable requirement that limits operation of the affected facility to an annual capacity factor of 10 percent (0.10) or less for coal, oil, natural gas (or any combination of the three).

(d) 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 simultaneously combusts natural gas and/or distillate oil with a potential SO_2 emissions rate of 26 ng/J (0.060 lb/MMBtu) or less with wood, municipal-type solid waste, or other solid fuel, except coal, shall cause to be discharged into the atmosphere from that affected facility any gases that contain NO_X in excess of 130 ng/J (0.30 lb/MMBtu) heat input unless the affected facility has an annual capacity factor for natural gas, distillate oil, or a mixture of these fuels of 10 percent (0.10) or less and is subject to a federally enforceable requirement that limits operation of the affected facility to an annual capacity factor of 10 percent (0.10) or less for natural gas, distillate oil, or a mixture of these fuels.

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

(f) Any owner or operator of an affected facility that combusts byproduct/waste with either natural gas or oil may petition the Administrator within 180 days of the initial startup of the affected facility to establish a NO_X emission limit that shall apply specifically to that affected facility when the byproduct/waste is combusted. The petition shall include sufficient and appropriate data, as determined by the Administrator, such as NO_X emissions from the affected facility, waste composition (including nitrogen content), and combustion conditions to allow the Administrator to confirm that the affected facility is unable to comply with the emission limits in paragraph (e) of this section and to determine the appropriate emission limit for the affected facility.

(1) Any owner or operator of an affected facility petitioning for a facility-specific NO_X emission limit under this section shall:

(i) Demonstrate compliance with the emission limits for natural gas and distillate oil in paragraph (a)(1) of this section or for residual oil in paragraph (a)(2) or (l)(1) of this section, as appropriate, by conducting a 30-day performance test as provided in § 60.46b(e). During the performance test only natural gas, distillate oil, or residual oil shall be combusted in the affected facility; and

(ii) Demonstrate that the affected facility is unable to comply with the emission limits for natural gas and distillate oil in paragraph (a)(1) of this section or for residual oil in paragraph (a)(2) or (l)(1) of this section, as appropriate, when gaseous or liquid byproduct/waste is combusted in the affected facility under the same conditions and using the same technological system of emission reduction applied when demonstrating compliance under paragraph (f)(1)(i) of this section.

(2) The NO_X emission limits for natural gas or distillate oil in paragraph (a)(1) of this section or for residual oil in paragraph (a)(2) or (l)(1) of this section, as appropriate, shall be applicable to the affected facility until and unless the petition is approved by the Administrator. If the petition is approved by the Administrator, a facility-specific NO_X emission limit will be established at the NO_X emission level achievable when the affected facility is combusting oil or natural gas and byproduct/waste in a manner that the Administrator determines to be consistent with minimizing NO_X emissions. In lieu of amending this subpart, a letter will be sent to the facility describing the facility-specific NO_X limit. The facility shall use the compliance procedures detailed in the letter and make the letter available to the public. If the Administrator determines it is appropriate, the conditions and requirements of the letter can be reviewed and changed at any point.

(g) Any owner or operator of an affected facility that combusts hazardous waste (as defined by 40 CFR part 261 or 40 CFR part 761) with natural gas or oil may petition the Administrator within 180 days of the initial startup of the affected facility for a waiver from compliance with the NO_X emission limit that applies specifically to that affected facility. The petition must include sufficient and appropriate data, as determined by the Administrator, on NO_X emissions from the affected facility, waste destruction efficiencies, waste composition (including nitrogen content), the quantity of specific wastes to be combusted and combustion conditions to allow the Administrator to determine if the affected facility is able to comply with the NO_X emission limits required by this section. The owner or operator of the affected facility shall demonstrate that when hazardous waste is combusted in the affected facility, thermal destruction efficiency requirements for hazardous waste specified in an applicable federally enforceable requirement preclude compliance with the NO_X emission limits of this section. The NO_X emission limits for natural gas or distillate oil in paragraph (a)(1) of this section or for residual oil in paragraph (a)(2) or (l)(1) of this section, as appropriate, are applicable to the affected facility until and unless the petition is approved by the Administrator. (See 40 CFR 761.70 for regulations applicable to the incineration of materials containing polychlorinated biphenyls (PCB's).) In lieu of amending this subpart, a letter will be sent to the facility describing the facility-specific NO_X limit. The facility shall use the compliance procedures detailed in the letter and make the letter available to the public. If the Administrator determines it is appropriate, the conditions and requirements of the letter can be reviewed and changed at any point.

(h) For purposes of paragraph (i) of this section, the NO_X standards under this section apply at all times including periods of startup, shutdown, or malfunction.

(i) Except as provided under paragraph (j) of this section, compliance with the emission limits under this section is determined on a 30-day rolling average basis.

(j) Compliance with the emission limits under this section is determined on a 24-hour average basis for the initial performance test and on a 3-hour average basis for subsequent performance tests for any affected facilities that:

(1) Combust, alone or in combination, only natural gas, distillate oil, or residual oil with a nitrogen content of 0.30 weight percent or less;

(2) Have a combined annual capacity factor of 10 percent or less for natural gas, distillate oil, and residual oil with a nitrogen content of 0.30 weight percent or less; and

(3) Are subject to a federally enforceable requirement limiting operation of the affected facility to the firing of natural gas, distillate oil, and/or residual oil with a nitrogen content of 0.30 weight percent or less and limiting operation of the affected facility to a combined annual capacity factor of 10 percent or less for natural gas, distillate oil, and residual oil with a nitrogen content of 0.30 weight percent or less.

(k) Affected facilities that meet the criteria described in paragraphs (j)(1), (2), and (3) of this section, and that have a heat input capacity of 73 MW (250 MMBtu/hr) or less, are not subject to the NO_X emission limits under this section.

(l) On and after the date on which the initial performance test is completed or is required to be completed under 60.8, whichever date is first, no owner or operator of an affected facility that commenced construction after July 9, 1997 shall cause to be discharged into the atmosphere from that affected facility any gases that contain NOx (expressed as NO2) in excess of the following limits:

(1) 86 ng/J (0.20 lb/MMBtu) heat input if the affected facility combusts coal, oil, or natural gas (or any combination of the three), alone or with any other fuels. The affected facility is not subject to this limit if it is subject to and in compliance with a federally enforceable requirement that limits operation of the facility to an annual capacity factor of 10 percent (0.10) or less for coal, oil, and natural gas (or any combination of the three); or

(2) If the affected facility has a low heat release rate and combusts natural gas or distillate oil in excess of 30 percent of the heat input on a 30-day rolling average from the combustion of all fuels, a limit determined by use of the following formula:

$$E_n = \frac{(0.10 \times H_{go}) + (0.20 \times H_r)}{(H_{go} + H_r)}$$

Where:

E_n = NO_X emission limit, (lb/MMBtu);

H_{go} = 30-day heat input from combustion of natural gas or distillate oil; and

H_r = 30-day heat input from combustion of any other fuel.

(3) After February 27, 2006, units where more than 10 percent of total annual output is electrical or mechanical may comply with an optional limit of 270 ng/J (2.1 lb/MWh) gross energy output, based on a 30-day rolling average. Units complying with this output-based limit must demonstrate compliance according to the procedures of § 60.48Da(i) of subpart Da of this part, and must monitor emissions according to § 60.49Da(c), (k), through (n) of subpart Da of this part.

[72 FR 32742, June 13, 2007, as amended at 74 FR 5086, Jan. 28, 2009; 77 FR 9459, Feb. 16, 2012]

§ 60.45b Compliance and performance test methods and procedures for sulfur dioxide.

(a) The SO_2 emission standards in § 60.42b apply at all times. Facilities burning coke oven gas alone or in combination with any other gaseous fuels or distillate oil are allowed to exceed the limit 30 operating days per calendar year for SO_2 control system maintenance.

(b) In conducting the performance tests required under § 60.8, the owner or operator shall use the methods and procedures in appendix A (including fuel certification and sampling) of this part or the methods and procedures as specified in this section, except as provided in § 60.8(b). Section 60.8(f) does not apply to this section. The 30-day notice required in § 60.8(d) applies only to the initial performance test unless otherwise specified by the Administrator.

(c) The owner or operator of an affected facility shall conduct performance tests to determine compliance with the percent of potential SO_2 emission rate (% P_s) and the SO_2 emission rate (E_s) pursuant to § 60.42b following the procedures listed below, except as provided under paragraph (d) and (k) of this section.

(1) The initial performance test shall be conducted over 30 consecutive operating days of the steam generating unit. Compliance with the SO_2 standards shall be determined using a 30-day average. The first operating day included in the initial performance test shall be scheduled within 30 days after achieving the maximum production rate at which the affected facility will be operated, but not later than 180 days after initial startup of the facility.

(2) If only coal, only oil, or a mixture of coal and oil is combusted, the following procedures are used:

(i) The procedures in Method 19 of appendix A-7 of this part are used to determine the hourly SO_2 emission rate (E_{ho}) and the 30-day average emission rate (E_{ao}). The hourly averages used to compute the 30-day averages are obtained from the CEMS of § 60.47b(a) or (b).

(ii) The percent of potential SO_2 emission rate (%P_s) emitted to the atmosphere 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, 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.

(3) If coal or oil is combusted with other fuels, the same procedures required in paragraph (c)(2) of this section are used, except as provided in the following:

(i) An adjusted hourly SO_2 emission rate ($E_{ho}{}^{o}$) is used in Equation 19-19 of Method 19 of appendix A of this part to compute an adjusted 30-day average emission rate ($E_{ao}{}^{o}$). The Eho° is computed using the following formula:

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

Where:

$E_{ho}{}^{o}$ = Adjusted hourly SO_2 emission rate, ng/J (lb/MMBtu);

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

E_w = SO_2 concentration in fuels other than coal and oil combusted in the affected facility, as determined by the 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; and

X_k = Fraction of total heat input from fuel combustion derived from coal, oil, or coal and oil, as determined by applicable procedures in Method 19 of appendix A of this part.

(ii) To compute the percent of potential SO_2 emission rate (%P_s), an adjusted %R_g (%$R_g{}^o$) is computed from the adjusted $E_{ao}{}^o$ from paragraph (b)(3)(i) of this section and an adjusted average SO_2 inlet rate ($E_{ai}{}^o$) using the following formula:

$$\%R_g^o = 100\left(1.0 - \frac{E_{ao}^o}{E_{ai}^o}\right)$$

To compute $E_{ai}{}^o$, an adjusted hourly SO_2 inlet rate ($E_{hi}{}^o$) is used. The $E_{hi}{}^o$ is computed using the following formula:

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

Where:

$E_{hi}{}^o$ = Adjusted hourly SO_2 inlet rate, ng/J (lb/MMBtu); and

E_{hi} = Hourly SO_2 inlet rate, ng/J (lb/MMBtu).

(4) The owner or operator of an affected facility subject to paragraph (c)(3) of this section does not have to measure parameters E_w or X_k if the owner or operator elects to assume that $X_k = 1.0$. Owners or operators of affected facilities who assume $X_k = 1.0$ shall:

(i) Determine %P_s following the procedures in paragraph (c)(2) of this section; and

(ii) Sulfur dioxide emissions (E_s) are considered to be in compliance with SO_2 emission limits under § 60.42b.

(5) The owner or operator of an affected facility that qualifies under the provisions of § 60.42b(d) does not have to measure parameters E_w or X_k in paragraph (c)(3) of this section if the owner or operator of the affected facility elects to measure SO_2 emission rates of the coal or oil following the fuel sampling and analysis procedures in Method 19 of appendix A-7 of this part.

(d) Except as provided in paragraph (j) of this section, the owner or operator of an affected facility that combusts only very low sulfur oil, natural gas, or a mixture of these fuels, has an annual capacity factor for oil of 10 percent (0.10) or less, and is subject to a federally enforceable requirement limiting operation of the affected facility to an annual capacity factor for oil of 10 percent (0.10) or less shall:

(1) Conduct the initial performance test over 24 consecutive steam generating unit operating hours at full load;

(2) Determine compliance with the standards after the initial performance test based on the arithmetic average of the hourly emissions data during each steam generating unit operating day if a CEMS is used, or based on a daily average if Method 6B of appendix A of this part or fuel sampling and analysis procedures under Method 19 of appendix A of this part are used.

(e) The owner or operator of an affected facility subject to § 60.42b(d)(1) shall demonstrate the maximum design capacity of the steam generating unit by operating the facility at maximum capacity for 24 hours. This demonstration will be made during the initial performance test and a subsequent demonstration may be requested at any other time. If the 24-hour average firing rate for the affected facility is less than the maximum design capacity provided by the manufacturer of the affected facility, the 24-hour average firing rate shall be used to determine the capacity utilization rate for the affected facility, otherwise the maximum design capacity provided by the manufacturer is used.

(f) For the initial performance test required under § 60.8, compliance with the SO_2 emission limits and percent reduction requirements under § 60.42b is based on the average emission rates and the average percent reduction for SO_2 for the first 30 consecutive steam generating unit operating days, except as provided under paragraph (d) of this section. The initial performance test is the only test for which at least 30 days prior notice is required unless otherwise specified by the Administrator. The initial performance test is to be scheduled so that the first steam generating unit operating day of the 30 successive steam generating unit operating days is completed within 30 days after achieving the maximum production rate at which the affected facility will be operated, but not later than 180 days after initial startup of the facility. The boiler load during the 30-day period does not have to be the maximum design load, but must be representative of future operating conditions and include at least one 24-hour period at full load.

(g) After the initial performance test required under § 60.8, compliance with the SO_2 emission limits and percent reduction requirements under § 60.42b is based on the average emission rates and the average percent reduction for SO_2 for 30 successive steam generating unit operating days, except as provided under paragraph (d). A separate performance test is completed at the end of each steam generating unit operating day after the initial performance test, and a new 30-day average emission rate and percent reduction for SO_2 are calculated to show compliance with the standard.

(h) Except as provided under paragraph (i) of this section, the owner or operator of an affected facility shall use all valid SO_2 emissions data in calculating $\%P_s$ and E_{ho} under paragraph (c), of this section whether or not the minimum emissions data requirements under § 60.46b are achieved. All valid emissions data, including valid SO_2 emission data collected during periods of startup, shutdown and malfunction, shall be used in calculating $\%P_s$ and E_{ho} pursuant to paragraph (c) of this section.

(i) During periods of malfunction or maintenance of the SO_2 control systems when oil is combusted as provided under § 60.42b(i), emission data are not used to calculate $\%P_s$ or E_s under § 60.42b(a), (b) or (c), however, the emissions data are used to determine compliance with the emission limit under § 60.42b(i).

(j) The owner or operator of an affected facility that only combusts very low sulfur oil, natural gas, or a mixture of these fuels with any other fuels not subject to an SO_2 standard is not subject to the compliance and performance testing requirements of this section if the owner or operator obtains fuel receipts as described in § 60.49b(r).

(k) The owner or operator of an affected facility seeking to demonstrate compliance in §§ 60.42b(d)(4), 60.42b(j), 60.42b(k)(2), and 60.42b(k)(3) (when not burning coal) shall follow the applicable procedures in § 60.49b(r).

[72 FR 32742, June 13, 2007, as amended at 74 FR 5086, Jan. 28, 2009]

§ 60.46b Compliance and performance test methods and procedures for particulate matter and nitrogen oxides.

(a) The PM emission standards and opacity limits under § 60.43b apply at all times except during periods of startup, shutdown, or malfunction. The NO_X emission standards under § 60.44b apply at all times.

(b) Compliance with the PM emission standards under § 60.43b shall be determined through performance testing as described in paragraph (d) of this section, except as provided in paragraph (i) of this section.

(c) Compliance with the NO_X emission standards under § 60.44b shall be determined through performance testing under paragraph (e) or (f), or under paragraphs (g) and (h) of this section, as applicable.

(d) To determine compliance with the PM emission limits and opacity limits under § 60.43b, the owner or operator of an affected facility shall conduct an initial performance test as required under § 60.8, and shall conduct subsequent performance tests as requested by the Administrator, using the following procedures and reference methods:

(1) Method 3A or 3B of appendix A-2 of this part is used for gas analysis when applying Method 5 of appendix A-3 of this part or Method 17 of appendix A-6 of this part.

(2) 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 shall be used at affected facilities without wet flue gas desulfurization (FGD) systems; and

(ii) Method 17 of appendix A-6 of this part may be used at 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-3 of this part may be used in Method 17 of appendix A-6 of this part only if it is used after a wet FGD system. Do not use Method 17 of appendix A-6 of this part after wet FGD systems if the effluent is saturated or laden with water droplets.

(iii) Method 5B of appendix A of this part is to be used only after wet FGD systems.

(3) Method 1 of appendix A of this part is used to select the sampling site and the number of traverse sampling points. The sampling time for each run is at least 120 minutes and the minimum sampling volume is 1.7 dscm (60 dscf) except that smaller sampling times or volumes may be approved by the Administrator when necessitated by process variables or other factors.

(4) For Method 5 of appendix A of this part, the temperature of the sample gas in the probe and filter holder is monitored and is maintained at 160±14 °C (320±25 °F).

(5) For determination of PM emissions, the oxygen (O_2) or CO_2 sample is 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.

(6) For each run using Method 5, 5B, or 17 of appendix A of this part, the emission rate expressed in ng/J heat input is determined using:

(i) The O_2 or CO_2 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.

(7) Method 9 of appendix A of this part is used for determining the opacity of stack emissions.

(e) To determine compliance with the emission limits for NO_X required under § 60.44b, the owner or operator of an affected facility shall conduct the performance test as required under § 60.8 using the continuous system for monitoring NO_X under § 60.48(b).

(1) For the initial compliance test, NO_X from the steam generating unit are monitored for 30 successive steam generating unit operating days and the 30-day average emission rate is used to determine compliance with the NO_X emission standards under § 60.44b. The 30-day average emission rate is calculated as the average of all hourly emissions data recorded by the monitoring system during the 30-day test period.

(2) Following the date on which the initial performance test is completed or is required to be completed in § 60.8, whichever date comes first, the owner or operator of an affected facility which combusts coal (except as specified under § 60.46b(e)(4)) or which combusts residual oil having a nitrogen content greater than 0.30 weight percent shall determine compliance with the NO_X emission standards in § 60.44b on a continuous basis through the use of a 30-day rolling average emission rate. A new 30-day rolling average emission rate is calculated for each steam generating unit operating day as the average of all of the hourly NO_X emission data for the preceding 30 steam generating unit operating days.

(3) Following the date on which the initial performance test is completed or is required to be completed under § 60.8, whichever date comes first, the owner or operator of an affected facility that has a heat input capacity greater than 73 MW (250 MMBtu/hr) and that combusts natural gas, distillate oil, or residual oil having a nitrogen content of 0.30 weight percent or less shall determine compliance with the NO_X standards under § 60.44b on a continuous basis through the use of a 30-day rolling average emission rate. A new 30-day rolling average emission rate is calculated each steam generating unit operating day as the average of all of the hourly NO_X emission data for the preceding 30 steam generating unit operating days.

(4) Following the date on which the initial performance test is completed or required to be completed under § 60.8, whichever date comes first, the owner or operator of an affected facility that has a heat input capacity of 73 MW (250 MMBtu/hr) or less and that combusts natural gas, distillate oil, gasified coal, or residual oil having a nitrogen content of 0.30 weight percent or less shall upon request determine compliance with the NO_X standards in § 60.44b through the use of a 30-day performance test. During periods when performance tests are not requested, NO_X emissions data collected pursuant to § 60.48b(g)(1) or § 60.48b(g)(2) are used to calculate a 30-day rolling average emission rate on a daily basis and used to prepare excess emission reports, but will not be used to determine compliance with the NO_X emission standards. A new 30-day rolling average emission rate is calculated each steam generating unit operating day as the average of all of the hourly NO_X emission data for the preceding 30 steam generating unit operating days.

(5) If the owner or operator of an affected facility that combusts residual oil does not sample and analyze the residual oil for nitrogen content, as specified in § 60.49b(e), the requirements of § 60.48b(g)(1) apply and the provisions of § 60.48b(g)(2) are inapplicable.

(f) To determine compliance with the emissions limits for NO_X required by § 60.44b(a)(4) or § 60.44b(l) for duct burners used in combined cycle systems, either of the procedures described in paragraph (f)(1) or (2) of this section may be used:

(1) The owner or operator of an affected facility shall conduct the performance test required under § 60.8 as follows:

(i) The emissions rate (E) of NO_X shall be computed using Equation 1 in this section:

$$E = E_{sg} + \left(\frac{H_g}{H_b}\right)\left(E_{sg} - E_g\right) \qquad \text{(Eq.1)}$$

Where:

E = Emissions rate of NO_X from the duct burner, ng/J (lb/MMBtu) heat input;

E_{sg} = Combined effluent emissions rate, in ng/J (lb/MMBtu) heat input using appropriate F factor as described in Method 19 of appendix A of this part;

H_g = Heat input rate to the combustion turbine, in J/hr (MMBtu/hr);

H_b = Heat input rate to the duct burner, in J/hr (MMBtu/hr); and

E_g = Emissions rate from the combustion turbine, in ng/J (lb/MMBtu) heat input calculated using appropriate F factor as described in Method 19 of appendix A of this part.

(ii) Method 7E of appendix A of this part shall be used to determine the NO_X concentrations. Method 3A or 3B of appendix A of this part shall be used to determine O_2 concentration.

(iii) The owner or operator shall identify and demonstrate to the Administrator's satisfaction suitable methods to determine the average hourly heat input rate to the combustion turbine and the average hourly heat input rate to the affected duct burner.

(iv) Compliance with the emissions limits under § 60.44b(a)(4) or § 60.44b(l) is determined by the three-run average (nominal 1-hour runs) for the initial and subsequent performance tests; or

(2) The owner or operator of an affected facility may elect to determine compliance on a 30-day rolling average basis by using the CEMS specified under § 60.48b for measuring NO_X and O_2 and meet the requirements of § 60.48b. The sampling site shall be located at the outlet from the steam generating unit. The NO_X emissions rate at the outlet from the steam generating unit shall constitute the NO_X emissions rate from the duct burner of the combined cycle system.

(g) The owner or operator of an affected facility described in § 60.44b(j) or § 60.44b(k) shall demonstrate the maximum heat input capacity of the steam generating unit by operating the facility at maximum capacity for 24 hours. The owner or operator of an affected facility shall determine the maximum heat input capacity using the heat loss method or the heat input method described in sections 5 and 7.3 of the ASME *Power Test Codes* 4.1 (incorporated by reference, see § 60.17). This demonstration of maximum heat input capacity shall be made during the initial performance test for affected facilities that meet the criteria of § 60.44b(j). It shall be made within 60 days after achieving the maximum production rate at which the affected facility will be operated, but not later than 180 days after initial start-up of each facility, for affected facilities meeting the criteria of § 60.44b(k). Subsequent demonstrations may be required by the Administrator at any other time. If this demonstration indicates that the maximum heat input capacity of the affected facility is less than that stated by the manufacturer of the affected facility, the maximum heat input capacity determined during this demonstration shall be used to determine the capacity utilization rate for the affected facility. Otherwise, the maximum heat input capacity provided by the manufacturer is used.

(h) The owner or operator of an affected facility described in § 60.44b(j) that has a heat input capacity greater than 73 MW (250 MMBtu/hr) shall:

(1) Conduct an initial performance test as required under § 60.8 over a minimum of 24 consecutive steam generating unit operating hours at maximum heat input capacity to demonstrate compliance with the NO_X emission standards under § 60.44b using Method 7, 7A, 7E of appendix A of this part, or other approved reference methods; and

(2) Conduct subsequent performance tests once per calendar year or every 400 hours of operation (whichever comes first) to demonstrate compliance with the NO_X emission standards under § 60.44b over a minimum of 3 consecutive steam generating unit operating hours at maximum heat input capacity using Method 7, 7A, 7E of appendix A of this part, or other approved reference methods.

(i) The owner or operator of an affected facility seeking to demonstrate compliance with the PM limit in paragraphs § 60.43b(a)(4) or § 60.43b(h)(5) shall follow the applicable procedures in § 60.49b(r).

(j) 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 comply with the requirements specified in paragraphs (j)(1) through (j)(14) of this section.

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

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

(3) The monitor shall be installed, evaluated, and operated in accordance with § 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 the 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 (j) 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 paragraphs (j)(7)(i) of this section for 75 percent of the total operating hours per 30-day rolling average.

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

(ii) [Reserved]

(8) The 1-hour arithmetic averages required under paragraph (j)(7) of this section shall be expressed in ng/J or lb/MMBtu heat input and shall be used to calculate the boiler operating day daily arithmetic average emission concentrations. The 1-hour arithmetic averages shall be calculated using the data points required under § 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 (j)(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_2 (or CO_2) 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_2 (or CO_2), 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 per 30-day rolling average.

(14) As of January 1, 2012, and within 90 days after the date of completing each performance test, as defined in § 60.8, conducted to demonstrate compliance with this subpart, you must submit relative accuracy test audit (*i.e.,* reference method) data and performance test (*i.e.,* compliance test) data, except opacity data, electronically to EPA's Central Data Exchange (CDX) by using the Electronic Reporting Tool (ERT) (see *http://www.epa.gov/ttn/chief/ert/ert_tool.html/*) or other compatible electronic spreadsheet. Only data collected using test methods compatible with ERT are subject to this requirement to be submitted electronically into EPA's WebFIRE database.

[72 FR 32742, June 13, 2007, as amended at 74 FR 5086, Jan. 28, 2009; 76 FR 3523, Jan. 20, 2011; 77 FR 9460, Feb. 16, 2012]

§ 60.47b Emission monitoring for sulfur dioxide.

(a) Except as provided in paragraphs (b) and (f) of this section, the owner or operator of an affected facility subject to the SO_2 standards in § 60.42b shall install, calibrate, maintain, and operate CEMS for measuring SO_2 concentrations and either O_2 or CO_2 concentrations and shall record the output of the systems. For units complying with the percent reduction standard, the SO_2 and either O_2 or CO_2 concentrations shall both be monitored at the inlet and outlet of the SO_2 control device. If the owner or operator has installed and certified SO_2 and O_2 or CO_2 CEMS according to the requirements of § 75.20(c)(1) of this chapter and appendix A to part 75 of this chapter, and is continuing to meet the ongoing quality assurance requirements of § 75.21 of this chapter and appendix B to part 75 of this chapter, those CEMS may be used to meet the requirements of this section, provided that:

(1) When relative accuracy testing is conducted, SO_2 concentration data and CO_2 (or O_2) data are collected simultaneously; and

(2) In addition to meeting the applicable SO_2 and CO_2 (or O_2) relative accuracy specifications in Figure 2 of appendix B to part 75 of this chapter, the relative accuracy (RA) standard in section 13.2 of

Performance Specification 2 in appendix B to this part is met when the RA is calculated on a lb/MMBtu basis; and

(3) The reporting requirements of § 60.49b are met. SO_2 and CO_2 (or O_2) data used to meet the requirements of § 60.49b shall not include substitute data values derived from the missing data procedures in subpart D of part 75 of this chapter, nor shall the SO_2 data have been bias adjusted according to the procedures of part 75 of this chapter.

(b) As an alternative to operating CEMS as required under paragraph (a) of this section, an owner or operator may elect to determine the average SO_2 emissions and percent reduction by:

(1) Collecting coal or oil samples in an as-fired condition at the inlet to the steam generating unit and analyzing them for sulfur and heat content according to Method 19 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_2 input rate, or

(2) Measuring SO_2 according to Method 6B of appendix A of this part at the inlet or outlet to the SO_2 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_2 and CO_2 measurement train operated at the candidate location and a second similar train operated according to the procedures in section 3.2 and the applicable procedures in section 7 of Performance Specification 2. Method 6B of appendix A of this part, Method 6A of appendix A of this part, or a combination of Methods 6 and 3 or 3B 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.

(3) A daily SO_2 emission rate, E_D , shall be determined using the procedure described in Method 6A of appendix A of this part, section 7.6.2 (Equation 6A-8) and stated in ng/J (lb/MMBtu) heat input.

(4) The mean 30-day emission rate is calculated using the daily measured values in ng/J (lb/MMBtu) for 30 successive steam generating unit operating days using equation 19-20 of Method 19 of appendix A of this part.

(c) The owner or operator of an affected facility shall obtain emission data for at least 75 percent of the operating hours in at least 22 out of 30 successive boiler operating days. If this minimum data requirement is not met with a single monitoring system, the owner or operator of the affected facility shall supplement the emission data with data collected with other monitoring systems as approved by the Administrator or the reference methods and procedures as described in paragraph (b) of this section.

(d) The 1-hour average SO_2 emission rates measured by the CEMS required by paragraph (a) of this section and required under § 60.13(h) is expressed in ng/J or lb/MMBtu heat input and is used to calculate the average emission rates under § 60.42(b). Each 1-hour average SO_2 emission rate must be based on 30 or more minutes of steam generating unit operation. The hourly averages shall be calculated according to § 60.13(h)(2). Hourly SO_2 emission rates are not calculated if the affected facility is operated less than 30 minutes in a given clock hour and are not counted toward determination of a steam generating unit operating day.

(e) The procedures under § 60.13 shall be followed for installation, evaluation, and operation of the CEMS.

(1) Except as provided for in paragraph (e)(4) of this section, 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) Except as provided for in paragraph (e)(4) of this section, 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 combusting coal or oil, alone or in combination with other fuels, the span value of the SO_2 CEMS at the inlet to the SO_2 control device is 125 percent of the maximum estimated hourly potential SO_2 emissions of the fuel combusted, and the span value of the CEMS at the outlet to the SO_2 control device is 50 percent of the maximum estimated hourly potential SO_2 emissions of the fuel combusted. Alternatively, SO_2 span values determined according to section 2.1.1 in appendix A to part 75 of this chapter may be used.

(4) As an alternative to meeting the requirements of requirements of paragraphs (e)(1) and (e)(2) of this section, the owner or operator may elect to implement the following alternative data accuracy assessment procedures:

(i) For all required CO_2 and O_2 monitors and for SO_2 and NO_X monitors with span values greater than or equal to 100 ppm, the daily calibration error test and calibration adjustment procedures described in sections 2.1.1 and 2.1.3 of appendix B to part 75 of this chapter may be followed instead of the CD assessment procedures in Procedure 1, section 4.1 of appendix F to this part.

(ii) For all required CO_2 and O_2 monitors and for SO_2 and NO_X monitors with span values greater than 30 ppm, quarterly linearity checks may be performed in accordance with section 2.2.1 of appendix B to part 75 of this chapter, instead of performing the cylinder gas audits (CGAs) described in Procedure 1, section 5.1.2 of appendix F to this part. If this option is selected: The frequency of the linearity checks shall be as specified in section 2.2.1 of appendix B to part 75 of this chapter; the applicable linearity specifications in section 3.2 of appendix A to part 75 of this chapter shall be met; the data validation and out-of-control criteria in section 2.2.3 of appendix B to part 75 of this chapter shall be followed instead of the excessive audit inaccuracy and out-of-control criteria in Procedure 1, section 5.2 of appendix F to this part; and the grace period provisions in section 2.2.4 of appendix B to part 75 of this chapter shall apply. For the purposes of data validation under this subpart, the cylinder gas audits described in Procedure 1, section 5.1.2 of appendix F to this part shall be performed for SO_2 and NO_X span values less than or equal to 30 ppm; and

(iii) For SO_2 , CO_2 , and O_2 monitoring systems and for NO_X emission rate monitoring systems, RATAs may be performed in accordance with section 2.3 of appendix B to part 75 of this chapter instead of following the procedures described in Procedure 1, section 5.1.1 of appendix F to this part. If this option is selected: The frequency of each RATA shall be as specified in section 2.3.1 of appendix B to part 75 of this chapter; the applicable relative accuracy specifications shown in Figure 2 in appendix B to part 75 of this chapter shall be met; the data validation and out-of-control criteria in section 2.3.2 of appendix B to part 75 of this chapter shall be followed instead of the excessive audit inaccuracy and out-of-control criteria in Procedure 1, section 5.2 of appendix F to this part; and the grace period provisions in section 2.3.3 of appendix B to part 75 of this chapter shall apply. For the purposes of data validation under this subpart, the relative accuracy specification in section 13.2 of Performance Specification 2 in appendix B to this part shall be met on a lb/MMBtu basis for SO_2 (regardless of the SO_2 emission level during the RATA), and for NO_X when the average NO_X emission rate measured by the reference method during the RATA is less than 0.100 lb/MMBtu.

(f) The owner or operator of an affected facility that combusts very low sulfur oil or is demonstrating compliance under § 60.45b(k) is not subject to the emission monitoring requirements under paragraph (a) of this section if the owner or operator maintains fuel records as described in § 60.49b(r).

[72 FR 32742, June 13, 2007, as amended at 74 FR 5087, Jan. 28, 2009]

§ 60.48b Emission monitoring for particulate matter and nitrogen oxides.

(a) Except as provided in paragraph (j) of this section, the owner or operator of an affected facility subject to the opacity standard under § 60.43b shall install, calibrate, maintain, and operate a continuous opacity monitoring systems (COMS) for measuring the opacity of 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 under § 60.43b and meeting the conditions under paragraphs (j)(1), (2), (3), (4), (5), or (6) of this section who 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 § 60.43b by April 29, 2011, within 45 days of stopping use of an existing COMS, or within 180 days after initial startup of the facility, whichever is later, and shall comply with either paragraphs (a)(1), (a)(2), or (a)(3) of this section. The observation period for Method 9 of appendix A-4 of this part performance tests may be reduced from 3 hours to 60 minutes if all 6-minute averages are less than 10 percent and all individual 15-second observations are less than or equal to 20 percent during the initial 60 minutes of observation.

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

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

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

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

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

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

(i) The owner or operator shall conduct 10 minute observations (during normal operation) each operating day the affected facility fires fuel for which an opacity standard is applicable using Method 22 of appendix A-7 of this part and demonstrate that the sum of the occurrences of any visible emissions is not in excess of 5 percent of the observation period (*i.e.* , 30 seconds per 10 minute period). If the sum of the occurrence of any visible emissions is greater than 30 seconds during the initial 10 minute observation, immediately conduct a 30 minute observation. If the sum of the occurrence of visible emissions is greater than 5 percent of the observation period (*i.e.,* 90 seconds per 30 minute period), the owner or operator shall either document and adjust the operation of the facility and demonstrate within 24 hours that the sum of the occurrence of visible emissions is equal to or less than 5 percent during a 30 minute observation (*i.e.,* 90 seconds) or conduct a new Method 9 of appendix A-4 of this part performance test using the procedures in paragraph (a) of this section within 45 calendar days according to the requirements in § 60.46d(d)(7).

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

(3) If the maximum 6-minute opacity is less than 10 percent during the most recent Method 9 of appendix A-4 of this part performance test, the owner or operator may, as an alternative to performing subsequent Method 9 of appendix A-4 performance tests, elect to perform subsequent monitoring using a digital opacity compliance system according to a site-specific monitoring plan approved by the Administrator. The observations shall be similar, but not necessarily identical, to the requirements in paragraph (a)(2) of this section. For reference purposes in preparing the monitoring plan, see OAQPS “Determination of Visible Emission Opacity from Stationary Sources Using Computer-Based Photographic Analysis Systems.” This document is available from the U.S. Environmental Protection Agency (U.S. EPA); Office of Air Quality and Planning Standards; Sector Policies and Programs Division; Measurement Policy Group (D243-02), Research Triangle Park, NC 27711. This document is also available on the Technology Transfer Network (TTN) under Emission Measurement Center Preliminary Methods.

(b) Except as provided under paragraphs (g), (h), and (i) of this section, the owner or operator of an affected facility subject to a NO_X standard under § 60.44b shall comply with either paragraphs (b)(1) or (b)(2) of this section.

(1) Install, calibrate, maintain, and operate CEMS for measuring NO_X and O_2 (or CO_2) emissions discharged to the atmosphere, and shall record the output of the system; or

(2) If the owner or operator has installed a NO_X emission rate CEMS to meet the requirements of part 75 of this chapter and is continuing to meet the ongoing requirements of part 75 of this chapter, that CEMS may be used to meet the requirements of this section, except that the owner or operator shall also meet the requirements of § 60.49b. Data reported to meet the requirements of § 60.49b shall not include data substituted using the missing data procedures in subpart D of part 75 of this chapter, nor shall the data have been bias adjusted according to the procedures of part 75 of this chapter.

(c) The CEMS required under paragraph (b) of this section 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.

(d) The 1-hour average NO_X emission rates measured by the continuous NO_X monitor required by paragraph (b) of this section and required under § 60.13(h) shall be expressed in ng/J or lb/MMBtu heat input and shall be used to calculate the average emission rates under § 60.44b. The 1-hour averages shall be calculated using the data points required under § 60.13(h)(2).

(e) The procedures under § 60.13 shall be followed for installation, evaluation, and operation of the continuous monitoring systems.

(1) For affected facilities combusting coal, wood or municipal-type solid waste, the span value for a COMS shall be between 60 and 80 percent.

(2) For affected facilities combusting coal, oil, or natural gas, the span value for NO_X is determined using one of the following procedures:

(i) Except as provided under paragraph (e)(2)(ii) of this section, NO_X span values shall be determined as follows:

Fuel	**Span values for NO_X (ppm)**
Natural gas	500.
Oil	500.
Coal	1,000.
Mixtures	500 (x + y) + 1,000z.

Where:

x = Fraction of total heat input derived from natural gas;

y = Fraction of total heat input derived from oil; and

z = Fraction of total heat input derived from coal.

(ii) As an alternative to meeting the requirements of paragraph (e)(2)(i) of this section, the owner or operator of an affected facility may elect to use the NO_X span values determined according to section 2.1.2 in appendix A to part 75 of this chapter.

(3) All span values computed under paragraph (e)(2)(i) of this section for combusting mixtures of regulated fuels are rounded to the nearest 500 ppm. Span values computed under paragraph (e)(2)(ii) of this section shall be rounded off according to section 2.1.2 in appendix A to part 75 of this chapter.

(f) When NO_X emission data are not obtained because of CEMS breakdowns, repairs, calibration checks and zero and span adjustments, emission data will be obtained by using standby monitoring systems, Method 7 of appendix A of this part, Method 7A of appendix A of this part, or other approved reference methods to provide emission data for a minimum of 75 percent of the operating hours in each steam generating unit operating day, in at least 22 out of 30 successive steam generating unit operating days.

(g) The owner or operator of an affected facility that has a heat input capacity of 73 MW (250 MMBtu/hr) or less, and that has an annual capacity factor for residual oil having a nitrogen content of 0.30 weight percent or less, natural gas, distillate oil, gasified coal, or any mixture of these fuels, greater than 10 percent (0.10) shall:

(1) Comply with the provisions of paragraphs (b), (c), (d), (e)(2), (e)(3), and (f) of this section; or

(2) Monitor steam generating unit operating conditions and predict NO_X emission rates as specified in a plan submitted pursuant to § 60.49b(c).

(h) The owner or operator of a duct burner, as described in § 60.41b, that is subject to the NO_X standards in § 60.44b(a)(4), § 60.44b(e), or § 60.44b(l) is not required to install or operate a continuous emissions monitoring system to measure NO_X emissions.

(i) The owner or operator of an affected facility described in § 60.44b(j) or § 60.44b(k) is not required to install or operate a CEMS for measuring NO_X emissions.

(j) The owner or operator of an affected facility that meets the conditions in either paragraph (j)(1), (2), (3), (4), (5), (6), or (7) of this section is not required to install or operate a COMS if:

(1) The affected facility uses a PM CEMS to monitor PM emissions; or

(2) The affected facility burns only liquid (excluding residual oil) or gaseous fuels with potential SO_2 emissions rates of 26 ng/J (0.060 lb/MMBtu) or less and does not use a post-combustion technology to reduce SO_2 or PM emissions. The owner or operator must maintain fuel records of the sulfur content of the fuels burned, as described under § 60.49b(r); or

(3) The affected facility burns coke oven gas alone or in combination with fuels meeting the criteria in paragraph (j)(2) of this section and does not use a post-combustion technology to reduce SO_2 or PM emissions; or

(4) The affected facility does not use post-combustion technology (except a wet scrubber) for reducing PM, SO_2 , or carbon monoxide (CO) emissions, burns only gaseous fuels or fuel oils that contain less than or equal to 0.30 weight percent sulfur, and is operated such that emissions of CO to the atmosphere from the affected facility are maintained at levels less than or equal to 0.15 lb/MMBtu on a steam generating unit operating day average basis. Owners and operators of affected facilities electing to comply with this paragraph must demonstrate compliance according to the procedures specified in paragraphs (j)(4)(i) through (iv) of this section; or

(i) You must monitor CO emissions using a CEMS according to the procedures specified in paragraphs (j)(4)(i)(A) through (D) of this section.

(A) 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.

(B) 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).

(C) 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).

(D) 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.

(ii) 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.

(iii) 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.

(iv) You must record the CO measurements and calculations performed according to paragraph (j)(4) 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.

(5) The affected facility uses a bag leak detection system to monitor the performance of a fabric filter (baghouse) according to the most current requirements in section § 60.48Da of this part; or

(6) The affected facility uses an ESP as the primary PM control device and uses an ESP predictive model to monitor the performance of the ESP developed in accordance and operated according to the most current requirements in section § 60.48Da of this part; or

(7) The affected facility burns only gaseous fuels or fuel oils that contain less than or equal to 0.30 weight percent sulfur and operates according to a written site-specific monitoring plan approved by the permitting authority. This monitoring plan must include procedures and criteria for establishing and monitoring specific parameters for the affected facility indicative of compliance with the opacity standard.

(k) 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 § 60.46b(j). The CEMS specified in paragraph § 60.46b(j) 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.

(l) An owner or operator of an affected facility that is subject to an opacity standard under § 60.43b(f) is not required to operate a COMS provided that the unit burns only gaseous fuels and/or liquid fuels (excluding residue oil) with a potential SO_2 emissions rate no greater than 26 ng/J (0.060 lb/MMBtu), and the unit 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. For testing performed as part of this site-specific monitoring plan, the permitting authority may require as an alternative to the notification and reporting requirements specified in §§ 60.8 and 60.11 that the owner or operator submit any deviations with the excess emissions report required under § 60.49b(h).

[72 FR 32742, June 13, 2007, as amended at 74 FR 5087, Jan. 28, 2009; 76 FR 3523, Jan. 20, 2011; 77 FR 9460, Feb. 16, 2012]

§ 60.49b Reporting and recordkeeping requirements.

(a) The owner or operator of each affected facility shall submit notification of the date of initial startup, as provided by § 60.7. This notification shall include:

(1) The design heat input capacity of the affected facility and identification of the fuels to be combusted in the affected facility;

(2) If applicable, a copy of any federally enforceable requirement that limits the annual capacity factor for any fuel or mixture of fuels under §§ 60.42b(d)(1), 60.43b(a)(2), (a)(3)(iii), (c)(2)(ii), (d)(2)(iii), 60.44b(c), (d), (e), (i), (j), (k), 60.45b(d), (g), 60.46b(h), or 60.48b(i);

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

(4) Notification that an emerging technology will be used for controlling emissions of SO_2 . The Administrator will examine the description of the emerging technology and will determine whether the technology qualifies as an emerging technology. In making this determination, the Administrator may require the owner or operator of the affected facility to submit additional information concerning the control device. The affected facility is subject to the provisions of § 60.42b(a) unless and until this determination is made by the Administrator.

(b) The owner or operator of each affected facility subject to the SO_2 , PM, and/or NO_X emission limits under §§ 60.42b, 60.43b, and 60.44b shall submit to the Administrator the performance test data from the initial performance test and the performance evaluation of the CEMS using the applicable performance specifications in appendix B of this part. The owner or operator of each affected facility described in § 60.44b(j) or § 60.44b(k) shall submit to the Administrator the maximum heat input capacity data from the demonstration of the maximum heat input capacity of the affected facility.

(c) The owner or operator of each affected facility subject to the NO_X standard in § 60.44b who seeks to demonstrate compliance with those standards through the monitoring of steam generating unit operating conditions in the provisions of § 60.48b(g)(2) shall submit to the Administrator for approval a plan that identifies the operating conditions to be monitored in § 60.48b(g)(2) and the records to be maintained in § 60.49b(g). This plan shall be submitted to the Administrator for approval within 360 days of the initial startup of the affected facility. An affected facility burning coke oven gas alone or in combination with other gaseous fuels or distillate oil shall submit this plan to the Administrator for approval within 360 days of the initial startup of the affected facility or by November 30, 2009, whichever date comes later. If the plan is approved, the owner or operator shall maintain records of predicted nitrogen oxide emission rates and the monitored operating conditions, including steam generating unit load, identified in the plan. The plan shall:

(1) Identify the specific operating conditions to be monitored and the relationship between these operating conditions and NO_X emission rates (*i.e.* , ng/J or lbs/MMBtu heat input). Steam generating unit operating conditions include, but are not limited to, the degree of staged combustion (*i.e.* , the ratio of primary air to secondary and/or tertiary air) and the level of excess air (*i.e.* , flue gas O_2 level);

(2) Include the data and information that the owner or operator used to identify the relationship between NO_X emission rates and these operating conditions; and

(3) Identify how these operating conditions, including steam generating unit load, will be monitored under § 60.48b(g) on an hourly basis by the owner or operator during the period of operation of the affected facility; the quality assurance procedures or practices that will be employed to ensure that the data generated by monitoring these operating conditions will be representative and accurate; and the type and format of the records of these operating conditions, including steam generating unit load, that will be maintained by the owner or operator under § 60.49b(g).

(d) Except as provided in paragraph (d)(2) of this section, the owner or operator of an affected facility shall record and maintain records as specified in paragraph (d)(1) of this section.

(1) The owner or operator of an affected facility shall record and maintain records of the amounts of each fuel combusted during each day and calculate the annual capacity factor individually for coal, distillate oil, residual oil, natural gas, wood, and municipal-type solid waste for the reporting period. The annual capacity factor is determined on a 12-month rolling average basis with a new annual capacity factor calculated at the end of each calendar month.

(2) As an alternative to meeting the requirements of paragraph (d)(1) of this section, the owner or operator of an affected facility that is subject to a federally enforceable permit restricting fuel use to a single fuel such that the facility is not required to continuously monitor any emissions (excluding opacity) or parameters indicative of emissions may elect to record and maintain records of the amount of each fuel combusted during each calendar month.

(e) For an affected facility that combusts residual oil and meets the criteria under §§ 60.46b(e)(4), 60.44b(j), or (k), the owner or operator shall maintain records of the nitrogen content of the residual oil combusted in the affected facility and calculate the average fuel nitrogen content for the reporting period. The nitrogen content shall be determined using ASTM Method D4629 (incorporated by reference, see §

60.17), or fuel suppliers. If residual oil blends are being combusted, fuel nitrogen specifications may be prorated based on the ratio of residual oils of different nitrogen content in the fuel blend.

(f) For an affected facility subject to the opacity standard in § 60.43b, the owner or operator shall maintain records of opacity. In addition, an owner or operator that elects to monitor emissions according to the requirements in § 60.48b(a) shall maintain records according to the requirements specified in paragraphs (f)(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 (f)(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 (f)(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.

(g) Except as provided under paragraph (p) of this section, the owner or operator of an affected facility subject to the NO_X standards under § 60.44b shall maintain records of the following information for each steam generating unit operating day:

(1) Calendar date;

(2) The average hourly NO_X emission rates (expressed as NO_2) (ng/J or lb/MMBtu heat input) measured or predicted;

(3) The 30-day average NO_X emission rates (ng/J or lb/MMBtu heat input) calculated at the end of each steam generating unit operating day from the measured or predicted hourly nitrogen oxide emission rates for the preceding 30 steam generating unit operating days;

(4) Identification of the steam generating unit operating days when the calculated 30-day average NO_X emission rates are in excess of the NO_X emissions standards under § 60.44b, with the reasons for such excess emissions as well as a description of corrective actions taken;

(5) Identification of the steam generating unit operating days for which pollutant data have not been obtained, including reasons for not obtaining sufficient data and a description of corrective actions taken;

(6) Identification of the times when emission data have been excluded from the calculation of average emission rates and the reasons for excluding data;

(7) Identification of “F” factor used for calculations, method of determination, and type of fuel combusted;

(8) Identification of the times when the pollutant concentration exceeded full span of the CEMS;

(9) Description of any modifications to the CEMS that could affect the ability of the CEMS to comply with Performance Specification 2 or 3; and

(10) Results of daily CEMS drift tests and quarterly accuracy assessments as required under appendix F, Procedure 1 of this part.

(h) The owner or operator of any affected facility in any category listed in paragraphs (h)(1) or (2) of this section is required to submit excess emission reports for any excess emissions that occurred during the reporting period.

(1) Any affected facility subject to the opacity standards in § 60.43b(f) or to the operating parameter monitoring requirements in § 60.13(i)(1).

(2) Any affected facility that is subject to the NO_X standard of § 60.44b, and that:

(i) Combusts natural gas, distillate oil, gasified coal, or residual oil with a nitrogen content of 0.3 weight percent or less; or

(ii) Has a heat input capacity of 73 MW (250 MMBtu/hr) or less and is required to monitor NO_X emissions on a continuous basis under § 60.48b(g)(1) or steam generating unit operating conditions under § 60.48b(g)(2).

(3) For the purpose of § 60.43b, excess emissions are defined as all 6-minute periods during which the average opacity exceeds the opacity standards under § 60.43b(f).

(4) For purposes of § 60.48b(g)(1), excess emissions are defined as any calculated 30-day rolling average NO_X emission rate, as determined under § 60.46b(e), that exceeds the applicable emission limits in § 60.44b.

(i) The owner or operator of any affected facility subject to the continuous monitoring requirements for NO_X under § 60.48(b) shall submit reports containing the information recorded under paragraph (g) of this section.

(j) The owner or operator of any affected facility subject to the SO_2 standards under § 60.42b shall submit reports.

(k) For each affected facility subject to the compliance and performance testing requirements of § 60.45b and the reporting requirement in paragraph (j) of this section, the following information shall be reported to the Administrator:

(1) Calendar dates covered in the reporting period;

(2) Each 30-day average SO_2 emission rate (ng/J or lb/MMBtu heat input) measured during the reporting period, ending with the last 30-day period; reasons for noncompliance with the emission standards; and a description of corrective actions taken; For an exceedance due to maintenance of the SO_2 control system covered in paragraph 60.45b(a), the report shall identify the days on which the maintenance was performed and a description of the maintenance;

(3) Each 30-day average percent reduction in SO_2 emissions calculated during the reporting period, ending with the last 30-day period; reasons for noncompliance with the emission standards; and a description of corrective actions taken;

(4) Identification of the steam generating unit operating days that coal or oil was combusted and for which SO_2 or diluent (O_2 or CO_2) data have not been obtained by an approved method for at least 75 percent of the operating hours in the steam generating unit operating day; justification for not obtaining sufficient data; and description of corrective action taken;

(5) Identification of the times when emissions data have been excluded from the calculation of average emission rates; justification for excluding data; and description of corrective action taken if data have been excluded for periods other than those during which coal or oil were not combusted in the steam generating unit;

(6) Identification of "F" factor used for calculations, method of determination, and type of fuel combusted;

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

(8) Identification of the times when the pollutant concentration exceeded full span of the CEMS;

(9) Description of any modifications to the CEMS that could affect the ability of the CEMS to comply with Performance Specification 2 or 3;

(10) Results of daily CEMS drift tests and quarterly accuracy assessments as required under appendix F, Procedure 1 of this part; and

(11) The annual capacity factor of each fired as provided under paragraph (d) of this section.

(l) For each affected facility subject to the compliance and performance testing requirements of § 60.45b(d) and the reporting requirements of paragraph (j) of this section, the following information shall be reported to the Administrator:

(1) Calendar dates when the facility was in operation during the reporting period;

(2) The 24-hour average SO_2 emission rate measured for each steam generating unit operating day during the reporting period that coal or oil was combusted, ending in the last 24-hour period in the quarter; reasons for noncompliance with the emission standards; and a description of corrective actions taken;

(3) Identification of the steam generating unit operating days that coal or oil was combusted for which $S0_2$ or diluent (O_2 or CO_2) data have not been obtained by an approved method for at least 75 percent of the operating hours; justification for not obtaining sufficient data; and description of corrective action taken;

(4) Identification of the times when emissions data have been excluded from the calculation of average emission rates; justification for excluding data; and description of corrective action taken if data have been excluded for periods other than those during which coal or oil were not combusted in the steam generating unit;

(5) Identification of “F” factor used for calculations, method of determination, and type of fuel combusted;

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

(7) Identification of the times when the pollutant concentration exceeded full span of the CEMS;

(8) Description of any modifications to the CEMS that could affect the ability of the CEMS to comply with Performance Specification 2 or 3; and

(9) Results of daily CEMS drift tests and quarterly accuracy assessments as required under Procedure 1 of appendix F 1 of this part. If the owner or operator elects to implement the alternative data assessment procedures described in §§ 60.47b(e)(4)(i) through (e)(4)(iii), each data assessment report shall include a summary of the results of all of the RATAs, linearity checks, CGAs, and calibration error or drift assessments required by §§ 60.47b(e)(4)(i) through (e)(4)(iii).

(m) For each affected facility subject to the SO_2 standards in § 60.42(b) for which the minimum amount of data required in § 60.47b(c) were not obtained during the reporting period, the following information is reported to the Administrator in addition to that required under paragraph (k) of this section:

(1) The number of hourly averages available for outlet emission rates and inlet emission rates;

(2) The standard deviation of hourly averages for outlet emission rates and inlet emission rates, as determined in Method 19 of appendix A of this part, section 7;

(3) The lower confidence limit for the mean outlet emission rate and the upper confidence limit for the mean inlet emission rate, as calculated in Method 19 of appendix A of this part, section 7; and

(4) The ratio of the lower confidence limit for the mean outlet emission rate and the allowable emission rate, as determined in Method 19 of appendix A of this part, section 7.

(n) If a percent removal efficiency by fuel pretreatment (*i.e.* , $\%R_f$) is used to determine the overall percent reduction (*i.e.* , $\%R_o$) under § 60.45b, the owner or operator of the affected facility shall submit a signed statement with the report.

(1) Indicating what removal efficiency by fuel pretreatment (*i.e.* , $\%R_f$) was credited during the reporting period;

(2) Listing the quantity, heat content, and date each pre-treated fuel shipment was received during the reporting period, the name and location of the fuel pretreatment facility; and the total quantity and total heat content of all fuels received at the affected facility during the reporting period;

(3) Documenting the transport of the fuel from the fuel pretreatment facility to the steam generating unit; and

(4) Including a signed statement from the owner or operator of the fuel pretreatment facility certifying that the percent removal efficiency achieved by fuel pretreatment was determined in accordance with the provisions of Method 19 of appendix A of this part and listing the heat content and sulfur content of each fuel before and after fuel pretreatment.

(o) All records required under this section shall be maintained by the owner or operator of the affected facility for a period of 2 years following the date of such record.

(p) The owner or operator of an affected facility described in § 60.44b(j) or (k) shall maintain records of the following information for each steam generating unit operating day:

(1) Calendar date;

(2) The number of hours of operation; and

(3) A record of the hourly steam load.

(q) The owner or operator of an affected facility described in § 60.44b(j) or § 60.44b(k) shall submit to the Administrator a report containing:

(1) The annual capacity factor over the previous 12 months;

(2) The average fuel nitrogen content during the reporting period, if residual oil was fired; and

(3) If the affected facility meets the criteria described in § 60.44b(j), the results of any NO_X emission tests required during the reporting period, the hours of operation during the reporting period, and the hours of operation since the last NO_X emission test.

(r) The owner or operator of an affected facility who elects to use the fuel based compliance alternatives in § 60.42b or § 60.43b shall either:

(1) The owner or operator of an affected facility who elects to demonstrate that the affected facility combusts only very low sulfur oil, natural gas, wood, a mixture of these fuels, or any of these fuels (or a mixture of these fuels) in combination with other fuels that are known to contain an insignificant amount of sulfur in § 60.42b(j) or § 60.42b(k) shall obtain and maintain at the affected facility fuel receipts (such as a current, valid purchase contract, tariff sheet, or transportation contract) from the fuel supplier that certify that the oil meets the definition of distillate oil and gaseous fuel meets the definition of natural gas as defined in § 60.41b and the applicable sulfur limit. For the purposes of this section, the distillate oil need not meet the fuel nitrogen content specification in the definition of distillate oil. Reports shall be submitted to the Administrator certifying that only very low sulfur oil meeting this definition, natural gas, wood, and/or other fuels that are known to contain insignificant amounts of sulfur were combusted in the affected facility during the reporting period; or

(2) The owner or operator of an affected facility who elects to demonstrate compliance based on fuel analysis in § 60.42b or § 60.43b shall develop and submit a site-specific fuel analysis plan to the Administrator for review and approval no later than 60 days before the date you intend to demonstrate compliance. Each fuel analysis plan shall include a minimum initial requirement of weekly testing and each analysis report shall contain, at a minimum, the following information:

(i) The potential sulfur emissions rate of the representative fuel mixture in ng/J heat input;

(ii) The method used to determine the potential sulfur emissions rate of each constituent of the mixture. For distillate oil and natural gas a fuel receipt or tariff sheet is acceptable;

(iii) The ratio of different fuels in the mixture; and

(iv) The owner or operator can petition the Administrator to approve monthly or quarterly sampling in place of weekly sampling.

(s) Facility specific NO_X standard for Cytec Industries Fortier Plant's C.AOG incinerator located in Westwego, Louisiana:

(1) *Definitions* .

Oxidation zone is defined as the portion of the C.AOG incinerator that extends from the inlet of the oxidizing zone combustion air to the outlet gas stack.

Reducing zone is defined as the portion of the C.AOG incinerator that extends from the burner section to the inlet of the oxidizing zone combustion air.

Total inlet air is defined as the total amount of air introduced into the C.AOG incinerator for combustion of natural gas and chemical by-product waste and is equal to the sum of the air flow into the reducing zone and the air flow into the oxidation zone.

(2) *Standard for nitrogen oxides* . (i) When fossil fuel alone is combusted, the NO_X emission limit for fossil fuel in § 60.44b(a) applies.

(ii) When natural gas and chemical by-product waste are simultaneously combusted, the NO_X emission limit is 289 ng/J (0.67 lb/MMBtu) and a maximum of 81 percent of the total inlet air provided for combustion shall be provided to the reducing zone of the C.AOG incinerator.

(3) *Emission monitoring* . (i) The percent of total inlet air provided to the reducing zone shall be determined at least every 15 minutes by measuring the air flow of all the air entering the reducing zone and the air flow of all the air entering the oxidation zone, and compliance with the percentage of total inlet air that is provided to the reducing zone shall be determined on a 3-hour average basis.

(ii) The NO_X emission limit shall be determined by the compliance and performance test methods and procedures for NO_X in § 60.46b(i).

(iii) The monitoring of the NO_X emission limit shall be performed in accordance with § 60.48b.

(4) *Reporting and recordkeeping requirements* . (i) The owner or operator of the C.AOG incinerator shall submit a report on any excursions from the limits required by paragraph (a)(2) of this section to the Administrator with the quarterly report required by paragraph (i) of this section.

(ii) The owner or operator of the C.AOG incinerator shall keep records of the monitoring required by paragraph (a)(3) of this section for a period of 2 years following the date of such record.

(iii) The owner of operator of the C.AOG incinerator shall perform all the applicable reporting and recordkeeping requirements of this section.

(t) Facility-specific NO_X standard for Rohm and Haas Kentucky Incorporated's Boiler No. 100 located in Louisville, Kentucky:

(1) *Definitions* .

Air ratio control damper is defined as the part of the low NO_X burner that is adjusted to control the split of total combustion air delivered to the reducing and oxidation portions of the combustion flame.

Flue gas recirculation line is defined as the part of Boiler No. 100 that recirculates a portion of the boiler flue gas back into the combustion air.

(2) *Standard for nitrogen oxides* . (i) When fossil fuel alone is combusted, the NO_X emission limit for fossil fuel in § 60.44b(a) applies.

(ii) When fossil fuel and chemical by-product waste are simultaneously combusted, the NO_X emission limit is 473 ng/J (1.1 lb/MMBtu), and the air ratio control damper tee handle shall be at a minimum of 5 inches (12.7 centimeters) out of the boiler, and the flue gas recirculation line shall be operated at a minimum of 10 percent open as indicated by its valve opening position indicator.

(3) *Emission monitoring for nitrogen oxides* . (i) The air ratio control damper tee handle setting and the flue gas recirculation line valve opening position indicator setting shall be recorded during each 8-hour operating shift.

(ii) The NO_X emission limit shall be determined by the compliance and performance test methods and procedures for NO_X in § 60.46b.

(iii) The monitoring of the NO_X emission limit shall be performed in accordance with § 60.48b.

(4) *Reporting and recordkeeping requirements* . (i) The owner or operator of Boiler No. 100 shall submit a report on any excursions from the limits required by paragraph (b)(2) of this section to the Administrator with the quarterly report required by § 60.49b(i).

(ii) The owner or operator of Boiler No. 100 shall keep records of the monitoring required by paragraph (b)(3) of this section for a period of 2 years following the date of such record.

(iii) The owner of operator of Boiler No. 100 shall perform all the applicable reporting and recordkeeping requirements of § 60.49b.

(u) *Site-specific standard for Merck & Co., Inc.'s Stonewall Plant in Elkton, Virginia* . (1) This paragraph (u) applies only to the pharmaceutical manufacturing facility, commonly referred to as the Stonewall Plant, located at Route 340 South, in Elkton, Virginia (“site”) and only to the natural gas-fired boilers installed as part of the powerhouse conversion required pursuant to 40 CFR 52.2454(g). The requirements of this paragraph shall apply, and the requirements of §§ 60.40b through 60.49b(t) shall not apply, to the natural gas-fired boilers installed pursuant to 40 CFR 52.2454(g).

(i) The site shall equip the natural gas-fired boilers with low NO_X technology.

(ii) The site shall install, calibrate, maintain, and operate a continuous monitoring and recording system for measuring NO_X emissions discharged to the atmosphere and opacity using a continuous emissions monitoring system or a predictive emissions monitoring system.

(iii) Within 180 days of the completion of the powerhouse conversion, as required by 40 CFR 52.2454, the site shall perform a performance test to quantify criteria pollutant emissions.

(2) [Reserved]

(v) The owner or operator of an affected facility may submit electronic quarterly reports for SO_2 and/or NO_X and/or opacity in lieu of submitting the written reports required under paragraphs (h), (i), (j), (k) or (l) of this section. The format of each quarterly electronic report shall be coordinated with the permitting authority. The electronic report(s) shall be submitted no later than 30 days after the end of the calendar quarter and shall be accompanied by a certification statement from the owner or operator, indicating whether compliance with the applicable emission standards and minimum data requirements of this subpart was achieved during the reporting period. Before submitting reports in the electronic format, the owner or operator shall coordinate with the permitting authority to obtain their agreement to submit reports in this alternative format.

(w) The reporting period for the reports required under this subpart is each 6 month period. All reports shall be submitted to the Administrator and shall be postmarked by the 30th day following the end of the reporting period.

(x) Facility-specific NO_X standard for Weyerhaeuser Company's No. 2 Power Boiler located in New Bern, North Carolina:

(1) *Standard for nitrogen oxides* . (i) When fossil fuel alone is combusted, the NO_X emission limit for fossil fuel in § 60.44b(a) applies.

(ii) When fossil fuel and chemical by-product waste are simultaneously combusted, the NO_X emission limit is 215 ng/J (0.5 lb/MMBtu).

(2) *Emission monitoring for nitrogen oxides* . (i) The NO_X emissions shall be determined by the compliance and performance test methods and procedures for NO_X in § 60.46b.

(ii) The monitoring of the NO_X emissions shall be performed in accordance with § 60.48b.

(3) *Reporting and recordkeeping requirements* . (i) The owner or operator of the No. 2 Power Boiler shall submit a report on any excursions from the limits required by paragraph (x)(2) of this section to the Administrator with the quarterly report required by § 60.49b(i).

(ii) The owner or operator of the No. 2 Power Boiler shall keep records of the monitoring required by paragraph (x)(3) of this section for a period of 2 years following the date of such record.

(iii) The owner or operator of the No. 2 Power Boiler shall perform all the applicable reporting and recordkeeping requirements of § 60.49b.

(y) Facility-specific NO_X standard for INEOS USA's AOGI located in Lima, Ohio:

(1) *Standard for NO* $_X$. (i) When fossil fuel alone is combusted, the NO_X emission limit for fossil fuel in § 60.44b(a) applies.

(ii) When fossil fuel and chemical byproduct/waste are simultaneously combusted, the NO_X emission limit is 645 ng/J (1.5 lb/MMBtu).

(2) *Emission monitoring for NO* $_X$. (i) The NO_X emissions shall be determined by the compliance and performance test methods and procedures for NO_X in § 60.46b.

(ii) The monitoring of the NO_X emissions shall be performed in accordance with § 60.48b.

(3) *Reporting and recordkeeping requirements* . (i) The owner or operator of the AOGI shall submit a report on any excursions from the limits required by paragraph (y)(2) of this section to the Administrator with the quarterly report required by paragraph (i) of this section.

(ii) The owner or operator of the AOGI shall keep records of the monitoring required by paragraph (y)(3) of this section for a period of 2 years following the date of such record.

(iii) The owner or operator of the AOGI shall perform all the applicable reporting and recordkeeping requirements of this section.

[72 FR 32742, June 13, 2007, as amended at 74 FR 5089, Jan. 28, 2009; 77 FR 9461, Feb. 16, 2012]

Indiana Department of Environmental Management
Office of Air Quality

Attachment G to a Part 70 Operating Permit

Source Background and Description

Source Name:	Ohio Valley Resources, LLC
Source Location:	300-400 East CR 350 North, Rockport, Indiana 47635
County:	Spencer
SIC Code:	2873
Permit No.:	T 147-32322-00062
Permit Reviewer:	David Matousek

40 CFR 61, Subpart FF

40 CFR 61, Subpart FF **National Emission Standards for Benzene Waste Operations**

Source: 55 FR 8346, March 7, 1990, unless otherwise noted.

§ 61.340 Applicability.

(a) The provisions of this subpart apply to owners and operators of chemical manufacturing plants, coke by-product recovery plants, and petroleum refineries.

(b) The provisions of this subpart apply to owners and operators of hazardous waste treatment, storage, and disposal facilities that treat, store, or dispose of hazardous waste generated by any facility listed in paragraph (a) of this section. The waste streams at hazardous waste treatment, storage, and disposal facilities subject to the provisions of this subpart are the benzene-containing hazardous waste from any facility listed in paragraph (a) of this section. A hazardous waste treatment, storage, and disposal facility is a facility that must obtain a hazardous waste management permit under subtitle C of the Solid Waste Disposal Act.

(c) At each facility identified in paragraph (a) or (b) of this section, the following waste is exempt from the requirements of this subpart:

(1) Waste in the form of gases or vapors that is emitted from process fluids:

(2) Waste that is contained in a segregated stormwater sewer system.

(d) At each facility identified in paragraph (a) or (b) of this section, any gaseous stream from a waste management unit, treatment process, or wastewater treatment system routed to a fuel gas system, as defined in § 61.341, is exempt from this subpart. No testing, monitoring, recordkeeping, or reporting is required under this subpart for any gaseous stream from a waste management unit, treatment process, or wastewater treatment unit routed to a fuel gas system.

[55 FR 8346, Mar. 7, 1990, as amended at 55 FR 37231, Sept. 10, 1990; 58 FR 3095, Jan. 7, 1993; 67 FR 68531, Nov. 12, 2002]

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§ 61.341 Definitions.

Benzene concentration means the fraction by weight of benzene in a waste as determined in accordance with the procedures specified in § 61.355 of this subpart.

Car-seal means a seal that is placed on a device that is used to change the position of a valve (e.g., from opened to closed) in such a way that the position of the valve cannot be changed without breaking the seal.

Chemical manufacturing plant means any facility engaged in the production of chemicals by chemical, thermal, physical, or biological processes for use as a product, co-product, by-product, or intermediate including but not limited to industrial organic chemicals, organic pesticide products, pharmaceutical preparations, paint and allied products, fertilizers, and agricultural chemicals. Examples of chemical manufacturing plants include facilities at which process units are operated to produce one or more of the following chemicals: benzenesulfonic acid, benzene, chlorobenzene, cumene, cyclohexane, ethylene, ethylbenzene, hydroquinone, linear alklylbenzene, nitrobenzene, resorcinol, sulfolane, or styrene.

Closed-vent system means a system that is not open to the atmosphere and is composed of piping, ductwork, connections, and, if necessary, flow inducing devices that transport gas or vapor from an emission source to a control device.

Coke by-product recovery plant means any facility designed and operated for the separation and recovery of coal tar derivatives (by-products) evolved from coal during the coking process of a coke oven battery.

Container means any portable waste management unit in which a material is stored, transported, treated, or otherwise handled. Examples of containers are drums, barrels, tank trucks, barges, dumpsters, tank cars, dump trucks, and ships.

Control device means an enclosed combustion device, vapor recovery system, or flare.

Cover means a device or system which is placed on or over a waste placed in a waste management unit so that the entire waste surface area is enclosed and sealed to minimize air emissions. A cover may have openings necessary for operation, inspection, and maintenance of the waste management unit such as access hatches, sampling ports, and gauge wells provided that each opening is closed and sealed when not in use. Example of covers include a fixed roof installed on a tank, a lid installed on a container, and an air-supported enclosure installed over a waste management unit.

External floating roof means a pontoon-type or double-deck type cover with certain rim sealing mechanisms that rests on the liquid surface in a waste management unit with no fixed roof.

Facility means all process units and product tanks that generate waste within a stationary source, and all waste management units that are used for waste treatment, storage, or disposal within a stationary source.

Fixed roof means a cover that is mounted on a waste management unit in a stationary manner and that does not move with fluctuations in liquid level.

Floating roof means a cover with certain rim sealing mechanisms consisting of a double deck, pontoon single deck, internal floating cover or covered floating roof, which rests upon and is supported by the liquid being contained, and is equipped with a closure seal or seals to close the space between the roof edge and unit wall.

Flow indicator means a device which indicates whether gas flow is present in a line or vent system.

Fuel gas system means the offsite and onsite piping and control system that gathers gaseous streams generated by facility operations, may blend them with sources of gas, if available, and transports the blended gaseous fuel at suitable pressures for use as fuel in heaters, furnaces, boilers, incinerators, gas turbines, and other combustion devices located within or outside the facility. The fuel is piped directly to each individual combustion device, and the system typically operates at pressures over atmospheric.

Individual drain system means the system used to convey waste from a process unit, product storage tank, or waste management unit to a waste management unit. The term includes all process drains and common junction boxes, together with their associated sewer lines and other junction boxes, down to the receiving waste management unit.

Internal floating roof means a cover that rests or floats on the liquid surface inside a waste management unit that has a fixed roof.

Liquid-mounted seal means a foam or liquid-filled primary seal mounted in contact with the liquid between the waste management unit wall and the floating roof continuously around the circumference.

Loading means the introduction of waste into a waste management unit but not necessarily to complete capacity (also referred to as filling).

Maximum organic vapor pressure means the equilibrium partial pressure exerted by the waste at the temperature equal to the highest calendar-month average of the waste storage temperature for waste stored above or below the ambient temperature or at the local maximum monthly average temperature as reported by the National Weather Service for waste stored at the ambient temperature, as determined:

(1) In accordance with § 60.17(c); or
(2) As obtained from standard reference texts; or
(3) In accordance with § 60.17(a)(37); or
(4) Any other method approved by the Administrator.

No detectable emissions means less than 500 parts per million by volume (ppmv) above background levels, as measured by a detection instrument reading in accordance with the procedures specified in § 61.355(h) of this subpart.

Oil-water separator means a waste management unit, generally a tank or surface impoundment, used to separate oil from water. An oil-water separator consists of not only the separation unit but also the forebay and other separator basins, skimmers, weirs, grit chambers, sludge hoppers, and bar screens that are located directly after the individual drain system and prior to additional treatment units such as an air flotation unit, clarifier, or biological treatment unit. Examples of an oil-water separator incude an API separator, parallel-plate interceptor, and corrugated-plate interceptor with the associated ancillary equipment.

Petroleum refinery means any facility engaged in producing gasoline, kerosene, distillate fuel oils, residual fuel oils, lubricants, or other products through the distillation of petroleum, or through the redistillation, cracking, or reforming of unfinished petroleum derivatives.

Petroleum means the crude oil removed from the earth and the oils derived from tar sands, shale, and coal.

Point of waste generation means the location where the waste stream exits the process unit component or storage tank prior to handling or treatment in an operation that is not an integral part of the production process, or in the case of waste management units that generate new wastes after treatment, the location where the waste stream exits the waste management unit component.

Process unit means equipment assembled and connected by pipes or ducts to produce intermediate or final products. A process unit can be operated independently if supplied with sufficient fuel or raw materials and sufficient product storage facilities.

Process unit turnaround means the shutting down of the operations of a process unit, the purging of the contents of the process unit, the maintenance or repair work, followed by restarting of the process.

Process unit turnaround waste means a waste that is generated as a result of a process unit turnaround.

Process wastewater means water which comes in contact with benzene during manufacturing or processing operations conducted within a process unit. Process wastewater is not organic wastes, process fluids, product tank drawdown, cooling tower blowdown, steam trap condensate, or landfill leachate.

Process wastewater stream means a waste stream that contains only process wastewater.

Product tank means a stationary unit that is designed to contain an accumulation of materials that are fed to or produced by a process unit, and is constructed primarily of non-earthen materials (e.g., wood, concrete, steel, plastic) which provide structural support.

Product tank drawdown means any material or mixture of materials discharged from a product tank for the purpose of removing water or other contaminants from the product tank.

Safety device means a closure device such as a pressure relief valve, frangible disc, fusible plug, or any other type of device which functions exclusively to prevent physical damage or permanent deformation to a unit or its air emission control equipment by venting gases or vapors directly to the atmosphere during unsafe conditions resulting from an unplanned, accidental, or emergency event. For the purpose of this subpart, a safety device is not used for routine venting of gases or vapors from the vapor headspace underneath a cover such as during filling of the unit or to adjust the pressure in this vapor headspace in response to normal daily diurnal ambient temperature fluctuations. A safety device is designed to remain in a closed position during normal operations and open only when the internal pressure, or another relevant parameter, exceeds the device threshold setting applicable to the air emission control equipment as determined by the owner or operator based on manufacturer recommendations, applicable regulations, fire protection and prevention codes, standard engineering codes and practices, or other requirements for the safe handling of flammable, ignitable, explosive, reactive, or hazardous materials.

Segregated stormwater sewer system means a drain and collection system designed and operated for the sole purpose of collecting rainfall runoff at a facility, and which is segregated from all other individual drain systems.

Sewer line means a lateral, trunk line, branch line, or other enclosed conduit used to convey waste to a downstream waste management unit.

Slop oil means the floating oil and solids that accumulate on the surface of an oil-water separator.

Sour water stream means a stream that:

(1) Contains ammonia or sulfur compounds (usually hydrogen sulfide) at concentrations of 10 ppm by weight or more;

(2) Is generated from separation of water from a feed stock, intermediate, or product that contained ammonia or sulfur compounds; and

(3) Requires treatment to remove the ammonia or sulfur compounds.

Sour water stripper means a unit that:

(1) Is designed and operated to remove ammonia or sulfur compounds (usually hydrogen sulfide) from

sour water streams;

(2) Has the sour water streams transferred to the stripper through hard piping or other enclosed system; and

(3) Is operated in such a manner that the offgases are sent to a sulfur recovery unit, processing unit, incinerator, flare, or other combustion device.

Surface impoundment means a waste management unit which is a natural topographic depression, man-made excavation, or diked area formed primarily of earthen materials (although it may be lined with man-made materials), which is designed to hold an accumulation of liquid wastes or waste containing free liquids, and which is not an injection well. Examples of surface impoundments are holding, storage, settling, and aeration pits, ponds, and lagoons.

Tank means a stationary waste management unit that is designed to contain an accumulation of waste and is constructed primarily of nonearthen materials (e.g., wood, concrete, steel, plastic) which provide structural support.

Treatment process means a stream stripping unit, thin-film evaporation unit, waste incinerator, or any other process used to comply with § 61.348 of this subpart.

Vapor-mounted seal means a foam-filled primary seal mounted continuously around the perimeter of a waste management unit so there is an annular vapor space underneath the seal. The annular vapor space is bounded by the bottom of the primary seal, the unit wall, the liquid surface, and the floating roof.

Waste means any material resulting from industrial, commercial, mining or agricultural operations, or from community activities that is discarded or is being accumulated, stored, or physically, chemically, thermally, or biologically treated prior to being discarded, recycled, or discharged.

Waste management unit means a piece of equipment, structure, or transport mechanism used in handling, storage, treatment, or disposal of waste. Examples of a waste management unit include a tank, surface impoundment, container, oil-water separator, individual drain system, steam stripping unit, thin-film evaporation unit, waste incinerator, and landfill.

Waste stream means the waste generated by a particular process unit, product tank, or waste management unit. The characteristics of the waste stream (e.g., flow rate, benzene concentration, water content) are determined at the point of waste generation. Examples of a waste stream include process wastewater, product tank drawdown, sludge and slop oil removed from waste management units, and landfill leachate.

Wastewater treatment system means any component, piece of equipment, or installation that receives, manages, or treats process wastewater, product tank drawdown, or landfill leachate prior to direct or indirect discharge in accordance with the National Pollutant Discharge Elimination System permit regulations under 40 CFR part 122. These systems typically include individual drain systems, oil-water separators, air flotation units, equalization tanks, and biological treatment units.

Water seal controls means a seal pot, p-leg trap, or other type of trap filled with water (e.g., flooded sewers that maintain water levels adequate to prevent air flow through the system) that creates a water barrier between the sewer line and the atmosphere. The water level of the seal must be maintained in the vertical leg of a drain in order to be considered a water seal.

[55 FR 8346, Mar. 7, 1990; 55 FR 12444, Apr. 3, 1990, as amended at 58 FR 3095, Jan. 7, 1993; 67 FR 68531, Nov. 12, 2002]

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§ 61.342 Standards: General.

(a) An owner or operator of a facility at which the total annual benzene quantity from facility waste is less than 10 megagrams per year (Mg/yr) (11 ton/yr) shall be exempt from the requirements of paragraphs (b) and (c) of this section. The total annual benzene quantity from facility waste is the sum of the annual benzene quantity for each waste stream at the facility that has a flow-weighted annual average water content greater than 10 percent or that is mixed with water, or other wastes, at any time and the mixture has an annual average water content greater than 10 percent. The benzene quantity in a waste stream is to be counted only once without multiple counting if other waste streams are mixed with or generated from the original waste stream. Other specific requirements for calculating the total annual benzene waste quantity are as follows:

(1) Wastes that are exempted from control under §§ 61.342(c)(2) and 61.342(c)(3) are included in the calculation of the total annual benzene quantity if they have an annual average water content greater than 10 percent, or if they are mixed with water or other wastes at any time and the mixture has an annual average water content greater than 10 percent.

(2) The benzene in a material subject to this subpart that is sold is included in the calculation of the total annual benzene quantity if the material has an annual average water content greater than 10 percent.
(3) Benzene in wastes generated by remediation activities conducted at the facility, such as the excavation of contaminated soil, pumping and treatment of groundwater, and the recovery of product from soil or groundwater, are not included in the calculation of total annual benzene quantity for that facility. If the facility's total annual benzene quantity is 10 Mg/yr (11 ton/yr) or more, wastes generated by remediation activities are subject to the requirements of paragraphs (c) through (h) of this section. If the facility is managing remediation waste generated offsite, the benzene in this waste shall be included in the calculation of total annual benzene quantity in facility waste, if the waste streams have an annual average water content greater than 10 percent, or if they are mixed with water or other wastes at any time and the mixture has an annual average water content greater than 10 percent.
(4) The total annual benzene quantity is determined based upon the quantity of benzene in the waste before any waste treatment occurs to remove the benzene except as specified in § 61.355(c)(1)(i) (A) through (C).
(b) Each owner or operator of a facility at which the total annual benzene quantity from facility waste is equal to or greater than 10 Mg/yr (11 ton/yr) as determined in paragraph (a) of this section shall be in compliance with the requirements of paragraphs (c) through (h) of this section no later than 90 days following the effective date, unless a waiver of compliance has been obtained under § 61.11, or by the initial startup for a new source with an initial startup after the effective date.
(1) The owner or operator of an existing source unable to comply with the rule within the required time may request a waiver of compliance under § 61.10.
(2) As part of the waiver application, the owner or operator shall submit to the Administrator a plan under § 61.10(b)(3) that is an enforceable commitment to obtain environmental benefits to mitigate the benzene emissions that result from extending the compliance date. The plan shall include the following information:
(i) A description of the method of compliance, including the control approach, schedule for installing controls, and quantity of the benzene emissions that result from extending the compliance date;
(ii) If the control approach involves a compliance strategy designed to obtain integrated compliance with multiple regulatory requirements, a description of the other regulations involved and their effective dates; and
(iii) A description of the actions to be taken at the facility to obtain mitigating environmental benefits, including how the benefits will be obtained, the schedule for these actions, and an estimate of the quantifiable benefits that directly result from these actions.
(c) Each owner or operator of a facility at which the total annual benzene quantity from facility waste is equal to or greater than 10 Mg/yr (11 ton/yr) as determined in paragraph (a) of this section shall manage and treat the facility waste as follows:
(1) For each waste stream that contains benzene, including (but not limited to) organic waste streams that contain less than 10 percent water and aqueous waste streams, even if the wastes are not discharged to an individual drain system, the owner or operator shall:
(i) Remove or destroy the benzene contained in the waste using a treatment process or wastewater treatment system that complies with the standards specified in § 61.348 of this subpart.
(ii) Comply with the standards specified in §§ 61.343 through 61.347 of this subpart for each waste management unit that receives or manages the waste stream prior to and during treatment of the waste stream in accordance with paragraph (c)(1)(i) of this section.
(iii) Each waste management unit used to manage or treat waste streams that will be recycled to a process shall comply with the standards specified in §§ 61.343 through 61.347. Once the waste stream is recycled to a process, including to a tank used for the storage of production process feed, product, or product intermediates, unless this tank is used primarily for the storage of wastes, the material is no longer subject to paragraph (c) of this section.
(2) A waste stream is exempt from paragraph (c)(1) of this section provided that the owner or operator demonstrates initially and, thereafter, at least once per year that the flow-weighted annual average benzene concentration for the waste stream is less than 10 ppmw as determined by the procedures specified in § 61.355(c)(2) or § 61.355(c)(3).
(3) A waste stream is exempt from paragraph (c)(1) of this section provided that the owner or operator demonstrates initially and, thereafter, at least once per year that the conditions specified in either paragraph (c)(3)(i) or (c)(3)(ii) of this section are met.

(i) The waste stream is process wastewater that has a flow rate less than 0.02 liters per minute (0.005 gallons per minute) or an annual wastewater quantity of less than 10 Mg/yr (11 ton/yr); or
(ii) All of the following conditions are met:
(A) The owner or operator does not choose to exempt process wastewater under paragraph (c)(3)(i) of this section,
(B) The total annual benzene quantity in all waste streams chosen for exemption in paragraph (c)(3)(ii) of this section does not exceed 2.0 Mg/yr (2.2 ton/yr) as determined in the procedures in § 61.355(j), and
(C) The total annual benzene quantity in a waste stream chosen for exemption, including process unit turnaround waste, is determined for the year in which the waste is generated.
(d) As an alternative to the requirements specified in paragraphs (c) and (e) of this section, an owner or operator of a facility at which the total annual benzene quantity from facility waste is equal to or greater than 10 Mg/yr (11 ton/yr) as determined in paragraph (a) of this section may elect to manage and treat the facility waste as follows:
(1) The owner or operator shall manage and treat facility waste other than process wastewater in accordance with the requirements of paragraph (c)(1) of this section.
(2) The owner or operator shall manage and treat process wastewater in accordance with the following requirements:
(i) Process wastewater shall be treated to achieve a total annual benzene quantity from facility process wastewater less than 1 Mg/yr (1.1 ton/yr). Total annual benzene from facility process wastewater shall be determined by adding together the annual benzene quantity at the point of waste generation for each untreated process wastewater stream plus the annual benzene quantity exiting the treatment process for each process wastewater stream treated in accordance with the requirements of paragraph (c)(1)(i) of this section.
(ii) Each treated process wastewater stream identified in paragraph (d)(2)(i) of this section shall be managed and treated in accordance with paragraph (c)(1) of this section.
(iii) Each untreated process wastewater stream identified in paragraph (d)(2)(i) of this section is exempt from the requirements of paragraph (c)(1) of this section.
(e) As an alternative to the requirements specified in paragraphs (c) and (d) of this section, an owner or operator of a facility at which the total annual benzene quantity from facility waste is equal to or greater than 10 Mg/yr (11 ton/yr) as determined in paragraph (a) of this section may elect to manage and treat the facility waste as follows:
(1) The owner or operator shall manage and treat facility waste with a flow-weighted annual average water content of less than 10 percent in accordance with the requirements of paragraph (c)(1) of this section; and
(2) The owner or operator shall manage and treat facility waste (including remediation and process unit turnaround waste) with a flow-weighted annual average water content of 10 percent or greater, on a volume basis as total water, and each waste stream that is mixed with water or wastes at any time such that the resulting mixture has an annual water content greater than 10 percent, in accordance with the following:
(i) The benzene quantity for the wastes described in paragraph (e)(2) of this section must be equal to or less than 6.0 Mg/yr (6.6 ton/yr), as determined in § 61.355(k). Wastes as described in paragraph (e)(2) of this section that are transferred offsite shall be included in the determination of benzene quantity as provided in § 61.355(k). The provisions of paragraph (f) of this section shall not apply to any owner or operator who elects to comply with the provisions of paragraph (e) of this section.
(ii) The determination of benzene quantity for each waste stream defined in paragraph (e)(2) of this section shall be made in accordance with § 61.355(k).
(f) Rather than treating the waste onsite, an owner or operator may elect to comply with paragraph (c)(1)(i) of this section by transferring the waste offsite to another facility where the waste is treated in accordance with the requirements of paragraph (c)(1)(i) of this section. The owner or operator transferring the waste shall:
(1) Comply with the standards specified in §§ 61.343 through 61.347 of this subpart for each waste management unit that receives or manages the waste prior to shipment of the waste offsite.
(2) Include with each offsite waste shipment a notice stating that the waste contains benzene which is required to be managed and treated in accordance with the provisions of this subpart.
(g) Compliance with this subpart will be determined by review of facility records and results from tests and inspections using methods and procedures specified in § 61.355 of this subpart.

(h) Permission to use an alternative means of compliance to meet the requirements of §§ 61.342 through 61.352 of this subpart may be granted by the Administrator as provided in § 61.353 of this subpart.
[55 FR 8346, Mar. 7, 1990, as amended at 58 FR 3095, Jan. 7, 1993; 65 FR 62159, 62160, Oct. 17, 2000]

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§ 61.343 Standards: Tanks.

(a) Except as provided in paragraph (b) of this section and in § 61.351, the owner or operator must meet the standards in paragraph (a)(1) or (2) of this section for each tank in which the waste stream is placed in accordance with § 61.342 (c)(1)(ii). The standards in this section apply to the treatment and storage of the waste stream in a tank, including dewatering.

(1) The owner or operator shall install, operate, and maintain a fixed-roof and closed-vent system that routes all organic vapors vented from the tank to a control device.

(i) The fixed-roof shall meet the following requirements:

(A) The cover and all openings (e.g., access hatches, sampling ports, and gauge wells) shall be designed to operate with no detectable emissions as indicated by an instrument reading of less than 500 ppmv above background, as determined initially and thereafter at least once per year by the methods specified in § 61.355(h) of this subpart.

(B) Each opening shall be maintained in a closed, sealed position (e.g., covered by a lid that is gasketed and latched) at all times that waste is in the tank except when it is necessary to use the opening for waste sampling or removal, or for equipment inspection, maintenance, or repair.

(C) If the cover and closed-vent system operate such that the tank is maintained at a pressure less than atmospheric pressure, then paragraph (a)(1)(i)(B) of this section does not apply to any opening that meets all of thefollowing conditions:

(1) The purpose of the opening is to provide dilution air to reduce the explosion hazard;

(2) The opening is designed to operate with no detectable emissions as indicated by an instrument reading of less than 500 ppmv above background, as determined initially and thereafter at least once per year by the methods specified in § 61.355(h); and

(3) The pressure is monitored continuously to ensure that the pressure in the tank remains below atmospheric pressure.

(ii) The closed-vent system and control device shall be designed and operated in accordance with the requirements of § 61.349 of this subpart.

(2) The owner or operator must install, operate, and maintain an enclosure and closed-vent system that routes all organic vapors vented from the tank, located inside the enclosure, to a control device in accordance with the requirements specified in paragraph (e) of this section.

(b) For a tank that meets all the conditions specified in paragraph (b)(1) of this section, the owner or operator may elect to comply with paragraph (b)(2) of this section as an alternative to the requirements specified in paragraph (a)(1) of this section.

(1) The waste managed in the tank complying with paragraph (b)(2) of this section shall meet all of the following conditions:

(i) Each waste stream managed in the tank must have a flow-weighted annual average water content less than or equal to 10 percent water, on a volume basis as total water.

(ii) The waste managed in the tank either:

(A) Has a maximum organic vapor pressure less than 5.2 kilopascals (kPa) (0.75 pounds per square inch (psi));

(B) Has a maximum organic vapor pressure less than 27.6 kPa (4.0 psi) and is managed in a tank having design capacity less than 151 m^3 (40,000 gal); or

(C) Has a maximum organic vapor pressure less than 76.6 kPa (11.1 psi) and is managed in a tank having a design capacity less than 75 m^3 (20,000 gal).

(2) The owner or operator shall install, operate, and maintain a fixed roof as specified in paragraph (a)(1)(i).

(3) For each tank complying with paragraph (b) of this section, one or more devices which vent directly to the atmosphere may be used on the tank provided each device remains in a closed, sealed position during normal operations except when the device needs to open to prevent physical damage or permanent deformation of the tank or cover resulting from filling or emptying the tank, diurnal temperature changes, atmospheric pressure changes or malfunction of the unit in accordance with good engineering and safety practices for handling flammable, explosive, or other hazardous materials.

(c) Each fixed-roof, seal, access door, and all other openings shall be checked by visual inspection initially and quarterly thereafter to ensure that no cracks or gaps occur and that access doors and other openings are closed and gasketed properly.

(d) Except as provided in § 61.350 of this subpart, when a broken seal or gasket or other problem is identified, or when detectable emissions are measured, first efforts at repair shall be made as soon as practicable, but not later than 45 calendar days after identification.

(e) Each owner or operator who controls air pollutant emissions by using an enclosure vented through a closed-vent system to a control device must meet the requirements specified in paragraphs (e)(1) through (4) of this section.

(1) The tank must be located inside a total enclosure. The enclosure must be designed and operated in accordance with the criteria for a permanent total enclosure as specified in “Procedure T—Criteria for and Verification of a Permanent or Temporary Total Enclosure” in 40 CFR 52.741, appendix B. The enclosure may have permanent or temporary openings to allow worker access; passage of material into or out of the enclosure by conveyor, vehicles, or other mechanical means; entry of permanent mechanical or electrical equipment; or direct airflow into the enclosure. The owner or operator must perform the verification procedure for the enclosure as specified in section 5.0 of Procedure T initially when the enclosure is first installed and, thereafter, annually. A facility that has conducted an initial compliance demonstration and that performs annual compliance demonstrations in accordance with the requirements for Tank Level 2 control requirements 40 CFR 264.1084(i) or 40 CFR 265(i) is not required to make repeat demonstrations of initial and continuous compliance for the purposes of this subpart.

(2) The enclosure must be vented through a closed-vent system to a control device that is designed and operated in accordance with the standards for control devices specified in § 61.349.

(3) Safety devices, as defined in this subpart, may be installed and operated as necessary on any enclosure, closed-vent system, or control device used to comply with the requirements of paragraphs (e)(1) and (2) of this section.

(4) The closed-vent system must be designed and operated in accordance with the requirements of § 61.349.

[55 FR 8346, Mar. 7, 1990, as amended at 55 FR 18331, May 2, 1990; 58 FR 3096, Jan. 7, 1993; 67 FR 68532, Nov. 12, 2002; 68 FR 6082, Feb. 6, 2003; 68 FR 67935, Dec. 4, 2003]

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§ 61.344 Standards: Surface impoundments.

(a) The owner or operator shall meet the following standards for each surface impoundment in which waste is placed in accordance with § 61.342(c)(1)(ii) of this subpart:

(1) The owner or operator shall install, operate, and maintain on each surface impoundment a cover (e.g., air-supported structure or rigid cover) and closed-vent system that routes all organic vapors vented from the surface impoundment to a control device.

(i) The cover shall meet the following requirements:

(A) The cover and all openings (e.g., access hatches, sampling ports, and gauge wells) shall be designed to operate with no detectable emissions as indicated by an instrument reading of less than 500 ppmv above background, initially and thereafter at least once per year by the methods specified in § 61.355(h) of this subpart.

(B) Each opening shall be maintained in a closed, sealed position (e.g., covered by a lid that is gasketed and latched) at all times that waste is in the surface impoundment except when it is necessary to use the opening for waste sampling or removal, or for equipment inspection, maintenance, or repair.

(C) If the cover and closed-vent system operate such that the enclosure of the surface impoundment is maintained at a pressure less than atmospheric pressure, then paragraph (a)(1)(i)(B) of this section does not apply to any opening that meets all of the following conditions:

(1) The purpose of the opening is to provide dilution air to reduce the explosion hazard;

(2) The opening is designed to operate with no detectable emissions as indicated by an instrument reading of less than 500 ppmv above background, as determined initially and thereafter at least once per year by the methods specified in § 61.355(h) of this subpart; and

(3) The pressure is monitored continuously to ensure that the pressure in the enclosure of the surface impoundment remains below atmospheric pressure.

(D) The cover shall be used at all times that waste is placed in the surface impoundment except during removal of treatment residuals in accordance with 40 CFR 268.4 or closure of the surface impoundment in accordance with 40 CFR 264.228. (Note: the treatment residuals generated by these activities may be subject to the requirements of this part.)

(ii) The closed-vent system and control device shall be designed and operated in accordance with § 61.349 of this subpart.

(b) Each cover seal, access hatch, and all other openings shall be checked by visual inspection initially and quarterly thereafter to ensure that no cracks or gaps occur and that access hatches and other openings are closed and gasketed properly.

(c) Except as provided in § 61.350 of this subpart, when a broken seal or gasket or other problem is identified, or when detectable emissions are measured, first efforts at repair shall be made as soon as practicable, but not later than 15 calendar days after identification.

[55 FR 8346, Mar. 7, 1990, as amended at 58 FR 3097, Jan. 7, 1993]

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§ 61.345 Standards: Containers.

(a) The owner or operator shall meet the following standards for each container in which waste is placed in accordance with § 61.342(c)(1)(ii) of this subpart:

(1) The owner or operator shall install, operate, and maintain a cover on each container used to handle, transfer, or store waste in accordance with the following requirements:

(i) The cover and all openings (e.g., bungs, hatches, and sampling ports) shall be designed to operate with no detectable emissions as indicated by an instrument reading of less than 500 ppmv above background, initially and thereafter at least once per year by the methods specified in § 61.355(h) of this subpart.

(ii) Except as provided in paragraph (a)(4) of this section, each opening shall be maintained in a closed, sealed position (e.g., covered by a lid that is gasketed and latched) at all times that waste is in the container except when it is necessary to use the opening for waste loading, removal, inspection, or sampling.

(2) When a waste is transferred into a container by pumping, the owner or operator shall perform the transfer using a submerged fill pipe. The submerged fill pipe outlet shall extend to within two fill pipe diameters of the bottom of the container while the container is being loaded. During loading of the waste, the cover shall remain in place and all openings shall be maintained in a closed, sealed position except for those openings required for the submerged fill pipe, those openings required for venting of the container to prevent physical damage or permanent deformation of the container or cover, and any openings complying with paragraph (a)(4) of this section.

(3) Treatment of a waste in a container, including aeration, thermal or other treatment, must be performed by the owner or operator in a manner such that while the waste is being treated the container meets the standards specified in paragraphs (a)(3)(i) through (iii) of this section, except for covers and closed-vent systems that meet the requirements in paragraph (a)(4) of this section.

(i) The owner or operator must either:

(A) Vent the container inside a total enclosure which is exhausted through a closed-vent system to a control device in accordance with the requirements of paragraphs (a)(3)(ii)(A) and (B) of this section; or

(B) Vent the covered or closed container directly through a closed-vent system to a control device in accordance with the requirements of paragraphs (a)(3)(ii)(B) and (C) of this section.

(ii) The owner or operator must meet the following requirements, as applicable to the type of air emission control equipment selected by the owner or operator:

(A) The total enclosure must be designed and operated in accordance with the criteria for a permanent total enclosure as specified in section 5 of the “Procedure T—Criteria for and Verification of a Permanent or Temporary Total Enclosure” in 40 CFR 52.741, appendix B. The enclosure may have permanent or temporary openings to allow worker access; passage of containers through the enclosure by conveyor or other mechanical means; entry of permanent mechanical or electrical equipment; or direct airflow into the enclosure. The owner or operator must perform the verification procedure for the enclosure as specified in section 5.0 of “Procedure T—Criteria for and Verification of a Permanent or Temporary Total Enclosure” initially when the enclosure is first installed and, thereafter, annually. A facility that has conducted an initial compliance demonstration and that performs annual compliance demonstrations in accordance with the Container Level 3 control requirements in 40 CFR 264.1086(e)(2)(i) or 40 CFR 265.1086(e)(2)(i) is not required to make repeat demonstrations of initial and continuous compliance for the purposes of this subpart.

(B) The closed-vent system and control device must be designed and operated in accordance with the requirements of § 61.349.

(C) For a container cover, the cover and all openings (e.g., doors, hatches) must be designed to operate with no detectable emissions as indicated by an instrument reading of less than 500 ppmv above background, initially and thereafter at least once per year by the methods specified in § 61.355(h).
(iii) Safety devices, as defined in this subpart, may be installed and operated as necessary on any container, enclosure, closed-vent system, or control device used to comply with the requirements of paragraph (a)(3)(i) of this section.
(4) If the cover and closed-vent system operate such that the container is maintained at a pressure less than atmospheric pressure, the owner or operator may operate the system with an opening that is not sealed and kept closed at all times if the following conditions are met:
(i) The purpose of the opening is to provide dilution air to reduce the explosion hazard;
(ii) The opening is designed to operate with no detectable emissions as indicated by an instrument reading of less than 500 ppmv above background, as determined initially and thereafter at least once per year by methods specified in § 61.355(h); and
(iii) The pressure is monitored continuously to ensure that the pressure in the container remains below atmospheric pressure.
(b) Each cover and all openings shall be visually inspected initially and quarterly thereafter to ensure that they are closed and gasketed properly.
(c) Except as provided in § 61.350 of this subpart, when a broken seal or gasket or other problem is identified, first efforts at repair shall be made as soon as practicable, but not later than 15 calendar days after identification.
[55 FR 8346, Mar. 7, 1990, as amended at 58 FR 3097, Jan. 7, 1993; 67 FR 68532, Nov. 12, 2002; 68 FR 67936, Dec. 4, 2003]

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§ 61.346 Standards: Individual drain systems.

(a) Except as provided in paragraph (b) of this section, the owner or operator shall meet the following standards for each individual drain system in which waste is placed in accordance with § 61.342(c)(1)(ii) of this subpart:
(1) The owner or operator shall install, operate, and maintain on each drain system opening a cover and closed-vent system that routes all organic vapors vented from the drain system to a control device.
(i) The cover shall meet the following requirements:
(A) The cover and all openings (e.g., access hatches, sampling ports) shall be designed to operate with no detactable emissions as indicated by an instrument reading of less than 500 ppmv above background, initially and thereafter at least once per year by the methods specified in § 61.355(h) of this subpart.
(B) Each opening shall be maintained in a closed, sealed position (e.g., covered by a lid that is gasketed and latched) at all times that waste is in the drain system except when it is necessary to use the opening for waste sampling or removal, or for equipment inspection, maintenance, or repair.
(C) If the cover and closed-vent system operate such that the individual drain system is maintained at a pressure less than atmospheric pressure, then paragraph (a)(1)(i)(B) of this section does not apply to any opening that meets all of the following conditions:
(1) The purpose of the opening is to provide dilution air to reduce the explosion hazard;
(2) The opening is designed to operate with no detectable emissions as indicated by an instrument reading of less than 500 ppmv above background, as determined initially and thereafter at least once per year by the methods specified in § 61.355(h); and
(3) The pressure is monitored continuously to ensure that the pressure in the individual drain system remains below atmospheric pressure.
(ii) The closed-vent system and control device shall be designed and operated in accordance with § 61.349 of this subpart.
(2) Each cover seal, access hatch, and all other openings shall be checked by visual inspection initially and quarterly thereafter to ensure that no cracks or gaps occur and that access hatches and other openings are closed and gasketed properly.
(3) Except as provided in § 61.350 of this subpart, when a broken seal or gasket or other problem is identified, or when detectable emissions are measured, first efforts at repair shall be made as soon as practicable, but not later than 15 calendar days after identification.
(b) As an alternative to complying with paragraph (a) of this section, an owner or operator may elect to comply with the following requirements:
(1) Each drain shall be equipped with water seal controls or a tightly sealed cap or plug.

(2) Each junction box shall be equipped with a cover and may have a vent pipe. The vent pipe shall be at least 90 cm (3 ft) in length and shall not exceed 10.2 cm (4 in) in diameter.
(i) Junction box covers shall have a tight seal around the edge and shall be kept in place at all times, except during inspection and maintenance.
(ii) One of the following methods shall be used to control emissions from the junction box vent pipe to the atmosphere:
(A) Equip the junction box with a system to prevent the flow of organic vapors from the junction box vent pipe to the atmosphere during normal operation. An example of such a system includes use of water seal controls on the junction box. A flow indicator shall be installed, operated, and maintained on each junction box vent pipe to ensure that organic vapors are not vented from the junction box to the atmosphere during normal operation.
(B) Connect the junction box vent pipe to a closed-vent system and control device in accordance with § 61.349 of this subpart.
(3) Each sewer line shall not be open to the atmosphere and shall be covered or enclosed in a manner so as to have no visual gaps or cracks in joints, seals, or other emission interfaces.
(4) Equipment installed in accordance with paragraphs (b)(1), (b)(2), or (b)(3) of this section shall be inspected as follows:
(i) Each drain using water seal controls shall be checked by visual or physical inspection initially and thereafter quarterly for indications of low water levels or other conditions that would reduce the effectiveness of water seal controls.
(ii) Each drain using a tightly sealed cap or plug shall be visually inspected initially and thereafter quarterly to ensure caps or plugs are in place and properly installed.
(iii) Each junction box shall be visually inspected initially and thereafter quarterly to ensure that the cover is in place and to ensure that the cover has a tight seal around the edge.
(iv) The unburied portion of each sewer line shall be visually inspected initially and thereafter quarterly for indication of cracks, gaps, or other problems that could result in benzene emissions.
(5) Except as provided in § 61.350 of this subpart, when a broken seal, gap, crack or other problem is identified, first efforts at repair shall be made as soon as practicable, but not later than 15 calendar days after identification.
[55 FR 8346, Mar. 7, 1990, as amended at 55 FR 37231, Sept. 10, 1990; 58 FR 3097, Jan. 7, 1993]

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§ 61.347 Standards: Oil-water separators.

(a) Except as provided in § 61.352 of this subpart, the owner or operator shall meet the following standards for each oil-water separator in which waste is placed in accordance with § 61.342(c)(1)(ii) of this subpart:
(1) The owner or operator shall install, operate, and maintain a fixed-roof and closed-vent system that routes all organic vapors vented from the oil-water separator to a control device.
(i) The fixed-roof shall meet the following requirements:
(A) The cover and all openings (e.g., access hatches, sampling ports, and gauge wells) shall be designed to operate with no detectable emissions as indicated by an instrument reading of less than 500 ppmv above background, as determined initially and thereafter at least once per year by the methods specified in § 61.355(h) of this subpart.
(B) Each opening shall be maintained in a closed, sealed position (e.g., covered by a lid that is gasketed and latched) at all times that waste is in the oil-water separator except when it is necessary to use the opening for waste sampling or removal, or for equipment inspection, maintenance, or repair.
(C) If the cover and closed-vent system operate such that the oil-water separator is maintained at a pressure less than atmospheric pressure, then paragraph (a)(1)(i)(B) of this section does not apply to any opening that meets all of the following conditions:
(1) The purpose of the opening is to provide dilution air to reduce the explosion hazard;
(2) The opening is designed to operate with no detectable emissions as indicated by an instrument reading of less than 500 ppmv above background, as determined initially and thereafter at least once per year by the methods specified in § 61.355(h); and
(3) The pressure is monitored continuously to ensure that the pressure in the oil-water separator remains below atmospheric pressure.
(ii) The closed-vent system and control device shall be designed and operated in accordance with the requirements of § 61.349 of this subpart.

(b) Each cover seal, access hatch, and all other openings shall be checked by visual inspection initially and quarterly thereafter to ensure that no cracks or gaps occur between the cover and oil-water separator wall and that access hatches and other openings are closed and gasketed properly.
(c) Except as provided in § 61.350 of this subpart, when a broken seal or gasket or other problem is identified, or when detectable emissions are measured, first efforts at repair shall be made as soon as practicable, but not later than 15 calendar days after identification.
[55 FR 8346, Mar. 7, 1990, as amended at 58 FR 3098, Jan. 7, 1993]

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§ 61.348 Standards: Treatment processes.

(a) Except as provided in paragraph (a)(5) of this section, the owner or operator shall treat the waste stream in accordance with the following requirements:
(1) The owner or operator shall design, install, operate, and maintain a treatment process that either:
(i) Removes benzene from the waste stream to a level less than 10 parts per million by weight (ppmw) on a flow-weighted annual average basis,
(ii) Removes benzene from the waste stream by 99 percent or more on a mass basis, or
(iii) Destroys benzene in the waste stream by incinerating the waste in a combustion unit that achieves a destruction efficiency of 99 percent or greater for benzene.
(2) Each treatment process complying with paragraphs (a)(1)(i) or (a)(1)(ii) of this section shall be designed and operated in accordance with the appropriate waste management unit standards specified in §§ 61.343 through 61.347 of this subpart. For example, if a treatment process is a tank, then the owner or operator shall comply with § 61.343 of this subpart.
(3) For the purpose of complying with the requirements specified in paragraph (a)(1)(i) of this section, the intentional or unintentional reduction in the benzene concentration of a waste stream by dilution of the waste stream with other wastes or materials is not allowed.
(4) An owner or operator may aggregate or mix together individual waste streams to create a combined waste stream for the purpose of facilitating treatment of waste to comply with the requirements of paragraph (a)(1) of this section except as provided in paragraph (a)(5) of this section.
(5) If an owner or operator aggregates or mixes any combination of process wastewater, product tank drawdown, or landfill leachate subject to § 61.342(c)(1) of this subpart together with other waste streams to create a combined waste stream for the purpose of facilitating management or treatment of waste in a wastewater treatment system, then the wastewater treatment system shall be operated in accordance with paragraph (b) of this section. These provisions apply to above-ground wastewater treatment systems as well as those that are at or below ground level.
(b) Except for facilities complying with § 61.342(e), the owner or operator that aggregates or mixes individual waste streams as defined in paragraph (a)(5) of this section for management and treatment in a wastewater treatment system shall comply with the following requirements:
(1) The owner or operator shall design and operate each waste management unit that comprises the wastewater treatment system in accordance with the appropriate standards specified in §§ 61.343 through 61.347 of this subpart.
(2) The provisions of paragraph (b)(1) of this section do not apply to any waste management unit that the owner or operator demonstrates to meet the following conditions initially and, thereafter, at least once per year:
(i) The benzene content of each waste stream entering the waste management unit is less than 10 ppmw on a flow-weighted annual average basis as determined by the procedures specified in § 61.355(c) of this subpart; and
(ii) The total annual benzene quantity contained in all waste streams managed or treated in exempt waste management units comprising the facility wastewater treatment systems is less than 1 Mg/yr (1.1 ton/yr). For this determination, total annual benzene quantity shall be calculated as follows:
(A) The total annual benzene quantity shall be calculated as the sum of the individual benzene quantities determined at each location where a waste stream first enters an exempt waste management unit. The benzene quantity discharged from an exempt waste management unit shall not be included in this calculation.
(B) The annual benzene quantity in a waste stream managed or treated in an enhanced biodegradation unit shall not be included in the calculation of the total annual benzene quantity, if the enhanced biodegradation unit is the first exempt unit in which the waste is managed or treated. A unit shall be considered enhanced biodegradation if it is a suspended-growth process that generates biomass, uses

recycled biomass, and periodically removes biomass from the process. An enhanced biodegradation unit typically operates at a food-to-microorganism ratio in the range of 0.05 to 1.0 kg of biological oxygen demand per kg of biomass per day, a mixed liquor suspended solids ratio in the range of 1 to 8 grams per liter (0.008 to 0.7 pounds per liter), and a residence time in the range of 3 to 36 hours.
(c) The owner and operator shall demonstrate that each treatment process or wastewater treatment system unit, except as provided in paragraph (d) of this section, achieves the appropriate conditions specified in paragraphs (a) or (b) of this section in accordance with the following requirements:
(1) Engineering calculations in accordance with requirements specified in § 61.356(e) of this subpart; or
(2) Performance tests conducted using the test methods and procedures that meet the requirements specified in § 61.355 of this subpart.
(d) A treatment process or waste stream is in compliance with the requirements of this subpart and exempt from the requirements of paragraph (c) of this section provided that the owner or operator documents that the treatment process or waste stream is in compliance with other regulatory requirements as follows:
(1) The treatment process is a hazardous waste incinerator for which the owner or operator has been issued a final permit under 40 CFR part 270 and complies with the requirements of 40 CFR part 264, subpart O;
(2) The treatment process is an industrial furnace or boiler burning hazardous waste for energy recovery for which the owner or operator has been issued a final permit under 40 CFR part 270 and complies with the requirements of 40 CFR part 266, subpart D;
(3) The waste stream is treated by a means or to a level that meets benzene-specific treatment standards in accordance with the Land Disposal Restrictions under 40 CFR part 268, and the treatment process is designed and operated with a closed-vent system and control device meeting the requirements of § 61.349 of this subpart;
(4) The waste stream is treated by a means or to a level that meets benzene-specific effluent limitations or performance standards in accordance with the Effluent Guidelines and Standards under 40 CFR parts 401-464, and the treatment process is designed and operated with a closed-vent system and control device meeting the requirements of § 61.349 of this subpart; or
(5) The waste stream is discharged to an underground injection well for which the owner or operator has been issued a final permit under 40 CFR part 270 and complies with the requirements of 40 CFR part 122.
(e) Except as specified in paragraph (e)(3) of this section, if the treatment process or wastewater treatment system unit has any openings (e.g., access doors, hatches, etc.), all such openings shall be sealed (e.g., gasketed, latched, etc.) and kept closed at all times when waste is being treated, except during inspection and maintenance.
(1) Each seal, access door, and all other openings shall be checked by visual inspections initially and quarterly thereafter to ensure that no cracks or gaps occur and that openings are closed and gasketed properly.
(2) Except as provided in § 61.350 of this subpart, when a broken seal or gasket or other problem is identified, first efforts at repair shall be made as soon as practicable, but not later than 15 calendar days after identification.
(3) If the cover and closed-vent system operate such that the treatment process and wastewater treatment system unit are maintained at a pressure less than atmospheric pressure, the owner or operator may operate the system with an opening that is not sealed and kept closed at all times if the following conditions are met:
(i) The purpose of the opening is to provide dilution air to reduce the explosion hazard;
(ii) The opening is designed to operate with no detectable emissions as indicated by an instrument reading of less than 500 ppmv above background, as determined initially and thereafter at least once per year by the methods specified in § 61.355(h); and
(iii) The pressure is monitored continuously to ensure that the pressure in the treatment process and wastewater treatment system unit remain below atmospheric pressure.
(f) Except for treatment processes complying with paragraph (d) of this section, the Administrator may request at any time an owner or operator demonstrate that a treatment process or wastewater treatment system unit meets the applicable requirements specified in paragraphs (a) or (b) of this section by conducting a performance test using the test methods and procedures as required in § 61.355 of this subpart.

(g) The owner or operator of a treatment process or wastewater treatment system unit that is used to comply with the provisions of this section shall monitor the unit in accordance with the applicable requirements in § 61.354 of this subpart.

[55 FR 8346, Mar. 7, 1990, as amended at 55 FR 37231, Sept. 10, 1990; 58 FR 3098, Jan. 7, 1993; 65 FR 62160, Oct. 17, 2000]

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§ 61.349 Standards: Closed-vent systems and control devices.

(a) For each closed-vent system and control device used to comply with standards in accordance with §§ 61.343 through 61.348 of this subpart, the owner or operator shall properly design, install, operate, and maintain the closed-vent system and control device in accordance with the following requirements:

(1) The closed-vent system shall:

(i) Be designed to operate with no detectable emissions as indicated by an instrument reading of less than 500 ppmv above background, as determined initially and thereafter at least once per year by the methods specified in § 61.355(h) of this subpart.

(ii) Vent systems that contain any bypass line that could divert the vent stream away from a control device used to comply with the provisions of this subpart shall install, maintain, and operate according to the manufacturer's specifications a flow indicator that provides a record of vent stream flow away from the control device at least once every 15 minutes, except as provided in paragraph (a)(1)(ii)(B) of this section.

(A) The flow indicator shall be installed at the entrance to any bypass line that could divert the vent stream away from the control device to the atmosphere.

(B) Where the bypass line valve is secured in the closed position with a car-seal or a lock-and-key type configuration, a flow indicator is not required.

(iii) All gauging and sampling devices shall be gas-tight except when gauging or sampling is taking place.

(iv) For each closed-vent system complying with paragraph (a) of this section, one or more devices which vent directly to the atmosphere may be used on the closed-vent system provided each device remains in a closed, sealed position during normal operations except when the device needs to open to prevent physical damage or permanent deformation of the closed-vent system resulting from malfunction of the unit in accordance with good engineering and safety practices for handling flammable, explosive, or other hazardous materials.

(2) The control device shall be designed and operated in accordance with the following conditions:

(i) An enclosed combustion device (e.g., a vapor incinerator, boiler, or process heater) shall meet one of the following conditions:

(A) Reduce the organic emissions vented to it by 95 weight percent or greater;

(B) Achieve a total organic compound concentration of 20 ppmv (as the sum of the concentrations for individual compounds using Method 18) on a dry basis corrected to 3 percent oxygen; or

(C) Provide a minimum residence time of 0.5 seconds at a minimum temperature of 760 °C (1,400 °F). If a boiler or process heater issued as the control device, then the vent stream shall be introduced into the flame zone of the boiler or process heater.

(ii) A vapor recovery system (e.g., a carbon adsorption system or a condenser) shall recover or control the organic emissions vented to it with an efficiency of 95 weight percent or greater, or shall recover or control the benzene emissions vented to it with an efficiency of 98 weight percent or greater.

(iii) A flare shall comply with the requirements of 40 CFR 60.18.

(iv) A control device other than those described in paragraphs (a)(2) (i) through (iii) of this section may be used provided that the following conditions are met:

(A) The device shall recover or control the organic emissions vented to it with an efficiency of 95 weight percent or greater, or shall recover or control the benzene emissions vented to it with an efficiency of 98 weight percent or greater.

(B) The owner or operator shall develop test data and design information that documents the control device will achieve an emission control efficiency of either 95 percent or greater for organic compounds or 98 percent or greater for benzene.

(C) The owner or operator shall identify:

(1) The critical operating parameters that affect the emission control performance of the device;

(2) The range of values of these operating parameters that ensure the emission control efficiency specified in paragraph (a)(2)(iv)(A) of this section is maintained during operation of the device; and

(3) How these operating parameters will be monitored to ensure the proper operation and maintenance of the device.

(D) The owner or operator shall submit the information and data specified in paragraphs (a)(2)(iv) (B) and (C) of this section to the Administrator prior to operation of the alternative control device.
(E) The Administrator will determine, based on the information submitted under paragraph (a)(2)(iv)(D) of this section, if the control device subiect to paragraph (a)(2)(iv) of this section meets the requirements of § 61.349. The control device subject to paragraph (a)(2)(iv) of this section may be operated prior to receiving approval from the Administrator. However, if the Administrator determines that the control device does not meet the requirements of § 61.349, the facility may be subject to enforcement action beginning from the time the control device began operation.
(b) Each closed-vent system and control device used to comply with this subpart shall be operated at all times when waste is placed in the waste management unit vented to the control device except when maintenance or repair of the waste management unit cannot be completed without a shutdown of the control device.
(c) An owner and operator shall demonstrate that each control device, except for a flare, achieves the appropriate conditions specified in paragraph (a)(2) of this section by using one of the following methods:
(1) Engineering calculations in accordance with requirements specified in § 61.356(f) of this subpart; or
(2) Performance tests conducted using the test methods and procedures that meet the requirements specified in § 61.355 of this subpart.
(d) An owner or operator shall demonstrate compliance of each flare in accordance with paragraph (a)(2)(iii) of this section.
(e) The Administrator may request at any time an owner or operator demonstrate that a control device meets the applicable conditions specified in paragraph (a)(2) of this section by conducting a performance test using the test methods and procedures as required in § 61.355, and for control devices subject to paragraph (a)(2)(iv) of this section, the Administrator may specify alternative test methods and procedures, as appropriate.
(f) Each closed-vent system and control device shall be visually inspected initially and quarterly thereafter. The visual inspection shall include inspection of ductwork and piping and connections to covers and control devices for evidence of visable defects such as holes in ductwork or piping and loose connections.
(g) Except as provided in § 61.350 of this subpart, if visible defects are observed during an inspection, or if other problems are identified, or if detectable emissions are measured, a first effort to repair the closed-vent system and control device shall be made as soon as practicable but no later than 5 calendar days after detection. Repair shall be completed no later than 15 calendar days after the emissions are detected or the visible defect is observed.
(h) The owner or operator of a control device that is used to comply with the provisions of this section shall monitor the control device in accordance with § 61.354(c) of this subpart.
[55 FR 8346, Mar. 7, 1990; 55 FR 12444, Apr. 3, 1990, as amended at 55 FR 37231, Sept. 10, 1990; 58 FR 3098, Jan. 7, 1993; 65 FR 62160, Oct. 17, 2000]

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§ 61.350 Standards: Delay of repair.

(a) Delay of repair of facilities or units that are subject to the provisions of this subpart will be allowed if the repair is technically impossible without a complete or partial facility or unit shutdown.
(b) Repair of such equipment shall occur before the end of the next facility or unit shutdown.

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§ 61.351 Alternative standards for tanks.

(a) As an alternative to the standards for tanks specified in § 61.343 of this subpart, an owner or operator may elect to comply with one of the following:
(1) A fixed roof and internal floating roof meeting the requirements in 40 CFR 60.112b(a)(1);
(2) An external floating roof meeting the requirements of 40 CFR 60.112b (a)(2); or
(3) An alternative means of emission limitation as described in 40 CFR 60.114b.
(b) If an owner or operator elects to comply with the provisions of this section, then the owner or operator is exempt from the provisions of § 61.343 of this subpart applicable to the same facilities.
[55 FR 8346, Mar. 7, 1990, as amended at 55 FR 37231, Sept. 10, 1990]

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§ 61.352 Alternative standards for oil-water separators.

(a) As an alternative to the standards for oil-water separators specified in § 61.347 of this subpart, an

owner or operator may elect to comply with one of the following:
(1) A floating roof meeting the requirements in 40 CFR 60.693-2(a); or
(2) An alternative means of emission limitation as described in 40 CFR 60.694.
(b) For portions of the oil-water separator where it is infeasible to construct and operate a floating roof, such as over the weir mechanism, a fixed roof vented to a vapor control device that meets the requirements in §§ 61.347 and 61.349 of this subpart shall be installed and operated.
(c) Except as provided in paragraph (b) of this section, if an owner or operator elects to comply with the provisions of this section, then the owner or operator is exempt from the provisions in § 61.347 of this subpart applicable to the same facilities.

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§ 61.353 Alternative means of emission limitation.

(a) If, in the Administrator's judgment, an alternative means of emission limitation will achieve a reduction in benzene emissions at least equivalent to the reduction in benzene emissions from the source achieved by the applicable design, equipment, work practice, or operational requirements in §§ 61.342 through 61.349, the Administrator will publish in the FEDERAL REGISTER a notice permitting the use of the alternative means for purposes of compliance with that requirement. The notice may condition the permission on requirements related to the operation and maintenance of the alternative means.
(b) Any notice under paragraph (a) of this section shall be published only after public notice and an opportunity for a hearing.
(c) Any person seeking permission under this section shall collect, verify, and submit to the Administrator information showing that the alternative means achieves equivalent emission reductions.
[55 FR 8346, Mar. 7, 1990, as amended at 58 FR 3099, Jan. 7, 1993]

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§ 61.354 Monitoring of operations.

(a) Except for a treatment process or waste stream complying with § 61.348(d), the owner or operator shall monitor each treatment process or wastewater treatment system unit to ensure the unit is properly operated and maintained by one of the following monitoring procedures:
(1) Measure the benzene concentration of the waste stream exiting the treatment process complying with § 61.348(a)(1)(i) at least once per month by collecting and analyzing one or more samples using the procedures specified in § 61.355(c)(3).
(2) Install, calibrate, operate, and maintain according to manufacturer's specifications equipment to continuously monitor and record a process parameter (or parameters) for the treatment process or wastewater treatment system unit that indicates proper system operation. The owner or operator shall inspect at least once each operating day the data recorded by the monitoring equipment (e.g., temperature monitor or flow indicator) to ensure that the unit is operating properly.
(b) If an owner or operator complies with the requirements of § 61.348(b), then the owner or operator shall monitor each wastewater treatment system to ensure the unit is properly operated and maintained by the appropriate monitoring procedure as follows:
(1) For the first exempt waste management unit in each waste treatment train, other than an enhanced biodegradation unit, measure the flow rate, using the procedures of § 61.355(b), and the benzene concentration of each waste stream entering the unit at least once per month by collecting and analyzing one or more samples using the procedures specified in § 61.355(c)(3).
(2) For each enhanced biodegradation unit that is the first exempt waste management unit in a treatment train, measure the benzene concentration of each waste stream entering the unit at least once per month by collecting and analyzing one or more samples using the procedures specified in § 61.355(c)(3).
(c) An owner or operator subject to the requirements in § 61.349 of this subpart shall install, calibrate, maintain, and operate according to the manufacturer's specifications a device to continuously monitor the control device operation as specified in the following paragraphs, unless alternative monitoring procedures or requirements are approved for that facility by the Administrator. The owner or operator shall inspect at least once each operating day the data recorded by the monitoring equipment (e.g., temperature monitor or flow indicator) to ensure that the control device is operating properly.
(1) For a thermal vapor incinerator, a temperature monitoring device equipped with a continuous recorder. The device shall have an accuracy of ±1 percent of the temperature being monitored in °C or ±0.5 °C, whichever is greater. The temperature sensor shall be installed at a representative location in the combustion chamber.

(2) For a catalytic vapor incinerator, a temperature monitoring device equipped with a continuous recorder. The device shall be capable of monitoring temperature at two locations, and have an accuracy of ±1 percent of the temperature being monitored in °C or ±0.5 °C, whichever is greater. One temperature sensor shall be installed in the vent stream at the nearest feasible point to the catalyst bed inlet and a second temperature sensor shall be installed in the vent stream at the nearest feasible point to the catalyst bed outlet.

(3) For a flare, a monitoring device in accordance with 40 CFR 60.18(f)(2) equipped with a continuous recorder.

(4) For a boiler or process heater having a design heat input capacity less than 44 MW (150 × 10^6 BTU/hr), a temperature monitoring device equipped with a continuous recorder. The device shall have an accuracy of ±1 percent of the temperature being monitored in °C or ±0.5 °C, whichever is greater. The temperature sensor shall be installed at a representative location in the combustion chamber.

(5) For a boiler or process heater having a design heat input capacity greater than or equal to 44 MW (150 × 10^6 BTU/hr), a monitoring device equipped with a continuous recorder to measure a parameter(s) that indicates good combustion operating practices are being used.

(6) For a condenser, either:

(i) A monitoring device equipped with a continuous recorder to measure either the concentration level of the organic compounds or the concentration level of benzene in the exhaust vent stream from the condenser; or

(ii) A temperature monitoring device equipped with a continuous recorder. The device shall be capable of monitoring temperature at two locations, and have an accuracy of ±1 percent of the temperature being monitored in °C or ±0.5 °C, whichever is greater. One temperature sensor shall be installed at a location in the exhaust stream from the condenser, and a second temperature sensor shall be installed at a location in the coolant fluid exiting the condenser.

(7) For a carbon adsorption system that regenerates the carbon bed directly in the control device such as a fixed-bed carbon adsorber, either:

(i) A monitoring device equipped with a continuous recorder to measure either the concentration level of the organic compounds or the benzene concentration level in the exhaust vent stream from the carbon bed; or

(ii) A monitoring device equipped with a continuous recorder to measure a parameter that indicates the carbon bed is regenerated on a regular, predetermined time cycle.

(8) For a vapor recovery system other than a condenser or carbon adsorption system, a monitoring device equipped with a continuous recorder to measure either the concentration level of the organic compounds or the benzene concentration level in the exhaust vent stream from the control device.

(9) For a control device subject to the requirements of § 61.349(a)(2)(iv), devices to monitor the parameters as specified in § 61.349(a)(2)(iv)(C).

(d) For a carbon adsorption system that does not regenerate the carbon bed directly on site in the control device (e.g., a carbon canister), either the concentration level of the organic compounds or the concentration level of benzene in the exhaust vent stream from the carbon adsorption system shall be monitored on a regular schedule, and the existing carbon shall be replaced with fresh carbon immediately when carbon breakthrough is indicated. The device shall be monitored on a daily basis or at intervals no greater than 20 percent of the design carbon replacement interval, whichever is greater. As an alternative to conducting this monitoring, an owner or operator may replace the carbon in the carbon adsorption system with fresh carbon at a regular predetermined time interval that is less than the carbon replacement interval that is determined by the maximum design flow rate and either the organic concentration or the benzene concentration in the gas stream vented to the carbon adsorption system.

(e) An alternative operation or process parameter may be monitored if it can be demonstrated that another parameter will ensure that the control device is operated in conformance with these standards and the control device's design specifications.

(f) Owners or operators using a closed-vent system that contains any bypass line that could divert a vent stream from a control device used to comply with the provisions of this subpart shall do the following:

(1) Visually inspect the bypass line valve at least once every month, checking the position of the valve and the condition of the car-seal or closure mechanism required under § 61.349(a)(1)(ii) to ensure that the valve is maintained in the closed position and the vent stream is not diverted through the bypass line.

(2) Visually inspect the readings from each flow monitoring device required by § 61.349(a)(1)(ii) at least once each operating day to check that vapors are being routed to the control device as required.

(g) Each owner or operator who uses a system for emission control that is maintained at a pressure less than atmospheric pressure with openings to provide dilution air shall install, calibrate, maintain, and operate according to the manufacturer's specifications a device equipped with a continuous recorder to monitor the pressure in the unit to ensure that it is less than atmospheric pressure.

[55 FR 8346, Mar. 7, 1990, as amended at 58 FR 3099, Jan. 7, 1993; 65 FR 62160, Oct. 17, 2000]

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§ 61.355 Test methods, procedures, and compliance provisions.

(a) An owner or operator shall determine the total annual benzene quantity from facility waste by the following procedure:

(1) For each waste stream subject to this subpart having a flow-weighted annual average water content greater than 10 percent water, on a volume basis as total water, or is mixed with water or other wastes at any time and the resulting mixture has an annual average water content greater than 10 percent as specified in § 61.342(a), the owner or operator shall:

(i) Determine the annual waste quantity for each waste stream using the procedures specified in paragraph (b) of this section.

(ii) Determine the flow-weighted annual average benzene concentration for each waste stream using the procedures specified in paragraph (c) of this section.

(iii) Calculate the annual benzene quantity for each waste stream by multiplying the annual waste quantity of the waste stream times the flow-weighted annual average benzene concentration.

(2) Total annual benzene quantity from facility waste is calculated by adding together the annual benzene quantity for each waste stream generated during the year and the annual benzene quantity for each process unit turnaround waste annualized according to paragraph (b)(4) of this section.

(3) If the total annual benzene quantity from facility waste is equal to or greater than 10 Mg/yr (11 ton/yr), then the owner or operator shall comply with the requirements of § 61.342 (c), (d), or (e).

(4) If the total annual benzene quantity from facility waste is less than 10 Mg/yr (11 ton/yr) but is equal to or greater than 1 Mg/yr (1.1 ton/yr), then the owner or operator shall:

(i) Comply with the recordkeeping requirements of § 61.356 and reporting requirements of § 61.357 of this subpart; and

(ii) Repeat the determination of total annual benzene quantity from facility waste at least once per year and whenever there is a change in the process generating the waste that could cause the total annual benzene quantity from facility waste to increase to 10 Mg/yr (11 ton/yr) or more.

(5) If the total annual benzene quantity from facility waste is less than 1 Mg/yr (1.1 ton/yr), then the owner or operator shall:

(i) Comply with the recordkeeping requirements of § 61.356 and reporting requirements of § 61.357 of this subpart; and

(ii) Repeat the determination of total annual benzene quantity from facility waste whenever there is a change in the process generating the waste that could cause the total annual benzene quantity from facility waste to increase to 1 Mg/yr (1.1 ton/yr) or more.

(6) The benzene quantity in a waste stream that is generated less than one time per year, except as provided for process unit turnaround waste in paragraph (b)(4) of this section, shall be included in the determination of total annual benzene quantity from facility waste for the year in which the waste is generated unless the waste stream is otherwise excluded from the determination of total annual benzene quantity from facility waste in accordance with paragraphs (a) through (c) of this section. The benzene quantity in this waste stream shall not be annualized or averaged over the time interval between the activities that resulted in generation of the waste, for purposes of determining the total annual benzene quantity from facility waste.

(b) For purposes of the calculation required by paragraph (a) of this section, an owner or operator shall determine the annual waste quantity at the point of waste generation, unless otherwise provided in paragraphs (b) (1), (2), (3), and (4) of this section, by one of the methods given in paragraphs (b) (5) through (7) of this section.

(1) The determination of annual waste quantity for sour water streams that are processed in sour water strippers shall be made at the point that the water exits the sour water stripper.

(2) The determination of annual waste quantity for wastes at coke by-product plants subject to and complying with the control requirements of § 61.132, 61.133, 61.134, or 61.139 of subpart L of this part shall be made at the location that the waste stream exits the process unit component or waste management unit controlled by that subpart or at the exit of the ammonia still, provided that the following

conditions are met:

(i) The transfer of wastes between units complying with the control requirements of subpart L of this part, process units, and the ammonia still is made through hard piping or other enclosed system.

(ii) The ammonia still meets the definition of a sour water stripper in § 61.341.

(3) The determination of annual waste quantity for wastes that are received at hazardous waste treatment, storage, or disposal facilities from offsite shall be made at the point where the waste enters the hazardous waste treatment, storage, or disposal facility.

(4) The determination of annual waste quantity for each process unit turnaround waste generated only at 2 year or greater intervals, may be made by dividing the total quantity of waste generated during the most recent process unit turnaround by the time period (in the nearest tenth of a year) between the turnaround resulting in generation of the waste and the most recent preceding process turnaround for the unit. The resulting annual waste quantity shall be included in the calculation of the annual benzene quantity as provided in paragraph (a)(1)(iii) of this section for the year in which the turnaround occurs and for each subsequent year until the unit undergoes the next process turnaround. For estimates of total annual benzene quantity as specified in the 90-day report, required under § 61.357(a)(1), the owner or operator shall estimate the waste quantity generated during the most recent turnaround, and the time period between turnarounds in accordance with good engineering practices. If the owner or operator chooses not to annualize process unit turnaround waste, as specified in this paragraph, then the process unit turnaround waste quantity shall be included in the calculation of the annual benzene quantity for the year in which the turnaround occurs.

(5) Select the highest annual quantity of waste managed from historical records representing the most recent 5 years of operation or, if the facility has been in service for less than 5 years but at least 1 year, from historical records representing the total operating life of the facility;

(6) Use the maximum design capacity of the waste management unit; or

(7) Use measurements that are representative of maximum waste generation rates.

(c) For the purposes of the calculation required by §§ 61.355(a) of this subpart, an owner or operator shall determine the flow-weighted annual average ben- zene concentration in a manner that meets the requirements given in paragraph (c)(1) of this section using either of the methods given in paragraphs (c)(2) and (c)(3) of this section.

(1) The determination of flow-weighted annual average benzene concentration shall meet all of the following criteria:

(i) The determination shall be made at the point of waste generation except for the specific cases given in paragraphs (c)(1)(i)(A) through (D) of this section.

(A) The determination for sour water streams that are processed in sour water strippers shall be made at the point that the water exits the sour water stripper.

(B) The determination for wastes at coke by-product plants subject to and complying with the control requirements of § 61.132, 61.133, 61.134, or 61.139 of subpart L of this part shall be made at the location that the waste stream exits the process unit component or waste management unit controlled by that subpart or at the exit of the ammonia still, provided that the following conditions are met:

(1) The transfer of wastes between units complying with the control requirements of subpart L of this part, process units, and the ammonia still is made through hard piping or other enclosed system.

(2) The ammonia still meets the definition of a sour water stripper in § 61.341.

(C) The determination for wastes that are received from offsite shall be made at the point where the waste enters the hazardous waste treatment, storage, or disposal facility.

(D) The determination of flow-weighted annual average benzene concentration for process unit turnaround waste shall be made using either of the methods given in paragraph (c)(2) or (c)(3) of this section. The resulting flow-weighted annual average benzene concentration shall be included in the calculation of annual benzene quantity as provided in paragraph (a)(1)(iii) of this section for the year in which the turnaround occurs and for each subsequent year until the unit undergoes the next process unit turnaround.

(ii) Volatilization of the benzene by exposure to air shall not be used in the determination to reduce the benzene concentration.

(iii) Mixing or diluting the waste stream with other wastes or other materials shall not be used in the determination—to reduce the benzene concentration.

(iv) The determination shall be made prior to any treatment of the waste that removes benzene, except as specified in paragraphs (c)(1)(i)(A) through (D) of this section.

(v) For wastes with multiple phases, the determination shall provide the weighted-average benzene concentration based on the benzene concentration in each phase of the waste and the relative proportion of the phases.

(2) Knowledge of the waste. The owner or operator shall provide sufficient information to document the flow-weighted annual average benzene concentration of each waste stream. Examples of information that could constitute knowledge include material balances, records of chemicals purchases, or previous test results provided the results are still relevant to the current waste stream conditions. If test data are used, then the owner or operator shall provide documentation describing the testing protocol and the means by which sampling variability and analytical variability were accounted for in the determination of the flow-weighted annual average benzene concentration for the waste stream. When an owner or operator and the Administrator do not agree on determinations of the flow-weighted annual average benzene concentration based on knowledge of the waste, the procedures under paragraph (c)(3) of this section shall be used to resolve the disagreement.

(3) Measurements of the benzene concentration in the waste stream in accordance with the following procedures:

(i) Collect a minimum of three representative samples from each waste stream. Where feasible, samples shall be taken from an enclosed pipe prior to the waste being exposed to the atmosphere.

(ii) For waste in enclosed pipes, the following procedures shall be used:

(A) Samples shall be collected prior to the waste being exposed to the atmosphere in order to minimize the loss of benzene prior to sampling.

(B) A static mixer shall be installed in the process line or in a by-pass line unless the owner or operator demonstrates that installation of a static mixer in the line is not necessary to accurately determine the benzene concentration of the waste stream.

(C) The sampling tap shall be located within two pipe diameters of the static mixer outlet.

(D) Prior to the initiation of sampling, sample lines and cooling coil shall be purged with at least four volumes of waste.

(E) After purging, the sample flow shall be directed to a sample container and the tip of the sampling tube shall be kept below the surface of the waste during sampling to minimize contact with the atmosphere.

(F) Samples shall be collected at a flow rate such that the cooling coil is able to maintain a waste temperature less than 10 °C (50 °F).

(G) After filling, the sample container shall be capped immediately (within 5 seconds) to leave a minimum headspace in the container.

(H) The sample containers shall immediately be cooled and maintained at a temperature below 10 °C (50 °F) for transfer to the laboratory.

(iii) When sampling from an enclosed pipe is not feasible, a minimum of three representative samples shall be collected in a manner to minimize exposure of the sample to the atmosphere and loss of benzene prior to sampling.

(iv) Each waste sample shall be analyzed using one of the following test methods for determining the benzene concentration in a waste stream:

(A) Method 8020, Aromatic Volatile Organics, in “Test Methods for Evaluating Solid Waste, Physical/Chemical Methods,” EPA Publication No. SW-846 (incorporation by reference as specified in § 61.18 of this part);

(B) Method 8021, Volatile Organic Compounds in Water by Purge and Trap Capillary Column Gas Chromatography with Photoionization and Electrolytic Conductivity Detectors in Series in “Test Methods for Evaluating Solid Waste, Physical/Chemical Methods,” EPA Publication No. SW-846 (incorporation by reference as specified in § 61.18 of this part);

(C) Method 8240, Gas Chromatography/Mass Spectrometry for Volatile Organics in “Test Methods for Evaluating Solid Waste, Physical/Chemical Methods,” EPA Publication No. SW-846 (incorporation by reference as specified in § 61.18 of this part);

(D) Method 8260, Gas Chromatography/Mass Spectrometry for Volatile Organics: Capillary Column Technique in “Test Methods for Evaluating Solid Waste, Physical/Chemical Methods,” EPA Publication No. SW-846 (incorporation by reference as specified in § 61.18 of this part);

(E) Method 602, Purgeable Aromatics, as described in 40 CFR part 136, appendix A, Test Procedures for Analysis of Organic Pollutants, for wastewaters for which this is an approved EPA methods; or

(F) Method 624, Purgeables, as described in 40 CFR part 136, appendix A, Test Procedures for Analysis of Organic Pollutants, for wastewaters for which this is an approved EPA method.

(v) The flow-weighted annual average benzene concentration shall be calculated by averaging the results of the sample analyses as follows:

$$\bar{C} = \frac{1}{Q_t} \times \sum_{i=1}^{n} (Q_i)(C_i)$$

Where:
$\bar{C}$=Flow-weighted annual average benzene concentration for waste stream, ppmw.
Q_t =Total annual waste quantity for waste stream, kg/yr (lb/yr).
n=Number of waste samples (at least 3).
Q_i =Annual waste quantity for waste stream represented by C_i , kg/yr (lb/yr).
C_i =Measured concentration of benzene in waste sample i, ppmw.

(d) An owner or operator using performance tests to demonstrate compliance of a treatment process with § 61.348 (a)(1)(i) shall measure the flow-weighted annual average benzene concentration of the waste stream exiting the treatment process by collecting and analyzing a minimum of three representative samples of the waste stream using the procedures in paragraph (c)(3) of this section. The test shall be conducted under conditions that exist when the treatment process is operating at the highest inlet waste stream flow rate and benzene content expected to occur. Operations during periods of startup, shutdown, and malfunction shall not constitute representative conditions for the purpose of a test. The owner or operator shall record all process information as is necessary to document the operating conditions during the test.

(e) An owner or operator using performance tests to demonstrate compliance of a treatment process with § 61.348(a)(1)(ii) of this subpart shall determine the percent reduction of benzene in the waste stream on a mass basis by the following procedure:

(1) The test shall be conducted under conditions that exist when the treatment process is operating at the highest inlet waste stream flow rate and benzene content expected to occur. Operations during periods of startup, shutdown, and malfunction shall not constitute representative conditions for the purpose of a test. The owner or operator shall record all process information as is necessary to document the operating conditions during the test.

(2) All testing equipment shall be prepared and installed as specified in the appropriate test methods.

(3) The mass flow rate of benzene entering the treatment process (E_b) shall be determined by computing the product of the flow rate of the waste stream entering the treatment process, as determined by the inlet flow meter, and the benzene concentration of the waste stream, as determined using the sampling and analytical procedures specified in paragraph (c)(2) or (c)(3) of this section. Three grab samples of the waste shall be taken at equally spaced time intervals over a 1-hour period. Each 1-hour period constitutes a run, and the performance test shall consist of a minimum of 3 runs conducted over a 3-hour period. The mass flow rate of benzene entering the treatment process is calculated as follows:

$$E_b = \frac{K}{n \times 10^6} \left[\sum_{i=1}^{n} V_i C_i \right]$$

Where:
E_b = Mass flow rate of benzene entering the treatment process, kg/hr (lb/hr).
K = Density of the waste stream, kg/m^3 (lb/ft^3).
V_i = Average volume flow rate of waste entering the treatment process during each run i, m^3 /hr (ft^3 /hr).
C_i = Average concentration of benzene in the waste stream entering the treatment process during each run i, ppmw.
n = Number of runs.
10^6 = Conversion factor for ppmw.

(4) The mass flow rate of benzene exiting the treatment process (E_a) shall be determined by computing the product of the flow rate of the waste stream exiting the treatment process, as determined by the outlet flow meter or the inlet flow meter, and the benzene concentration of the waste stream, as determined using the sampling and analytical procedures specified in paragraph (c)(2) or (c)(3) of this section. Three grab samples of the waste shall be taken at equally spaced time intervals over a 1-hour period. Each 1-hour period constitutes a run, and the performance test shall consist of a minimum of 3 runs conducted over the same 3-hour period at which the mass flow rate of benzene entering the treatment process is determined. The mass flow rate of benzene exiting the treatment process is calculated as follows:

$$E_a = \frac{K}{n \times 10^6}\left[\sum_{i=1}^{n} V_i C_i\right]$$

Where:
E_a = Mass flow rate of benzene exiting the treatment process, kg/hr (lb/hr).
K = Density of the waste stream, kg/m^3 (lb/ft^3).
V_i = Average volume flow rate of waste exiting the treatment process during each run i, m^3 /hr (ft^3 /hr).
C_i = Average concentration of benzene in the waste stream exiting the treatment process during each run i, ppmw.
n = Number of runs.
10^6 = Conversion factor for ppmw.

(f) An owner or operator using performance tests to demonstrate compliance of a treatment process with § 61.348(a)(1)(iii) of this subpart shall determine the benzene destruction efficiency for the combustion unit by the following procedure:

(1) The test shall be conducted under conditions that exist when the combustion unit is operating at the highest inlet waste stream flow rate and benzene content expected to occur. Operations during periods of startup, shutdown, and malfunction shall not constitute representative conditions for the purpose of a test. The owner or operator shall record all process information necessary to document the operating conditions during the test.

(2) All testing equipment shall be prepared and installed as specified in the appropriate test methods.

(3) The mass flow rate of benzene entering the combustion unit shall be determined by computing the product of the flow rate of the waste stream entering the combustion unit, as determined by the inlet flow meter, and the benzene concentration of the waste stream, as determined using the sampling procedures in paragraph (c)(2) or (c)(3) of this section. Three grab samples of the waste shall be taken at equally spaced time intervals over a 1-hour period. Each 1-hour period constitutes a run, and the performance test shall consist of a minimum of 3 runs conducted over a 3-hour period. The mass flow rate of benzene into the combustion unit is calculated as follows:

$$E_b = \frac{K}{n \times 10^6}\left[\sum_{i=1}^{n} V_i C_i\right]$$

Where:
E_b = Mass flow rate of benzene entering the combustion unit, kg/hr (lb/hr).
K = Density of the waste stream, kg/m^3 (lb/ft^3).
V_i = Average volume flow rate of waste entering the combustion unit during each run i, m^3 /hr (ft^3 /hr).
C_i = Average concentration of benzene in the waste stream entering the combustion unit during each run i, ppmw.
n = Number of runs.
10^6 = Conversion factor for ppmw.

(4) The mass flow rate of benzene exiting the combustion unit exhaust stack shall be determined as follows:

(i) The time period for the test shall not be less than 3 hours during which at least 3 stack gas samples are collected and be the same time period at which the mass flow rate of benzene entering the treatment process is determined. Each sample shall be collected over a 1-hour period (e.g., in a tedlar bag) to represent a time-integrated composite sample and each 1-hour period shall correspond to the periods when the waste feed is sampled.

(ii) A run shall consist of a 1-hour period during the test. For each run:

(A) The reading from each measurement shall be recorded;

(B) The volume exhausted shall be determined using Method 2, 2A, 2C, or 2D from appendix A of 40 CFR part 60, as appropriate.

(C) The average benzene concentration in the exhaust downstream of the combustion unit shall be determined using Method 18 from appendix A of 40 CFR part 60.

(iii) The mass of benzene emitted during each run shall be calculated as follows:

$$M_i = D_b VC\left(10^{-6}\right)$$

Where:
M_i = Mass of benzene emitted during run i, kg (lb).

V = Volume of air-vapor mixture exhausted at standard conditions, m^3 (ft^3).
C = Concentration of benzene measured in the exhaust, ppmv.
D_b = Density of benzene, 3.24 kg/m^3 (0.202 lb/ft^3).
10^6 = Conversion factor for ppmv.
(iv) The benzene mass emission rate in the exhaust shall be calculated as follows:

$$E_a = \left(\sum_{i=1}^{n} M_i \right) / T$$

Where:
E_a = Mass flow rate of benzene emitted from the combustion unit, kg/hr (lb/hr).
M_i = Mass of benzene emitted from the combustion unit during run i, kg (lb).
T = Total time of all runs, hr.
n = Number of runs.
(5) The benzene destruction efficiency for the combustion unit shall be calculated as follows:

$$R = \frac{E_b - E_a}{E_b} \times 100$$

Where:
R = Benzene destruction efficiency for the combustion unit, percent.
E_b = Mass flow rate of benzene entering the combustion unit, kg/hr (lb/hr).
E_a = Mass flow rate of benzene emitted from the combustion unit, kg/hr (lb/hr).
(g) An owner or operator using performance tests to demonstrate compliance of a wastewater treatment system unit with § 61.348(b) shall measure the flow-weighted annual average benzene concentration of the wastewater stream where the waste stream enters an exempt waste management unit by collecting and analyzing a minimum of three representative samples of the waste stream using the procedures in paragraph (c)(3) of this section. The test shall be conducted under conditions that exist when the wastewater treatment system is operating at the highest inlet wastewater stream flow rate and benzene content expected to occur. Operations during periods of startup, shutdown, and malfunction shall not constitute representative conditions for the purpose of a test. The owner or operator shall record all process information as is necessary to document the operating conditions during the test.
(h) An owner or operator shall test equipment for compliance with no detectable emissions as required in §§ 61.343 through 61.347, and § 61.349 of this subpart in accordance with the following requirements:
(1) Monitoring shall comply with Method 21 from appendix A of 40 CFR part 60.
(2) The detection instrument shall meet the performance criteria of Method 21.
(3) The instrument shall be calibrated before use on each day of its use by the procedures specified in Method 21.
(4) Calibration gases shall be:
(i) Zero air (less than 10 ppm of hydrocarbon in air); and
(ii) A mixture of methane or n-hexane and air at a concentration of approximately, but less than, 10,000 ppm methane or n-hexane.
(5) The background level shall be determined as set forth in Method 21.
(6) The instrument probe shall be traversed around all potential leak interfaces as close as possible to the interface as described in Method 21.
(7) The arithmetic difference between the maximum concentration indicated by the instrument and the background level is compared to 500 ppm for determining compliance.
(i) An owner or operator using a performance test to demonstrate compliance of a control device with either the organic reduction efficiency requirement or the benzene reduction efficiency requirement specified under § 61.349(a)(2) shall use the following procedures:
(1) The test shall be conducted under conditions that exist when the waste management unit vented to the control device is operating at the highest load or capacity level expected to occur. Operations during periods of startup, shutdown, and malfunction shall not constitute representative conditions for the purpose of a test. The owner or operator shall record all process information necessary to document the operating conditions during the test.
(2) Sampling sites shall be selected using Method 1 or 1A from appendix A of 40 CFR part 60, as appropriate.
(3) The mass flow rate of either the organics or benzene entering and exiting the control device shall be

determined as follows:

(i) The time period for the test shall not be less than 3 hours during which at least 3 stack gas samples are collected. Samples of the vent stream entering and exiting the control device shall be collected during the same time period. Each sample shall be collected over a 1-hour period (e.g., in a tedlar bag) to represent a time-integrated composite sample.

(ii) A run shall consist of a 1-hour period during the test. For each run:

(A) The reading from each measurement shall be recorded;

(B) The volume exhausted shall be determined using Method 2, 2A, 2C, or 2D from appendix A of 40 CFR part 60, as appropriate;

(C) The organic concentration or the benzene concentration, as appropriate, in the vent stream entering and exiting the control shall be determined using Method 18 from appendix A of 40 CFR part 60.

(iii) The mass of organics or benzene entering and exiting the control device during each run shall be calculated as follows:

$$M_{aj} = \frac{K_1 V_{aj}}{10^6}\left(\sum_{i-1}^{n} C_{ai} MW_i\right) \quad M_{bj} = \frac{K_1 V_{bj}}{10^6}\left(\sum_{i-1}^{n} C_{bi} MW_i\right)$$

M_{aj} = Mass of organics or benzene in the vent stream entering the control device during run j, kg (lb).

M_{bj} = Mass of organics or benzene in the vent stream exiting the control device during run j, kg (lb).

V_{aj} = Volume of vent stream entering the control device during run j, at standard conditions, m^3 (ft^3).

V_{bj} = Volume of vent stream exiting the control device during run j, at standard conditions, m^3 (ft^3).

C_{ai} = Organic concentration of compound i or the benzene concentration measured in the vent stream entering the control device as determined by Method 18, ppm by volume on a dry basis.

C_{bi} = Organic concentration of compound i or the benzene concentration measured in the vent stream exiting the control device as determined by Method 18, ppm by volume on a dry basis.

MW_i = Molecular weight of organic compound i in the vent stream, or the molecular weight of benzene, kg/kg-mol (lb/lb-mole).

n = Number of organic compounds in the vent stream; if benzene reduction efficiency is being demonstrated, then n=1.

K_1 = Conversion factor for molar volume at standard conditions (293 K and 760 mm Hg (527 R and 14.7 psia))
= 0.0416 kg-mol/m^3 (0.00118 lb-mol/ft^3)

10^{-6} =Conversion factor for ppmv.

(iv) The mass flow rate of organics or benzene entering and exiting the control device shall be calculated as follows:

$$E_a - \left(\sum_{j-1}^{n} M_{aj}\right)/T$$

$$E_b - \left(\sum_{j-1}^{n} M_{bj}\right)/T$$

Where:

E_a = Mass flow rate of organics or benzene entering the control device, kg/hr (lb/hr).

E_b = Mass flow rate of organics or benzene exiting the control device, kg/hr (lb/hr).

M_{aj} = Mass of organics or benzene in the vent stream entering the control device during run j, kg (lb).

M_{bj} = Mass of organics or benzene in the vent stream exiting the control device during run j, kg (lb).

T = Total time of all runs, hr.

n = Number of runs.

(4) The organic reduction efficiency or the benzene reduction efficiency for the control device shall be calculated as follows:

$$R = \frac{E_a - E_b}{E_a} \times 100$$

Where:

R = Total organic reduction of efficiency or benzene reduction efficiency for the control device, percent.
E_b = Mass flow rate of organics or benzene entering the control device, kg/hr (lb/hr).
E_a = Mass flow rate of organic or benzene emitted from the control device, kg/hr (lb/hr).
(j) An owner or operator shall determine the benzene quantity for the purposes of the calculation required by § 61.342 (c)(3)(ii)(B) according to the provisions of paragraph (a) of this section, except that the procedures in paragraph (a) of this section shall also apply to wastes with a water content of 10 percent or less.
(k) An owner or operator shall determine the benzene quantity for the purposes of the calculation required by § 61.342(e)(2) by the following procedure:
(1) For each waste stream that is not controlled for air emissions in accordance with § 61.343. 61.344, 61.345, 61.346, 61.347, or 61.348(a), as applicable to the waste management unit that manages the waste, the benzene quantity shall be determined as specified in paragraph (a) of this section, except that paragraph (b)(4) of this section shall not apply, i.e., the waste quantity for process unit turnaround waste is not annualized but shall be included in the determination of benzene quantity for the year in which the waste is generated for the purposes of the calculation required by § 61.342(e)(2).
(2) For each waste stream that is controlled for air emissions in accordance with § 61.343. 61.344, 61.345, 61.346, 61.347, or 61.348(a), as applicable to the waste management unit that manages the waste, the determination of annual waste quantity and flow-weighted annual average benzene concentration shall be made at the first applicable location as described in paragraphs (k)(2)(i), (k)(2)(ii), and (k)(2)(iii) of this section and prior to any reduction of benzene concentration through volatilization of the benzene, using the methods given in (k)(2)(iv) and (k)(2)(v) of this section.
(i) Where the waste stream enters the first waste management unit not complying with §§ 61.343, 61.344, 61.345, 61.346, 61.347, and 61.348(a) that are applicable to the waste management unit,
(ii) For each waste stream that is managed or treated only in compliance with §§ 61.343 through 61.348(a) up to the point of final direct discharge from the facility, the determination of benzene quantity shall be prior to any reduction of benzene concentration through volatilization of the benzene, or
(iii) For wastes managed in units controlled for air emissions in accordance with §§ 61.343, 61.344, 61.345, 61.346, 61.347, and 61.348(a), and then transferred offsite, facilities shall use the first applicable offsite location as described in paragraphs (k)(2)(i) and (k)(2)(ii) of this section if they have documentation from the offsite facility of the benzene quantity at this location. Facilities without this documentation for offsite wastes shall use the benzene quantity determined at the point where the transferred waste leaves the facility.
(iv) Annual waste quantity shall be determined using the procedures in paragraphs (b)(5), (6), or (7) of this section, and
(v) The flow-weighted annual average benzene concentration shall be determined using the procedures in paragraphs (c)(2) or (3) of this section.
(3) The benzene quantity in a waste stream that is generated less than one time per year, including process unit turnaround waste, shall be included in the determination of benzene quantity as determined in paragraph (k)(6) of this section for the year in which the waste is generated. The benzene quantity in this waste stream shall not be annualized or averaged over the time interval between the activities that resulted in generation of the waste for purposes of determining benzene quantity as determined in paragraph (k)(6) of this section.
(4) The benzene in waste entering an enhanced biodegradation unit, as defined in § 61.348(b)(2)(ii)(B), shall not be included in the determination of benzene quantity, determined in paragraph (k)(6) of this section, if the following conditions are met:
(i) The benzene concentration for each waste stream entering the enhanced biodegradation unit is less than 10 ppmw on a flow-weighted annual average basis, and
(ii) All prior waste management units managing the waste comply with §§ 61.343, 61.344, 61.345, 61.346, 61.347 and 61.348(a).
(5) The benzene quantity for each waste stream in paragraph (k)(2) of this section shall be determined by multiplying the annual waste quantity of each waste stream times its flow-weighted annual average benzene concentration.
(6) The total benzene quantity for the purposes of the calculation required by § 61.342(e)(2) shall be determined by adding together the benzene quantities determined in paragraphs (k)(1) and (k)(5) of this section for each applicable waste stream.
(7) If the benzene quantity determined in paragraph (6) of this section exceeds 6.0 Mg/yr (6.6 ton/yr) only

because of multiple counting of the benzene quantity for a waste stream, the owner or operator may use the following procedures for the purposes of the calculation required by § 61.342(e)(2):
(i) Determine which waste management units are involved in the multiple counting of benzene;
(ii) Determine the quantity of benzene that is emitted, recovered, or removed from the affected units identified in paragraph (k)(7)(i) of this section, or destroyed in the units if applicable, using either direct measurements or the best available estimation techniques developed or approved by the Administrator.
(iii) Adjust the benzene quantity to eliminate the multiple counting of benzene based on the results from paragraph (k)(7)(ii) of this section and determine the total benzene quantity for the purposes of the calculation required by § 61.342(e)(2).
(iv) Submit in the annual report required under § 61.357(a) a description of the methods used and the resulting calculations for the alternative procedure under paragraph (k)(7) of this section, the benzene quantity determination from paragraph (k)(6) of this section, and the adjusted benzene quantity determination from paragraph (k)(7)(iii) of this section.
[55 FR 8346, Mar. 7, 1990; 55 FR 12444, Apr. 3, 1990, as amended at 55 FR 37231, Sept. 10, 1990; 58 FR 3099, Jan. 7, 1993; 65 FR 62160, Oct. 17, 2000]

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§ 61.356 Recordkeeping requirements.

(a) Each owner or operator of a facility subject to the provisions of this subpart shall comply with the recordkeeping requirements of this section. Each record shall be maintained in a readily accessible location at the facility site for a period not less than two years from the date the information is recorded unless otherwise specified.
(b) Each owner or operator shall maintain records that identify each waste stream at the facility subject to this subpart, and indicate whether or not the waste stream is controlled for benzene emissions in accordance with this subpart. In addition the owner or operator shall maintain the following records:
(1) For each waste stream not controlled for benzene emissions in accordance with this subpart, the records shall include all test results, measurements, calculations, and other documentation used to determine the following information for the waste stream: waste stream identification, water content, whether or not the waste stream is a process wastewater stream, annual waste quantity, range of benzene concentrations, annual average flow-weighted benzene concentration, and annual benzene quantity.
(2) For each waste stream exempt from § 61.342(c)(1) in accordance with § 61.342(c)(3), the records shall include:
(i) All measurements, calculations, and other documentation used to determine that the continuous flow of process wastewater is less than 0.02 liters (0.005 gallons) per minute or the annual waste quantity of process wastewater is less than 10 Mg/yr (11 ton/yr) in accordance with § 61.342(c)(3)(i), or
(ii) All measurements, calculations, and other documentation used to determine that the sum of the total annual benzene quantity in all exempt waste streams does not exceed 2.0 Mg/yr (2.2 ton/yr) in accordance with § 61.342(c)(3)(ii).
(3) For each facility where process wastewater streams are controlled for benzene emissions in accordance with § 61.342(d) of this subpart, the records shall include for each treated process wastewater stream all measurements, calculations, and other documentation used to determine the annual benzene quantity in the process wastewater stream exiting the treatment process.
(4) For each facility where waste streams are controlled for benzene emissions in accordance with § 61.342(e), the records shall include for each waste stream all measurements, including the locations of the measurements, calculations, and other documentation used to determine that the total benzene quantity does not exceed 6.0 Mg/yr (6.6 ton/yr).
(5) For each facility where the annual waste quantity for process unit turnaround waste is determined in accordance with § 61.355(b)(5), the records shall include all test results, measurements, calculations, and other documentation used to determine the following information: identification of each process unit at the facility that undergoes turnarounds, the date of the most recent turnaround for each process unit, identification of each process unit turnaround waste, the water content of each process unit turnaround waste, the annual waste quantity determined in accordance with § 61.355(b)(5), the range of benzene concentrations in the waste, the annual average flow-weighted benzene concentration of the waste, and the annual benzene quantity calculated in accordance with § 61.355(a)(1)(iii) of this section.
(6) For each facility where wastewater streams are controlled for benzene emissions in accordance with § 61.348(b)(2), the records shall include all measurements, calculations, and other documentation used

to determine the annual benzene content of the waste streams and the total annual benzene quantity contained in all waste streams managed or treated in exempt waste management units.

(c) An owner or operator transferring waste off-site to another facility for treatment in accordance with § 61.342(f) shall maintain documentation for each offsite waste shipment that includes the following information: Date waste is shipped offsite, quantity of waste shipped offsite, name and address of the facility receiving the waste, and a copy of the notice sent with the waste shipment.

(d) An owner or operator using control equipment in accordance with §§ 61.343 through 61.347 shall maintain engineering design documentation for all control equipment that is installed on the waste management unit. The documentation shall be retained for the life of the control equipment. If a control device is used, then the owner or operator shall maintain the control device records required by paragraph (f) of this section.

(e) An owner or operator using a treatment process or wastewater treatment system unit in accordance with § 61.348 of this subpart shall maintain the following records. The documentation shall be retained for the life of the unit.

(1) A statement signed and dated by the owner or operator certifying that the unit is designed to operate at the documented performance level when the waste stream entering the unit is at the highest waste stream flow rate and benzene content expected to occur.

(2) If engineering calculations are used to determine treatment process or wastewater treatment system unit performance, then the owner or operator shall maintain the complete design analysis for the unit. The design analysis shall include for example the following information: Design specifications, drawings, schematics, piping and instrumentation diagrams, and other documentation necessary to demonstrate the unit performance.

(3) If performance tests are used to determine treatment process or wastewater treatment system unit performance, then the owner or operator shall maintain all test information necessary to demonstrate the unit performance.

(i) A description of the unit including the following information: type of treatment process; manufacturer name and model number; and for each waste stream entering and exiting the unit, the waste stream type (e.g., process wastewater, sludge, slurry, etc.), and the design flow rate and benzene content.

(ii) Documentation describing the test protocol and the means by which sampling variability and analytical variability were accounted for in the determination of the unit performance. The description of the test protocol shall include the following information: sampling locations, sampling method, sampling frequency, and analytical procedures used for sample analysis.

(iii) Records of unit operating conditions during each test run including all key process parameters.

(iv) All test results.

(4) If a control device is used, then the owner or operator shall maintain the control device records required by paragraph (f) of this section.

(f) An owner or operator using a closed-vent system and control device in accordance with § 61.349 of this subpart shall maintain the following records. The documentation shall be retained for the life of the control device.

(1) A statement signed and dated by the owner or operator certifying that the closed-vent system and control device is designed to operate at the documented performance level when the waste management unit vented to the control device is or would be operating at the highest load or capacity expected to occur.

(2) If engineering calculations are used to determine control device performance in accordance with § 61.349(c), then a design analysis for the control device that includes for example:

(i) Specifications, drawings, schematics, and piping and instrumentation diagrams prepared by the owner or operator, or the control device manufacturer or vendor that describe the control device design based on acceptable engineering texts. The design analysis shall address the following vent stream characteristics and control device operating parameters:

(A) For a thermal vapor incinerator, the design analysis shall consider the vent stream composition, constituent concentrations, and flow rate. The design analysis shall also establish the design minimum and average temperature in the combustion zone and the combustion zone residence time.

(B) For a catalytic vapor incinerator, the design analysis shall consider the vent stream composition, constituent concentrations, and flow rate. The design analysis shall also establish the design minimum and average temperatures across the catalyst bed inlet and outlet.

(C) For a boiler or process heater, the design analysis shall consider the vent stream composition,

constituent concentrations, and flow rate. The design analysis shall also establish the design minimum and average flame zone temperatures, combustion zone residence time, and description of method and location where the vent stream is introduced into the flame zone.
(D) For a flare, the design analysis shall consider the vent stream composition, constituent concentrations, and flow rate. The design analysis shall also consider the requirements specified in 40 CFR 60.18.
(E) For a condenser, the design analysis shall consider the vent stream composition, constituent concentration, flow rate, relative humidity, and temperature. The design analysis shall also establish the design outlet organic compound concentration level or the design outlet benzene concentration level, design average temperature of the condenser exhaust vent stream, and the design average temperatures of the coolant fluid at the condenser inlet and outlet.
(F) For a carbon adsorption system that regenerates the carbon bed directly on-site in the control device such as a fixed-bed adsorber, the design analysis shall consider the vent stream composition, constituent concentration, flow rate, relative humidity, and temperature. The design analysis shall also establish the design exhaust vent stream organic compound concentration level or the design exhaust vent stream benzene concentration level, number and capacity of carbon beds, type and working capacity of activated carbon used for carbon beds, design total steam flow over the period of each complete carbon bed regeneration cycle, duration of the carbon bed steaming and cooling/drying cycles, design carbon bed temperature after regeneration, design carbon bed regeneration time, and design service life of carbon.
(G) For a carbon adsorption system that does not regenerate the carbon bed directly on-site in the control device, such as a carbon canister, the design analysis shall consider the vent stream composition, constituent concentration, flow rate, relative humidity, and temperature. The design analysis shall also establish the design exhaust vent stream organic compound concentration level or the design exhaust vent stream benzene concentration level, capacity of carbon bed, type and working capacity of activated carbon used for carbon bed, and design carbon replacement interval based on the total carbon working capacity of the control device and source operating schedule.
(H) For a control device subject to the requirements of § 61.349(a)(2)(iv), the design analysis shall consider the vent stream composition, constituent concentration, and flow rate. The design analysis shall also include all of the information submitted under § 61.349 (a)(2)(iv).
(ii) [Reserved]
(3) If performance tests are used to determine control device performance in accordance with § 61.349(c) of this subpart:
(i) A description of how it is determined that the test is conducted when the waste management unit or treatment process is operating at the highest load or capacity level. This description shall include the estimated or design flow rate and organic content of each vent stream and definition of the acceptable operating ranges of key process and control parameters during the test program.
(ii) A description of the control device including the type of control device, control device manufacturer's name and model number, control device dimensions, capacity, and construction materials.
(iii) A detailed description of sampling and monitoring procedures, including sampling and monitoring locations in the system, the equipment to be used, sampling and monitoring frequency, and planned analytical procedures for sample analysis.
(iv) All test results.
(g) An owner or operator shall maintain a record for each visual inspection required by §§ 61.343 through 61.347 of this subpart that identifies a problem (such as a broken seal, gap or other problem) which could result in benzene emissions. The record shall include the date of the inspection, waste management unit and control equipment location where the problem is identified, a description of the problem, a description of the corrective action taken, and the date the corrective action was completed.
(h) An owner or operator shall maintain a record for each test of no detectable emissions required by §§ 61.343 through 61.347 and § 61.349 of this subpart. The record shall include the following information: date the test is performed, background level measured during test, and maximum concentration indicated by the instrument reading measured for each potential leak interface. If detectable emissions are measured at a leak interface, then the record shall also include the waste management unit, control equipment, and leak interface location where detectable emissions were measured, a description of the problem, a description of the corrective action taken, and the date the corrective action was completed.
(i) For each treatment process and wastewater treatment system unit operated to comply with § 61.348, the owner or operator shall maintain documentation that includes the following information regarding the

unit operation:
(1) Dates of startup and shutdown of the unit.
(2) If measurements of waste stream benzene concentration are performed in accordance with § 61.354(a)(1) of this subpart, the owner or operator shall maintain records that include date each test is performed and all test results.
(3) If a process parameter is continuously monitored in accordance with § 61.354(a)(2) of this subpart, the owner or operator shall maintain records that include a description of the operating parameter (or parameters) to be monitored to ensure that the unit will be operated in conformance with these standards and the unit's design specifications, and an explanation of the criteria used for selection of that parameter (or parameters). This documentation shall be kept for the life of the unit.
(4) If measurements of waste stream benzene concentration are performed in accordance with § 61.354(b), the owner or operator shall maintain records that include the date each test is performed and all test results.
(5) Periods when the unit is not operated as designed.
(j) For each control device, the owner or operator shall maintain documentation that includes the following information regarding the control device operation:
(1) Dates of startup and shutdown of the closed-vent system and control device.
(2) A description of the operating parameter (or parameters) to be monitored to ensure that the control device will be operated in conformance with these standards and the control device's design specifications and an explanation of the criteria used for selection of that parameter (or parameters). This documentation shall be kept for the life of the control device.
(3) Periods when the closed-vent system and control device are not operated as designed including all periods and the duration when:
(i) Any valve car-seal or closure mechanism required under § 61.349(a)(1)(ii) is broken or the by-pass line valve position has changed.
(ii) The flow monitoring devices required under § 61.349(a)(1)(ii) indicate that vapors are not routed to the control device as required.
(4) If a thermal vapor incinerator is used, then the owner or operator shall maintain continuous records of the temperature of the gas stream in the combustion zone of the incinerator and records of all 3-hour periods of operation during which the average temperature of the gas stream in the combustion zone is more than 28 °C (50 °F) below the design combustion zone temperature.
(5) If a catalytic vapor incinerator is used, then the owner or operator shall maintain continuous records of the temperature of the gas stream both upstream and downstream of the catalyst bed of the incinerator, records of all 3-hour periods of operation during which the average temperature measured before the catalyst bed is more than 28 °C (50 °F) below the design gas stream temperature, and records of all 3-hour periods of operation during which the average temperature difference across the catalyst bed is less than 80 percent of the design temperature difference.
(6) If a boiler or process heater is used, then the owner or operator shall maintain records of each occurrence when there is a change in the location at which the vent stream is introduced into the flame zone as required by § 61.349(a)(2)(i)(C). For a boiler or process heater having a design heat input capacity less than 44 MW (150 × 106 BTU/hr), the owner or operator shall maintain continuous records of the temperature of the gas stream in the combustion zone of the boiler or process heater and records of all 3-hour periods of operation during which the average temperature of the gas stream in the combustion zone is more than 28 °C (50 °F) below the design combustion zone temperature. For a boiler or process heater having a design heat input capacity greater than or equal to 44 MW (150 × 106 BTU/hr), the owner or operator shall maintain continuous records of the parameter(s) monitored in accordance with the requirements of § 61.354(c)(5).
(7) If a flare is used, then the owner or operator shall maintain continuous records of the flare pilot flame monitoring and records of all periods during which the pilot flame is absent.
(8) If a condenser is used, then the owner or operator shall maintain records from the monitoring device of the parameters selected to be monitored in accordance with § 61.354(c)(6). If concentration of organics or concentration of benzene in the control device outlet gas stream is monitored, then the owner or operator shall record all 3-hour periods of operation during which the concentration of organics or the concentration of benzene in the exhaust stream is more than 20 percent greater than the design value. If the temperature of the condenser exhaust stream and coolant fluid is monitored, then the owner or operator shall record all 3-hour periods of operation during which the temperature of the condenser

exhaust vent stream is more than 6 °C (11 °F) above the design average exhaust vent stream temperature, or the temperature of the coolant fluid exiting the condenser is more than 6 °C (11 °F) above the design average coolant fluid temperature at the condenser outlet.

(9) If a carbon adsorber is used, then the owner or operator shall maintain records from the monitoring device of the concentration of organics or the concentration of benzene in the control device outlet gas stream. If the concentration of organics or the concentration of benzene in the control device outlet gas stream is monitored, then the owner or operator shall record all 3-hour periods of operation during which the concentration of organics or the concentration of benzene in the exhaust stream is more than 20 percent greater than the design value. If the carbon bed regeneration interval is monitored, then the owner or operator shall record each occurrence when the vent stream continues to flow through the control device beyond the predetermined carbon bed regeneration time.

(10) If a carbon adsorber that is not regenerated directly on site in the control device is used, then the owner or operator shall maintain records of dates and times when the control device is monitored, when breakthrough is measured, and shall record the date and time then the existing carbon in the control device is replaced with fresh carbon.

(11) If an alternative operational or process parameter is monitored for a control device, as allowed in § 61.354(e) of this subpart, then the owner or operator shall maintain records of the continuously monitored parameter, including periods when the device is not operated as designed.

(12) If a control device subject to the requirements of § 61.349(a)(2)(iv) is used, then the owner or operator shall maintain records of the parameters that are monitored and each occurrence when the parameters monitored are outside the range of values specified in § 61.349(a)(2)(iv)(C), or other records as specified by the Administrator.

(k) An owner or operator who elects to install and operate the control equipment in § 61.351 of this subpart shall comply with the recordkeeping requirements in 40 CFR 60.115b.

(l) An owner or operator who elects to install and operate the control equipment in § 61.352 of this subpart shall maintain records of the following:

(1) The date, location, and corrective action for each visual inspection required by 40 CFR 60.693-2(a)(5), during which a broken seal, gap, or other problem is identified that could result in benzene emissions.

(2) Results of the seal gap measurements required by 40 CFR 60.693-2(a).

(m) If a system is used for emission control that is maintained at a pressure less than atmospheric pressure with openings to provide dilution air, then the owner or operator shall maintain records of the monitoring device and records of all periods during which the pressure in the unit is operated at a pressure that is equal to or greater than atmospheric pressure.

(n) Each owner or operator using a total enclosure to comply with control requirements for tanks in § 61.343 or the control requirements for containers in § 61.345 must keep the records required in paragraphs (n)(1) and (2) of this section. Owners or operators may use records as required in 40 CFR 264.1089(b)(2)(iv) or 40 CFR 265.1090(b)(2)(iv) for a tank or as required in 40 CFR 264.1089(d)(1) or 40 CFR 265.1090(d)(1) for a container to meet the recordkeeping requirement in paragraph (n)(1) of this section. The owner or operator must make the records of each verification of a total enclosure available for inspection upon request.

(1) Records of the most recent set of calculations and measurements performed to verify that the enclosure meets the criteria of a permanent total enclosure as specified in "Procedure T—Criteria for and Verification of a Permanent or Temporary Total Enclosure" in 40 CFR 52.741, appendix B;

(2) Records required for a closed-vent system and control device according to the requirements in paragraphs (d) (f), and (j) of this section.

[55 FR 8346, Mar. 7, 1990; 55 FR 12444, Apr. 3, 1990; 55 FR 18331, May 2, 1990, as amended at 58 FR 3103, Jan. 7, 1993; 65 FR 62161, Oct. 17, 2000; 67 FR 68533, Nov. 12, 2002]

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§ 61.357 Reporting requirements.

(a) Each owner or operator of a chemical plant, petroleum refinery, coke by-product recovery plant, and any facility managing wastes from these industries shall submit to the Administrator within 90 days after January 7, 1993, or by the initial startup for a new source with an initial startup after the effective date, a report that summarizes the regulatory status of each waste stream subject to § 61.342 and is determined by the procedures specified in § 61.355(c) to contain benzene. Each owner or operator subject to this subpart who has no benzene onsite in wastes, products, by-products, or intermediates shall submit an initial report that is a statement to this effect. For all other owners or operators subject to this subpart, the

report shall include the following information:
(1) Total annual benzene quantity from facility waste determined in accordance with § 61.355(a) of this subpart.
(2) A table identifying each waste stream and whether or not the waste stream will be controlled for benzene emissions in accordance with the requirements of this subpart.
(3) For each waste stream identified as not being controlled for benzene emissions in accordance with the requirements of this subpart the following information shall be added to the table:
(i) Whether or not the water content of the waste stream is greater than 10 percent;
(ii) Whether or not the waste stream is a process wastewater stream, product tank drawdown, or landfill leachate;
(iii) Annual waste quantity for the waste stream;
(iv) Range of benzene concentrations for the waste stream;
(v) Annual average flow-weighted benzene concentration for the waste stream; and
(vi) Annual benzene quantity for the waste stream.
(4) The information required in paragraphs (a) (1), (2), and (3) of this section should represent the waste stream characteristics based on current configuration and operating conditions. An owner or operator only needs to list in the report those waste streams that contact materials containing benzene. The report does not need to include a description of the controls to be installed to comply with the standard or other information required in § 61.10(a).
(b) If the total annual benzene quantity from facility waste is less than 1 Mg/yr (1.1 ton/yr), then the owner or operator shall submit to the Administrator a report that updates the information listed in paragraphs (a)(1) through (a)(3) of this section whenever there is a change in the process generating the waste stream that could cause the total annual benzene quantity from facility waste to increase to 1 Mg/yr (1.1 ton/yr) or more.
(c) If the total annual benzene quantity from facility waste is less than 10 Mg/yr (11 ton/yr) but is equal to or greater than 1 Mg/yr (1.1 ton/yr), then the owner or operator shall submit to the Administrator a report that updates the information listed in paragraphs (a)(1) through (a)(3) of this section. The report shall be submitted annually and whenever there is a change in the process generating the waste stream that could cause the total annual benzene quantity from facility waste to increase to 10 Mg/yr (11 ton/yr) or more. If the information in the annual report required by paragraphs (a)(1) through (a)(3) of this section is not changed in the following year, the owner or operator may submit a statement to that effect.
(d) If the total annual benzene quantity from facility waste is equal to or greater than 10 Mg/yr (11 ton/yr), then the owner or operator shall submit to the Administrator the following reports:
(1) Within 90 days after January 7, 1993, unless a waiver of compliance under § 61.11 of this part is granted, or by the date of initial startup for a new source with an initial startup after the effective date, a certification that the equipment necessary to comply with these standards has been installed and that the required initial inspections or tests have been carried out in accordance with this subpart. If a waiver of compliance is granted under § 61.11, the certification of equipment necessary to comply with these standards shall be submitted by the date the waiver of compliance expires.
(2) Beginning on the date that the equipment necessary to comply with these standards has been certified in accordance with paragraph (d)(1) of this section, the owner or operator shall submit annually to the Administrator a report that updates the information listed in paragraphs (a)(1) through (a)(3) of this section. If the information in the annual report required by paragraphs (a)(1) through (a)(3) of this section is not changed in the following year, the owner or operator may submit a statement to that effect.
(3) If an owner or operator elects to comply with the requirements of § 61.342(c)(3)(ii), then the report required by paragraph (d)(2) of this section shall include a table identifying each waste stream chosen for exemption and the total annual benzene quantity in these exempted streams.
(4) If an owner or operator elects to comply with the alternative requirements of § 61.342(d) of this subpart, then he shall include in the report required by paragraph (d)(2) of this section a table presenting the following information for each process wastewater stream:
(i) Whether or not the process wastewater stream is being controlled for benzene emissions in accordance with the requirements of this subpart;
(ii) For each process wastewater stream identified as not being controlled for benzene emissions in accordance with the requirements of this subpart, the table shall report the following information for the process wastewater stream as determined at the point of waste generation: annual waste quantity, range of benzene concentrations, annual average flow-weighted benzene concentration, and annual benzene

quantity;
(iii) For each process wastewater stream identified as being controlled for benzene emissions in accordance with the requirements of this subpart, the table shall report the following information for the process wastewater stream as determined at the exit to the treatment process: Annual waste quantity, range of benzene concentrations, annual average flow-weighted benzene concentration, and annual benzene quantity.
(5) If an owner or operator elects to comply with the alternative requirements of § 61.342(e), then the report required by paragraph (d)(2) of this section shall include a table presenting the following information for each waste stream:
(i) For each waste stream identified as not being controlled for benzene emissions in accordance with the requirements of this subpart; the table shall report the following information for the waste stream as determined at the point of waste generation: annual waste quantity, range of benzene concentrations, annual average flow-weighted benzene concentration, and annual benzene quantity;
(ii) For each waste stream identified as being controlled for benzene emissions in accordance with the requirements of this subpart; the table shall report the following information for the waste stream as determined at the applicable location described in § 61.355(k)(2): Annual waste quantity, range of benzene concentrations, annual average flow-weighted benzene concentration, and annual benzene quantity.
(6) Beginning 3 months after the date that the equipment necessary to comply with these standards has been certified in accordance with paragraph (d)(1) of this section, the owner or operator shall submit quarterly to the Administrator a certification that all of the required inspections have been carried out in accordance with the requirements of this subpart.
(7) Beginning 3 months after the date that the equipment necessary to comply with these standards has been certified in accordance with paragraph (d)(1) of this section, the owner or operator shall submit a report quarterly to the Administrator that includes:
(i) If a treatment process or wastewater treatment system unit is monitored in accordance with § 61.354(a)(1) of this subpart, then each period of operation during which the concentration of benzene in the monitored waste stream exiting the unit is equal to or greater than 10 ppmw.
(ii) If a treatment process or wastewater treatment system unit is monitored in accordance with § 61.354(a)(2) of this subpart, then each 3-hour period of operation during which the average value of the monitored parameter is outside the range of acceptable values or during which the unit is not operating as designed.
(iii) If a treatment process or wastewater treatment system unit is monitored in accordance with § 61.354(b), then each period of operation during which the flow-weighted annual average concentration of benzene in the monitored waste stream entering the unit is equal to or greater than 10 ppmw and/or the total annual benzene quantity is equal to or greater than 1.0 mg/yr.
(iv) For a control device monitored in accordance with § 61.354(c) of this subpart, each period of operation monitored during which any of the following conditions occur, as applicable to the control device:
(A) Each 3-hour period of operation during which the average temperature of the gas stream in the combustion zone of a thermal vapor incinerator, as measured by the temperature monitoring device, is more than 28 °C (50 °F) below the design combustion zone temperature.
(B) Each 3-hour period of operation during which the average temperature of the gas stream immediately before the catalyst bed of a catalytic vapor incinerator, as measured by the temperature monitoring device, is more than 28 °C (50 °F) below the design gas stream temperature, and any 3-hour period during which the average temperature difference across the catalyst bed (i.e., the difference between the temperatures of the gas stream immediately before and after the catalyst bed), as measured by the temperature monitoring device, is less than 80 percent of the design temperature difference.
(C) Each 3-hour period of operation during which the average temperature of the gas stream in the combustion zone of a boiler or process heater having a design heat input capacity less than 44 MW (150 × 106 BTU/hr), as mesured by the temperature monitoring device, is more than 28 °C (50 °F) below the design combustion zone temperature.
(D) Each 3-hour period of operation during which the average concentration of organics or the average concentration of benzene in the exhaust gases from a carbon adsorber, condenser, or other vapor recovery system is more than 20 percent greater than the design concentration level of organics or benzene in the exhaust gas.

(E) Each 3-hour period of operation during which the temperature of the condenser exhaust vent stream is more than 6 °C (11 °F) above the design average exhaust vent stream temperature, or the temperature of the coolant fluid exiting the condenser is more than 6 °C (11 °F) above the design average coolant fluid temperature at the condenser outlet.
(F) Each period in which the pilot flame of a flare is absent.
(G) Each occurrence when there is a change in the location at which the vent stream is introduced into the flame zone of a boiler or process heater as required by § 61.349(a)(2)(i)(C) of this subpart.
(H) Each occurrence when the carbon in a carbon adsorber system that is regenerated directly on site in the control device is not regenerated at the predetermined carbon bed regeneration time.
(I) Each occurrence when the carbon in a carbon adsorber system that is not regenerated directly on site in the control device is not replaced at the predetermined interval specified in § 61.354(c) of this subpart.
(J) Each 3-hour period of operation during which the parameters monitored are outside the range of values specified in § 61.349(a)(2)(iv)(C), or any other periods specified by the Administrator for a control device subject to the requirements of § 61.349(a)(2)(iv).
(v) For a cover and closed-vent system monitored in accordance with § 61.354(g), the owner or operator shall submit a report quarterly to the Administrator that identifies any period in which the pressure in the waste management unit is equal to or greater than atmospheric pressure.
(8) Beginning one year after the date that the equipment necessary to comply with these standards has been certified in accordance with paragraph (d)(1) of this section, the owner or operator shall submit annually to the Administrator a report that summarizes all inspections required by §§ 61.342 through 61.354 during which detectable emissions are measured or a problem (such as a broken seal, gap or other problem) that could result in benzone emissions is identified, including information about the repairs or corrective action taken.
(e) An owner or operator electing to comply with the provisions of §§ 61.351 or 61.352 of this subpart shall notify the Administrator of the alternative standard selected in the report required under § 61.07 or § 61.10 of this part.
(f) An owner or operator who elects to install and operate the control equipment in § 61.351 of this subpart shall comply with the reporting requirements in 40 CFR 60.115b.
(g) An owner or operator who elects to install and operate the control equipment in § 61.352 of this subpart shall submit initial and quarterly reports that identify all seal gap measurements, as required in 40 CFR 60.693-2(a), that are outside the prescribed limits.
[55 FR 8346, Mar. 7 1990; 55 FR 12444, Apr. 3, 1990, as amended at 55 FR 37231, Sept. 10, 1990; 58 FR 3105, Jan. 7, 1993; 65 FR 62161, Oct. 17, 2000]

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§ 61.358 Delegation of authority.

(a) In delegating implementation and enforcement authority to a State under section 112(d) of the Clean Air Act, the authorities contained in paragraph (b) of this section shall be retained by the Administrator and not transferred to a State.
(b) Alternative means of emission limitation under § 61.353 of this subpart will not be delegated to States.

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§ 61.359 [Reserved]

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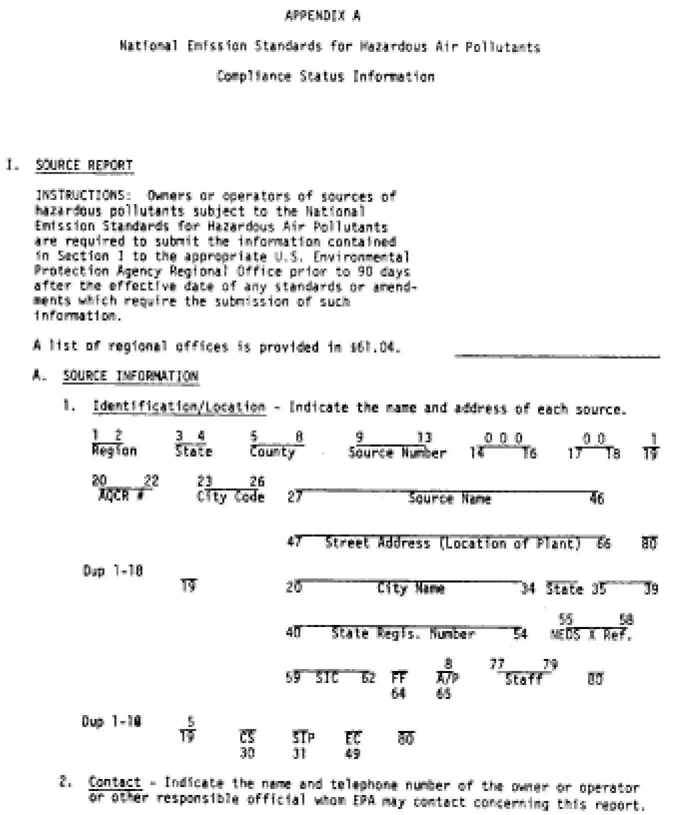
Appendix A to Part 61



APPENDIX A

National Emission Standards for Hazardous Air Pollutants

Compliance Status Information

I. SOURCE REPORT

INSTRUCTIONS: Owners or operators of sources of hazardous pollutants subject to the National Emission Standards for Hazardous Air Pollutants are required to submit the information contained in Section I to the appropriate U.S. Environmental Protection Agency Regional Office prior to 90 days after the effective date of any standards or amendments which require the submission of such information.

A list of regional offices is provided in §61.04. ______________

A. SOURCE INFORMATION

1. Identification/Location - Indicate the name and address of each source.

1 2 Region   3 4 State   5 8 County   9 13 Source Number   0 0 0 14 16   0 0 17 18   1 19

20 22 AQCR #   23 26 City Code   27 Source Name 46

47 Street Address (Location of Plant) 66   80

Dup 1-18   19   20 City Name 34   State 35 39

40 State Regis. Number 54   55 58 NEDS X Ref.

59 SIC 62   FF 64   8 A/P 65   77 79 Staff   80

Dup 1-18   5 19   CS 30   STP 31   EC 49   80

2. Contact - Indicate the name and telephone number of the owner or operator or other responsible official whom EPA may contact concerning this report.

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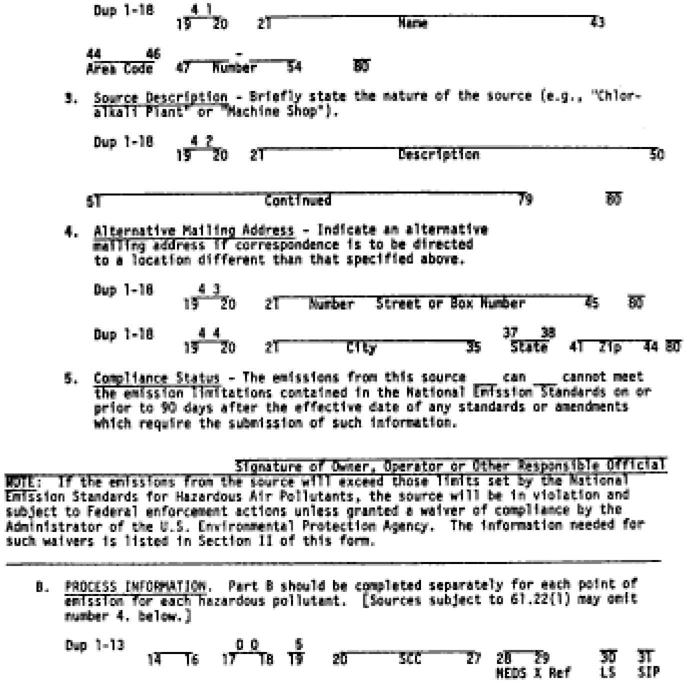

Dup 1-18   4 1 19 20   21 Name 43

44 46 Area Code   47 - Number 54   80

3. Source Description - Briefly state the nature of the source (e.g., "Chlor-alkali Plant" or "Machine Shop").

Dup 1-18   4 2 19 20   21 Description 50

51 Continued 79   80

4. Alternative Mailing Address - Indicate an alternative mailing address if correspondence is to be directed to a location different than that specified above.

Dup 1-18   4 3 19 20   21 Number Street or Box Number 45   80

Dup 1-18   4 4 19 20   21 City 35   37 38 State   41 Zip 44 80

5. Compliance Status - The emissions from this source ___ can ___ cannot meet the emission limitations contained in the National Emission Standards on or prior to 90 days after the effective date of any standards or amendments which require the submission of such information.

Signature of Owner, Operator or Other Responsible Official

NOTE: If the emissions from the source will exceed those limits set by the National Emission Standards for Hazardous Air Pollutants, the source will be in violation and subject to Federal enforcement actions unless granted a waiver of compliance by the Administrator of the U.S. Environmental Protection Agency. The information needed for such waivers is listed in Section II of this form.

B. PROCESS INFORMATION. Part B should be completed separately for each point of emission for each hazardous pollutant. [Sources subject to 61.22(l) may omit number 4. below.]

Dup 1-13   14 16   0 0 17 18   5 19   20 SCC 27   28 29 NEDS X Ref   30 LS   31 SIP

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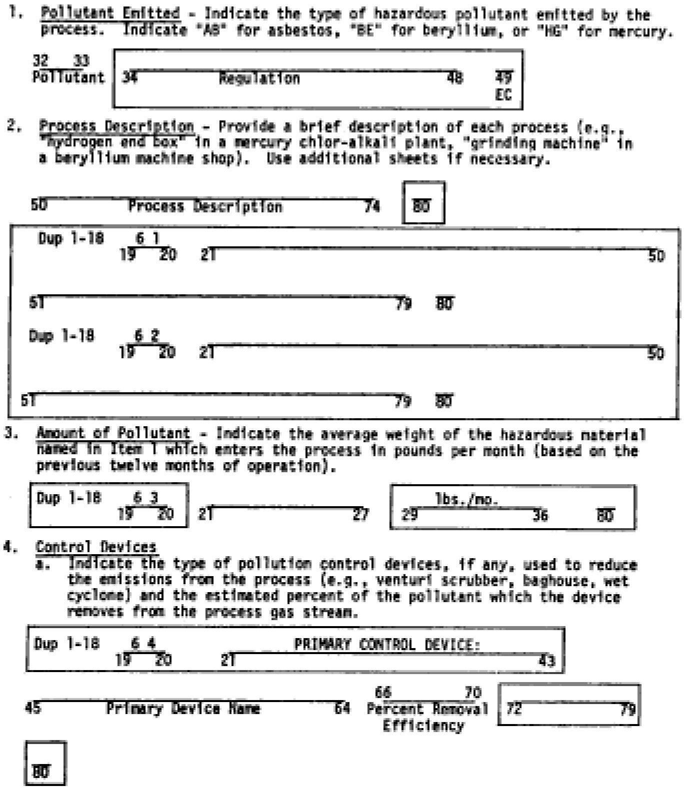

1. Pollutant Emitted - Indicate the type of hazardous pollutant emitted by the process. Indicate "AB" for asbestos, "BE" for beryllium, or "HG" for mercury.

32 33
Pollutant
34 Regulation 48
49
EC

2. Process Description - Provide a brief description of each process (e.g., "hydrogen end box" in a mercury chlor-alkali plant, "grinding machine" in a beryllium machine shop). Use additional sheets if necessary.

50 Process Description 74
80

Dup 1-18 6 1
19 20 21 50
51 79 80

Dup 1-18 6 2
19 20 21 50
51 79 80

3. Amount of Pollutant - Indicate the average weight of the hazardous material named in Item 1 which enters the process in pounds per month (based on the previous twelve months of operation).

Dup 1-18 6 3
19 20 21 27
lbs./mo.
29 36 80

4. Control Devices
   a. Indicate the type of pollution control devices, if any, used to reduce the emissions from the process (e.g., venturi scrubber, baghouse, wet cyclone) and the estimated percent of the pollutant which the device removes from the process gas stream.

Dup 1-18 6 4 PRIMARY CONTROL DEVICE:
19 20 21 43

45 Primary Device Name 64
66 70
Percent Removal Efficiency
72 79
80

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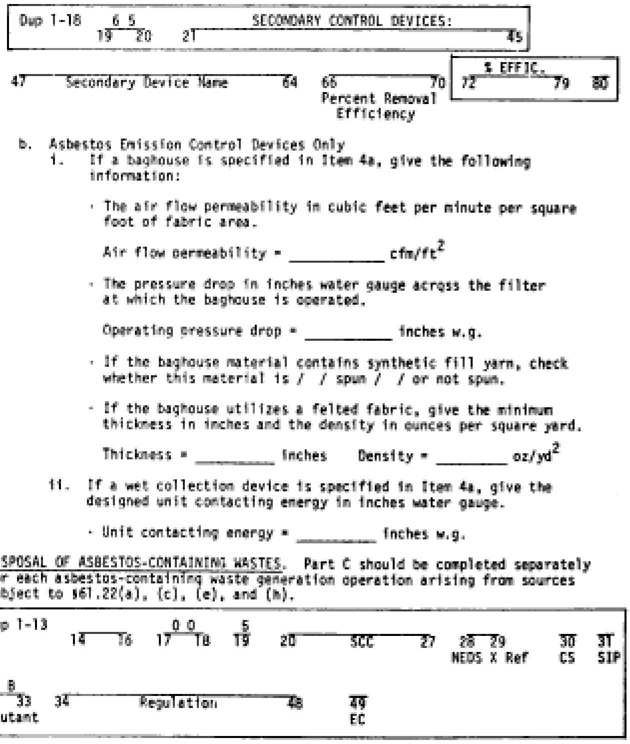

Dup 1-18 6 5 SECONDARY CONTROL DEVICES:
19 20 21 45

47 Secondary Device Name 64
66 70
Percent Removal Efficiency
% EFFIC.
72 79 80

b. Asbestos Emission Control Devices Only
   i. If a baghouse is specified in Item 4a, give the following information:

- The air flow permeability in cubic feet per minute per square foot of fabric area.

Air flow permeability = ___________ cfm/ft^2

- The pressure drop in inches water gauge across the filter at which the baghouse is operated.

Operating pressure drop = ___________ inches w.g.

- If the baghouse material contains synthetic fill yarn, check whether this material is / / spun / / or not spun.

- If the baghouse utilizes a felted fabric, give the minimum thickness in inches and the density in ounces per square yard.

Thickness = __________ inches Density = _________ oz/yd^2

   ii. If a wet collection device is specified in Item 4a, give the designed unit contacting energy in inches water gauge.

- Unit contacting energy = __________ inches w.g.

C. DISPOSAL OF ASBESTOS-CONTAINING WASTES. Part C should be completed separately for each asbestos-containing waste generation operation arising from sources subject to §61.22(a), (c), (e), and (h).

Dup 1-13
0 0 5
14 16 17 18 19 20 SCC 27 28 29 30 31
NEDS X Ref CS SIP

A B
32 33 34 Regulation 48 49
Pollutant EC

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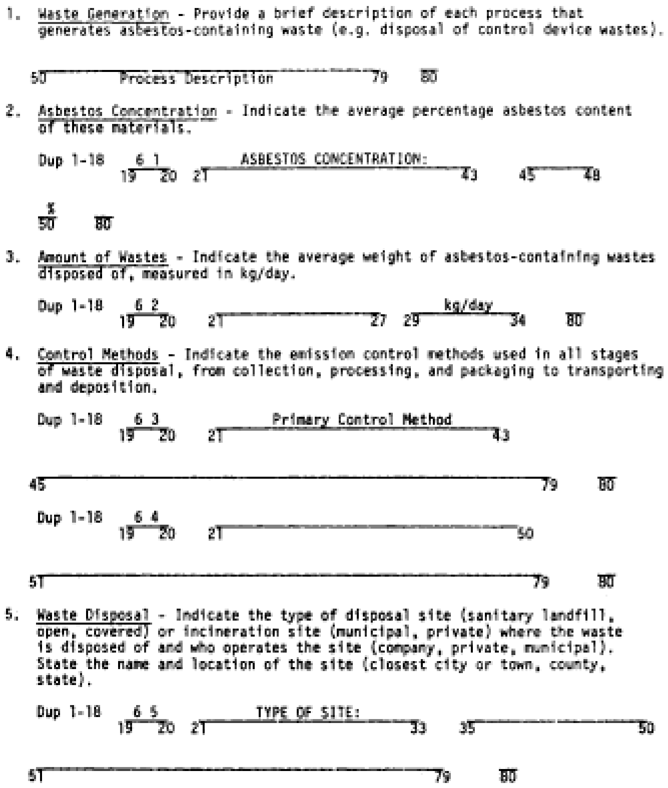

1. Waste Generation - Provide a brief description of each process that generates asbestos-containing waste (e.g. disposal of control device wastes).

50 Process Description 79 80

2. Asbestos Concentration - Indicate the average percentage asbestos content of these materials.

Dup 1-18 6 1 19 20 21 ASBESTOS CONCENTRATION: 43 45 48

% 50 80

3. Amount of Wastes - Indicate the average weight of asbestos-containing wastes disposed of, measured in kg/day.

Dup 1-18 6 2 19 20 21 27 29 kg/day 34 80

4. Control Methods - Indicate the emission control methods used in all stages of waste disposal, from collection, processing, and packaging to transporting and deposition.

Dup 1-18 6 3 19 20 21 Primary Control Method 43

45 79 80

Dup 1-18 6 4 19 20 21 50

51 79 80

5. Waste Disposal - Indicate the type of disposal site (sanitary landfill, open, covered) or incineration site (municipal, private) where the waste is disposed of and who operates the site (company, private, municipal). State the name and location of the site (closest city or town, county, state).

Dup 1-18 6 5 19 20 21 TYPE OF SITE: 33 35 50

51 79 80

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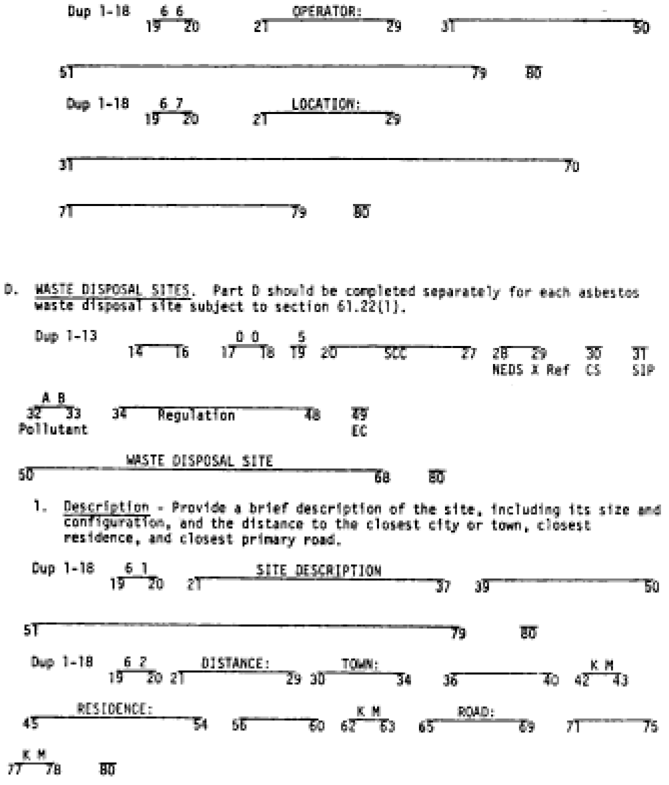

Dup 1-18 6 6 19 20 21 OPERATOR: 29 31 50

51 79 80

Dup 1-18 6 7 19 20 21 LOCATION: 29

31 70

71 79 80

D. WASTE DISPOSAL SITES. Part D should be completed separately for each asbestos waste disposal site subject to section 61.22(l).

Dup 1-13 14 16 0 0 17 18 5 19 20 SCC 27 28 29 NEDS X Ref 30 CS 31 SIP

A B 32 33 Pollutant 34 Regulation 48 49 EC

50 WASTE DISPOSAL SITE 68 80

1. Description - Provide a brief description of the site, including its size and configuration, and the distance to the closest city or town, closest residence, and closest primary road.

Dup 1-18 6 1 19 20 21 SITE DESCRIPTION 37 39 50

51 79 80

Dup 1-18 6 2 19 20 21 DISTANCE: 29 30 TOWN: 34 36 40 K M 42 43

45 RESIDENCE: 54 56 60 K M 62 63 65 ROAD: 69 71 75

K M 77 78 80

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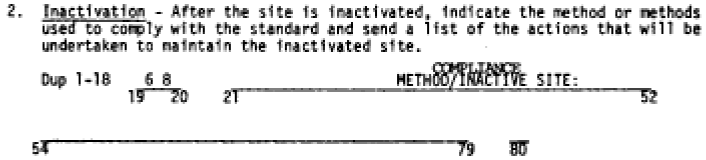

2. Inactivation - After the site is inactivated, indicate the method or methods used to comply with the standard and send a list of the actions that will be undertaken to maintain the inactivated site.

Dup 1-18 6 8 19 20 21 COMPLIANCE METHOD/INACTIVE SITE: 52

54 79 80

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II. WAIVER REQUESTS

A. Waiver of Compliance. Owners or operators of sources unable to operate in compliance with the National Emission Standards for Hazardous Air Pollutants prior to 90 days after the effective date of any standards or amendments which require the submission of such information may request a waiver of compliance from the Administrator of the U.S. Environmental Protection Agency for the time period necessary to install appropriate control devices or make modifications to achieve compliance. The Administrator may grant a waiver of compliance with the standard for a period not exceeding two years from the effective date of the hazardous pollutant standards, if he finds that such period is necessary for the installation of controls and that steps will be taken during the period of the waiver to assure that the health of persons will be protected from imminent endangerment.

The report information provided in Section I must accompany this application. Applications should be sent to the appropriate EPA regional office.

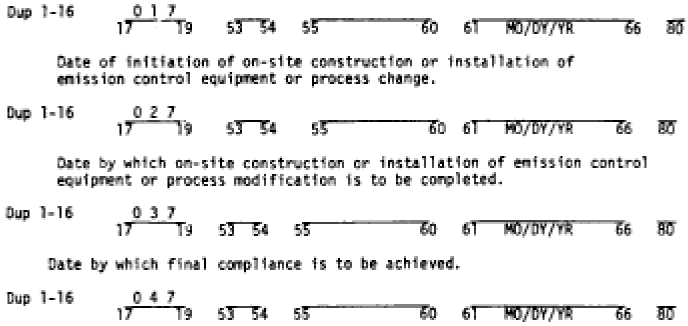
1. Processes Involved —Indicate the process or processes emitting hazardous pollutants to which emission controls are to be applied.

2. Controls

a. Describe the proposed type of control device to be added or modification to be made to the process to reduce the emission of hazardous pollutants to an acceptable level. (Use additional sheets if necessary.)

b. Describe the measures that will be taken during the waiver period to assure that the health of persons will be protected from imminent endangerment. (Use additional sheets if necessary.)

3. Increments of Progress —Specify the dates by which the following increments of progress will be met. Date by which contracts for emission control systems or process modifications will be awarded; or date by which orders will be issued for the purchase of the component parts to accomplish emission control or process modification.



Dup 1-16 0 1 7 17 19 53 54 55 60 61 MO/DY/YR 66 80

Date of initiation of on-site construction or installation of emission control equipment or process change.

Dup 1-16 0 2 7 17 19 53 54 55 60 61 MO/DY/YR 66 80

Date by which on-site construction or installation of emission control equipment or process modification is to be completed.

Dup 1-16 0 3 7 17 19 53 54 55 60 61 MO/DY/YR 66 80

Date by which final compliance is to be achieved.

Dup 1-16 0 4 7 17 19 53 54 55 60 61 MO/DY/YR 66 80

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B. Waiver of Emission Tests. A waiver of emission testing may be granted to owners or operators of sources subject to emission testing if, in the judgment of the Administrator of the Environmental Protection Agency the emissions from the source comply with the appropriate standard or if the owners or operators of the source have requested a waiver of compliance or have been granted a waiver of compliance.

This application should accompany the report information provided in Section I.

1. Reason —State the reasons for requesting a waiver of emission testing. If the reason stated is that the emissions from the source are within the prescribed limits, documentation of this condition must be attached.

Date

Signature of the owner or operator

(Sec. 114, of the Clean Air Act as amended (42 U.S.C. 7414))

[40 FR 48303, Oct. 14, 1975, as amended at 43 FR 8800, Mar. 3, 1978; 50 FR 46295, Sept. 9, 1985]

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Appendix B to Part 61—Test Methods

Method 101—Determination of particulate and gaseous mercury emissions from chlor-alkali plants (air streams)
Method 101A—Determination of particulate and gaseous mercury emissions from sewage sludge incinerators
Method 102—Determination of particulate and gaseous mercury emissions from chlor-alkali plants (hydrogen streams)
Method 103—Beryllium screening method
Method 104—Determination of beryllium emissions from stationary sources
Method 105—Determination of mercury in wastewater treatment plant sewage sludges
Method 106—Determination of vinyl chloride emissions from stationary sources
Method 107—Determination of vinyl chloride content of in-process wastewater samples, and vinyl chloride content of polyvinyl chloride resin slurry, wet cake, and latex samples
Method 107A—Determination of vinyl chloride content of solvents, resin-solvent solution, polyvinyl chloride resin, resin slurry, wet resin, and latex samples
Method 108—Determination of particulate and gaseous arsenic emissions
Method 108A—Determination of arsenic content in ore samples from nonferrous smelters
Method 108B—Determination of arsenic content in ore samples from nonferrous smelters
Method 108C—Determination of arsenic content in ore samples from nonferrous smelters (molybdenum blue photometric procedure)
Method 111—Determination of Polonium—210 emissions from stationary sources

METHOD 101—DETERMINATION OF PARTICULATE AND GASEOUS MERCURY EMISSIONS FROM CHLOR-ALKALI PLANTS (AIR STREAMS)

NOTE: This method does not include all of the specifications (e.g., equipment and supplies) and procedures (e.g., sampling and analytical) essential to its performance. Some material is incorporated by reference from methods in appendix A to 40 CFR part 60. Therefore, to obtain reliable results, persons using this method should have a thorough knowledge of at least the following additional test methods: Method 1, Method 2, Method 3, and Method 5.

1.0 Scope and Application

1.1 Analytes.

Analyte	CAS No.	Sensitivity
Mercury (Hg)	7439-97-6	Dependent upon recorder and spectrophotometer.

1.2 Applicability. This method is applicable for the determination of Hg emissions, including both particulate and gaseous Hg, from chlor-alkali plants and other sources (as specified in the regulations) where the carrier-gas stream in the duct or stack is principally air.

1.3 Data Quality Objectives. Adherence to the requirements of this method will enhance the quality of the data obtained from air pollutant sampling methods.

2.0 Summary of Method

Particulate and gaseous Hg emissions are withdrawn isokinetically from the source and collected in acidic iodine monochloride (ICl) solution. The Hg collected (in the mercuric form) is reduced to elemental Hg, which is then aerated from the solution into an optical cell and measured by atomic absorption spectrophotometry.

3.0 Definitions [Reserved]

4.0 Interferences

4.1 Sample Collection. Sulfur dioxide (SO_2) reduces ICl and causes premature depletion of the ICl solution.

4.2 Sample Analysis.

4.2.1 ICl concentrations greater than 10^{-4} molar inhibit the reduction of the Hg (II) ion in the aeration cell.

4.2.2 Condensation of water vapor on the optical cell windows causes a positive interference.

5.0 Safety

5.1 Disclaimer. This method may involve hazardous materials, operations, and equipment. This test method does not purport to address all of the safety problems associated with its use. It is the responsibility of the user of this test method to establish appropriate safety and health practices and determine the applicability of regulatory limitations prior to performing this test method.

5.2 Corrosive Reagents. The following reagents are hazardous. Personal protective equipment and safe procedures are useful in preventing chemical splashes. If contact occurs, immediately flush with copious amounts of water for at least 15 minutes. Remove clothing under shower and decontaminate. Treat residual chemical burn as thermal burn.

5.2.1 Hydrochloric Acid (HCl). Highly toxic and corrosive. Causes severe damage to tissues. Vapors are highly irritating to eyes, skin, nose, and lungs, causing severe damage. May cause bronchitis, pneumonia, or edema of lungs. Exposure to concentrations of 0.13 to 0.2 percent can be lethal to humans in a few minutes. Provide ventilation to limit exposure. Reacts with metals, producing hydrogen gas.

5.2.2 Nitric Acid (HNO_3). Highly corrosive to eyes, skin, nose, and lungs. Vapors cause bronchitis, pneumonia, or edema of lungs. Reaction to inhalation may be delayed as long as 30 hours and still be fatal. Provide ventilation to limit exposure. Strong oxidizer. Hazardous reaction may occur with organic materials such as solvents.

5.2.3 Sulfuric Acid (H_2SO_4). Rapidly destructive to body tissue. Will cause third degree burns. Eye damage may result in blindness. Inhalation may be fatal from spasm of the larynx, usually within 30 minutes. 3 mg/m^3 will cause lung damage. 1 mg/m^3 for 8 hours will cause lung damage or, in higher concentrations, death. Provide ventilation to limit inhalation. Reacts violently with metals and organics.

6.0 Equipment and Supplies.

6.1 Sample Collection. A schematic of the sampling train used in performing this method is shown in Figure 101-1; it is similar to the Method 5 sampling train. The following items are required for sample collection:

6.1.1 Probe Nozzle, Pitot Tube, Differential Pressure Gauge, Metering System, Barometer, and Gas Density Determination Equipment. Same as Method 5, Sections 6.1.1.1, 6.1.1.3, 6.1.1.4, 6.1.1.9, 6.1.2, and 6.1.3, respectively.

6.1.2 Probe Liner. Borosilicate or quartz glass tubing. A heating system capable of maintaining a gas temperature of 120 ±14 °C (248 ±25 °F) at the probe exit during sampling may be used to prevent water condensation.

NOTE: Do not use metal probe liners.

6.1.3 Impingers. Four Greenburg-Smith impingers connected in series with leak-free ground glass fittings or any similar leak-free noncontaminating fittings. For the first, third, and fourth impingers, impingers that are modified by replacing the tip with a 13-mm ID (0.5-in.) glass tube extending to 13 mm (0.5 in.) from the bottom of the flask may be used.

6.1.4 Acid Trap. Mine Safety Appliances air line filter, Catalog number 81857, with acid absorbing cartridge and suitable connections, or equivalent.

6.2 Sample Recovery. The following items are needed for sample recovery:

6.2.1 Glass Sample Bottles. Leakless, with Teflon-lined caps, 1000- and 100-ml.

6.2.2 Graduated Cylinder. 250-ml.

6.2.3 Funnel and Rubber Policeman. To aid in transfer of silica gel to container; not necessary if silica gel is weighed in the field.

6.2.4 Funnel. Glass, to aid in sample recovery.

6.3 Sample Preparation and Analysis. The following items are needed for sample preparation and analysis:

6.3.1 Atomic Absorption Spectrophotometer. Perkin-Elmer 303, or equivalent, containing a hollow-cathode mercury lamp and the optical cell described in Section 6.3.2.

6.3.2 Optical Cell. Cylindrical shape with quartz end windows and having the dimensions shown in Figure 101-2. Wind the cell with approximately 2 meters (6 ft) of 24-gauge Nichrome wire, or equivalent, and wrap with fiberglass insulation tape, or equivalent; do not let the wires touch each other.

6.3.3 Aeration Cell. Constructed according to the specifications in Figure 101-3. Do not use a glass frit as a substitute for the blown glass bubbler tip shown in Figure 101-3.

6.3.4 Recorder. Matched to output of the spectrophotometer described in Section 6.3.1.

6.3.5 Variable Transformer. To vary the voltage on the optical cell from 0 to 40 volts.

6.3.6 Hood. For venting optical cell exhaust.

6.3.7 Flow Metering Valve.

6.3.8 Rate Meter. Rotameter, or equivalent, capable of measuring to within 2 percent a gas flow of 1.5 liters/min (0.053 cfm).

6.3.9 Aeration Gas Cylinder. Nitrogen or dry, Hg-free air, equipped with a single-stage regulator.

6.3.10 Tubing. For making connections. Use glass tubing (ungreased ball and socket connections are recommended) for all tubing connections between the solution cell and the optical cell; do not use Tygon tubing, other types of flexible tubing, or metal tubing as substitutes. Teflon, steel, or copper tubing may be used between the nitrogen tank and flow metering valve (Section 6.3.7), and Tygon, gum, or rubber tubing between the flow metering valve and the aeration cell.

6.3.11 Flow Rate Calibration Equipment. Bubble flow meter or wet-test meter for measuring a gas flow rate of 1.5 ±0.1 liters/min (0.053 ±0.0035 cfm).

6.3.12 Volumetric Flasks. Class A with penny head standard taper stoppers; 100-, 250-, 500-, and 1000-ml.

6.3.13 Volumetric Pipets. Class A; 1-, 2-, 3-, 4-, and 5-ml.

6.3.14 Graduated Cylinder. 50-ml.

6.3.15 Magnetic Stirrer. General-purpose laboratory type.

6.3.16 Magnetic Stirring Bar. Teflon-coated.

6.3.17 Balance. Capable of weighing to ±0.5 g.

6.3.18 Alternative Analytical Apparatus. Alternative systems are allowable as long as they meet the following criteria:

6.3.18.1 A linear calibration curve is generated and two consecutive samples of the same aliquot size and concentration agree within 3 percent of their average.

6.3.18.2 A minimum of 95 percent of the spike is recovered when an aliquot of a source sample is spiked with a known concentration of Hg (II) compound.

6.3.18.3 The reducing agent should be added after the aeration cell is closed.

6.3.18.4 The aeration bottle bubbler should not contain a frit.

6.3.18.5 Any Tygon tubing used should be as short as possible and conditioned prior to use until blanks and standards yield linear and reproducible results.

6.3.18.6 If manual stirring is done before aeration, it should be done with the aeration cell closed.

6.3.18.7 A drying tube should not be used unless it is conditioned as the Tygon tubing above.

7.0 Reagents and Standards

Unless otherwise indicated, all reagents must conform to the specifications established by the Committee on Analytical Reagents of the American Chemical Society; where such specifications are not available, use the best available grade.

7.1 Sample Collection. The following reagents are required for sample collection:

7.1.1 Water. Deionized distilled, to conform to ASTM D 1193-77 or 91 (incorporated by reference—see § 61.18), Type 1. If high concentrations of organic matter are not expected to be present, the analyst may eliminate the $KMnO_4$ test for oxidizable organic matter. Use this water in all dilutions and solution preparations.

7.1.2 Nitric Acid, 50 Percent (v/v). Mix equal volumes of concentrated HNO_3 and water, being careful to add the acid to the water slowly.

7.1.3 Silica Gel. Indicating type, 6- to 16-mesh. If previously used, dry at 175 °C (350 °F) for 2 hours. The tester may use new silica gel as received.

7.1.4 Potassium Iodide (KI) Solution, 25 Percent. Dissolve 250 g of KI in water, and dilute to 1 liter.

7.1.5 Iodine Monochloride Stock Solution, 1.0 M. To 800 ml of 25 percent KI solution, add 800 ml of concentrated HCl. Cool to room temperature. With vigorous stirring, slowly add 135 g of potassium iodate (KIO_3), and stir until all free iodine has dissolved. A clear orange-red solution occurs when all the KIO_3 has been added. Cool to room temperature, and dilute to 1800 ml with water. Keep the solution in amber glass bottles to prevent degradation.

7.1.6 Absorbing Solution, 0.1 M ICl. Dilute 100 ml of the 1.0 M ICl stock solution to 1 liter with water. Keep the solution in amber glass bottles and in darkness to prevent degradation. This reagent is stable for at least two months.

7.2 Sample Preparation and Analysis. The following reagents and standards are required for sample preparation and analysis:

7.2.1 Reagents.

7.2.1.1 Tin (II) Solution. Prepare fresh daily, and keep sealed when not being used. Completely dissolve 20 g of tin (II) chloride (or 25 g of tin (II) sulfate) crystals (Baker Analyzed reagent grade or any other brand that will give a clear solution) in 25 ml of concentrated HCl. Dilute to 250 ml with water. Do not substitute HNO_3 , H_2SO_4 , or other strong acids for the HCl.

7.2.1.2 Sulfuric Acid, 5 Percent (v/v). Dilute 25 ml of concentrated H_2SO_4 to 500 ml with water.

7.2.2 Standards

7.2.2.1 Hg Stock Solution, 1 mg Hg/ml. Prepare and store all Hg standard solutions in borosilicate glass containers. Completely dissolve 0.1354 g of Hg (II) chloride in 75 ml of water in a 100-ml glass volumetric flask. Add 10 ml of concentrated HNO_3 , and adjust the volume to exactly 100 ml with water. Mix thoroughly. This solution is stable for at least one month.

7.2.2.2 Intermediate Hg Standard Solution, 10 µg Hg/ml. Prepare fresh weekly. Pipet 5.0 ml of the Hg stock solution (Section 7.2.2.1) into a 500-ml glass volumetric flask, and add 20 ml of the 5 percent H_2SO_4 solution. Dilute to exactly 500 ml with water. Thoroughly mix the solution.

7.2.2.3 Working Hg Standard Solution, 200 ng Hg/ml. Prepare fresh daily. Pipet 5.0 ml of the intermediate Hg standard solution (Section 7.2.2.2) into a 250-ml volumetric glass flask. Add 10 ml of the 5 percent H_2SO_4 and 2 ml of the 0.1 M ICl absorbing solution taken as a blank (Section 8.7.4.3), and dilute to 250 ml with water. Mix thoroughly.

8.0 Sample Collection, Preservation, Transport, and Storage

Because of the complexity of this method, testers should be trained and experienced with the test procedures to ensure reliable results. Since the amount of Hg that is collected generally is small, the method must be carefully applied to prevent contamination or loss of sample.

8.1 Pretest Preparation. Follow the general procedure outlined in Method 5, Section 8.1, except omit Sections 8.1.2 and 8.1.3.

8.2 Preliminary Determinations. Follow the general procedure outlined in Method 5, Section 8.2, with the exception of the following:

8.2.1 Select a nozzle size based on the range of velocity heads to assure that it is not necessary to change the nozzle size in order to maintain isokinetic sampling rates below 28 liters/min (1.0 cfm).

8.2.2 Perform test runs such that samples are obtained over a period or periods that accurately determine the maximum emissions that occur in a 24-hour period. In the case of cyclic operations, run sufficient tests for the accurate determination of the emissions that occur over the duration of the cycle. A minimum sample time of 2 hours is recommended. In some instances, high Hg or high SO_2 concentrations make it impossible to sample for the desired minimum time. This is indicated by reddening (liberation of free iodine) in the first impinger. In these cases, the sample run may be divided into two or more subruns to ensure that the absorbing solution is not depleted.

8.3 Preparation of Sampling Train.

8.3.1 Clean all glassware (probe, impingers, and connectors) by rinsing with 50 percent HNO_3 , tap water, 0.1 M ICl, tap water, and finally deionized distilled water. Place 100 ml of 0.1 M ICl in each of the first three impingers. Take care to prevent the absorbing solution from contacting any greased surfaces. Place approximately 200 g of preweighed silica gel in the fourth impinger. More silica gel may be used, but care should be taken to ensure that it is not entrained and carried out from the impinger during sampling. Place the silica gel container in a clean place for later use in the sample recovery. Alternatively, determine and record the weight of the silica gel plus impinger to the nearest 0.5 g.

8.3.2 Install the selected nozzle using a Viton A O-ring when stack temperatures are less than 260 °C (500 °F). Use a fiberglass string gasket if temperatures are higher. See APTD-0576 (Reference 3 in Method 5) for details. Other connecting systems using either 316 stainless steel or Teflon ferrules may be used. Mark the probe with heat-resistant tape or by some other method to denote the proper distance into the stack or duct for each sampling point.

8.3.3 Assemble the train as shown in Figure 101-1, using (if necessary) a very light coat of silicone grease on all ground glass joints. Grease only the outer portion (see APTD-0576) to avoid the possibility of contamination by the silicone grease.

NOTE: An empty impinger may be inserted between the third impinger and the silica gel to remove excess moisture from the sample stream.

8.3.4 After the sampling train has been assembled, turn on and set the probe heating system, if applicable, at the desired operating temperature. Allow time for the temperatures to stabilize. Place crushed ice around the impingers.

8.4 Leak-Check Procedures. Follow the leak-check procedures outlined in Method 5, Section 8.4.

8.5 Sampling Train Operation. Follow the general procedure outlined in Method 5, Section 8.5. For each run, record the data required on a data sheet such as the one shown in Figure 101-4.

8.6 Calculation of Percent Isokinetic. Same as Method 5, Section 8.6.

8.7 Sample Recovery. Begin proper cleanup procedure as soon as the probe is removed from the stack at the end of the sampling period.

8.7.1 Allow the probe to cool. When it can be safely handled, wipe off any external particulate matter near the tip of the probe nozzle, and place a cap over it. Do not cap off the probe tip tightly while the sampling train is cooling. Capping would create a vacuum and draw liquid out from the impingers.

8.7.2 Before moving the sampling train to the cleanup site, remove the probe from the train, wipe off the silicone grease, and cap the open outlet of the probe. Be careful not to lose any condensate that might be present. Wipe off the silicone grease from the impinger. Use either ground-glass stoppers, plastic caps, or serum caps to close these openings.

8.7.3 Transfer the probe and impinger assembly to a cleanup area that is clean, protected from the wind, and free of Hg contamination. The ambient air in laboratories located in the immediate vicinity of Hg-using facilities is not normally free of Hg contamination.

8.7.4 Inspect the train before and during disassembly, and note any abnormal conditions. Treat the samples as follows.

8.7.4.1 Container No. 1 (Impingers and Probe).

8.7.4.1.1 Using a graduated cylinder, measure the liquid in the first three impingers to within 1 ml. Record the volume of liquid present (e.g., see Figure 5-6 of Method 5). This information is needed to calculate the moisture content of the effluent gas. (Use only glass storage bottles and graduated cylinders that have been precleaned as in Section 8.3.1) Place the contents of the first three impingers into a 1000-ml glass sample bottle.

8.7.4.1.2 Taking care that dust on the outside of the probe or other exterior surfaces does not get into the sample, quantitatively recover the Hg (and any condensate) from the probe nozzle, probe fitting, and probe liner as follows: Rinse these components with two 50-ml portions of 0.1 M ICl. Next, rinse the probe nozzle, fitting and liner, and each piece of connecting glassware between the probe liner and the back half of the third impinger with a maximum of 400 ml of water. Add all washings to the 1000-ml glass sample bottle containing the liquid from the first three impingers.

8.7.4.1.3 After all washings have been collected in the sample container, tighten the lid on the container to prevent leakage during shipment to the laboratory. Mark the height of the liquid to determine later whether leakage occurred during transport. Label the container to identify clearly its contents.

8.7.4.2 Container No. 2 (Silica Gel). Same as Method 5, Section 8.7.6.3.

8.7.4.3 Container No. 3 (Absorbing Solution Blank). Place 50 ml of the 0.1 M ICl absorbing solution in a 100-ml sample bottle. Seal the container. Use this blank to prepare the working Hg standard solution (Section 7.2.2.3).

9.0 Quality Control

9.1 Miscellaneous Quality Control Measures.

Section	**Quality control measure**	**Effect**
8.4 10.2	Sampling equipment leak-checks and calibration	Ensure accuracy and precision of sampling measurements.
10.5, 10.6	Spectrophotometer calibration	Ensure linearity of spectrophotometer response to standards.
11.3.3	Check for matrix effects	Eliminate matrix effects.

9.2 Volume Metering System Checks. Same as Method 5, Section 9.2.

10.0 Calibration and Standardizations

NOTE: Maintain a laboratory log of all calibrations.

10.1 Before use, clean all glassware, both new and used, as follows: brush with soap and tap water, liberally rinse with tap water, soak for 1 hour in 50 percent HNO_3 , and then rinse with deionized distilled water.

10.2 Sampling Equipment. Calibrate the sampling equipment according to the procedures outlined in the following sections of Method 5: Section 10.1 (Probe Nozzle), Section 10.2 (Pitot Tube Assembly), Section 10.3 (Metering System), Section 10.5 (Temperature Sensors), Section 10.6 (Barometer).

10.3 Aeration System Flow Rate Meter. Assemble the aeration system as shown in Figure 101-5. Set the outlet pressure on the aeration gas cylinder regulator to a minimum pressure of 500 mm Hg (10 psi), and use the flow metering valve and a bubble flowmeter or wet-test meter to obtain a flow rate of 1.5 ±0.1 liters/min (0.053 ±0.0035 cfm) through the aeration cell. After the calibration of the aeration system flow rate meter is complete, remove the bubble flowmeter from the system.

10.4 Optical Cell Heating System. Using a 50-ml graduated cylinder, add 50 ml of water to the bottle section of the aeration cell, and attach the bottle section to the bubbler section of the cell. Attach the aeration cell to the optical cell and while aerating at 1.5 ±0.1 liters/min (0.053 ±0.0035 cfm), determine the minimum variable transformer setting necessary to prevent condensation of moisture in the optical cell and in the connecting tubing. (This setting should not exceed 20 volts.)

10.5 Spectrophotometer and Recorder.

10.5.1 The Hg response may be measured by either peak height or peak area.

NOTE: The temperature of the solution affects the rate at which elemental Hg is released from a solution and, consequently, it affects the shape of the absorption curve (area) and the point of maximum absorbance (peak height). Therefore, to obtain reproducible results, bring all solutions to room temperature before use.

10.5.2 Set the spectrophotometer wavelength at 253.7 nm, and make certain the optical cell is at the minimum temperature that will prevent water condensation. Then set the recorder scale as follows: Using a 50-ml graduated cylinder, add 50 ml of water to the aeration cell bottle. Add three drops of Antifoam B to the bottle, and then pipet 5.0 ml of the working Hg standard solution into the aeration cell.

NOTE: Always add the Hg-containing solution to the aeration cell after the 50 ml of water.

10.5.3 Place a Teflon-coated stirring bar in the bottle. Before attaching the bottle section to the bubbler section of the aeration cell, make certain that (1) the aeration cell exit arm stopcock (Figure 101-3) is closed (so that Hg will not prematurely enter the optical cell when the reducing agent is being added) and (2) there is no flow through the bubbler. If conditions (1) and (2) are met, attach the bottle section to the bubbler section of the aeration cell. Pipet 5 ml of tin (II) reducing solution into the aeration cell through the side arm, and immediately stopper the side arm. Stir the solution for 15 seconds, turn on the recorder, open the aeration cell exit arm stopcock, and immediately initiate aeration with continued stirring. Determine the maximum absorbance of the standard, and set this value to read 90 percent of the recorder full scale.

10.6 Calibration Curve.

10.6.1 After setting the recorder scale, repeat the procedure in Section 10.5 using 0.0-, 1.0-, 2.0-, 3.0-, 4.0-, and 5.0-ml aliquots of the working standard solution (final amount of Hg in the aeration cell is 0, 200, 400, 600, 800, and 1000 ng, respectively). Repeat this procedure on each aliquot size until two consecutive peaks agree within 3 percent of their average value.

NOTE: To prevent Hg carryover from one sample to another, do not close the aeration cell from the optical cell until the recorder pen has returned to the baseline.)

10.6.2 It should not be necessary to disconnect the aeration gas inlet line from the aeration cell when changing samples. After separating the bottle and bubbler sections of the aeration cell, place the bubbler section into a 600-ml beaker containing approximately 400 ml of water. Rinse the bottle section of the aeration cell with a stream of water to remove all traces of the tin (II) reducing agent. Also, to prevent the loss of Hg before aeration, remove all traces of the reducing agent between samples by washing with water. It will be necessary, however, to wash the aeration cell parts with concentrated HCl if any of the following conditions occur: (1) A white film appears on any inside surface of the aeration cell, (2) the calibration curve changes suddenly, or (3) the replicate samples do not yield reproducible results.

10.6.3 Subtract the average peak height (or peak area) of the blank (0.0-ml aliquot)—which must be less than 2 percent of recorder full scale—from the averaged peak heights of the 1.0-, 2.0-, 3.0-, 4.0-, and 5.0-ml aliquot standards. If the blank absorbance is greater than 2 percent of full-scale, the probable cause is Hg contamination of a reagent or carry-over of Hg from a previous sample. Prepare the calibration curve by plotting the corrected peak height of each standard solution versus the corresponding final total Hg weight in the aeration cell (in ng), and draw the best fit straight line. This line should either pass through the origin or pass through a point no further from the origin than ±2 percent of the recorder full scale. If the line does not pass through or very near to the origin, check for nonlinearity of the curve and for incorrectly prepared standards.

11.0 Analytical Procedure

11.1 Sample Loss Check. Check the liquid level in each container to see whether liquid was lost during transport. If a noticeable amount of leakage occurred, either void the sample or use methods subject to the approval of the Administrator to account for the losses.

11.2 Sample Preparation. Treat each sample as follows:

11.2.1 Container No. 1 (Impingers and Probe). Carefully transfer the contents of Container No. 1 into a 1000-ml volumetric flask, and adjust the volume to exactly 1000 ml with water.

11.2.2 Dilutions. Pipet a 2-ml aliquot from the diluted sample from Section 11.2.1 into a 250-ml volumetric flask. Add 10 ml of 5 percent H_2SO_4 , and adjust the volume to exactly 250 ml with water. This solution is stable for at least 72 hours.

NOTE: The dilution factor will be 250/2 for this solution.

11.3 Analysis. Calibrate the analytical equipment and develop a calibration curve as outlined in Sections 10.3 through 10.6.

11.3.1 Mercury Samples. Repeat the procedure used to establish the calibration curve with an appropriately sized aliquot (1 to 5 ml) of the diluted sample (from Section 11.2.2) until two consecutive peak heights agree within 3 percent of their average value. The peak maximum of an aliquot (except the 5-ml aliquot) must be greater than 10 percent of the recorder full scale. If the peak maximum of a 1.0-ml aliquot is off scale on the recorder, further dilute the original source sample to bring the Hg concentration into the calibration range of the spectrophotometer.

11.3.2 Run a blank and standard at least after every five samples to check the spectrophotometer calibration. The peak height of the blank must pass through a point no further from the origin than ±2 percent of the recorder full scale. The difference between the measured concentration of the standard (the product of the corrected peak height and the reciprocal of the least squares slope) and the actual concentration of the standard must be less than 7 percent, or recalibration of the analyzer is required.

11.3.3 Check for Matrix Effects (optional). Use the Method of Standard Additions as follows to check at least one sample from each source for matrix effects on the Hg results. The Method of Standard Additions procedures described on pages 9-4 and 9-5 of the section entitled “General Information” of the Perkin Elmer Corporation Atomic Absorption Spectrophotometry Manual, Number 303-0152 (Reference 16 in Section 16.0) are recommended. If the results of the Method of Standard Additions procedure used on the single source sample do not agree to within ±5 percent of the value obtained by the routine atomic absorption analysis, then reanalyze all samples from the source using the Method of Standard Additions procedure.

11.4 Container No. 2 (Silica Gel). Weigh the spent silica gel (or silica gel plus impinger) to the nearest 0.5 g using a balance. (This step may be conducted in the field.)

12.0 Data Analysis and Calculations

Carry out calculations, retaining at least one extra decimal significant figure beyond that of the acquired data. Round off figures only after the final calculation. Other forms of the equations may be used as long as they give equivalent results.

12.1 Average Dry Gas Meter Temperature and Average Orifice Pressure Drop, Dry Gas Volume, Volume of Water Vapor Condensed, Moisture Content, and Isokinetic Variation. Same as Method 5, Sections 12.2 through 12.5 and 12.11, respectively.

12.2 Stack Gas Velocity. Using the data from this test and Equation 2-9 of Method 2, calculate the average stack gas velocity v_s .

12.3 Total Mercury.

12.3.1 For each source sample, correct the average maximum absorbance of the two consecutive samples whose peak heights agree within 3 percent of their average for the contribution of the solution blank (see Section 10.6.3). Use the calibration curve and these corrected averages to determine the final total weight of Hg in ng in the aeration cell for each source sample.

12.3.2 Correct for any dilutions made to bring the sample into the working range of the spectrophotometer. Then calculate the Hg in the original solution, m_{Hg} , as follows:

$$m_{Hg} = \left[C_{Hg(AC)}\left(DF\right)\left(V_f\right)\left(10^{-3}\right)\right]/S \qquad \text{Eq. 101-1}$$

Where:

$C_{Hg(AC)}$ = Total ng of Hg in aliquot analyzed (reagent blank subtracted).

DF = Dilution factor for the Hg-containing solution (before adding to the aeration cell; e.g., DF = 250/2 if the source samples were diluted as described in Section 11.2.2).

V_f = Solution volume of original sample, 1000 ml for samples diluted as described in Section 11.2.1.

10^{-3} = Conversion factor, µg/ng.

S = Aliquot volume added to aeration cell, ml.

12.4 Mercury Emission Rate. Calculate the daily Hg emission rate, R, using Equation 101-2. For continuous operations, the operating time is equal to 86,400 seconds per day. For cyclic operations, use only the time per day each stack is in operation. The total Hg emission rate from a source will be the summation of results from all stacks.

$$R = \frac{K m_{Hg} V_s A_s \left(86,400\times10^{-6}\right)}{\left[V_{m(std)} + V_{w(std)}\right]\left(T_s / P_s\right)} \qquad \text{Eq. 101-2}$$

Where:

K_1 = 0.3858 °K/mm Hg for metric units.
K_1 = 17.64 °R/in. Hg for English units.
K_3 = 10^{-6} g/μg for metric units.
= 2.2046 “ × 10^{-9} lb/μg for English units.
P_s = Absolute stack gas pressure, mm Hg (in. Hg).
t = Daily operating time, sec/day.
T_s = Absolute average stack gas temperature, °K (°R).
$V_{m(std)}$ = Dry gas sample volume at standard conditions, scm (scf).
$V_{w(std)}$ = Volume of water vapor at standard conditions, scm (scf).

12.5 Determination of Compliance. Each performance test consists of three repetitions of the applicable test method. For the purpose of determining compliance with an applicable national emission standard, use the average of the results of all repetitions.

13.0 Method Performance

The following estimates are based on collaborative tests, wherein 13 laboratories performed duplicate analyses on two Hg-containing samples from a chlor-alkali plant and on one laboratory-prepared sample of known Hg concentration. The sample concentrations ranged from 2 to 65 μg Hg/ml.

13.1 Precision. The estimated intra-laboratory and inter-laboratory standard deviations are 1.6 and 1.8 μg Hg/ml, respectively.

13.2 Accuracy. The participating laboratories that analyzed a 64.3 μg Hg/ml (in 0.1 M ICl) standard obtained a mean of 63.7 μg Hg/ml.

13.3 Analytical Range. After initial dilution, the range of this method is 0.5 to 120 μg Hg/ml. The upper limit can be extended by further dilution of the sample.

14.0 Pollution Prevention. [Reserved]

15.0 Waste Management. [Reserved]

16.0 References

Same as Method 5, Section 17.0, References 1-3, 5, and 6, with the addition of the following:

1. Determining Dust Concentration in a Gas Stream. ASME Performance Test Code No. 27. New York, NY. 1957.
2. DeVorkin, Howard, et al. Air Pollution Source Testing Manual. Air Pollution Control District. Los Angeles, CA. November 1963.
3. Hatch, W.R., and W.I. Ott. Determination of Sub-Microgram Quantities of Mercury by Atomic Absorption Spectrophotometry. Anal. Chem. 40:2085-87. 1968.
4. Mark, L.S. Mechanical Engineers' Handbook. McGraw-Hill Book Co., Inc. New York, NY. 1951.
5. Western Precipitation Division of Joy Manufacturing Co. Methods for Determination of Velocity, Volume, Dust and Mist Content of Gases. Bulletin WP-50. Los Angeles, CA. 1968.
6. Perry, J.H. Chemical Engineers' Handbook. McGraw-Hill Book Co., Inc. New York, NY. 1960.
7. Shigehara, R.T., W.F. Todd, and W.S. Smith. Significance of Errors in Stack Sampling Measurements. Stack Sampling News. 1 (3):6-18. September 1973.
8. Smith, W.S., R.T. Shigehara, and W.F. Todd. A Method of Interpreting Stack Sampling Data. Stack Sampling News. 1 (2):8-17. August 1973.
9. Standard Method for Sampling Stacks for Particulate Matter. In: 1971 Annual Book of ASTM Standards, Part 23. ASTM Designation D 2928-71. Philadelphia, PA 1971.
10. Vennard, J.K. Elementary Fluid Mechanics. John Wiley and Sons, Inc. New York. 1947.
11. Mitchell, W.J. and M.R. Midgett. Improved Procedure for Determining Mercury Emissions from Mercury Cell Chlor-Alkali Plants. J. APCA. 26 :674-677. July 1976.
12. Shigehara, R.T. Adjustments in the EPA Nomograph for Different Pitot Tube Coefficients and Dry Molecular Weights. Stack Sampling News. 2 :4-11. October 1974.
13. Vollaro, R.F. Recommended Procedure for Sample Traverses in Ducts Smaller than 12 Inches in Diameter. U.S. Environmental Protection Agency, Emission Measurement Branch. Research Triangle Park, NC. November 1976.
14. Klein, R. and C. Hach. Standard Additions: Uses and Limitation in Spectrophotometric

Measurements. Amer. Lab. 9 :21. 1977.
15. Perkin Elmer Corporation. Analytical Methods for Atomic Absorption Spectrophotometry. Norwalk, Connecticut. September 1976.

17.0 Tables, Diagrams, Flowcharts, and Validation Data

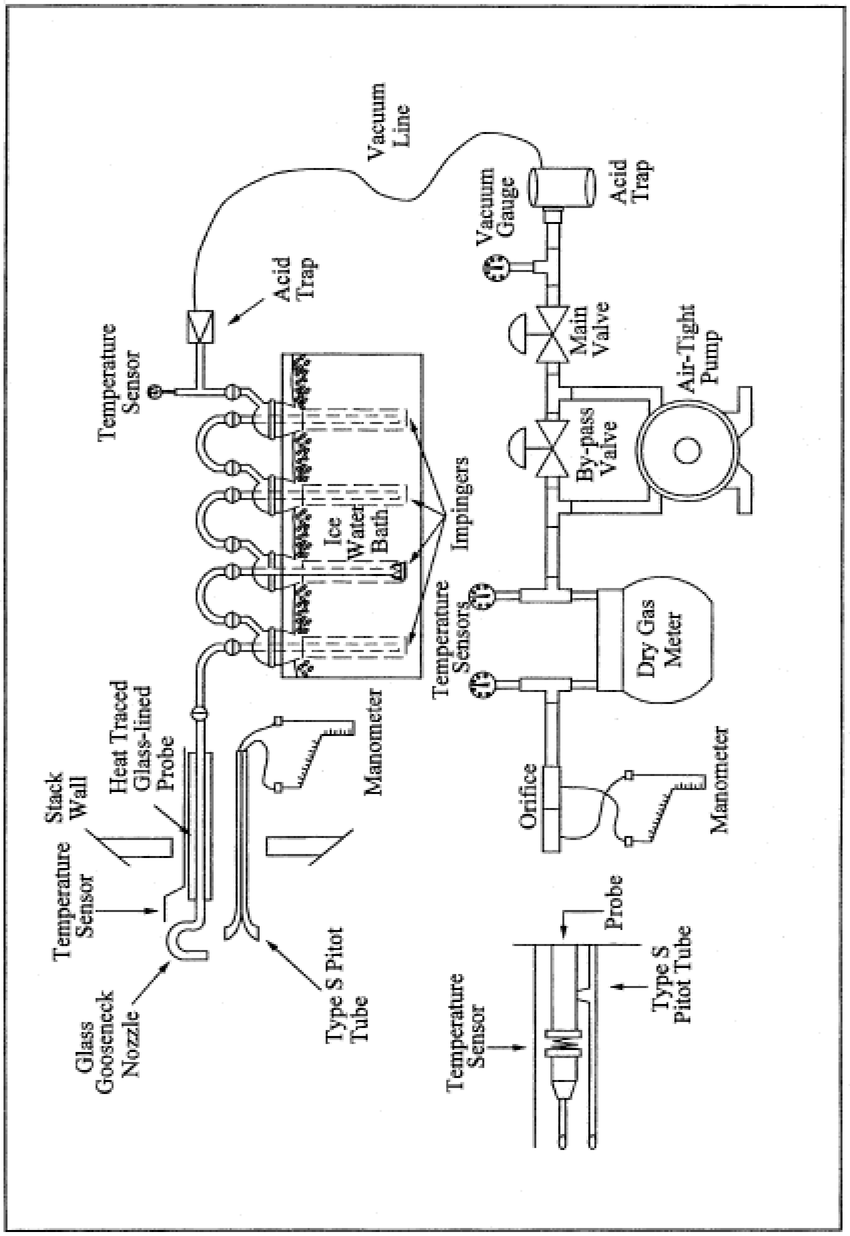

Figure 101-1. Mercury Sampling Train.

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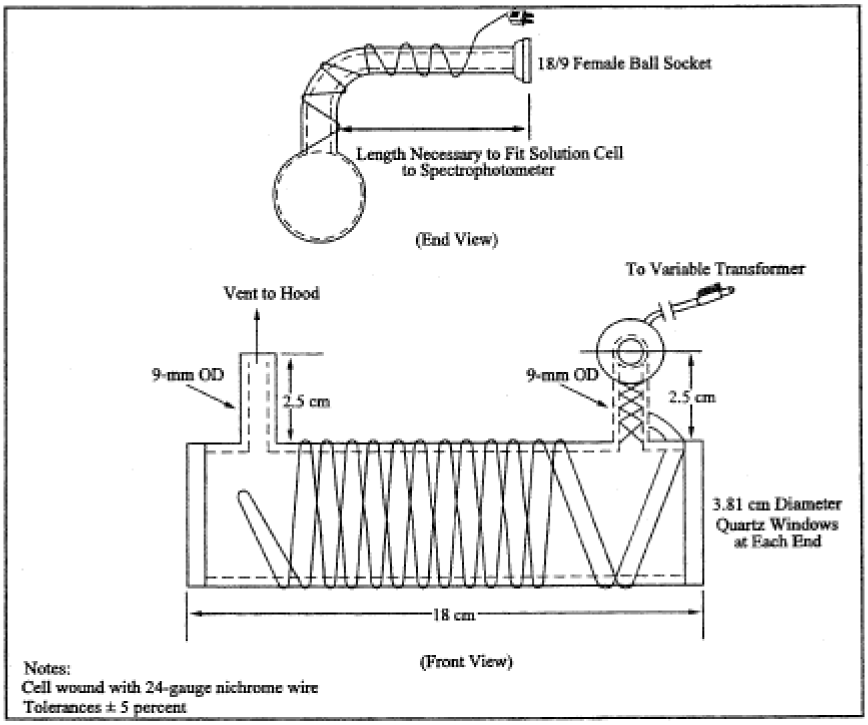

Figure 101-2. Optical Cell.

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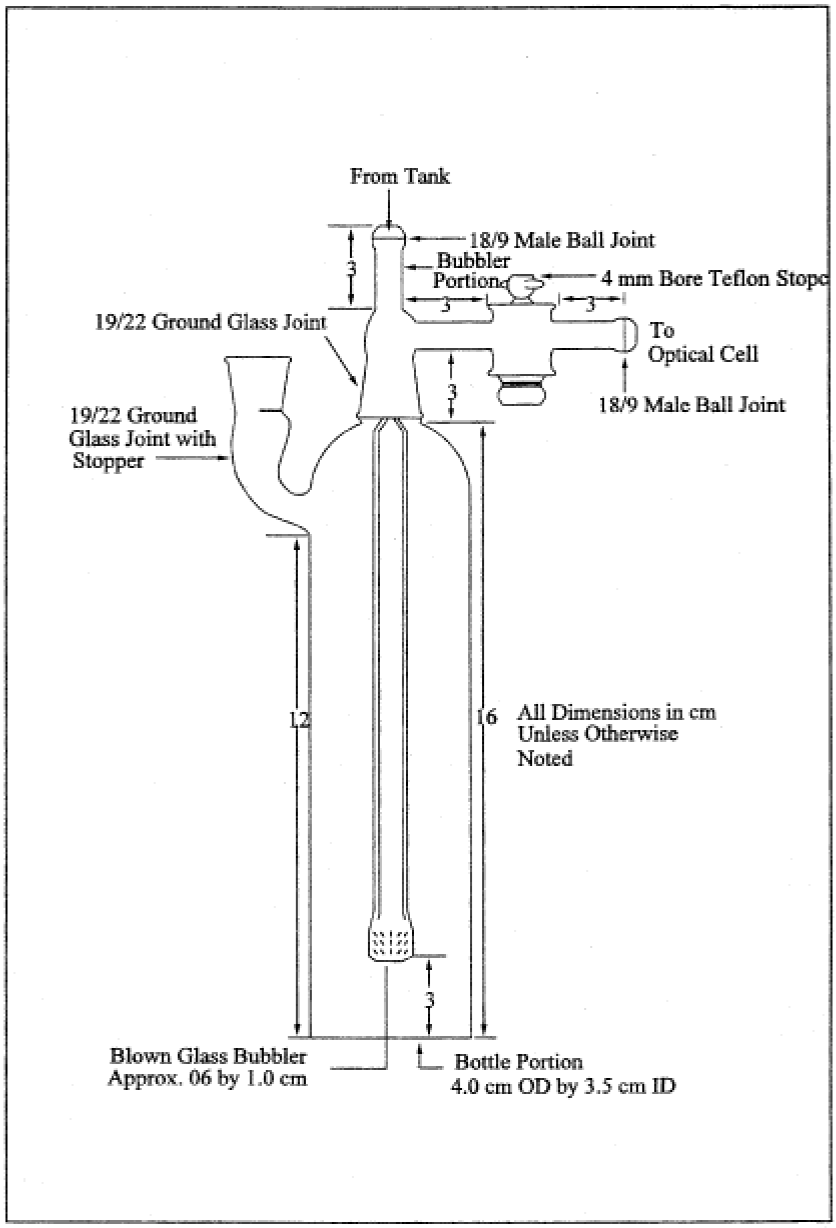

Figure 101-3. Aeration Cell.

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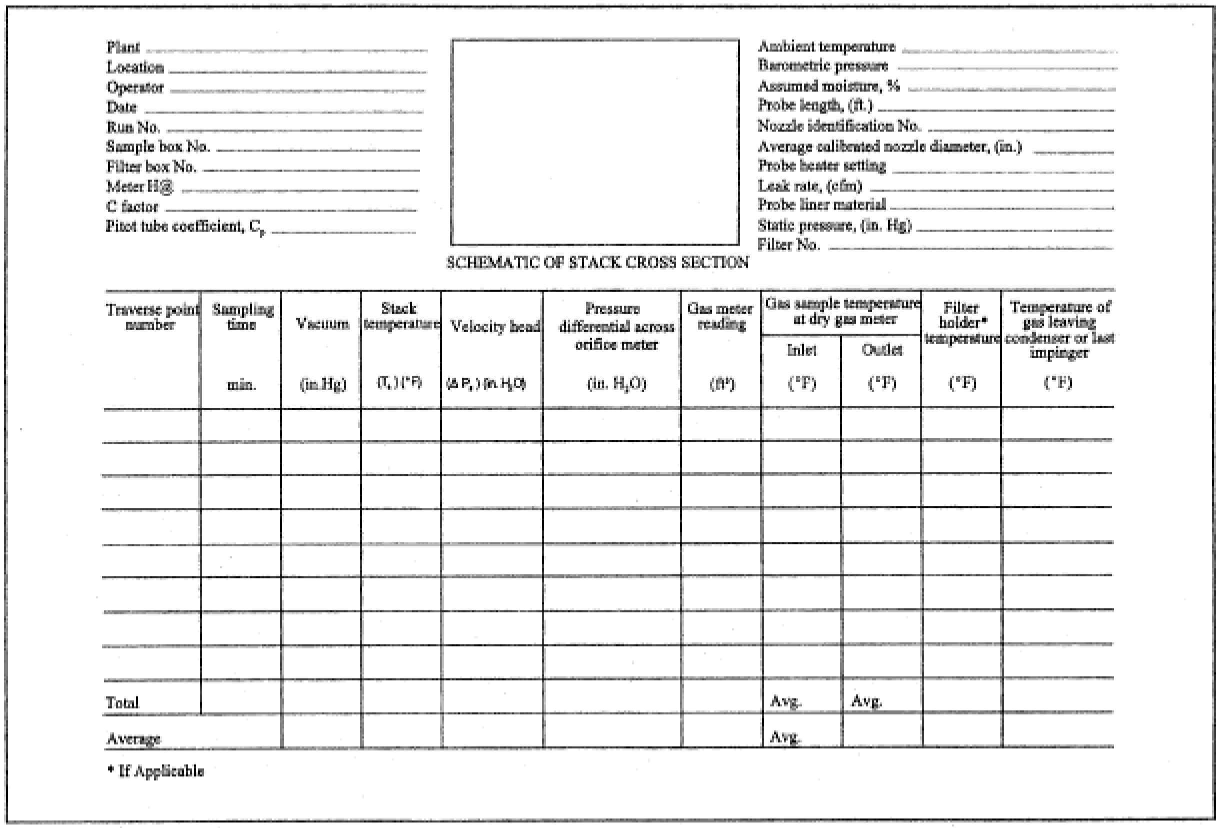

Plant ____________
Location ____________
Operator ____________
Date ____________
Run No. ____________
Sample box No. ____________
Filter box No. ____________
Meter H@ ____________
C factor ____________
Pitot tube coefficient, C_p ____________

SCHEMATIC OF STACK CROSS SECTION

Ambient temperature ____________
Barometric pressure ____________
Assumed moisture, % ____________
Probe length, (ft.) ____________
Nozzle identification No. ____________
Average calibrated nozzle diameter, (in.) ____________
Probe heater setting ____________
Leak rate, (cfm) ____________
Probe liner material ____________
Static pressure, (in. Hg) ____________
Filter No. ____________

Traverse point number	Sampling time	Vacuum	Stack temperature	Velocity head	Pressure differential across orifice meter	Gas meter reading	Gas sample temperature at dry gas meter		Filter holder* temperature	Temperature of gas leaving condenser or last impinger
	min.	(in.Hg)	(T_s) (°F)	(ΔP_s) (in. H_2O)	(in. H_2O)	(ft^3)	Inlet (°F)	Outlet (°F)	(°F)	(°F)
Total							Avg.	Avg.		
Average							Avg.			

* If Applicable

Figure 101-4. Mercury Field Data.

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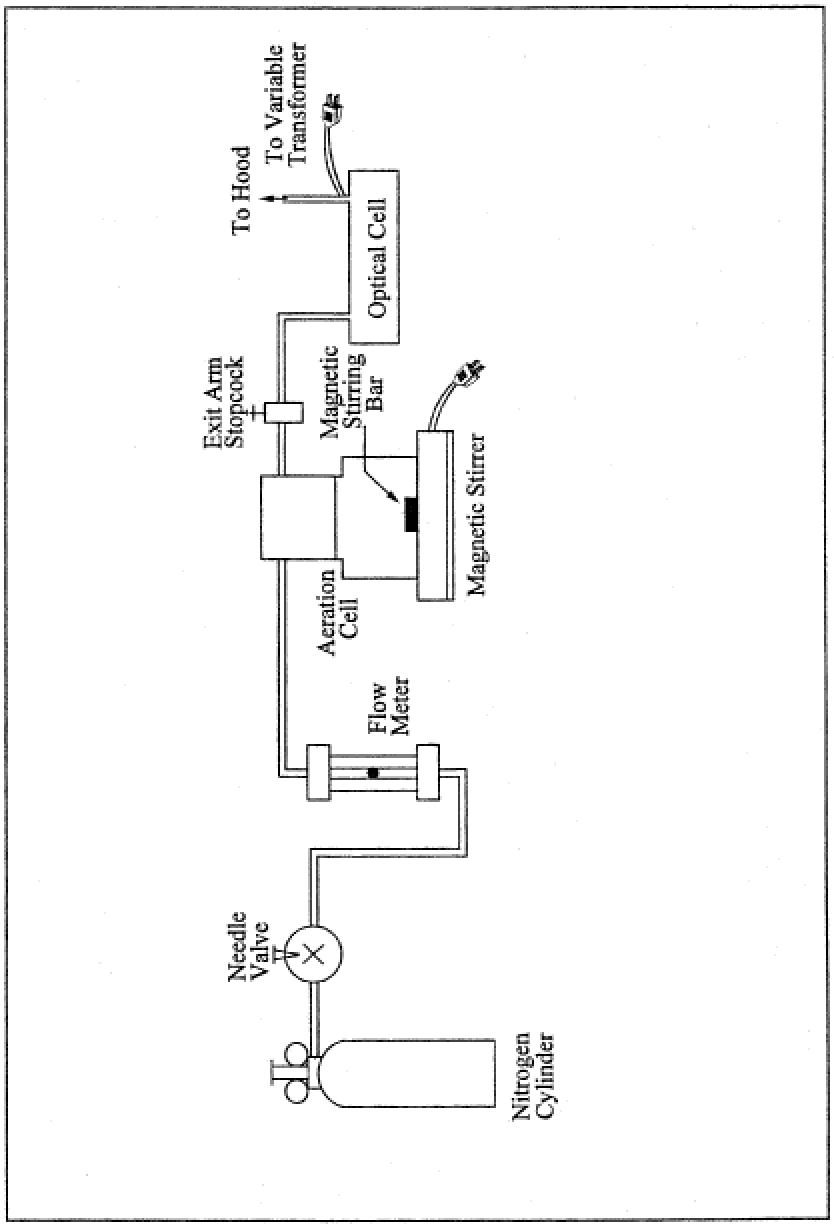

Figure 101-5. Schematic of Aeration System.

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METHOD 101A—DETERMINATION OF PARTICULATE AND GASEOUS MERCURY EMISSIONS FROM SEWAGE SLUDGE INCINERATORS

NOTE: This method does not include all of the specifications (e.g., equipment and supplies) and procedures (e.g., sampling and analytical) essential to its performance. Some material is incorporated by reference from methods in appendix A to 40 CFR part 60 and in this part. Therefore, to obtain reliable results, persons using this method should also have a thorough knowledge of at least the following additional test methods: Methods 1, Method 2, Method 3, and Method 5 of part 60 (appendix A), and Method 101 part 61 (appendix B).

1.0 Scope and Application

1.1 Analytes.

Analyte	CAS No.	Sensitivity
Mercury (Hg)	7439-97-6	Dependent upon spectrophotometer and recorder.

1.2 Applicability. This method is applicable for the determination of Hg emissions from sewage sludge incinerators and other sources as specified in an applicable subpart of the regulations.

1.3 Data Quality Objectives. Adherence to the requirements of this method will enhance the quality of the data obtained from air pollutant sampling methods.

2.0 Summary of Method

2.1 Particulate and gaseous Hg emissions are withdrawn isokinetically from the source and are collected in acidic potassium permanganate ($KMnO_4$) solution. The Hg collected (in the mercuric form) is reduced to elemental Hg, which is then aerated from the solution into an optical cell and measured by atomic absorption spectrophotometry.

3.0 Definitions. [Reserved]

4.0 Interferences

4.1 Sample Collection. Excessive oxidizable organic matter in the stack gas prematurely depletes the $KMnO_4$ solution and thereby prevents further collection of Hg.

4.2 Analysis. Condensation of water vapor on the optical cell windows causes a positive interference.

5.0 Safety

5.1 Disclaimer. This method may involve hazardous materials, operations, and equipment. This test method may not address all of the safety problems associated with its use. It is the responsibility of the user of this test method to establish appropriate safety and health practices and determine the applicability of regulatory limitations prior to performing this test method.

5.2 Corrosive Reagents. The following reagents are hazardous. Personal protective equipment and safe procedures are useful in preventing chemical splashes. If contact occurs, immediately flush with copious amounts of water for at least 15 minutes. Remove clothing under shower and decontaminate. Treat residual chemical burns as thermal burns.

5.2.1 Hydrochloric Acid (HCl). Highly toxic. Vapors are highly irritating to eyes, skin, nose, and lungs, causing severe damage. May cause bronchitis, pneumonia, or edema of lungs. Exposure to concentrations of 0.13 to 0.2 percent can be lethal to humans in a few minutes. Provide ventilation to limit exposure. Reacts with metals, producing hydrogen gas.

5.2.2 Nitric Acid (HNO_3). Highly corrosive to eyes, skin, nose, and lungs. Vapors cause bronchitis, pneumonia, or edema of lungs. Reaction to inhalation may be delayed as long as 30 hours and still be fatal. Provide ventilation to limit exposure. Strong oxidizer. Hazardous reaction may occur with organic materials such as solvents.

5.2.3 Sulfuric acid (H_2SO_4). Rapidly destructive to body tissue. Will cause third degree burns. Eye damage may result in blindness. Inhalation may be fatal from spasm of the larynx, usually within 30 minutes. May cause lung tissue damage with edema. 3 mg/m^3 will cause lung damage in uninitiated. 1 mg/m^3 for 8 hours will cause lung damage or, in higher concentrations, death. Provide ventilation to limit inhalation. Reacts violently with metals and organics.

5.3 Chlorine Evolution. Hydrochloric acid reacts with $KMnO_4$ to liberate chlorine gas. Although this is a minimal concern when small quantities of HCl (5-10 ml) are used in the impinger rinse, a potential safety hazard may still exist. At sources that emit higher concentrations of oxidizable materials (e.g., power plants), more HCl may be required to remove the larger amounts of brown deposit formed in the impingers. In such cases, the potential safety hazards due to sample container pressurization are greater, because of the larger volume of HCl rinse added to the recovered sample. These hazards are eliminated by storing and analyzing the HCl impinger wash separately from the permanganate impinger sample.

6.0 Equipment and Supplies

6.1 Sample Collection and Sample Recovery. Same as Method 101, Sections 6.1 and 6.2, respectively, with the following exceptions:

6.1.1 Probe Liner. Same as in Method 101, Section 6.1.2, except that if a filter is used ahead of the impingers, the probe heating system must be used to minimize the condensation of gaseous Hg.

6.1.2 Filter Holder (Optional). Borosilicate glass with a rigid stainless-steel wire-screen filter support (do not use glass frit supports) and a silicone rubber or Teflon gasket, designed to provide a positive seal against leakage from outside or around the filter. The filter holder must be equipped with a filter heating system capable of maintaining a temperature around the filter holder of 120 ±14 °C (248 ±25 °F) during sampling to minimize both water and gaseous Hg condensation. A filter may also be used in cases where the stream contains large quantities of particulate matter.

6.2 Sample Analysis. Same as Method 101, Section 6.3, with the following additions and exceptions:

6.2.1 Volumetric Pipets. Class A; 1-, 2-, 3-, 4-, 5-, 10-, and 20-ml.

6.2.2 Graduated Cylinder. 25-ml.
6.2.3 Steam Bath.
6.2.4 Atomic Absorption Spectrophotometer or Equivalent. Any atomic absorption unit with an open sample presentation area in which to mount the optical cell is suitable. Instrument settings recommended by the particular manufacturer should be followed. Instruments designed specifically for the measurement of mercury using the cold-vapor technique are commercially available and may be substituted for the atomic absorption spectrophotometer.
6.2.5 Optical Cell. Alternatively, a heat lamp mounted above the cell or a moisture trap installed upstream of the cell may be used.
6.2.6 Aeration Cell. Alternatively, aeration cells available with commercial cold vapor instrumentation may be used.
6.2.7 Aeration Gas Cylinder. Nitrogen, argon, or dry, Hg-free air, equipped with a single-stage regulator. Alternatively, aeration may be provided by a peristaltic metering pump. If a commercial cold vapor instrument is used, follow the manufacturer's recommendations.

7.0 Reagents and Standards

Unless otherwise indicated, it is intended that all reagents conform to the specifications established by the Committee on Analytical Reagents of the American Chemical Society, where such specifications are available; otherwise, use the best available grade.
7.1 Sample Collection and Recovery. The following reagents are required for sample collection and recovery:
7.1.1 Water. Deionized distilled, to conform to ASTM D 1193-77 or 91 Type 1. If high concentrations of organic matter are not expected to be present, the analyst may eliminate the $KMnO_4$ test for oxidizable organic matter. Use this water in all dilutions and solution preparations.
7.1.2 Nitric Acid, 50 Percent (V/V). Mix equal volumes of concentrated HNO_3 and water, being careful to add the acid to the water slowly.
7.1.3 Silica Gel. Indicating type, 6 to 16 mesh. If previously used, dry at 175 °C (350 °F) for 2 hours. New silica gel may be used as received.
7.1.4 Filter (Optional). Glass fiber filter, without organic binder, exhibiting at least 99.95 percent efficiency on 0.3-μm dioctyl phthalate smoke particles. The filter in cases where the gas stream contains large quantities of particulate matter, but blank filters should be analyzed for Hg content.
7.1.5 Sulfuric Acid, 10 Percent (V/V). Carefully add and mix 100 ml of concentrated $H_2 SO_4$ to 900 ml of water.
7.1.6 Absorbing Solution, 4 Percent $KMnO_4$ (W/V). Prepare fresh daily. Dissolve 40 g of $KMnO_4$ in sufficient 10 percent $H_2 SO_4$ to make 1 liter. Prepare and store in glass bottles to prevent degradation.
7.1.7 Hydrochloric Acid, 8 N. Carefully add and mix 67 ml of concentrated HCl to 33 ml of water.
7.2 Sample Analysis. The following reagents and standards are required for sample analysis:
7.2.1 Water. Same as in Section 7.1.1.
7.2.2 Tin (II) Solution. Prepare fresh daily, and keep sealed when not being used. Completely dissolve 20 g of tin (II) chloride (or 25 g of tin (II) sulfate) crystals (Baker Analyzed reagent grade or any other brand that will give a clear solution) in 25 ml of concentrated HCl. Dilute to 250 ml with water. Do not substitute HNO_3 $H2SO_4$, or other strong acids for the HCl.
7.2.3 Sodium Chloride-Hydroxylamine Solution. Dissolve 12 g of sodium chloride and 12 g of hydroxylamine sulfate (or 12 g of hydroxylamine hydrochloride) in water and dilute to 100 ml.
7.2.4 Hydrochloric Acid, 8 N. Same as Section 7.1.7.
7.2.5 Nitric Acid, 15 Percent (V/V). Carefully add 15 ml HNO_3 to 85 ml of water.
7.2.6 Antifoam B Silicon Emulsion. J.T. Baker Company (or equivalent).
7.2.7 Mercury Stock Solution, 1 mg Hg/ml. Prepare and store all Hg standard solutions in borosilicate glass containers. Completely dissolve 0.1354 g of Hg (II) chloride in 75 ml of water. Add 10 ml of concentrated HNO_3 , and adjust the volume to exactly 100 ml with water. Mix thoroughly. This solution is stable for at least one month.
7.2.8 Intermediate Hg Standard Solution, 10 μg/ml. Prepare fresh weekly. Pipet 5.0 ml of the Hg stock solution (Section 7.2.7) into a 500 ml volumetric flask, and add 20 ml of 15 percent HNO_3 solution. Adjust the volume to exactly 500 ml with water. Thoroughly mix the solution.
7.2.9 Working Hg Standard Solution, 200 ng Hg/ml. Prepare fresh daily. Pipet 5.0 ml from the "Intermediate Hg Standard Solution" (Section 7.2.8) into a 250-ml volumetric flask. Add 5 ml of 4 percent $KMnO_4$ absorbing solution and 5 ml of 15 percent HNO_3 . Adjust the volume to exactly 250 ml with water.

Mix thoroughly.

7.2.10 Potassium Permanganate, 5 Percent (W/V). Dissolve 5 g of $KMnO_4$ in water and dilute to 100 ml.

7.2.11 Filter. Whatman No. 40, or equivalent.

8.0 Sample Collection, Preservation, Transport, and Storage

Same as Method 101, Section 8.0, with the exception of the following:

8.1 Preliminary Determinations. Same as Method 101, Section 8.2, except that the liberation of free iodine in the first impinger due to high Hg or sulfur dioxide concentrations is not applicable. In this method, high oxidizable organic content may make it impossible to sample for the desired minimum time. This problem is indicated by the complete bleaching of the purple color of the $KMnO_4$ solution. In cases where an excess of water condensation is encountered, collect two runs to make one sample, or add an extra impinger in front of the first impinger (also containing acidified $KMnO_4$ solution).

8.2 Preparation of Sampling Train. Same as Method 101, Section 8.3, with the exception of the following:

8.2.1 In this method, clean all the glass components by rinsing with 50 percent HNO_3 , tap water, 8 N HCl, tap water, and finally with deionized distilled water. Then place 50 ml of absorbing solution in the first impinger and 100 ml in each of the second and third impingers.

8.2.2 If a filter is used, use a pair of tweezers to place the filter in the filter holder. Be sure to center the filter, and place the gasket in the proper position to prevent the sample gas stream from bypassing the filter. Check the filter for tears after assembly is completed. Be sure also to set the filter heating system at the desired operating temperature after the sampling train has been assembled.

8.3 Sampling Train Operation. In addition to the procedure outlined in Method 101, Section 8.5, maintain a temperature around the filter (if applicable) of 120 ±14 °C (248 ±25 °F).

8.4 Sample Recovery. Same as Method 101, Section 8.7, with the exception of the following:

8.4.1 Transfer the probe, impinger assembly, and (if applicable) filter assembly to the cleanup area.

8.4.2 Treat the sample as follows:

8.4.2.1 Container No. 1 (Impinger, Probe, and Filter Holder) and, if applicable, Container No. 1A (HCl rinse).

8.4.2.1.1 Using a graduated cylinder, measure the liquid in the first three impingers to within 1 ml. Record the volume of liquid present (e.g., see Figure 5-6 of Method 5). This information is needed to calculate the moisture content of the effluent gas. (Use only graduated cylinder and glass storage bottles that have been precleaned as in Section 8.2.1.) Place the contents of the first three impingers (four if an extra impinger was added as described in Section 8.1) into a 1000-ml glass sample bottle labeled Container No. 1.

NOTE: If a filter is used, remove the filter from its holder as outlined under Section 8.4.3.

8.4.2.1.2 Taking care that dust on the outside of the probe or other exterior surfaces does not get into the sample, quantitatively recover the Hg (and any condensate) from the probe nozzle, probe fitting, probe liner, front half of the filter holder (if applicable), and impingers as follows: Rinse these components with a total of 400 ml (350 ml if an extra impinger was added as described in Section 8.1) of fresh absorbing solution, carefully assuring removal of all loose particulate matter from the impingers; add all washings to the 1000 ml glass sample bottle. To remove any residual brown deposits on the glassware following the permanganate rinse, rinse with approximately 100 ml of water, carefully assuring removal of all loose particulate matter from the impingers. Add this rinse to Container No. 1.

8.4.2.1.3 If no visible deposits remain after this water rinse, do not rinse with 8 N HCl. If deposits do remain on the glassware after the water rinse, wash impinger walls and stems with 25 ml of 8 N HCl, and place the wash in a separate container labeled Container No. 1A as follows: Place 200 ml of water in a sample container labeled Container No. 1A. Wash the impinger walls and stem with the HCl by turning the impinger on its side and rotating it so that the HCl contacts all inside surfaces. Pour the HCl wash carefully with stirring into Container No. 1A.

8.4.2.1.4 After all washings have been collected in the appropriate sample container(s), tighten the lid(s) on the container(s) to prevent leakage during shipment to the laboratory. Mark the height of the fluid level to allow subsequent determination of whether leakage has occurred during transport. Label each container to identify its contents clearly.

8.4.3 Container No. 2 (Silica Gel). Same as Method 5, Section 8.7.6.3.

8.4.4 Container No. 3 (Filter). If a filter was used, carefully remove it from the filter holder, place it in a 100-ml glass sample bottle, and add 20 to 40 ml of absorbing solution. If it is necessary to fold the filter, be sure that the particulate cake is inside the fold. Carefully transfer to the 100-ml sample bottle any particulate matter and filter fibers that adhere to the filter holder gasket by using a dry Nylon bristle brush and a sharp-edged blade. Seal the container. Label the container to identify its contents clearly. Mark the height of the fluid level to allow subsequent determination of whether leakage has occurred during transport.

8.4.5 Container No. 4 (Filter Blank). If a filter was used, treat an unused filter from the same filter lot as that used for sampling according to the procedures outlined in Section 8.4.4.

8.4.6 Container No. 5 (Absorbing Solution Blank). Place 650 ml of 4 percent $KMnO_4$ absorbing solution in a 1000-ml sample bottle. Seal the container.

8.4.7 Container No. 6 (HCl Rinse Blank). Place 200 ml of water in a 1000-ml sample bottle, and add 25 ml of 8 N HCl carefully with stirring. Seal the container. Only one blank sample per 3 runs is required.

9.0 Quality Control

9.1 Miscellaneous Quality Control Measures.

Section	Quality control measure	Effect
8.0, 10.0	Sampling equipment leak-checks and calibration	Ensure accuracy and precision of sampling measurements.
10.2	Spectrophotometer calibration	Ensure linearity of spectrophotometer response to standards.
11.3.3	Check for matrix effects	Eliminate matrix effects.

9.2 Volume Metering System Checks. Same as Method 5, Section 9.2.

10.0 Calibration and Standardization

Same as Method 101, Section 10.0, with the following exceptions:

10.1 Optical Cell Heating System Calibration. Same as in Method 101, Section 10.4, except use a-25 ml graduated cylinder to add 25 ml of water to the bottle section of the aeration cell.

10.2 Spectrophotometer and Recorder Calibration.

10.2.1 The Hg response may be measured by either peak height or peak area.

NOTE: The temperature of the solution affects the rate at which elemental Hg is released from a solution and, consequently, it affects the shape of the absorption curve (area) and the point of maximum absorbance (peak height). To obtain reproducible results, all solutions must be brought to room temperature before use.

10.2.2 Set the spectrophotometer wave length at 253.7 nm, and make certain the optical cell is at the minimum temperature that will prevent water condensation. Then set the recorder scale as follows: Using a 25-ml graduated cylinder, add 25 ml of water to the aeration cell bottle. Add three drops of Antifoam B to the bottle, and then pipet 5.0 ml of the working Hg standard solution into the aeration cell.

NOTE: Always add the Hg-containing solution to the aeration cell after the 25 ml of water.

10.2.3 Place a Teflon-coated stirring bar in the bottle. Add 5 ml of absorbing solution to the aeration bottle, and mix well. Before attaching the bottle section to the bubbler section of the aeration cell, make certain that (1) the aeration cell exit arm stopcock (Figure 101-3 of Method 101) is closed (so that Hg will not prematurely enter the optical cell when the reducing agent is being added) and (2) there is no flow through the bubbler. If conditions (1) and (2) are met, attach the bottle section to the bubbler section of the aeration cell. Add sodium chloride-hydroxylamine in 1 ml increments until the solution is colorless. Now add 5 ml of tin (II) solution to the aeration bottle through the side arm, and immediately stopper the side arm. Stir the solution for 15 seconds, turn on the recorder, open the aeration cell exit arm stopcock, and immediately initiate aeration with continued stirring. Determine the maximum absorbance of the standard, and set this value to read 90 percent of the recorder full scale.

11.0 Analytical Procedure

11.1 Sample Loss Check. Check the liquid level in each container to see if liquid was lost during transport. If a noticeable amount of leakage occurred, either void the sample or use methods subject to the approval of the Administrator to account for the losses.

11.2 Sample Preparation. Treat sample containers as follows:

11.2.1 Containers No. 3 and No. 4 (Filter and Filter Blank).

11.2.1.1 If a filter is used, place the contents, including the filter, of Containers No. 3 and No. 4 in separate 250-ml beakers, and heat the beakers on a steam bath until most of the liquid has evaporated. Do not heat to dryness. Add 20 ml of concentrated HNO_3 to the beakers, cover them with a watch glass, and heat on a hot plate at 70 °C (160 °F) for 2 hours. Remove from the hot plate.

11.2.1.2 Filter the solution from digestion of the Container No. 3 contents through Whatman No. 40 filter paper, and save the filtrate for addition to the Container No. 1 filtrate as described in Section 11.2.2. Discard the filter paper.

11.2.1.3 Filter the solution from digestion of the Container No. 4 contents through Whatman No. 40 filter paper, and save the filtrate for addition to Container No. 5 filtrate as described in Section 11.2.3 below. Discard the filter paper.

11.2.2 Container No. 1 (Impingers, Probe, and Filter Holder) and, if applicable, No. 1A (HCl rinse).

11.2.2.1 Filter the contents of Container No. 1 through Whatman No. 40 filter paper into a 1 liter volumetric flask to remove the brown manganese dioxide (MnO_2) precipitate. Save the filter for digestion of the brown MnO_2 precipitate. Add the sample filtrate from Container No. 3 to the 1-liter volumetric flask, and dilute to volume with water. If the combined filtrates are greater than 1000 ml, determine the volume to the nearest ml and make the appropriate corrections for blank subtractions. Mix thoroughly. Mark the filtrate as analysis Sample No. A.1 and analyze for Hg within 48 hr of the filtration step. Place the saved filter, which was used to remove the brown MnO_2 precipitate, into an appropriate sized container. In a laboratory hood, add 25 ml of 8 N HCl to the filter and allow to digest for a minimum of 24 hours at room temperature.

11.2.2.2 Filter the contents of Container 1A through Whatman No. 40 filter paper into a 500-ml volumetric flask. Then filter the digestate of the brown MnO_2 precipitate from Container No. 1 through Whatman No. 40 filter paper into the same 500-ml volumetric flask, and dilute to volume with water. Mark this combined 500 ml dilute solution as analysis Sample No. A.2. Discard the filters.

11.2.3 Container No. 5 (Absorbing Solution Blank) and No. 6 (HCl Rinse Blank).

11.2.3.1 Treat Container No. 5 as Container No. 1 (as described in Section 11.2.2), except substitute the filter blank filtrate from Container No. 4 for the sample filtrate from Container No. 3, and mark as Sample A.1 Blank.

11.2.3.2 Treat Container No. 6 as Container No. 1A, (as described in Section 11.2.2, except substitute the filtrate from the digested blank MnO_2 precipitate for the filtrate from the digested sample MnO_2 precipitate, and mark as Sample No. A.2 Blank.

NOTE: When analyzing samples A.1 Blank and HCl A.2 Blank, always begin with 10 ml aliquots. This applies specifically to blank samples.

11.3 Analysis. Calibrate the analytical equipment and develop a calibration curve as outlined in Section 10.0.

11.3.1 Mercury Samples. Then repeat the procedure used to establish the calibration curve with appropriately sized aliquots (1 to 10 ml) of the samples (from Sections 11.2.2 and 11.2.3) until two consecutive peak heights agree within 3 percent of their average value. If the 10 ml sample is below the detectable limit, use a larger aliquot (up to 20 ml), but decrease the volume of water added to the aeration cell accordingly to prevent the solution volume from exceeding the capacity of the aeration bottle. If the peak maximum of a 1.0 ml aliquot is off scale, further dilute the original sample to bring the Hg concentration into the calibration range of the spectrophotometer. If the Hg content of the absorbing solution and filter blank is below the working range of the analytical method, use zero for the blank.

11.3.2 Run a blank and standard at least after every five samples to check the spectrophotometer calibration; recalibrate as necessary.

11.3.3 Check for Matrix Effects (optional). Same as Method 101, Section 11.3.3.

12.0 Data Analysis and Calculations

NOTE: Carry out calculations, retaining at least one extra decimal significant figure beyond that of the acquired data. Round off figures only after the final calculation. Other forms of the equations may be used as long as they give equivalent results.

12.1 Nomenclature.

$C_{(fltr)Hg}$ = Total ng of Hg in aliquot of $KMnO_4$ filtrate and HNO_3 digestion of filter analyzed (aliquot of analysis Sample No. A.1).

$C_{(fltr\ blk)Hg}$ = Total ng of Hg in aliquot of $KMnO_4$ blank and HNO_3 digestion of blank filter analyzed (aliquot of analysis Sample No. A.1 blank).

$C_{(HC1\ blk)Hg}$ = Total ng of Hg analyzed in aliquot of the 500-ml analysis Sample No. HCl A.2 blank.

$C_{(HCl)Hg}$ = Total ng of Hg analyzed in the aliquot from the 500-ml analysis Sample No. HCl A.2.

DF = Dilution factor for the HCl-digested Hg-containing solution, Analysis Sample No. “HCl A.2.”

DF_{blk} = Dilution factor for the HCl-digested Hg containing solution, Analysis Sample No. “HCl A.2 blank.”

(Refer to sample No. “HCl A.2” dilution factor above.)

$m_{(fltr)Hg}$ = Total blank corrected µg of Hg in $KMnO_4$ filtrate and HNO_3 digestion of filter sample.

$m_{(HCl)Hg}$ = Total blank corrected µg of Hg in HCl rinse and HCl digestate of filter sample.

m_{Hg} = Total blank corrected Hg content in each sample, µg.

S = Aliquot volume of sample added to aeration cell, ml.

S_{blk} = Aliquot volume of blank added to aeration cell, ml.

$Vf_{(blk)}$ = Solution volume of blank sample, 1000 ml for samples diluted as described in Section 11.2.2.

$V_{f(fltr)}$ = Solution volume of original sample, normally 1000 ml for samples diluted as described in Section 11.2.2.

$V_{f(HCl)}$ = Solution volume of original sample, 500 ml for samples diluted as described in Section 11.2.1.

10^{-3} = Conversion factor, µg/ng.

12.2 Average Dry Gas Meter Temperature and Average Orifice Pressure Drop, Dry Gas Volume, Volume of Water Vapor Condensed, Moisture Content, Isokinetic Variation, and Stack Gas Velocity and Volumetric Flow Rate. Same as Method 5, Sections 12.2 through 12.5, 12.11, and 12.12, respectively.

12.3 Total Mercury.

12.3.1 For each source sample, correct the average maximum absorbance of the two consecutive samples whose peak heights agree within 3 percent of their average for the contribution of the blank. Use the calibration curve and these corrected averages to determine the final total weight of Hg in ng in the aeration cell for each source sample.

12.3.2 Correct for any dilutions made to bring the sample into the working range of the spectrophotometer.

$$m_{(HCl)Hg} = \frac{\left[C_{(HCl)Hg} DF\right]}{S} - \frac{\left[C_{(HClblk)Hg} DF_{blk}\right]}{S_{blk}} Vf_{(HCl)} \left(10^{-3}\right) \qquad \text{Eq. 101A-1}$$

NOTE: This dilution factor applies only to the intermediate dilution steps, since the original sample volume [$(V_f)_{HCL}$] of “HCl A.2” has been factored out in the equation along with the sample aliquot (S). In Eq. 101A-1, the sample aliquot, S, is introduced directly into the aeration cell for analysis according to the procedure outlined in Section 11.3.1. A dilution factor is required only if it is necessary to bring the sample into the analytical instrument's calibration range.

NOTE: The maximum allowable blank subtraction for the HCl is the lesser of the two following values: (1) the actual blank measured value (analysis Sample No. HCl A.2 blank), or (2) 5% of the Hg content in the combined HCl rinse and digested sample (analysis Sample No. HCl A.2).

$$m_{(fltr)Hg} = \frac{\left[C_{(fltr)Hg} DF\, V_{f(fltr)}\right]}{S} - \frac{\left[C_{(fltrblk)Hg} DF_{blk} V_{f(blk)}\right]}{S_{blk}} \qquad \text{Eq. 101A-2}$$

NOTE: The maximum allowable blank subtraction for the HCl is the lesser of the two following values: (1) the actual blank measured value (analysis Sample No. “A.1 blank”), or (2) 5% of the Hg content in the filtrate (analysis Sample No. “A.1”).

$$m_{Hg} = m_{(HCl)Hg} + m_{(fltr)Hg} \qquad \text{Eq. 101A-3}$$

12.3 Mercury Emission Rate. Same as Method 101, Section 12.3.

12.4 Determination of Compliance. Same as Method 101, Section 12.4.

13.0 Method Performance

13.1 Precision. Based on eight paired-train tests, the intra-laboratory standard deviation was estimated to be 4.8 µg/ml in the concentration range of 50 to 130 µg/m ^{3} .

13.2 Bias. [Reserved]

13.3 Range. After initial dilution, the range of this method is 20 to 800 ng Hg/ml. The upper limit can be extended by further dilution of the sample.

14.0 Pollution Prevention [Reserved]

15.0 Waste Management [Reserved]

16.0 References

Same as Section 16.0 of Method 101, with the addition of the following:

1. Mitchell, W.J., et al. Test Methods to Determine the Mercury Emissions from Sludge Incineration Plants. U.S. Environmental Protection Agency. Research Triangle Park, NC. Publication No. EPA-600/4-79-058. September 1979.

2. Wilshire, Frank W., et al. Reliability Study of the U.S. EPA's Method 101A—Determination of Particulate and Gaseous Mercury Emissions. U.S. Environmental Protection Agency. Research Triangle Park, NC. Report No. 600/D-31/219 AREAL 367, NTIS Acc No. PB91-233361.

3. Memorandum from William J. Mitchell to Roger T. Shigehara discussing the potential safety hazard in Section 7.2 of Method 101A. February 28, 1990.

17.0 Tables, Diagrams, Flowcharts, And Validation Data [Reserved]

METHOD 102—DETERMINATION OF PARTICULATE AND GASEOUS MERCURY EMISSIONS FROM CHLOR-ALKALI PLANTS (HYDROGEN STREAMS)

NOTE: This method does not include all of the specifications (e.g., equipment and supplies) and procedures (e.g., sampling and analytical) essential to its performance. Some material is incorporated by reference from other methods in this part and in appendix A to 40 CFR part 60. Therefore, to obtain reliable results, persons using this method should have a thorough knowledge of at least the following additional test methods: Method 1, Method 2, Method 3, Method 5, and Method 101.

1.0 Scope and Application

1.1 Analytes.

Analyte	CAS No.	Sensitivity
Mercury (Hg)	7439-97-6	Dependent upon recorder and spectrophotometer.

1.2 Applicability. This method is applicable for the determination of Hg emissions, including both particulate and gaseous Hg, from chlor-alkali plants and other sources (as specified in the regulations) where the carrier-gas stream in the duct or stack is principally hydrogen.

1.3 Data Quality Objectives. Adherence to the requirements of this method will enhance the quality of the data obtained from air pollutant sampling methods.

2.0 Summary of Method

2.1 Particulate and gaseous Hg emissions are withdrawn isokinetically from the source and collected in acidic iodine monochloride (ICl) solution. The Hg collected (in the mercuric form) is reduced to elemental Hg, which is then aerated from the solution into an optical cell and measured by atomic absorption spectrophotometry.

3.0 Definitions [Reserved]

4.0 Interferences

Same as Method 101, Section 4.2.

5.0 Safety

5.1 Disclaimer. This method may involve hazardous materials, operations, and equipment. This test method may not address all of the safety problems associated with its use. It is the responsibility of the user of this test method to establish appropriate safety and health practices and determine the applicability of regulatory limitations prior to performing this test method.

5.2 Corrosive Reagents. Same as Method 101, Section 5.2.

5.3 Explosive Mixtures. The sampler must conduct the source test under conditions of utmost safety because hydrogen and air mixtures are explosive. Since the sampling train essentially is leakless, attention to safe operation can be concentrated at the inlet and outlet. If a leak does occur, however, remove the meter box cover to avoid a possible explosive mixture. The following specific precautions are recommended:

5.3.1 Operate only the vacuum pump during the test. The other electrical equipment, e.g., heaters, fans, and timers, normally are not essential to the success of a hydrogen stream test.

5.3.2 Seal the sample port to minimize leakage of hydrogen from the stack.

5.3.3 Vent sampled hydrogen at least 3 m (10 ft) away from the train. This can be accomplished by attaching a 13-mm (0.50-in.) ID Tygon tube to the exhaust from the orifice meter.

NOTE: A smaller ID tubing may cause the orifice meter calibration to be erroneous. Take care to ensure that the exhaust line is not bent or pinched.

6.0 Equipment and Supplies

Same as Method 101, Section 6.0, with the exception of the following:

6.1 Probe Heating System. Do not use, unless otherwise specified.

6.2 Glass Fiber Filter. Do not use, unless otherwise specified.

7.0 Reagents and Standards

Same as Method 101, Section 7.0.

8.0 Sample Collection, Preservation, Transport, and Storage

Same as Method 101, Section 8.0, with the exception of the following:

8.1 Setting of Isokinetic Rates.

8.1.1 If a nomograph is used, take special care in the calculation of the molecular weight of the stack gas and in the setting of the nomograph to maintain isokinetic conditions during sampling (Sections 8.1.1.1 through 8.1.1.3 below).

8.1.1.1 Calibrate the meter box orifice. Use the techniques described in APTD-0576 (see Reference 9 in Section 17.0 of Method 5). Calibration of the orifice meter at flow conditions that simulate the conditions at the source is suggested. Calibration should either be done with hydrogen or with some other gas having similar Reynolds Number so that there is similarity between the Reynolds Numbers during calibration and during sampling.

8.1.1.2 The nomograph described in APTD-0576 cannot be used to calculate the C factor because the nomograph is designed for use when the stack gas dry molecular weight is 29 ±4. Instead, the following calculation should be made to determine the proper C factor:

$$C = 0.00154 \Delta H@ C_p^2 T_m \left(P_s/P_m\right) \frac{\left(1-B_{ws}\right)^2}{\left(1-B_{ws}\right)+18B_{ws}} \qquad \text{Eq. 102-1}$$

Where:

B_{ws} = Fraction by volume of water vapor in the stack gas.
C_p = Pitot tube calibration coefficient, dimensionless.
M_d = Dry molecular weight of stack gas, lb/lb-mole.
P_s = Absolute pressure of stack gas, in. Hg.
P_m = Absolute pressure of gas at the meter, in. Hg.
T_m = Absolute temperature of gas at the orifice, °R.
$\Delta H_@$ = Meter box calibration factor obtained in Section 8.1.1.1, in. H_2O.
0.00154 = (in. H_2O/°R).

NOTE: This calculation is left in English units, and is not converted to metric units because nomographs are based on English units.

8.1.1.3 Set the calculated C factor on the operating nomograph, and select the proper nozzle diameter and K factor as specified in APTD-0576. If the C factor obtained in Section 8.1.1.2 exceeds the values specified on the existing operating nomograph, expand the C scale logarithmically so that the values can be properly located.

8.1.2 If a calculator is used to set isokinetic rates, it is suggested that the isokinetic equation presented in Reference 13 in Section 17.0 of Method 101 be consulted.

8.2 Sampling in Small (<12-in. Diameter) Stacks. When the stack diameter (or equivalent diameter) is less than 12 inches, conventional pitot tube-probe assemblies should not be used. For sampling guidelines, see Reference 14 in Section 17.0 of Method 101.

9.0 Quality Control

Same as Method 101, Section 9.0.

10.0 Calibration and Standardizations

Same as Method 101, Section 10.0.

11.0 Analytical Procedure

Same as Method 101, Section 11.0.

12.0 Data Analysis and Calculations

Same as Method 101, Section 12.0.

13.0 Method Performance

Same as Method 101, Section 13.0.

13.1 Analytical Range. After initial dilution, the range of this method is 0.5 to 120 µg Hg/ml. The upper limit can be extended by further dilution of the sample.

14.0 Pollution Prevention. [Reserved]

15.0 Waste Management. [Reserved]

16.0 References

Same as Method 101, Section 16.0.

17.0 Tables, Diagrams, Flowcharts, and Validation Data. [Reserved]

METHOD 103—BERYLLIUM SCREENING METHOD

1.0 Scope and Application

1.1 Analytes.

Analyte	CAS No.	Sensitivity
Beryllium (Be)	7440-41-7	Dependent upon analytical procedure used.

1.2 Applicability. This procedure details guidelines and requirements for methods acceptable for use in determining Be emissions in ducts or stacks at stationary sources.

1.3 Data Quality Objectives. Adherence to the requirements of this method will enhance the quality of the data obtained from air pollutant sampling methods.

2.0 Summary of Method

2.1 Particulate Be emissions are withdrawn isokinetically from three points in a duct or stack and are collected on a filter. The collected sample is analyzed for Be using an appropriate technique.

3.0 Definitions. [Reserved]

4.0 Interferences. [Reserved]

5.0 Safety

5.1 Disclaimer. This method may involve hazardous materials, operations, and equipment. This test method may not address all of the safety problems associated with its use. It is the responsibility of the user of this test method to establish appropriate safety and health practices and determine the applicability of regulatory limitations prior to performing this test method.

5.2 Hydrochloric Acid (HCl). Highly corrosive and toxic. Vapors are highly irritating to eyes, skin, nose, and lungs, causing severe damage. May cause bronchitis, pneumonia, or edema of lungs. Exposure to concentrations of 0.13 to 0.2 percent can be lethal to humans in a few minutes. Provide ventilation to limit exposure. Reacts with metals, producing hydrogen gas. Personal protective equipment and safe procedures are useful in preventing chemical splashes. If contact occurs, immediately flush with copious amounts of water at least 15 minutes. Remove clothing under shower and decontaminate. Treat residual chemical burn as thermal burn.

6.0 Equipment and Supplies

6.1 Sample Collection. A schematic of the required sampling train configuration is shown in Figure 103-1 in Section 17.0. The essential components of the train are as follows:

6.1.1 Nozzle. Stainless steel, or equivalent, with sharp, tapered leading edge.

6.1.2 Probe. Sheathed borosilicate or quartz glass tubing.

6.1.3 Filter. Millipore AA, or equivalent, with appropriate filter holder that provides a positive seal against leakage from outside or around the filter. It is suggested that a Whatman 41, or equivalent, be placed immediately against the back side of the Millipore filter as a guard against breakage of the Millipore. Include the backup filter in the analysis. To be equivalent, other filters shall exhibit at least 99.95 percent efficiency (0.05 percent penetration) on 0.3 micron dioctyl phthalate smoke particles, and be amenable to the Be analysis procedure. The filter efficiency tests shall be conducted in accordance with ASTM D 2986-71, 78, 95a (incorporated by reference—see § 61.18). Test data from the supplier's quality control program are sufficient for this purpose.

6.1.4 Meter-Pump System. Any system that will maintain isokinetic sampling rate, determine sample volume, and is capable of a sampling rate of greater than 14 lpm (0.5 cfm).

6.2 Measurement of Stack Conditions. The following equipment is used to measure stack conditions:

6.2.1 Pitot Tube. Type S, or equivalent, with a constant coefficient (±5 percent) over the working range.

6.2.2 Inclined Manometer, or Equivalent. To measure velocity head to ±10 percent of the minimum value.

6.2.3 Temperature Measuring Device. To measure stack temperature to ±1.5 percent of the minimum absolute stack temperature.

6.2.4 Pressure Measuring Device. To measure stack pressure to ±2.5 mm Hg (0.1 in. Hg).

6.2.5 Barometer. To measure atmospheric pressure to ±2.5 mm Hg (0.1 in. Hg).

6.2.6 Wet and Dry Bulb Thermometers, Drying Tubes, Condensers, or Equivalent. To determine stack gas moisture content to ±1 percent.

6.3 Sample Recovery.

6.3.1 Probe Cleaning Equipment. Probe brush or cleaning rod at least as long as probe, or equivalent. Clean cotton balls, or equivalent, should be used with the rod.

6.3.2 Leakless Glass Sample Bottles. To contain sample.

6.4 Analysis. All equipment necessary to perform an atomic absorption, spectrographic, fluorometric, chromatographic, or equivalent analysis.

7.0 Reagents and Standards

7.1 Sample Recovery.

7.1.1 Water. Deionized distilled, to conform to ASTM D 1193-77, 91 (incorporated by reference—see § 61.18), Type 3.

7.1.2 Acetone. Reagent grade.

7.1.3 Wash Acid, 50 Percent (V/V) Hydrochloric Acid (HCl). Mix equal volumes of concentrated HCl and water, being careful to add the acid slowly to the water.

7.2 Analysis. Reagents and standards as necessary for the selected analytical procedure.

8.0 Sample Collection, Preservation, Transport, and Storage

Guidelines for source testing are detailed in the following sections. These guidelines are generally applicable; however, most sample sites differ to some degree and temporary alterations such as stack extensions or expansions often are required to insure the best possible sample site. Further, since Be is hazardous, care should be taken to minimize exposure. Finally, since the total quantity of Be to be collected is quite small, the test must be carefully conducted to prevent contamination or loss of sample.

8.1 Selection of a Sampling Site and Number of Sample Runs. Select a suitable sample site that is as close as practicable to the point of atmospheric emission. If possible, stacks smaller than one foot in diameter should not be sampled.

8.1.1 Ideal Sampling Site. The ideal sampling site is at least eight stack or duct diameters downstream and two diameters upstream from any flow disturbance such as a bend, expansion or contraction. For rectangular cross sections, use Equation 103-1 in Section 12.2 to determine an equivalent diameter, D_e .

8.1.2 Alternate Sampling Site. Some sampling situations may render the above sampling site criteria impractical. In such cases, select an alternate site no less than two diameters downstream and one-half diameter upstream from any point of flow disturbance. Additional sample runs are recommended at any sample site not meeting the criteria of Section 8.1.1.

8.1.3 Number of Sample Runs Per Test. Three sample runs constitute a test. Conduct each run at one of three different points. Select three points that proportionately divide the diameter, or are located at 25, 50, and 75 percent of the diameter from the inside wall. For horizontal ducts, sample on a vertical line through the centroid. For rectangular ducts, sample on a line through the centroid and parallel to a side. If additional sample runs are performed per Section 8.1.2, proportionately divide the duct to accommodate the total number of runs.

8.2 Measurement of Stack Conditions. Using the equipment described in Section 6.2, measure the stack gas pressure, moisture, and temperature to determine the molecular weight of the stack gas. Sound engineering estimates may be made in lieu of direct measurements. Describe the basis for such estimates in the test report.

8.3 Preparation of Sampling Train.

8.3.1 Assemble the sampling train as shown in Figure 103-1. It is recommended that all glassware be precleaned by soaking in wash acid for two hours.

8.3.2 Leak check the sampling train at the sampling site. The leakage rate should not be in excess of 1 percent of the desired sample rate.

8.4 Sampling Train Operation.

8.4.1 For each run, measure the velocity at the selected sampling point. Determine the isokinetic sampling rate. Record the velocity head and the required sampling rate. Place the nozzle at the sampling point with the tip pointing directly into the gas stream. Immediately start the pump and adjust the flow to isokinetic conditions. At the conclusion of the test, record the sampling rate. Again measure the velocity head at the sampling point. The required isokinetic rate at the end of the period should not have deviated more than 20 percent from that originally calculated. Describe the reason for any deviation beyond 20 percent in the test report.

8.4.2 Sample at a minimum rate of 14 liters/min (0.5 cfm). Obtain samples over such a period or periods of time as are necessary to determine the maximum emissions which would occur in a 24-hour period. In the case of cyclic operations, perform sufficient sample runs so as to allow determination or calculation of the emissions that occur over the duration of the cycle. A minimum sampling time of two hours per run is recommended.

8.5 Sample Recovery.

8.5.1 It is recommended that all glassware be precleaned as in Section 8.3. Sample recovery should also be performed in an area free of possible Be contamination. When the sampling train is moved, exercise care to prevent breakage and contamination. Set aside a portion of the acetone used in the sample recovery as a blank for analysis. The total amount of acetone used should be measured for accurate blank correction. Blanks can be eliminated if prior analysis shows negligible amounts.

8.5.2 Remove the filter (and backup filter, if used) and any loose particulate matter from filter holder, and place in a container.

8.5.3 Clean the probe with acetone and a brush or long rod and cotton balls. Wash into the container with the filter. Wash out the filter holder with acetone, and add to the same container.

9.0 Quality Control. [Reserved]

10.0 Calibration and Standardization

10.1 Sampling Train. As a procedural check, compare the sampling rate regulation with a dry gas meter, spirometer, rotameter (calibrated for prevailing atmospheric conditions), or equivalent, attached to the nozzle inlet of the complete sampling train.

10.2 Analysis. Perform the analysis standardization as suggested by the manufacturer of the instrument, or the procedures for the analytical method in use.

11.0 Analytical Procedure

Make the necessary preparation of samples and analyze for Be. Any currently acceptable method (e.g., atomic absorption, spectrographic, fluorometric, chromatographic) may be used.

12.0 Data Analysis and Calculations

12.1 Nomenclature.

A_s (avg) = Stack area, m^2 (ft^2).
L = Length.
R = Be emission rate, g/day.
V_s (avg) = Average stack gas velocity, m/sec (ft/sec).
V_{total} = Total volume of gas sampled, m^3 (ft^3).
W = Width.
W_t = Total weight of Be collected, mg.
10^{-6} = Conversion factor, g/µg.
86,400 = Conversion factor, sec/day.

12.2 Calculate the equivalent diameter, De, for a rectangular cross section as follows:

$$D_e = \frac{2 \cdot L \cdot W}{L + W} \qquad \text{Eq. 103-1}$$

12.3 Calculate the Be emission rate, R, in g/day for each stack using Equation 103-2. For cyclic operations, use only the time per day each stack is in operation. The total Be emission rate from a source is the summation of results from all stacks.

$$R = \frac{W_t V_{s(avg)} A_s (86,400)(10^{-6})}{V_{total}} \qquad \text{Eq. 103-2}$$

12.4 Test Report. Prepare a test report that includes as a minimum: A detailed description of the sampling train used, results of the procedural check described in Section 10.1 with all data and calculations made, all pertinent data taken during the test, the basis for any estimates made, isokinetic sampling calculations, and emission results. Include a description of the test site, with a block diagram and brief description of the process, location of the sample points in the stack cross section, and stack dimensions and distances from any point of disturbance.

13.0 Method Performance. [Reserved]

14.0 Pollution Prevention. [Reserved]

15.0 Waste Management. [Reserved]

16.0 References. [Reserved]

17.0 Tables, Diagrams, Flow Charts, and Validation Data

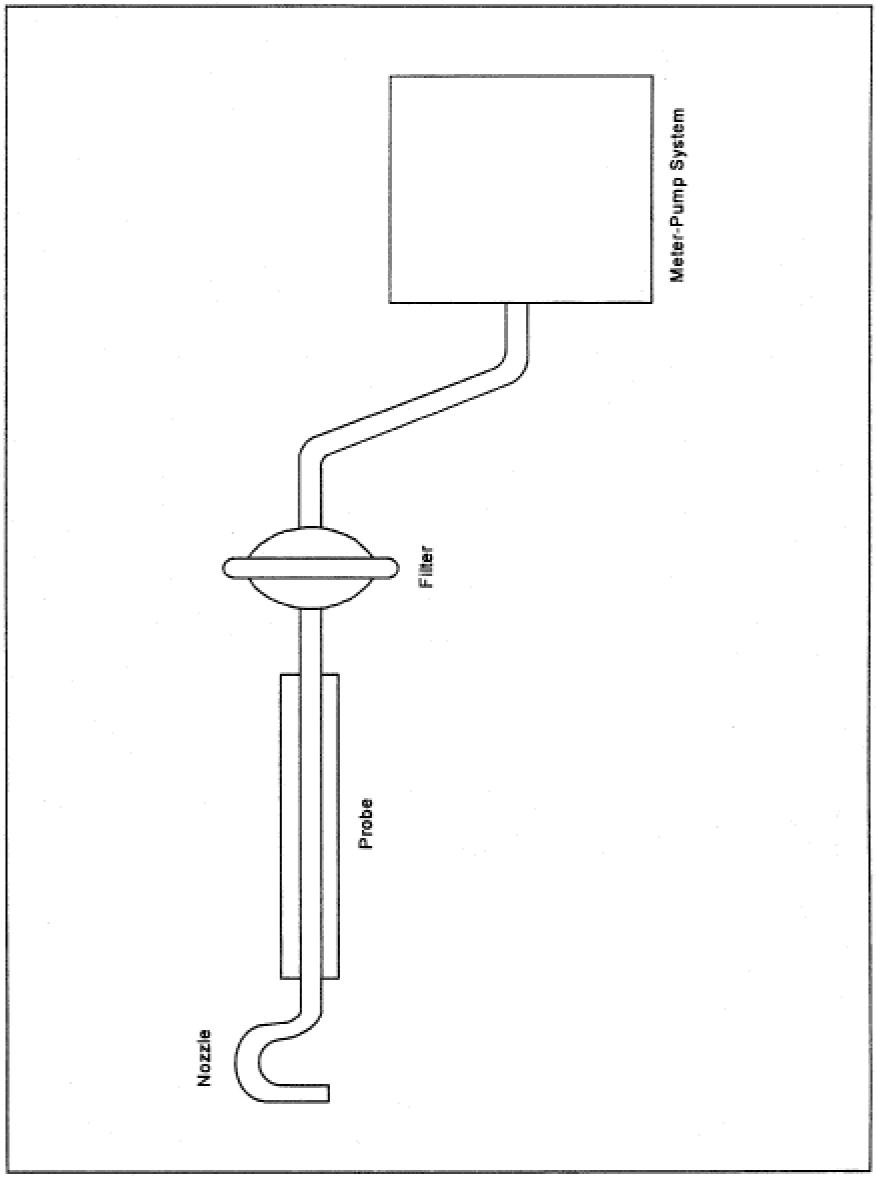

Figure 103-1. Beryllium Screening Method Sampling Train Schematic.

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METHOD 104—DETERMINATION OF BERYLLIUM EMISSIONS FROM STATIONARY SOURCES

NOTE: This method does not include all of the specifications (e.g., equipment and supplies) and procedures (e.g., sampling and analytical) essential to its performance. Some material is incorporated by reference from methods in appendix A to 40 CFR part 60. Therefore, to obtain reliable results, persons using this method should have a thorough knowledge of at least the following additional test methods: Method 1, Method 2, Method 3, and Method 5 in appendix A, part 60.

1.0 Scope and Application

1.1 Analytes.

Analyte	CAS No.	Sensitivity
Beryllium (Be)	7440-41-7	Dependent upon recorder and spectrophotometer.

1.2 Applicability. This method is applicable for the determination of Be emissions in ducts or stacks at stationary sources. Unless otherwise specified, this method is not intended to apply to gas streams other than those emitted directly to the atmosphere without further processing.

1.3 Data Quality Objectives. Adherences to the requirements of this method will enhance the quality of the data obtained from air pollutant sampling methods.

2.0 Summary of Method

2.1 Particulate and gaseous Be emissions are withdrawn isokinetically from the source and are collected on a glass fiber filter and in water. The collected sample is digested in an acid solution and is analyzed by atomic absorption spectrophotometry.

3.0 Definitions [Reserved]

4.0 Interferences

4.1 Matrix Effects. Analysis for Be by flame atomic absorption spectrophotometry is sensitive to the chemical composition and to the physical properties (e.g., viscosity, pH) of the sample. Aluminum and silicon in particular are known to interfere when present in appreciable quantities. The analytical procedure includes (optionally) the use of the Method of Standard Additions to check for these matrix effects, and sample analysis using the Method of Standard Additions if significant matrix effects are found to be present (see Reference 2 in Section 16.0).

5.0 Safety

5.1 Disclaimer. This method may involve hazardous materials, operations, and equipment. This test method may not address all of the safety problems associated with its use. It is the responsibility of the user of this test method to establish appropriate safety and health practices and determine the applicability of regulatory limitations prior to performing this test method.

5.2 Corrosive reagents. The following reagents are hazardous. Personal protective equipment and safe procedures are useful in preventing chemical splashes. If contact occurs, immediately flush with copious amounts of water at least 15 minutes. Remove clothing under shower and decontaminate. Treat residual chemical burn as thermal burn.

5.2.1 Hydrochloric Acid (HC_l). Highly toxic. Vapors are highly irritating to eyes, skin, nose, and lungs, causing severe damage. May cause bronchitis, pneumonia, or edema of lungs. Exposure to concentrations of 0.13 to 0.2 percent can be lethal to humans in a few minutes. Provide ventilation to limit exposure. Reacts with metals, producing hydrogen gas.

5.2.2 Hydrogen Peroxide (H_2O_2). Irritating to eyes, skin, nose, and lungs.

5.2.3 Nitric Acid (HNO_3). Highly corrosive to eyes, skin, nose, and lungs. Vapors cause bronchitis, pneumonia, or edema of lungs. Reaction to inhalation may be delayed as long as 30 hours and still be fatal. Provide ventilation to limit exposure. Strong oxidizer. Hazardous reaction may occur with organic materials such as solvents.

5.2.4 Sodium Hydroxide (NaOH). Causes severe damage to eyes and skin. Inhalation causes irritation to nose, throat, and lungs. Reacts exothermically with limited amounts of water.

5.3 Beryllium is hazardous, and precautions should be taken to minimize exposure.

6.0 Equipment and Supplies

6.1 Sample Collection. Same as Method 5, Section 6.1, with the exception of the following:

6.1.1 Sampling Train. Same as Method 5, Section 6.1.1, with the exception of the following:

6.1.2 Probe Liner. Borosilicate or quartz glass tubing. A heating system capable of maintaining a gas temperature of 120 ±14 °C (248 ±25 °F) at the probe exit during sampling to prevent water condensation may be used.

NOTE: Do not use metal probe liners.

6.1.3 Filter Holder. Borosilicate glass, with a glass frit filter support and a silicone rubber gasket. Other materials of construction (e.g., stainless steel, Teflon, Viton) may be used, subject to the approval of the Administrator. The holder design shall provide a positive seal against leakage from the outside or around the filter. The holder shall be attached immediately at the outlet of the probe. A heating system capable of maintaining the filter at a minimum temperature in the range of the stack temperature may be used to prevent condensation from occurring.

6.1.4 Impingers. Four Greenburg-Smith impingers connected in series with leak-free ground glass fittings or any similar leak-free noncontaminating fittings. For the first, third, and fourth impingers, use impingers that are modified by replacing the tip with a 13 mm-ID (0.5 in.) glass tube extending to 13 mm (0.5 in.) from the bottom of the flask may be used.

6.2 Sample Recovery. The following items are needed for sample recovery:

6.2.1 Probe Cleaning Rod. At least as long as probe.

6.2.2 Glass Sample Bottles. Leakless, with Teflon-lined caps, 1000 ml.

6.2.3 Petri Dishes. For filter samples, glass or polyethylene, unless otherwise specified by the Administrator.
6.2.4 Graduated Cylinder. 250 ml.
6.2.5 Funnel and Rubber Policeman. To aid in transfer of silica gel to container; not necessary if silica gel is weighed in the field.
6.2.6 Funnel. Glass, to aid in sample recovery.
6.2.7 Plastic Jar. Approximately 300 ml.
6.3 Analysis. The following items are needed for sample analysis:
6.3.1 Atomic Absorption Spectrophotometer. Perkin-Elmer 303, or equivalent, with nitrous oxide/acetylene burner.
6.3.2 Hot Plate.
6.3.3 Perchloric Acid Fume Hood.

7.0 Reagents and Standards

NOTE: Unless otherwise indicated, it is intended that all reagents conform to the specifications established by the Committee on Analytical Reagents of the American Chemical Society, where such specifications are available; otherwise, use the best available grade.

7.1 Sample Collection. Same as Method 5, Section 7.1, including deionized distilled water conforming to ASTM D 1193-77 or 91 (incorporated by reference—see § 61.18), Type 3. The Millipore AA filter is recommended.
7.2 Sample Recovery. Same as Method 5 in appendix A, part 60, Section 7.2, with the addition of the following:
7.2.1 Wash Acid, 50 Percent (V/V) Hydrochloric Acid (HCl). Mix equal volumes of concentrated HCl and water, being careful to add the acid slowly to the water.
7.3 Sample Preparation and Analysis. The following reagents and standards and standards are needed for sample preparation and analysis:
7.3.1 Water. Same as in Section 7.1.
7.3.2. Perchloric Acid ($HClO_4$). Concentrated (70 percent V/V).
7.3.3 Nitric Acid (HNO_3). Concentrated.
7.3.4 Beryllium Powder. Minimum purity 98 percent.
7.3.5 Sulfuric Acid (H_2SO_4) Solution, 12 N. Dilute 33 ml of concentrated H_2SO_4 to 1 liter with water.
7.3.6 Hydrochloric Acid Solution, 25 Percent HCl (V/V).
7.3.7 Stock Beryllium Standard Solution, 10 μg Be/ml. Dissolve 10.0 mg of Be in 80 ml of 12 N H_2SO_4 in a 1000-ml volumetric flask. Dilute to volume with water. This solution is stable for at least one month. Equivalent strength Be stock solutions may be prepared from Be salts such as $BeCl_2$ and $Be(NO_3)_2$ (98 percent minimum purity).
7.3.8 Working Beryllium Standard Solution, 1 μg Be/ml. Dilute a 10 ml aliquot of the stock beryllium standard solution to 100 ml with 25 percent HCl solution to give a concentration of 1 mg/ml. Prepare this dilute stock solution fresh daily.

8.0 Sample Collection, Preservation, Transport, and Storage

The amount of Be that is collected is generally small, therefore, it is necessary to exercise particular care to prevent contamination or loss of sample.
8.1 Pretest Preparation. Same as Method 5, Section 8.1, except omit Section 8.1.3.
8.2 Preliminary Determinations. Same as Method 5, Section 8.2, with the exception of the following:
8.2.1 Select a nozzle size based on the range of velocity heads to assure that it is not necessary to change the nozzle size in order to maintain isokinetic sampling rates below 28 liters/min (1.0 cfm).
8.2.2 Obtain samples over a period or periods of time that accurately determine the maximum emissions that occur in a 24-hour period. In the case of cyclic operations, perform sufficient sample runs for the accurate determination of the emissions that occur over the duration of the cycle. A minimum sample time of 2 hours per run is recommended.
8.3 Preparation of Sampling Train. Same as Method 5, Section 8.3, with the exception of the following:
8.3.1 Prior to assembly, clean all glassware (probe, impingers, and connectors) by first soaking in wash acid for 2 hours, followed by rinsing with water.
8.3.2 Save a portion of the water for a blank analysis.
8.3.3 Procedures relating to the use of metal probe liners are not applicable.
8.3.4 Probe and filter heating systems are needed only if water condensation is a problem. If this is the case, adjust the heaters to provide a temperature at or above the stack temperature. However,

membrane filters such as the Millipore AA are limited to about 107 °C (225 °F). If the stack gas is in excess of about 93 °C (200 °F), consideration should be given to an alternate procedure such as moving the filter holder downstream of the first impinger to insure that the filter does not exceed its temperature limit. After the sampling train has been assembled, turn on and set the probe heating system, if applicable, at the desired operating temperature. Allow time for the temperatures to stabilize. Place crushed ice around the impingers.

NOTE: An empty impinger may be inserted between the third impinger and the silica gel to remove excess moisture from the sample stream.

8.4 Leak Check Procedures, Sampling Train Operation, and Calculation of Percent Isokinetic. Same as Method 5, Sections 8.4, 8.5, and 8.6, respectively.

8.5 Sample Recovery. Same as Method 5, Section 8.7, except treat the sample as follows: Transfer the probe and impinger assembly to a cleanup area that is clean, protected from the wind, and free of Be contamination. Inspect the train before and during this assembly, and note any abnormal conditions. Treat the sample as follows: Disconnect the probe from the impinger train.

8.5.1 Container No. 1. Same as Method 5, Section 8.7.6.1.

8.5.2 Container No. 2. Place the contents (measured to 1 ml) of the first three impingers into a glass sample bottle. Use the procedures outlined in Section 8.7.6.2 of Method 5, where applicable, to rinse the probe nozzle, probe fitting, probe liner, filter holder, and all glassware between the filter holder and the back half of the third impinger with water. Repeat this procedure with acetone. Place both water and acetone rinse solutions in the sample bottle with the contents of the impingers.

8.5.3 Container No. 3. Same as Method 5, Section 8.7.6.3.

8.6 Blanks.

8.6.1 Water Blank. Save a portion of the water as a blank. Take 200 ml directly from the wash bottle being used and place it in a plastic sample container labeled “H_2 O blank.”

8.6.2 Filter. Save two filters from each lot of filters used in sampling. Place these filters in a container labeled “filter blank.”

8.7 Post-test Glassware Rinsing. If an additional test is desired, the glassware can be carefully double rinsed with water and reassembled. However, if the glassware is out of use more than 2 days, repeat the initial acid wash procedure.

9.0 QUALITY CONTROL

Section	Quality control measure	Effect
8.4, 10.1	Sampling equipment leak checks and calibration	Ensure accuracy and precision of sampling measurements.
10.2	Spectrophotometer calibration	Ensure linearity of spectrophotometer response to standards.
11.5	Check for matrix effects	Eliminate matrix effects.

10.0 Calibration and Standardization

NOTE: Maintain a laboratory log of all calibrations.

10.1 Sampling Equipment. Same as Method 5, Section 10.0.

10.2 Preparation of Standard Solutions. Pipet 1, 3, 5, 8, and 10 ml of the 1.0 µg Be/ml working standard solution into separate 100 ml volumetric flasks, and dilute to the mark with water. The total amounts of Be in these standards are 1, 3, 5, 8, and 10 µg, respectively.

10.3 Spectrophotometer and Recorder. The Be response may be measured by either peak height or peak area. Analyze an aliquot of the 10-µg standard at 234.8 nm using a nitrous oxide/acetylene flame. Determine the maximum absorbance of the standard, and set this value to read 90 percent of the recorder full scale.

10.4 Calibration Curve.

10.4.1 After setting the recorder scale, analyze an appropriately sized aliquot of each standard and the BLANK (see Section 11) until two consecutive peaks agree within 3 percent of their average value.

10.4.3 Subtract the average peak height (or peak area) of the blank—which must be less than 2 percent of recorder full scale—from the averaged peak heights of the standards. If the blank absorbance is greater than 2 percent of full-scale, the probable cause is Be contamination of a reagent or carry-over of Be from a previous sample. Prepare the calibration curve by plotting the corrected peak height of each standard solution versus the corresponding total Be weight in the standard (in µg).

10.5 Spectrophotometer Calibration Quality Control. Calculate the least squares slope of the calibration curve. The line must pass through the origin or through a point no further from the origin than ±2 percent of the recorder full scale. Multiply the corrected peak height by the reciprocal of the least squares slope to determine the distance each calibration point lies from the theoretical calibration line. The difference between the calculated concentration values and the actual concentrations (i.e., 1, 3, 5, 8, and 10 µg Be) must be less than 7 percent for all standards.

11.0 Analytical Procedure

11.1 Sample Loss Check. Prior to analysis, check the liquid level in Container No. 2. Note on the analytical data sheet whether leakage occurred during transport. If a noticeable amount of leakage occurred, either void the sample or take steps, subject to the approval of the Administrator, to adjust the final results.

11.2 Glassware Cleaning. Before use, clean all glassware according to the procedure of Section 8.3.1.

11.3 Sample Preparation. The digestion of Be samples is accomplished in part in concentrated $HClO_4$.

NOTE: The sample must be heated to light brown fumes after the initial HNO3 addition; otherwise, dangerous perchlorates may result from the subsequent $HClO_4$ digestion. $HClO_4$ should be used only under a hood.

11.3.1 Container No. 1. Transfer the filter and any loose particulate matter from Container No. 1 to a 150-ml beaker. Add 35 ml concentrated HNO_3 . To oxidize all organic matter, heat on a hotplate until light brown fumes are evident. Cool to room temperature, and add 5 ml 12 N H_2SO_4 and 5 ml concentrated $HClO_4$.

11.3.2 Container No. 2. Place a portion of the water and acetone sample into a 150 ml beaker, and put on a hotplate. Add portions of the remainder as evaporation proceeds and evaporate to dryness. Cool the residue, and add 35 ml concentrated HNO_3 . To oxidize all organic matter, heat on a hotplate until light brown fumes are evident. Cool to room temperature, and add 5 ml 12 N H_2SO_4 and 5 ml concentrated $HClO_4$. Then proceed with step 11.3.4.

11.3.3 Final Sample Preparation. Add the sample from Section 11.3.2 to the 150-ml beaker from Section 11.3.1. Replace on a hotplate, and evaporate to dryness in a $HClO_4$ hood. Cool the residue to room temperature, add 10.0 ml of 25 percent V/V HCl, and mix to dissolve the residue.

11.3.4 Filter and Water Blanks. Cut each filter into strips, and treat each filter individually as directed in Section 11.3.1. Treat the 200-ml water blank as directed in Section 11.3.2. Combine and treat these blanks as directed in Section 11.3.3.

11.4 Spectrophotometer Preparation. Turn on the power; set the wavelength, slit width, and lamp current; and adjust the background corrector as instructed by the manufacturer's manual for the particular atomic absorption spectrophotometer. Adjust the burner and flame characteristics as necessary.

11.5 Analysis. Calibrate the analytical equipment and develop a calibration curve as outlined in Sections 10.4 and 10.5.

11.5.1 Beryllium Samples. Repeat the procedure used to establish the calibration curve with an appropriately sized aliquot of each sample (from Section 11.3.3) until two consecutive peak heights agree within 3 percent of their average value. The peak height of each sample must be greater than 10 percent of the recorder full scale. If the peak height of the sample is off scale on the recorder, further dilute the original source sample to bring the Be concentration into the calibration range of the spectrophotometer.

11.5.2 Run a blank and standard at least after every five samples to check the spectrophotometer calibration. The peak height of the blank must pass through a point no further from the origin than ±2 percent of the recorder full scale. The difference between the measured concentration of the standard (the product of the corrected peak height and the reciprocal of the least squares slope) and the actual concentration of the standard must be less than 7 percent, or recalibration of the analyzer is required.

11.5.3 Check for Matrix Effects (optional). Use the Method of Standard Additions (see Reference 2 in Section 16.0) to check at least one sample from each source for matrix effects on the Be results. If the results of the Method of Standard Additions procedure used on the single source sample do not agree to within 5 percent of the value obtained by the routine atomic absorption analysis, then reanalyze all samples from the source using the Method of Standard Additions procedure.

11.6 Container No. 2 (Silica Gel). Weigh the spent silica gel (or silica gel plus impinger) to the nearest 0.5 g using a balance. (This step may be conducted in the field.)

12.0 Data Analysis and Calculations

Carry out calculations, retaining at least one extra decimal significant figure beyond that of the acquired data. Round off figures only after the final calculation. Other forms of the equations may be used as long as they give equivalent results.

12.1 Nomenclature.

K_1 = 0.3858 °K/mm Hg for metric units.
= 17.64 °R/in. Hg for English units.
$K_3 = 10^{-6}$ g/μg for metric units.
$= 2.2046 \times 10^{-9}$ lb/μg for English units.
m_{Be} = Total weight of beryllium in the source sample.
P_s = Absolute stack gas pressure, mm Hg (in. Hg).
t = Daily operating time, sec/day.
T_s = Absolute average stack gas temperature, °K (°R).
$V_{m(std)}$ = Dry gas sample volume at standard conditions, scm (scf).
$V_{w(std)}$ = Volume of water vapor at standard conditions, scm (scf).

12.2 Average Dry Gas Meter Temperature and Average Orifice Pressure Drop, Dry Gas Volume, Volume of Water Vapor Condensed, Moisture Content, Isokinetic Variation, and Stack Gas Velocity and Volumetric Flow Rate. Same as Method 5, Sections 12.2 through 12.5, 12.11, and 12.12, respectively.

12.3 Total Beryllium. For each source sample, correct the average maximum absorbance of the two consecutive samples whose peak heights agree within 3 percent of their average for the contribution of the solution blank (see Sections 11.3.4 and 11.5.2). Correcting for any dilutions if necessary, use the calibration curve and these corrected averages to determine the total weight of Be in each source sample.

12.4 Beryllium Emission Rate. Calculate the daily Hg emission rate, R, using Equation 104-1. For continuous operations, the operating time is equal to 86,400 seconds per day. For cyclic operations, use only the time per day each stack is in operation. The total Hg emission rate from a source will be the summation of results from all stacks.

$$R = \frac{K_1 K_3 t m_{Be} P_s v_s A_s}{T_s \left(V_{m(std)} + V_{w(std)} \right)} \qquad \text{Eq. 104-1}$$

12.5 Determination of Compliance. Each performance test consists of three sample runs. For the purpose of determining compliance with an applicable national emission standard, use the average of the results of all sample runs.

13.0 Method Performance. [Reserved]

14.0 Pollution Prevention. [Reserved]

15.0 Waste Management. [Reserved]

16.0 References

Same as References 1, 2, and 4-11 of Section 16.0 of Method 101 with the addition of the following:

1. Amos, M.D., and J.B. Willis. Use of High-Temperature Pre-Mixed Flames in Atomic Absorption Spectroscopy. Spectrochim. Acta. 22:1325. 1966.
2. Fleet, B., K.V. Liberty, and T. S. West. A Study of Some Matrix Effects in the Determination of Beryllium by Atomic Absorption Spectroscopy in the Nitrous Oxide-Acetylene Flame. Talanta 17:203. 1970.

17.0 Tables, Diagrams, Flowcharts, And Validation Data [Reserved]

METHOD 105—DETERMINATION OF MERCURY IN WASTEWATER TREATMENT PLANT SEWAGE SLUDGES

NOTE: This method does not include all of the specifications (e.g., equipment and supplies) and procedures (e.g., sampling and analytical) essential to its performance. Some material is incorporated by reference from other methods in this part. Therefore, to obtain reliable results, persons using this method should also have a thorough knowledge of at least the following additional test methods: Method 101 and Method 101A.

1.0 Scope and Application

1.1 Analytes.

Analyte	CAS No.	Sensitivity
Mercury (Hg)	7439-97-6	Dependent upon spectrophotometer and recorder.

1.2 Applicability. This method is applicable for the determination of total organic and inorganic Hg content in sewage sludges.

1.3 Data Quality Objectives. Adherence to the requirements of this method will enhance the quality of the data obtained from air pollutant sampling methods.

2.0 Summary of Method

2.1 Time-composite sludge samples are withdrawn from the conveyor belt subsequent to dewatering and before incineration or drying. A weighed portion of the sludge is digested in aqua regia and is oxidized by potassium permanganate ($KMnO_4$). Mercury in the digested sample is then measured by the conventional spectrophotometric cold-vapor technique.

3.0 Definitions [Reserved]

4.0 Interferences [Reserved]

5.0 Safety

5.1 Disclaimer. This method may involve hazardous materials, operations, and equipment. This test method may not address all of the safety problems associated with its use. It is the responsibility of the user of this test method to establish appropriate safety and health practices and determine the applicability of regulatory limitations prior to performing this test method.

5.2 Corrosive Reagents. The following reagents are hazardous. Personal protective equipment and safe procedures are useful in preventing chemical splashes. If contact occurs, immediately flush with copious amounts of water at least 15 minutes. Remove clothing under shower and decontaminate. Treat residual chemical burn as thermal burn.

5.2.1 Hydrochloric Acid (HCl). Highly toxic. Vapors are highly irritating to eyes, skin, nose, and lungs, causing severe damage. May cause bronchitis, pneumonia, or edema of lungs. Exposure to concentrations of 0.13 to 0.2 percent can be lethal to humans in a few minutes. Provide ventilation to limit exposure. Reacts with metals, producing hydrogen gas.

5.2.2 Nitric Acid (HNO_3). Highly corrosive to eyes, skin, nose, and lungs. Vapors cause bronchitis, pneumonia, or edema of lungs. Reaction to inhalation may be delayed as long as 30 hours and still be fatal. Provide ventilation to limit exposure. Strong oxidizer. Hazardous reaction may occur with organic materials such as solvents.

6.0 Equipment and Supplies

6.1 Sample Collection and Mixing. The following items are required for collection and mixing of the sludge samples:

6.1.1 Container. Plastic, 50-liter.

6.1.2 Scoop. To remove 950-ml (1 quart.) sludge sample.

6.1.3 Mixer. Mortar mixer, wheelbarrow-type, 57-liter (or equivalent) with electricity-driven motor.

6.1.4 Blender. Waring-type, 2-liter.

6.1.5 Scoop. To remove 100-ml and 20-ml samples of blended sludge.

6.1.6 Erlenmeyer Flasks. Four, 125-ml.

6.1.7 Beakers. Glass beakers in the following sizes: 50 ml (1), 200 ml (1), 400 ml (2).

6.2 Sample Preparation and Analysis. Same as Method 101, Section 6.3, with the addition of the following:

6.2.1 Hot Plate.

6.2.2 Desiccator.

6.2.3 Filter Paper. S and S No. 588 (or equivalent).

6.2.4 Beakers. Glass beakers, 200 ml and 400 ml (2 each).

7.0 Reagents and Standards

NOTE: Unless otherwise indicated, it is intended that all reagents conform to the specifications established by the Committee on Analytical Reagents of the American Chemical Society, where such specifications are available; otherwise, use the best available grade.

7.1 Sample Analysis. Same as Method 101A, Section 7.2, with the following additions and exceptions:

7.1.1 Hydrochloric Acid. The concentrated HCl specified in Method 101A, Section 7.2.4, is not required.

7.1.2 Aqua Regia. Prepare immediately before use. Carefully add one volume of concentrated HNO_3 to three volumes of concentrated HCl.

8.0 Sample Collection, Preservation, Storage, and Transport

8.1 Sludge Sampling. Withdraw equal volume increments of sludge [for a total of at least 15 liters (16 quarts)] at intervals of 30 min over an 8-hr period, and combine in a rigid plastic container.

8.2 Sludge Mixing. Transfer the entire 15-liter sample to a mortar mixer. Mix the sample for a minimum of 30 min at 30 rpm. Take six 100-ml portions of sludge, and combine in a 2-liter blender. Blend sludge for 5 min; add water as necessary to give a fluid consistency. Immediately after stopping the blender, withdraw four 20-ml portions of blended sludge, and place them in separate, tared 125-ml Erlenmeyer flasks. Reweigh each flask to determine the exact amount of sludge added.

8.3 Sample Holding Time. Samples shall be analyzed within the time specified in the applicable subpart of the regulations.

9.0 Quality Control

Section	Quality control measure	Effect
10.0	Spectrophotometer calibration	Ensure linearity of spectrophotometer response to standards.
11.0	Check for matrix effects	Eliminate matrix effects.

10.0 Calibration and Standardization

Same as Method 101A, Section 10.2.

11.0 Analytical Procedures

11.1 Solids Content of Blended Sludge. Dry one of the 20-ml blended samples from Section 8.2 in an oven at 105 °C (221 °F) to constant weight. Cool in a desiccator, weigh and record the dry weight of the sample.

11.2 Aqua Regia Digestion of Blended Samples.

11.2.1 To each of the three remaining 20-ml samples from Section 8.2 add 25 ml of aqua regia, and digest the on a hot plate at low heat (do not boil) for 30 min, or until samples are a pale yellow-brown color and are void of the dark brown color characteristic of organic matter. Remove from hotplate and allow to cool.

11.2.2 Filter each digested sample separately through an S and S No. 588 filter or equivalent, and rinse the filter contents with 50 ml of water. Transfer the filtrate and filter washing to a 100-ml volumetric flask, and carefully dilute to volume with water.

11.3 Solids Content of the Sludge Before Blending. Remove two 100-ml portions of mixed sludge from the mortar mixer and place in separate, tared 400-ml beakers. Reweigh each beaker to determine the exact amount of sludge added. Dry in oven at 105 °C (221 °F) and cool in a desiccator to constant weight.

11.4 Analysis for Mercury. Analyze the three aqua regia-digested samples using the procedures outlined in Method 101A, Section 11.0.

12.0 Data Analysis and Calculations

12.1 Nomenclature.

C_m = Concentration of Hg in the digested sample, μg/g.
F_{sb} = Weight fraction of solids in the blended sludge.
F_{sm} = Weight fraction of solids in the collected sludge after mixing.
M = Hg content of the sewage sludge (on a dry basis), μg/g.
m = Mass of Hg in the aliquot of digested sample analyzed, μg.
n = number of digested samples (specified in Section 11.2 as three).
V_a = Volume of digested sample analyzed, ml.
V_s = Volume of digested sample, ml.
W_b = Weight of empty sample beaker, g.
W_{bs} = Weight of sample beaker and sample, g.
W_{bd} = Weight of sample beaker and sample after drying, g.
W_f = Weight of empty sample flask, g.
W_{fd} = Weight of sample flask and sample after drying, g.
W_{fs} = Weight of sample flask and sample, g.

12.2 Mercury Content of Digested Sample (Wet Basis).

12.2.1 For each sample analyzed for Hg content, calculate the arithmetic mean maximum absorbance of the two consecutive samples whose peak heights agree ±3 percent of their average. Correct this average value for the contribution of the blank. Use the calibration curve and these corrected averages to determine the final Hg concentration in the solution cell for each sludge sample.

12.2.2 Calculate the average Hg concentration of the digested samples by correcting for any dilutions made to bring the sample into the working range of the spectrophotometer and for the weight of the sludge portion digested, using Equation 105-1.

$$\bar{C}_m = \sum_{i=1}^{n} \left[\frac{m V_s}{V_a \left(W_{fs} - W_f \right)} \right]_i \qquad \text{Eq. 105-1}$$

12.3 Solids Content of Blended Sludge. Determine the solids content of the blended sludge using Equation 105-2.

$$F_{sb} = 1 - \frac{W_{fs} - W_{fd}}{W_{fs} - W_f} \qquad \text{Eq. 105-2}$$

12.4 Solids Content of Bulk Sample (before blending but, after mixing in mortar mixer). Determine the solids content of each 100 ml aliquot (Section 11.3), and average the results.

$$F_{sm} = 1 - \frac{W_{bs} - W_{bd}}{W_{bs} - W_b} \qquad \text{Eq. 105-3}$$

12.5 Mercury Content of Bulk Sample (Dry Basis). Average the results from the three samples from each 8-hr composite sample, and calculate the Hg concentration of the composite sample on a dry basis.

$$M = \frac{\bar{C}_m}{F_{sb}} \qquad \text{Eq. 105-4}$$

13.0 Method Performance

13.1 Range. The range of this method is 0.2 to 5 micrograms per gram; it may be extended by increasing or decreasing sample size.

14.0 Pollution Prevention. [Reserved]

15.0 Waste Management. [Reserved]

16.0 References

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2. Salma, M. Private Communication. EPA California/Nevada Basin Office. Alameda, California.
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5. Analytical Quality Control Laboratory (AQCL). Mercury in Sediment (Cold Vapor Technique) (Provisional Method). U.S. Environmental Protection Agency. Cincinnati, Ohio. April 1972.
6. Kopp, J.F., M.C. Longbottom, and L.B. Lobring. “Cold Vapor” Method for Determining Mercury. Journal AWWA. 64(1):20-25. 1972.
7. Manual of Methods for Chemical Analysis of Water and Wastes. U.S. Environmental Protection Agency. Cincinnati, Ohio. Publication No. EPA-624/2-74-003. December 1974. pp. 118-138.
8. Mitchell, W.J., M.R. Midgett, J. Suggs, R.J. Velton, and D. Albrink. Sampling and Homogenizing Sewage for Analysis. Environmental Monitoring and Support Laboratory, Office of Research and Development, U.S. Environmental Protection Agency. Research Triangle Park, N.C. March 1979. p. 7.

17.0 Tables, Diagrams, Flowcharts, and Validation Data. [Reserved]

METHOD 106—DETERMINATION OF VINYL CHLORIDE EMISSIONS FROM STATIONARY SOURCES

1.0 Scope and Application

1.1 Analytes.

Analyte	**CAS No.**	**Sensitivity**
Vinyl Chloride (CH_2:CHCl)	75-01-4	Dependent upon analytical equipment.

1.2 Applicability. This method is applicable for the determination of vinyl chloride emissions from ethylene dichloride, vinyl chloride, and polyvinyl chloride manufacturing processes. This method does not measure vinyl chloride contained in particulate matter.

1.3 Data Quality Objectives. Adherence to the requirements of this method will enhance the quality of the data obtained from air pollutant sampling methods.

2.0 Summary of Method

2.1 An integrated bag sample of stack gas containing vinyl chloride is subjected to GC analysis using a flame ionization detector (FID).

3.0 Definitions. [Reserved]

4.0 Interferences

4.1 Resolution interferences of vinyl chloride may be encountered on some sources. Therefore, the chromatograph operator should select the column and operating parameters best suited to the particular analysis requirements. The selection made is subject to approval of the Administrator. Approval is automatic, provided that confirming data are produced through an adequate supplemental analytical technique, and that the data are available for review by the Administrator. An example of this would be analysis with a different column or GC/mass spectroscopy.

5.0 Safety

5.1 Disclaimer. This method may involve hazardous materials, operations, and equipment. This test method may not address all of the safety problems associated with its use. It is the responsibility of the user of this test method to establish appropriate safety and health practices and determine the applicability of regulatory limitations prior to performing this test method.

5.2 Toxic Analyte. Care must be exercised to prevent exposure of sampling personnel to vinyl chloride, which is a carcinogen.

6.0 Equipment and Supplies

6.1 Sample Collection (see Figure 106-1). The sampling train consists of the following components:

6.1.1 Probe. Stainless steel, borosilicate glass, Teflon tubing (as stack temperature permits), or equivalent, equipped with a glass wool plug to remove particulate matter.

6.1.2 Sample Lines. Teflon, 6.4-mm outside diameter, of sufficient length to connect probe to bag. Use a new unused piece for each series of bag samples that constitutes an emission test, and discard upon completion of the test.

6.1.3 Quick Connects. Stainless steel, male (2) and female (2), with ball checks (one pair without), located as shown in Figure 106-1.

6.1.4 Tedlar Bags. 50- to 100-liter capacity, to contain sample. Aluminized Mylar bags may be used if the samples are analyzed within 24 hours of collection.

6.1.5 Bag Containers. Rigid leak-proof containers for sample bags, with covering to protect contents from sunlight.

6.1.6 Needle Valve. To adjust sample flow rates.

6.1.7 Pump. Leak-free, with minimum of 2-liter/min capacity.

6.1.8 Charcoal Tube. To prevent admission of vinyl chloride and other organics to the atmosphere in the vicinity of samplers.

6.1.9 Flowmeter. For observing sampling flow rate; capable of measuring a flow range from 0.10 to 1.00 liter/min.

6.1.10 Connecting Tubing. Teflon, 6.4-mm outside diameter, to assemble sampling train (Figure 106-1).

6.1.11 Tubing Fittings and Connectors. Teflon or stainless steel, to assemble sampling training.

6.2 Sample Recovery. Teflon tubing, 6.4-mm outside diameter, to connect bag to GC sample loop. Use a new unused piece for each series of bag samples that constitutes an emission test, and discard upon conclusion of analysis of those bags.

6.3 Analysis. The following equipment is required:

6.3.1 Gas Chromatograph. With FID potentiometric strip chart recorder and 1.0 to 5.0-ml heated sampling loop in automatic sample valve. The chromatographic system shall be capable of producing a response to 0.1-ppmv vinyl chloride that is at least as great as the average noise level. (Response is measured from the average value of the base line to the maximum of the wave form, while standard operating conditions are in use.)

6.3.2 Chromatographic Columns. Columns as listed below. Other columns may be used provided that the precision and accuracy of the analysis of vinyl chloride standards are not impaired and that information is available for review confirming that there is adequate resolution of vinyl chloride peak. (Adequate resolution is defined as an area overlap of not more than 10 percent of the vinyl chloride peak by an interferent peak. Calculation of area overlap is explained in Procedure 1 of appendix C to this part: “Determination of Adequate Chromatographic Peak Resolution.”)

6.3.2.1 Column A. Stainless steel, 2.0 m by 3.2 mm, containing 80/100-mesh Chromasorb 102.

6.3.2.2 Column B. Stainless steel, 2.0 m by 3.2 mm, containing 20 percent GE SF-96 on 60/ip-mesh Chromasorb P AW; or stainless steel, 1.0 m by 3.2 mm containing 80/100-mesh Porapak T. Column B is required as a secondary column if acetaldehyde is present. If used, column B is placed after column A. The combined columns should be operated at 120 °C (250 °F).

6.3.3 Rate Meters (2). Rotameter , or equivalent, 100-ml/min capacity, with flow control valves.

6.3.4 Gas Regulators. For required gas cylinders.

6.3.5 Temperature Sensor. Accurate to ±1 °C (±2 °F), to measure temperature of heated sample loop at time of sample injection.

6.3.6 Barometer. Accurate to ±5 mm Hg, to measure atmospheric pressure around GC during sample analysis.

6.3.7 Pump. Leak-free, with minimum of 100-ml/min capacity.

6.3.8 Recorder. Strip chart type, optionally equipped with either disc or electronic integrator.

6.3.9 Planimeter. Optional, in place of disc or electronic integrator on recorder, to measure chromatograph peak areas.

6.4 Calibration and Standardization.

6.4.1 Tubing. Teflon, 6.4-mm outside diameter, separate pieces marked for each calibration concentration.

NOTE: The following items are required only if the optional standard gas preparation procedures (Section 10.1) are followed.

6.4.2 Tedlar Bags. Sixteen-inch-square size, with valve; separate bag marked for each calibration concentration.

6.4.3 Syringes. 0.5-ml and 50-µl, gas tight, individually calibrated to dispense gaseous vinyl chloride.

6.4.4 Dry Gas Meter with Temperature and Pressure Gauges. Singer Model DTM-115 with 802 index, or equivalent, to meter nitrogen in preparation of standard gas mixtures, calibrated at the flow rate used to prepare standards.

7.0 Reagents and Standards

7.1 Analysis. The following reagents are required for analysis.

7.1.1 Helium or Nitrogen. Purity 99.9995 percent or greater, for chromatographic carrier gas.

7.1.2 Hydrogen. Purity 99.9995 percent or greater.

7.1.3 Oxygen or Air. Either oxygen (purity 99.99 percent or greater) or air (less than 0.1 ppmv total hydrocarbon content), as required by detector.

7.2 Calibration. Use one of the following options: either Sections 7.2.1 and 7.2.2, or Section 7.2.3.

7.2.1 Vinyl Chloride. Pure vinyl chloride gas certified by the manufacturer to contain a minimum of 99.9 percent vinyl chloride. If the gas manufacturer maintains a bulk cylinder supply of 99.9+ percent vinyl chloride, the certification analysis may have been performed on this supply, rather than on each gas cylinder prepared from this bulk supply. The date of gas cylinder preparation and the certified analysis must have been affixed to the cylinder before shipment from the gas manufacturer to the buyer.

7.2.2 Nitrogen. Same as described in Section 7.1.1.

7.2.3 Cylinder Standards. Gas mixture standards (50-,10-, and 5 ppmv vinyl chloride) in nitrogen cylinders may be used to directly prepare a chromatograph calibration curve as described in Section 10.3 if the following conditions are met: (a) The manufacturer certifies the gas composition with an accuracy of ±3 percent or better. (b) The manufacturer recommends a maximum shelf life over which the gas concentration does not change by greater than ±5 percent from the certified value. (c) The manufacturer affixes the date of gas cylinder preparation, certified vinyl chloride concentration, and recommended maximum shelf to the cylinder before shipment to the buyer.

7.2.3.1 Cylinder Standards Certification. The manufacturer shall certify the concentration of vinyl chloride in nitrogen in each cylinder by (a) directly analyzing each cylinder and (b) calibrating his analytical procedure on the day of cylinder analysis. To calibrate his analytical procedure, the manufacturer shall use as a minimum, a three point calibration curve. It is recommended that the manufacturer maintain (1) a high concentration calibration standard (between 50 and 100 ppmv) to prepare his calibration curve by an appropriate dilution technique and (2) a low-concentration calibration standard (between 5 and 10 ppmv) to verify the dilution technique used. If the difference between the apparent concentration read from the calibration curve and the true concentration assigned to the low-concentration calibration standard exceeds 5 percent of the true concentration, the manufacturer shall determine the source of error and correct it, then repeat the three-point calibration.

7.2.3.2 Verification of Manufacturer's Calibration Standards. Before using a standard, the manufacturer shall verify each calibration standard (a) by comparing it to gas mixtures prepared (with 99 mole percent vinyl chloride) in accordance with the procedure described in Section 7.2.1 or (b) calibrating it against vinyl chloride cylinder Standard Reference Materials (SRM's) prepared by the National Institute of Standards and Technology, if such SRM's are available. The agreement between the initially determined concentration value and the verification concentration value must be ±5 percent. The manufacturer must reverify all calibration standards on a time interval consistent with the shelf life of the cylinder standards sold.

8.0 Sample Collection, Preservation, Storage, and Transport

NOTE: Performance of this method should not be attempted by persons unfamiliar with the operation of a gas chromatograph (GC) nor by those who are unfamiliar with source sampling, because knowledge beyond the scope of this presentation is required.

8.1 Bag Leak-Check. The following leak-check procedure is recommended, but not required, prior to sample collection. The post-test leak-check procedure is mandatory. Connect a water manometer and pressurize the bag to 5 to 10 cm H_2O (2 to 4 in. H_2O). Allow to stand for 10 min. Any displacement in the water manometer indicates a leak. Also, check the rigid container for leaks in this manner.

NOTE: An alternative leak-check method is to pressurize the bag to 5 to 10 cm H2O and allow it to stand overnight. A deflated bag indicates a leak. For each sample bag in its rigid container, place a rotameter in line between the bag and the pump inlet. Evacuate the bag. Failure of the rotameter to register zero flow when the bag appears to be empty indicates a leak.

8.2 Sample Collection. Assemble the sample train as shown in Figure 106-1. Join the quick connects as illustrated, and determine that all connection between the bag and the probe are tight. Place the end of the probe at the centroid of the stack and start the pump with the needle valve adjusted to yield a flow that will fill over 50 percent of bag volume in the specific sample period. After allowing sufficient time to purge the line several times, change the vacuum line from the container to the bag and evacuate the bag until the rotameter indicates no flow. Then reposition the sample and vacuum lines and begin the actual sampling, keeping the rate proportional to the stack velocity. At all times, direct the gas exiting the rotameter away from sampling personnel. At the end of the sample period, shut off the pump, disconnect the sample line from the bag, and disconnect the vacuum line from the bag container. Protect the bag container from sunlight.

8.3 Sample Storage. Keep the sample bags out of direct sunlight. When at all possible, analysis is to be performed within 24 hours, but in no case in excess of 72 hours of sample collection. Aluminized Mylar bag samples must be analyzed within 24 hours.

8.4 Post-test Bag Leak-Check. Subsequent to recovery and analysis of the sample, leak-check the sample bag according to the procedure outlined in Section 8.1.

9.0 QUALITY CONTROL

Section	Quality control measure	Effect
10.3	Chromatograph calibration	Ensure precision and accuracy of chromatograph.

10.0 Calibration and Standardization

NOTE: Maintain a laboratory log of all calibrations.

10.1 Preparation of Vinyl Chloride Standard Gas Mixtures. (Optional Procedure-delete if cylinder standards are used.) Evacuate a 16-inch square Tedlar bag that has passed a leak-check (described in Section 8.1) and meter in 5.0 liters of nitrogen. While the bag is filling, use the 0.5-ml syringe to inject 250 µl of 99.9+ percent vinyl chloride gas through the wall of the bag. Upon withdrawing the syringe, immediately cover the resulting hole with a piece of adhesive tape. The bag now contains a vinyl chloride concentration of 50 ppmv. In a like manner use the 50 µl syringe to prepare gas mixtures having 10-and 5-ppmv vinyl chloride concentrations. Place each bag on a smooth surface and alternately depress opposite sides of the bag 50 times to further mix the gases. These gas mixture standards may be used for 10 days from the date of preparation, after which time new gas mixtures must be prepared. (Caution: Contamination may be a problem when a bag is reused if the new gas mixture standard is a lower concentration than the previous gas mixture standard.)

10.2 Determination of Vinyl Chloride Retention Time. (This section can be performed simultaneously with Section 10.3.) Establish chromatograph conditions identical with those in Section 11.3. Determine proper attenuator position. Flush the sampling loop with helium or nitrogen and activate the sample valve. Record the injection time, sample loop temperature, column temperature, carrier gas flow rate, chart speed, and attenuator setting. Record peaks and detector responses that occur in the absence of vinyl chloride. Maintain conditions with the equipment plumbing arranged identically to Section 11.2, and flush the sample loop for 30 seconds at the rate of 100 ml/min with one of the vinyl chloride calibration mixtures. Then activate the sample valve. Record the injection time. Select the peak that corresponds to vinyl chloride. Measure the distance on the chart from the injection time to the time at which the peak maximum occurs. This quantity divided by the chart speed is defined as the retention time. Since other organics may be present in the sample, positive identification of the vinyl chloride peak must be made.

10.3 Preparation of Chromatograph Calibration Curve. Make a GC measurement of each gas mixture standard (described in Section 7.2.3 or 10.1) using conditions identical to those listed in Sections 11.2 and 11.3. Flush the sampling loop for 30 seconds at the rate of 100 ml/min with one of the standard mixtures, and activate the sample valve. Record the concentration of vinyl chloride injected (C_c), attenuator setting, chart speed, peak area, sample loop temperature, column temperature, carrier gas flow rate, and retention time. Record the barometric pressure. Calculate A_c , the peak area multiplied by the attenuator setting. Repeat until two consecutive injection areas are within 5 percent, then plot the average of those two values versus C_c . When the other standard gas mixtures have been similarly analyzed and plotted, draw a straight line through the points derived by the least squares method. Perform calibration daily, or before and after the analysis of each emission test set of bag samples, whichever is more frequent. For each group of sample analyses, use the average of the two calibration curves which bracket that group to determine the respective sample concentrations. If the two calibration curves differ by more than 5 percent from their mean value, then report the final results by both calibration curves.

11.0 Analytical Procedure

11.2 Sample Recovery. With a new piece of Teflon tubing identified for that bag, connect a bag inlet valve to the gas chromatograph sample valve. Switch the valve to receive gas from the bag through the sample loop. Arrange the equipment so the sample gas passes from the sample valve to 100-ml/min rotameter with flow control valve followed by a charcoal tube and a 1-in. H_2 O pressure gauge. Maintain the sample flow either by a vacuum pump or container pressurization if the collection bag remains in the rigid container. After sample loop purging is ceased, allow the pressure gauge to return to zero before activating the gas sampling valve.

11.3 Analysis.

11.3.1 Set the column temperature to 100 °C (210 °F) and the detector temperature to 150 °C (300 °F). When optimum hydrogen and oxygen (or air) flow rates have been determined, verify and maintain these flow rates during all chromatography operations. Using helium or nitrogen as the carrier gas, establish a flow rate in the range consistent with the manufacturer's requirements for satisfactory detector operation. A flow rate of approximately 40 ml/min should produce adequate separations. Observe the base line periodically and determine that the noise level has stabilized and that base line drift has ceased. Purge the sample loop for 30 seconds at the rate of 100 ml/min, shut off flow, allow the sample loop pressure to reach atmospheric pressure as indicated by the H_2 O manometer, then activate the sample valve. Record the injection time (the position of the pen on the chart at the time of sample injection), sample number, sample loop temperature, column temperature, carrier gas flow rate, chart speed, and attenuator setting. Record the barometric pressure. From the chart, note the peak having the retention time corresponding to vinyl chloride as determined in Section 10.2. Measure the vinyl chloride peak area, A_m , by use of a disc integrator, electronic integrator, or a planimeter. Measure and record the peak heights, H_m . Record A_m and retention time. Repeat the injection at least two times or until two consecutive values for the total area of the vinyl chloride peak agree within 5 percent of their average. Use the average value for these two total areas to compute the bag concentration.

11.3.2 Compare the ratio of H_m to A_m for the vinyl chloride sample with the same ratio for the standard peak that is closest in height. If these ratios differ by more than 10 percent, the vinyl chloride peak may not be pure (possibly acetaldehyde is present) and the secondary column should be employed (see Section 6.3.2.2).

11.4 Determination of Bag Water Vapor Content. Measure the ambient temperature and barometric pressure near the bag. From a water saturation vapor pressure table, determine and record the water vapor content of the bag, B_{wb} , as a decimal figure. (Assume the relative humidity to be 100 percent unless a lesser value is known.)

12.0 Calculations and Data Analysis

12.1 Nomenclature.

A_m = Measured peak area.
A_f = Attenuation factor.
B_{wb} = Water vapor content of the bag sample, as analyzed, volume fraction.
C_b = Concentration of vinyl chloride in the bag, ppmv.
C_c = Concentration of vinyl chloride in the standard sample, ppmv.

P_i = Laboratory pressure at time of analysis, mm Hg.
P_r = Reference pressure, the laboratory pressure recorded during calibration, mm Hg.
T_i = Absolute sample loop temperature at the time of analysis, °K (°R).
T_r = Reference temperature, the sample loop temperature recorded during calibration, °K (°R).

12.2 Sample Peak Area. Determine the sample peak area, A_c , as follows:

$$A_c = A_m A_f \qquad \text{Eq. 106-1}$$

12.3 Vinyl Chloride Concentration. From the calibration curves prepared in Section 10.3, determine the average concentration value of vinyl chloride, C_c , that corresponds to A_c , the sample peak area. Calculate the concentration of vinyl chloride in the bag, C_b , as follows:

$$C_b = \frac{C_c P_r T_i}{P_i T_r (1 - B_{wb})} \qquad \text{Eq. 106-2}$$

13.0 Method Performance

13.1 Analytical Range. This method is designed for the 0.1 to 50 parts per million by volume (ppmv) range. However, common gas chromatograph (GC) instruments are capable of detecting 0.02 ppmv vinyl chloride. With proper calibration, the upper limit may be extended as needed.

14.0 Pollution Prevention, [Reserved]

15.0 Waste Management, [Reserved]

16.0 References

1. Brown D.W., E.W. Loy, and M.H. Stephenson. Vinyl Chloride Monitoring Near the B. F. Goodrich Chemical Company in Louisville, KY. Region IV, U.S. Environmental Protection Agency, Surveillance and Analysis Division, Athens, GA. June 24, 1974.
2. G.D. Clayton and Associates. Evaluation of a Collection and Analytical Procedure for Vinyl Chloride in Air. U.S. Environmental Protection Agency, Research Triangle Park, N.C. EPA Contract No. 68-02-1408, Task Order No. 2, EPA Report No. 75-VCL-1. December 13, 1974.
3. Midwest Research Institute. Standardization of Stationary Source Emission Method for Vinyl Chloride. U.S. Environmental Protection Agency, Research Triangle Park, N.C. Publication No. EPA-600/4-77-026. May 1977.
4. Scheil, G. and M.C. Sharp. Collaborative Testing of EPA Method 106 (Vinyl Chloride) that Will Provide for a Standardized Stationary Source Emission Measurement Method. U.S. Environmental Protection Agency, Research Triangle Park, N.C. Publication No. EPA 600/4-78-058. October 1978.

17.0 Tables, Diagrams Flowcharts, and Validation Data.

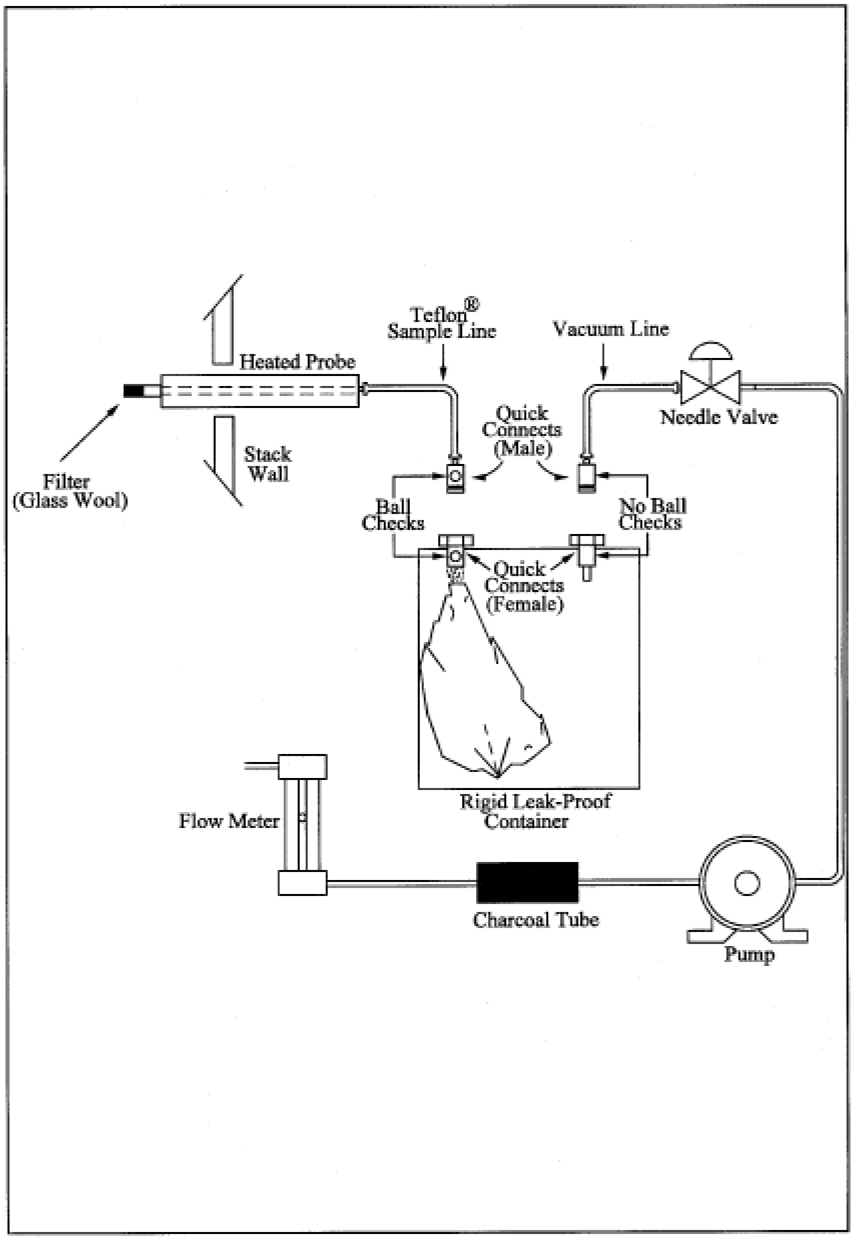

Figure 106-1. Integrated-bag sampling train.

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METHOD 107—DETERMINATION OF VINYL CHLORIDE CONTENT OF IN-PROCESS WASTEWATER SAMPLES, AND VINYL CHLORIDE CONTENT OF POLYVINYL CHLORIDE RESIN SLURRY, WET CAKE, AND LATEX SAMPLES

NOTE: Performance of this method should not be attempted by persons unfamiliar with the operation of a gas chromatograph (GC) nor by those who are unfamiliar with source sampling, because knowledge beyond the scope of this presentation is required. This method does not include all of the specifications (e.g., equipment and supplies) and procedures (e.g., sampling and analytical) essential to its performance. Some material is incorporated by reference from other methods in this part. Therefore, to obtain reliable results, persons using this method should have a thorough knowledge of at least the following additional test methods: Method 106.

1.0 Scope and Application

1.1 Analytes.

Analyte	**CAS No.**	**Sensitivity**

Vinyl Chloride (CH_2:CHCl)	75-01-4	Dependent upon analytical equipment.

1.2 Applicability. This method is applicable for the determination of the vinyl chloride monomer (VCM) content of in-process wastewater samples, and the residual vinyl chloride monomer (RCVM) content of polyvinyl chloride (PVC) resins, wet, cake, slurry, and latex samples. It cannot be used for polymer in fused forms, such as sheet or cubes. This method is not acceptable where methods from section 304(h) of the Clean Water Act, 33 U.S.C. 1251 et seq. (the Federal Water Pollution Control Amendments of 1972 as amended by the Clean Water Act of 1977) are required.

1.3 Data Quality Objectives. Adherence to the requirements of this method will enhance the quality of the data obtained from air pollutant sampling methods.

2.0 Summary of Method

2.1 The basis for this method relates to the vapor equilibrium that is established at a constant known temperature in a closed system between RVCM, PVC resin, water, and air. The RVCM in a PVC resin will equilibrate rapidly in a closed vessel, provided that the temperature of the PVC resin is maintained above the glass transition temperature of that specific resin.

2.2 A sample of PVC or in-process wastewater is collected in a vial or bottle and is conditioned. The headspace in the vial or bottle is then analyzed for vinyl chloride using gas chromatography with a flame ionization detector.

3.0 Definitions [Reserved]

4.0 Interferences

4.1 The chromatograph columns and the corresponding operating parameters herein described normally provide an adequate resolution of vinyl chloride; however, resolution interferences may be encountered on some sources. Therefore, the chromatograph operator shall select the column and operating parameters best suited to his particular analysis requirements, subject to the approval of the Administrator. Approval is automatic provided that confirming data are produced through an adequate supplemental analytical technique, such as analysis with a different column or GC/mass spectroscopy, and that these data are made available for review by the Administrator.

5.0 Safety

5.1 Disclaimer. This method may involve hazardous materials, operations, and equipment. This test method may not address all of the safety problems associated with its use. It is the responsibility of the user of this test method to establish appropriate safety and health practices and determine the applicability of regulatory limitations prior to performing this test method.

5.2 Toxic Analyte. Care must be exercised to prevent exposure of sampling personnel to vinyl chloride, which is a carcinogen. Do not release vinyl chloride to the laboratory atmosphere during preparation of standards. Venting or purging with VCM/air mixtures must be held to a minimum. When they are required, the vapor must be routed to outside air. Vinyl chloride, even at low ppm levels, must never be vented inside the laboratory. After vials have been analyzed, the gas must be vented prior to removal of the vial from the instrument turntable. Vials must be vented through a hypodermic needle connected to an activated charcoal tube to prevent release of vinyl chloride into the laboratory atmosphere. The charcoal must be replaced prior to vinyl chloride breakthrough.

6.0 Equipment and Supplies

6.1 Sample Collection. The following equipment is required:

6.1.1 Glass bottles. 60-ml (2-oz) capacity, with wax-lined screw-on tops, for PVC samples.

6.1.2 Glass Vials. Headspace vials, with Teflon-faced butyl rubber sealing discs, for water samples.

6.1.3 Adhesive Tape. To prevent loosening of bottle tops.

6.2 Sample Recovery. The following equipment is required:

6.2.1 Glass Vials. Headspace vials, with butyl rubber septa and aluminum caps. Silicone rubber is not acceptable.

6.2.2 Analytical Balance. Capable of determining sample weight within an accuracy of ±1 percent.

6.2.3 Vial Sealer. To seal headspace vials.

6.2.4 Syringe. 100-ml capacity.

6.3 Analysis. The following equipment is required:

6.3.1 Headspace Sampler and Chromatograph. Capable of sampling and analyzing a constant amount of headspace gas from a sealed vial, while maintaining that vial at a temperature of 90 °C ±0.5 °C (194 °F ±0.9 °F). The chromatograph shall be equipped with a flame ionization detector (FID). Perkin-Elmer Corporation Models F-40, F-42, F-45, HS-6, and HS-100, and Hewlett-Packard Corporation Model

19395A have been found satisfactory. Chromatograph backflush capability may be required.

6.3.2 Chromatographic Columns. Stainless steel 1 m by 3.2 mm and 2 m by 3.2 mm, both containing 50/80-mesh Porapak Q. Other columns may be used provided that the precision and accuracy of the analysis of vinyl chloride standards are not impaired and information confirming that there is adequate resolution of the vinyl chloride peak are available for review. (Adequate resolution is defined as an area overlap of not more than 10 percent of the vinyl chloride peak by an interferant peak. Calculation of area overlap is explained in Procedure 1 of appendix C to this part: “Determination of Adequate Chromatographic Peak Resolution.”) Two 1.83 m columns, each containing 1 percent Carbowax 1500 on Carbopak B, have been found satisfactory for samples containing acetaldehyde.

6.3.3 Temperature Sensor. Range 0 to 100 °C (32 to 212 °F) accurate to 0.1 °C.

6.3.4 Integrator-Recorder. To record chromatograms.

6.3.5 Barometer. Accurate to 1 mm Hg.

6.3.6 Regulators. For required gas cylinders.

6.3.7 Headspace Vial Pre-Pressurizer. Nitrogen pressurized hypodermic needle inside protective shield.

7.0 Reagents and Standards

7.1 Analysis. Same as Method 106, Section 7.1, with the addition of the following:

7.1.1 Water. Interference-free.

7.2 Calibration. The following items are required for calibration:

7.2.1 Cylinder Standards (4). Gas mixture standards (50-, 500-, 2000- and 4000-ppm vinyl chloride in nitrogen cylinders). Cylinder standards may be used directly to prepare a chromatograph calibration curve as described in Section 10.3, if the following conditions are met: (a) The manufacturer certifies the gas composition with an accuracy of ±3 percent or better (see Section 7.2.1.1). (b) The manufacturer recommends a maximum shelf life over which the gas concentration does not change by greater than ±5 percent from the certified value. (c) The manufacturer affixes the date of gas cylinder preparation, certified vinyl chloride concentration, and recommended maximum shelf life to the cylinder before shipment to the buyer.

7.2.1.1 Cylinder Standards Certification. The manufacturer shall certify the concentration of vinyl chloride in nitrogen in each cylinder by (a) directly analyzing each cylinder and (b) calibrating the analytical procedure on the day of cylinder analysis. To calibrate the analytical procedure, the manufacturer shall use, as a minimum, a 3-point calibration curve. It is recommended that the manufacturer maintain (1) a high-concentration calibration standard (between 4000 and 8000 ppm) to prepare the calibration curve by an appropriate dilution technique and (2) a low-concentration calibration standard (between 50 and 500 ppm) to verify the dilution technique used. If the difference between the apparent concentration read from the calibration curve and the true concentration assigned to the low-concentration calibration standard exceeds 5 percent of the true concentration, the manufacturer shall determine the source of error and correct it, then repeat the 3-point calibration.

7.2.1.2 Verification of Manufacturer's Calibration Standards. Before using, the manufacturer shall verify each calibration standard by (a) comparing it to gas mixtures prepared (with 99 mole percent vinyl chloride) in accordance with the procedure described in Section 10.1 of Method 106 or by (b) calibrating it against vinyl chloride cylinder Standard Reference Materials (SRMs) prepared by the National Institute of Standards and Technology, if such SRMs are available. The agreement between the initially determined concentration value and the verification concentration value must be within 5 percent. The manufacturer must reverify all calibration standards on a time interval consistent with the shelf life of the cylinder standards sold.

8.0 Sample Collection, Preservation, Storage, and Transport

8.1 Sample Collection.

8.1.1 PVC Sampling. Allow the resin or slurry to flow from a tap on the tank or silo until the tap line has been well purged. Extend and fill a 60-ml sample bottle under the tap, and immediately tighten a cap on the bottle. Wrap adhesive tape around the cap and bottle to prevent the cap from loosening. Place an identifying label on each bottle, and record the date, time, and sample location both on the bottles and in a log book.

8.1.2 Water Sampling. At the sampling location fill the vials bubble-free to overflowing so that a convex meniscus forms at the top. The excess water is displaced as the sealing disc is carefully placed, with the Teflon side down, on the opening of the vial. Place the aluminum seal over the disc and the neck of the vial, and crimp into place. Affix an identifying label on the bottle, and record the date, time, and sample location both on the vials and in a log book.

8.2 Sample Storage. All samples must be analyzed within 24 hours of collection, and must be refrigerated during this period.

9.0 Quality Control

Section	Quality control measure	Effect
10.3	Chromatograph calibration	Ensure precision and accuracy of chromatograph.

10.0 Calibration and Standardization

NOTE: Maintain a laboratory log of all calibrations.

10.1 Preparation of Standards. Calibration standards are prepared as follows: Place 100 µl or about two equal drops of distilled water in the sample vial, then fill the vial with the VCM/nitrogen standard, rapidly seat the septum, and seal with the aluminum cap. Use a $\frac{1}{8}$ -in. stainless steel line from the cylinder to the vial. Do not use rubber or Tygon tubing. The sample line from the cylinder must be purged (into a properly vented hood) for several minutes prior to filling the vials. After purging, reduce the flow rate to between 500 and 1000 cc/min. Place end of tubing into vial (near bottom). Position a septum on top of the vial, pressing it against the $\frac{1}{8}$ -in. filling tube to minimize the size of the vent opening. This is necessary to minimize mixing air with the standard in the vial. Each vial is to be purged with standard for 90 seconds, during which time the filling tube is gradually slid to the top of the vial. After the 90 seconds, the tube is removed with the septum, simultaneously sealing the vial. Practice will be necessary to develop good technique. Rubber gloves should be worn during the above operations. The sealed vial must then be pressurized for 60 seconds using the vial prepressurizer. Test the vial for leakage by placing a drop of water on the septum at the needle hole. Prepressurization of standards is not required unless samples have been prepressurized.

10.2 Analyzer Calibration. Calibration is to be performed each 8-hour period the chromatograph is used. Alternatively, calibration with duplicate 50-, 500-, 2,000-, and 4,000-ppm standards (hereafter described as a four-point calibration) may be performed on a monthly basis, provided that a calibration confirmation test consisting of duplicate analyses of an appropriate standard is performed once per plant shift, or once per chromatograph carrousel operation (if the chromatograph operation is less frequent than once per shift). The criterion for acceptance of each calibration confirmation test is that both analyses of 500-ppm standards [2,000-ppm standards if dispersion resin (excluding latex resin) samples are being analyzed] must be within 5 percent of the most recent four-point calibration curve. If this criterion is not met, then a complete four-point calibration must be performed before sample analyses can proceed.

10.3 Preparation of Chromatograph Calibration Curve. Prepare two vials each of 50-, 500-, 2,000-, and 4,000-ppm standards. Run the calibration samples in exactly the same manner as regular samples. Plot A_s , the integrator area counts for each standard sample, versus C_c , the concentration of vinyl chloride in each standard sample. Draw a straight line through the points derived by the least squares method.

11.0 Analytical Procedure

11.1 Preparation of Equipment. Install the chromatographic column and condition overnight at 160 °C (320 °F). In the first operation, Porapak columns must be purged for 1 hour at 230 °C (450 °F).

Do not connect the exit end of the column to the detector while conditioning. Hydrogen and air to the detector must be turned off while the column is disconnected.

11.2 Flow Rate Adjustments. Adjust flow rates as follows:

11.2.1. Nitrogen Carrier Gas. Set regulator on cylinder to read 50 psig. Set regulator on chromatograph to produce a flow rate of 30.0 cc/min. Accurately measure the flow rate at the exit end of the column using the soap film flowmeter and a stopwatch, with the oven and column at the analysis temperature. After the instrument program advances to the “B” (backflush) mode, adjust the nitrogen pressure regulator to exactly balance the nitrogen flow rate at the detector as was obtained in the “A” mode.

11.2.2. Vial Prepressurizer Nitrogen.

11.2.2.1 After the nitrogen carrier is set, solve the following equation and adjust the pressure on the vial prepressurizer accordingly.

$$P = \frac{T_1}{T_2}\left[P_1 - \frac{P_{w1} - P_{w2}}{7.50}\right] - 10kPa \qquad \text{Eq. 107-1}$$

Where:

T_1 = Ambient temperature, °K (°R).

T_2 = Conditioning bath temperature, °K (°R).

P_1 = Gas chromatograph absolute dosing pressure (analysis mode), k Pa.

P_{w1} = Water vapor pressure 525.8 mm Hg @ 90 °C.
P_{w2} = Water vapor pressure 19.8 mm Hg @ 22 °C.
7.50 = mm Hg per k Pa.
10 kPa = Factor to adjust the prepressurized pressure to slightly less than the dosing pressure.

11.2.2.2 Because of gauge errors, the apparatus may over-pressurize the vial. If the vial pressure is at or higher than the dosing pressure, an audible double injection will occur. If the vial pressure is too low, errors will occur on resin samples because of inadequate time for head-space gas equilibrium. This condition can be avoided by running several standard gas samples at various pressures around the calculated pressure, and then selecting the highest pressure that does not produce a double injection. All samples and standards must be pressurized for 60 seconds using the vial prepressurizer. The vial is then placed into the 90 °C conditioning bath and tested for leakage by placing a drop of water on the septum at the needle hole. A clean, burr-free needle is mandatory.

11.2.3. Burner Air Supply. Set regulator on cylinder to read 50 psig. Set regulator on chromatograph to supply air to burner at a rate between 250 and 300 cc/min. Check with bubble flowmeter.

11.2.4. Hydrogen Supply. Set regulator on cylinder to read 30 psig. Set regulator on chromatograph to supply approximately 35 ±5 cc/min. Optimize hydrogen flow to yield the most sensitive detector response without extinguishing the flame. Check flow with bubble meter and record this flow.

11.3 Temperature Adjustments. Set temperatures as follows:

11.3.1. Oven (chromatograph column), 140 °C (280 °F).

11.3.2. Dosing Line, 150 °C (300 °F).

11.3.3. Injection Block, 170 °C (340 °F).

11.3.4. Sample Chamber, Water Temperature, 90 °C ±1.0 °C (194 °F ±1.8 °F).

11.4 Ignition of Flame Ionization Detector. Ignite the detector according to the manufacturer's instructions.

11.5 Amplifier Balance. Balance the amplifier according to the manufacturer's instructions.

11.6 Programming the Chromatograph. Program the chromatograph as follows:

11.6.1. I—Dosing or Injection Time. The normal setting is 2 seconds.

11.6.2. A—Analysis Time. The normal setting is approximately 70 percent of the VCM retention time. When this timer terminates, the programmer initiates backflushing of the first column.

11.6.3. B—Backflushing Time. The normal setting is double the analysis time.

11.6.4. W—Stabilization Time. The normal setting is 0.5 min to 1.0 min.

11.6.5. X—Number of Analyses Per Sample. The normal setting is one.

11.7. Sample Treatment. All samples must be recovered and analyzed within 24 hours after collection.

11.7.1 Resin Samples. The weight of the resin used must be between 0.1 and 4.5 grams. An exact weight must be obtained (within ±1 percent) for each sample. In the case of suspension resins, a volumetric cup can be prepared for holding the required amount of sample. When the cup is used, open the sample bottle, and add the cup volume of resin to the tared sample vial (tared, including septum and aluminum cap). Obtain the exact sample weight, add 100 ml or about two equal drops of water, and immediately seal the vial. Report this value on the data sheet; it is required for calculation of RVCM. In the case of dispersion resins, the cup cannot be used. Weigh the sample in an aluminum dish, transfer the sample to the tared vial, and accurately weigh it in the vial. After prepressurization of the samples, condition them for a minimum of 1 hour in the 90 °C (190 °F) bath. Do not exceed 5 hours. Prepressurization is not required if the sample weight, as analyzed, does not exceed 0.2 gram. It is also not required if solution of the prepressurization equation yields an absolute prepressurization value that is within 30 percent of the atmospheric pressure.

NOTE: Some aluminum vial caps have a center section that must be removed prior to placing into sample tray. If the cap is not removed, the injection needle will be damaged.

11.7.2 Suspension Resin Slurry and Wet Cake Samples. Decant the water from a wet cake sample, and turn the sample bottle upside down onto a paper towel. Wait for the water to drain, place approximately 0.2 to 4.0 grams of the wet cake sample in a tared vial (tared, including septum and aluminum cap) and seal immediately. Then determine the sample weight (1 percent). All samples weighing over 0.2 gram, must be prepressurized prior to conditioning for 1 hour at 90 °C (190 °F), except as noted in Section 11.7.1. A sample of wet cake is used to determine total solids (TS). This is required for calculating the RVCM.

11.7.3 Dispersion Resin Slurry and Geon Latex Samples. The materials should not be filtered. Sample must be thoroughly mixed. Using a tared vial (tared, including septum and aluminum cap) add approximately eight drops (0.25 to 0.35 g) of slurry or latex using a medicine dropper. This should be done immediately after mixing. Seal the vial as soon as possible. Determine sample weight (1 percent). Condition the vial for 1 hour at 90 °C (190 °F) in the analyzer bath. Determine the TS on the slurry sample (Section 11.10).

11.7.4 In-process Wastewater Samples. Using a tared vial (tared, including septum and aluminum cap) quickly add approximately 1 cc of water using a medicine dropper. Seal the vial as soon as possible. Determine sample weight (1 percent). Condition the vial for 1 hour at 90 °C (190 °F) in the analyzer bath.

11.8 Preparation of Sample Turntable.

11.8.1 Before placing any sample into turntable, be certain that the center section of the aluminum cap has been removed. The numbered sample vials should be placed in the corresponding numbered positions in the turntable. Insert samples in the following order:

11.8.1.1 Positions 1 and 2. Old 2000-ppm standards for conditioning. These are necessary only after the analyzer has not been used for 24 hours or longer.

11.8.1.2 Position 3. 50-ppm standard, freshly prepared.

11.8.1.3 Position 4. 500-ppm standard, freshly prepared.

11.8.1.4 Position 5. 2000-ppm standard, freshly prepared.

11.8.1.5 Position 6. 4000-ppm standard, freshly prepared.

11.8.1.6 Position 7. Sample No. 7 (This is the first sample of the day, but is given as 7 to be consistent with the turntable and the integrator printout.)

11.8.2 After all samples have been positioned, insert the second set of 50-, 500-, 2000-, and 4000-ppm standards. Samples, including standards, must be conditioned in the bath of 90 °C (190 °F) for a minimum of one hour and a maximum of five hours.

11.9 Start Chromatograph Program. When all samples, including standards, have been conditioned at 90 °C (190 °F) for at least one hour, start the analysis program according to the manufacturer's instructions. These instructions must be carefully followed when starting and stopping a program to prevent damage to the dosing assembly.

11.10 Determination of Total Solids. For wet cake, slurry, resin solution, and PVC latex samples, determine TS for each sample by accurately weighing approximately 3 to 4 grams of sample in an aluminum pan before and after placing in a draft oven (105 to 110 °C (221 to 230 °F)). Samples must be dried to constant weight. After first weighing, return the pan to the oven for a short period of time, and then reweigh to verify complete dryness. The TS are then calculated as the final sample weight divided by initial sample weight.

12.0 Calculations and Data Analysis

12.1 Nomenclature.

A_s = Chromatogram area counts of vinyl chloride for the sample, area counts.
A_s = Chromatogram area counts of vinyl chloride for the sample.
C_c = Concentration of vinyl chloride in the standard sample, ppm.
K_p = Henry's Law Constant for VCM in PVC 90 °C, 6.52×10^{-6} g/g/mm Hg.
K_w = Henry's Law Constant for VCM in water 90 °C, 7×10^{-7} g/g/mm Hg.
M_v = Molecular weight of VCM, 62.5 g/mole.
m = Sample weight, g.
P_a = Ambient atmospheric pressure, mm Hg.
R = Gas constant, (62360^3 ml) (mm Hg)/(mole)(°K).
R_f = Response factor in area counts per ppm VCM.
R_s = Response factor, area counts/ppm.
T_l = Ambient laboratory temperature, °K.
TS = Total solids expressed as a decimal fraction.
T_2 = Equilibrium temperature, °K.
V_g = Volume of vapor phase, ml.

$$= V_v - \frac{m(TS)}{1.36} - \frac{m(1-TS)}{0.9653}$$

V_v = Vial volume,^{3} ml.
1.36 = Density of PVC at 90 °C, g/^{3} ml.
0.9653 = Density of water at 90 °C, g/^{3} ml.

12.2 Response Factor. If the calibration curve described in Section 10.3 passes through zero, an average response factor, R_f , may be used to facilitate computation of vinyl chloride sample concentrations.

12.2.1 To compute R_f , first compute a response factor, R_s , for each sample as follows:

$$R_s = \frac{A_s}{C_c} \qquad \text{Eq. 107-2}$$

12.2.2 Sum the individual response factors, and calculate R_f . If the calibration curve does not pass through zero, use the calibration curve to determine each sample concentration.

12.3 Residual Vinyl Chloride Monomer Concentration, (C_{rvc}) or Vinyl Chloride Monomer Concentration. Calculate C_{rvc} in ppm or mg/kg as follows:

$$C_{rvc} = \frac{A_s P_a}{R_f T_1}\left[\frac{M_v V_g}{Rm} + K_p\left(TS\right)T_2 K_w\left(1-TS\right)T_2\right] \qquad \text{Eq. 107-3}$$

NOTE: Results calculated using these equations represent concentration based on the total sample. To obtain results based on dry PVC content, divide by TS.

13.0 Method Performance

13.1 Range and Sensitivity. The lower limit of detection of vinyl chloride will vary according to the sampling and chromatographic system. The system should be capable of producing a measurement for a 50-ppm vinyl chloride standard that is at least 10 times the standard deviation of the system background noise level.

13.2 An interlaboratory comparison between seven laboratories of three resin samples, each split into three parts, yielded a standard deviation of 2.63 percent for a sample with a mean of 2.09 ppm, 4.16 percent for a sample with a mean of 1.66 ppm, and 5.29 percent for a sample with a mean of 62.66 ppm.

14.0 Pollution Prevention [Reserved]

15.0 Waste Management [Reserved]

16.0 References

1. B.F. Goodrich, Residual Vinyl Chloride Monomer Content of Polyvinyl Chloride Resins, Latex, Wet Cake, Slurry and Water Samples. B.F. Goodrich Chemical Group Standard Test Procedure No. 1005-E. B.F. Goodrich Technical Center, Avon Lake, Ohio. October 8, 1979.

2. Berens, A.R. The Diffusion of Vinyl Chloride in Polyvinyl Chloride. ACS-Division of Polymer Chemistry, Polymer Preprints 15 (2):197. 1974.

3. Berens, A.R. The Diffusion of Vinyl Chloride in Polyvinyl Chloride. ACS-Division of Polymer Chemistry, Polymer Preprints 15 (2):203. 1974.

4. Berens, A.R., et. al. Analysis for Vinyl Chloride in PVC Powders by Head-Space Gas Chromatography. Journal of Applied Polymer Science. 19:3169-3172. 1975.

5. Mansfield, R.A. The Evaluation of Henry's Law Constant (Kp) and Water Enhancement in the Perkin-Elmer Multifract F-40 Gas Chromatograph. B.F. Goodrich. Avon Lake, Ohio. February 10, 1978.

17.0 Tables, Diagrams, Flowcharts, and Validation Data [Reserved]

METHOD 107A—DETERMINATION OF VINYL CHLORIDE CONTENT OF SOLVENTS, RESIN-SOLVENT SOLUTION, POLYVINYL CHLORIDE RESIN, RESIN SLURRY, WET RESIN, AND LATEX SAMPLES

Introduction

Performance of this method should not be attempted by persons unfamiliar with the operation of a gas chromatograph (GC) or by those who are unfamiliar with source sampling because knowledge beyond the scope of this presentation is required. Care must be exercised to prevent exposure of sampling personnel to vinyl chloride, a carcinogen.

1. Applicability and Principle

1.1 Applicability. This is an alternative method and applies to the measurement of the vinyl chloride content of solvents, resin solvent solutions, polyvinyl chloride (PVC) resin, wet cake slurries, latex, and fabricated resin samples. This method is not acceptable where methods from Section 304(h) of the Clean Water Act, 33 U.S.C. 1251 et seq., (the Federal Water Pollution Control Act Amendments of 1972 as amended by the Clean Water Act of 1977) are required.

1.2 Principle. The basis for this method lies in the direct injection of a liquid sample into a chromatograph and the subsequent evaporation of all volatile material into the carrier gas stream of the chromatograph, thus permitting analysis of all volatile material including vinyl chloride.

2. Range and Sensitivity

The lower limit of detection of vinyl chloride in dry PVC resin is 0.2 ppm. For resin solutions, latexes, and wet resin, this limit rises inversely as the nonvolatile (resin) content decreases.

With proper calibration, the upper limit may be extended as needed.

3. Interferences

The chromatograph columns and the corresponding operating parameters herein described normally provide an adequate resolution of vinyl chloride. In cases where resolution interferences are encountered, the chromatograph operator shall select the column and operating parameters best suited to his particular analysis problem, subject to the approval of the Administrator. Approval is automatic, provided that the tester produces confirming data through an adequate supplemental analytical technique, such as analysis with a different column or GC/mass spectroscopy, and has the data available for review by the Administrator.

4. Precision and Reproducibility

A standard sample of latex containing 181.8 ppm vinyl chloride analyzed 10 times by the alternative method showed a standard deviation of 7.5 percent and a mean error of 0.21 percent.

A sample of vinyl chloride copolymer resin solution was analyzed 10 times by the alternative method and showed a standard deviation of 6.6 percent at a level of 35 ppm.

5. Safety

Do not release vinyl chloride to the laboratory atmosphere during preparation of standards. Venting or purging with vinyl chloride monomer (VCM) air mixtures must be held to minimum. When purging is required, the vapor must be routed to outside air. Vinyl chloride, even at low-ppm levels, must never be vented inside the laboratory.

6. Apparatus

6.1 Sampling. The following equipment is required:

6.1.1 Glass Bottles. 16-oz wide mouth wide polyethylene-lined, screw-on tops.

6.1.2 Adhesive Tape. To prevent loosening of bottle tops.

6.2 Sample Recovery. The following equipment is required:

6.2.1 Glass Vials. 20-ml capacity with polycone screw caps.

6.2.2 Analytical Balance. Capable of weighing to ±0.01 gram.

6.2.3 Syringe. 50-microliter size, with removable needle.

6.2.4 Fritted Glass Sparger. Fine porosity.

6.2.5 Aluminum Weighing Dishes.

6.2.6 Sample Roller or Shaker. To help dissolve sample.

6.3 Analysis. The following equipment is required:

6.3.1 Gas Chromatograph. Hewlett Packard Model 5720A or equivalent.

6.3.2 Chromatograph Column. Stainless steel, 6.1 m by 3.2 mm, packed with 20 percent Tergitol E-35 on Chromosorb W AW 60/80 mesh. The analyst may use other columns provided that the precision and accuracy of the analysis of vinyl chloride standards are not impaired and that he has available for review information confirming that there is adequate resolution of the vinyl chloride peak. (Adequate resolution is defined as an area overlap of not more than 10 percent of the vinyl chloride peak by an interfering peak. Calculation of area overlap is explained in Appendix C, Procedure 1: “Determination of Adequate Chromatographic Peak Resolution.”)

6.3.3 Valco Instrument Six-Port Rotary Valve. For column back flush.

6.3.4 Septa. For chromatograph injection port.

6.3.5 Injection Port Liners. For chromatograph used.

6.3.6 Regulators. For required gas cylinders.

6.3.7 Soap Film Flowmeter. Hewlett Packard No. 0101-0113 or equivalent.

6.4 Calibration. The following equipment is required:

6.4.1 Analytical Balance. Capable of weighing to ±0.0001 g.

6.4.2 Erlenmeyer Flask With Glass Stopper. 125 ml.

6.4.3 Pipets. 0.1, 0.5, 1, 5, 10, and 50 ml.

6.4.4 Volumetric Flasks. 10 and 100 ml.

7. Reagents

Use only reagents that are of chromatograph grade.

7.1 Analysis. The following items are required:

7.1.1 Hydrogen Gas. Zero grade.

7.1.2 Nitrogen Gas. Zero grade.

7.1.3 Air. Zero grade.

7.1.4 Tetrahydrofuran (THF). Reagent grade.
Analyze the THF by injecting 10 microliters into the prepared gas chromatograph. Compare the THF chromatogram with that shown in Figure 107A-1. If the chromatogram is comparable to A, the THF should be sparged with pure nitrogen for approximately 2 hours using the fritted glass sparger to attempt to remove the interfering peak. Reanalyze the sparged THF to determine whether the THF is acceptable for use. If the scan is comparable to B, the THF should be acceptable for use in the analysis.

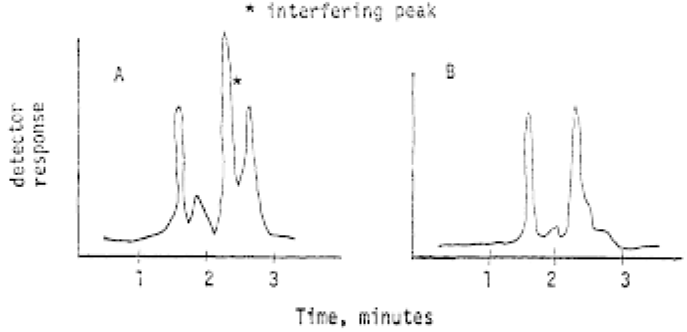

Figure 107A-1

7.1.5 N, N-Dimethylacetamide (DMAC). Spectrographic grade. For use in place of THF.
7.2 Calibration. The following item is required:
7.2.1 Vinyl Chloride 99.9 Percent. Ideal Gas Products lecture bottle, or equivalent. For preparation of standard solutions.
8. Procedure
8.1 Sampling. Allow the liquid or dried resin to flow from a tap on the tank, silo, or pipeline until the tap has been purged. Fill a wide-mouth pint bottle, and immediately tightly cap the bottle. Place an identifying label on each bottle and record the date, time, sample location, and material.
8.2 Sample Treatment. Sample must be run within 24 hours.
8.2.1 Resin Samples. Weigh 9.00 ±0.01 g of THF or DMAC in a tared 20-ml vial. Add 1.00 ±0.01 g of resin to the tared vial containing the THF or DMAC. Close the vial tightly with the screw cap, and shake or otherwise agitate the vial until complete solution of the resin is obtained. Shaking may require several minutes to several hours, depending on the nature of the resin.
8.2.2 Suspension Resin Slurry and Wet Resin Sample. Slurry must be filtered using a small Buchner funnel with vacuum to yield a wet resin sample. The filtering process must be continued only as long as a steady stream of water is exiting from the funnel. Excessive filtration time could result in some loss of VCM. The wet resin sample is weighed into a tared 20-ml vial with THF or DMAC as described earlier for resin samples (8.2.1) and treated the same as the resin sample. A sample of the wet resin is used to determine total solids as required for calculating the residual VCM (Section 8.3.4).
8.2.3 Latex and Resin Solvent Solutions. Samples must be thoroughly mixed. Weigh 1.00 ±0.01 g of the latex or resin-solvent solution into a 20-ml vial containing 9.00 ±0.01 g of THF or DMAC as for the resin samples (8.2.1). Cap and shake until complete solution is obtained. Determine the total solids of the latex or resin solution sample (Section 8.3.4).
8.2.4 Solvents and Non-viscous Liquid Samples. No preparation of these samples is required. The neat samples are injected directly into the GC.
8.3 Analysis.
8.3.1 Preparation of GC. Install the chromatographic column, and condition overnight at 70 °C. Do not connect the exit end of the column to the detector while conditioning.
8.3.1.1 Flow Rate Adjustments. Adjust the flow rate as follows:
a. Nitrogen Carrier Gas. Set regulator on cylinder to read 60 psig. Set column flow controller on the chromatograph using the soap film flowmeter to yield a flow rate of 40 cc/min.
b. Burner Air Supply. Set regulator on the cylinder at 40 psig. Set regulator on the chromatograph to supply air to the burner to yield a flow rate of 250 to 300 cc/min using the flowmeter.
c. Hydrogen. Set regulator on cylinder to read 60 psig. Set regulator on the chromatograph to supply 30 to 40 cc/min using the flowmeter. Optimize hydrogen flow to yield the most sensitive detector response without extinguishing the flame. Check flow with flowmeter and record this flow.
d. Nitrogen Back Flush Gas. Set regulator on the chromatograph using the soap film flowmeter to yield a flow rate of 40 cc/min.

8.3.1.2 Temperature Adjustments. Set temperature as follows:
a. Oven (chromatographic column) at 70 °C.
b. Injection Port at 100 °C.
c. Detector at 300 °C.

8.3.1.3 Ignition of Flame Ionization Detector. Ignite the detector according to the manufacturer's instructions. Allow system to stabilize approximately 1 hour.

8.3.1.4 Recorder. Set pen at zero and start chart drive.

8.3.1.5 Attenuation. Set attenuation to yield desired peak height depending on sample VCM content.

8.3.2 Chromatographic Analyses.

a. Sample Injection. Remove needle from 50-microliter syringe. Open sample vial and draw 50-microliters of THF or DMAC sample recovery solution into the syringe. Recap sample vial. Attach needle to the syringe and while holding the syringe vertically (needle uppermost), eject 40 microliters into an absorbent tissue. Wipe needle with tissue. Now inject 10 microliters into chromatograph system. Repeat the injection until two consecutive values for the height of the vinyl chloride peak do not vary more than 5 percent. Use the average value for these two peak heights to compute the sample concentration.

b. Back Flush. After 4 minutes has elapsed after sample injection, actuate the back flush valve to purge the first 4 feet of the chromatographic column of solvent and other high boilers.

c. Sample Data. Record on the chromatograph strip chart the data from the sample label.

d. Elution Time. Vinyl chloride elutes at 2.8 minutes. Acetaldehyde elutes at 3.7 minutes. Analysis is considered complete when chart pen becomes stable. After 5 minutes, reset back flush valve and inject next sample.

8.3.3 Chromatograph Servicing.

a. Septum. Replace after five sample injections.

b. Sample Port Liner. Replace the sample port liner with a clean spare after five sample injections.

c. Chromatograph Shutdown. If the chromatograph has been shut down overnight, rerun one or more samples from the preceding day to test stability and precision prior to starting on the current day's work.

8.3.4 Determination of Total Solids (TS). For wet resin, resin solution, and PVC latex samples, determine the TS for each sample by accurately weighing approximately 3 to 5 grams of sample into a tared aluminum pan. The initial procedure is as follows:

a. Where water is the major volatile component: Tare the weighing dish, and add 3 to 5 grams of sample to the dish. Weigh to the nearest milligram.

b. Where volatile solvent is the major volatile component: Transfer a portion of the sample to a 20-ml screw cap vial and cap immediately. Weigh the vial to the nearest milligram. Uncap the vial and transfer a 3- to 5-gram portion of the sample to a tared aluminum weighing dish. Recap the vial and reweigh to the nearest milligram. The vial weight loss is the sample weight.

To continue, place the weighing pan in a 130 °C oven for 1 hour. Remove the dish and allow to cool to room temperature in a desiccator. Weigh the pan to the nearest 0.1 mg. Total solids is the weight of material in the aluminum pan after heating divided by the net weight of sample added to the pan originally times 100.

9. Calibration of the Chromatograph

9.1 Preparation of Standards. Prepare a 1 percent by weight (approximate) solution of vinyl chloride in THF or DMAC by bubbling vinyl chloride gas from a cylinder into a tared 125-ml glass-stoppered flask containing THF or DMAC. The weight of vinyl chloride to be added should be calculated prior to this operation, i.e., 1 percent of the weight of THF or DMAC contained in the tared flask. This must be carried out in a laboratory hood. Adjust the vinyl chloride flow from the cylinder so that the vinyl chloride dissolves essentially completely in the THF or DMAC and is not blown to the atmosphere. Take particular care not to volatize any of the solution. Stopper the flask and swirl the solution to effect complete mixing. Weigh the stoppered flask to nearest 0.1 mg to determine the exact amount of vinyl chloride added.

Pipet 10 ml of the approximately 1 percent solution into a 100-ml glass-stoppered volumetric flask, and add THF or DMAC to fill to the mark. Cap the flask and invert 10 to 20 times. This solution contains approximately 1,000 ppm by weight of vinyl chloride (note the exact concentration).

Pipet 50-, 10-, 5-, 1-, 0.5-, and 0.1-ml aliquots of the approximately 1,000 ppm solution into 10 ml glass stoppered volumetric flasks. Dilute to the mark with THF or DMAC, cap the flasks and invert each 10 to 20 times. These solutions contain approximately 500, 100, 50, 10, 5, and 1 ppm vinyl chloride. Note the exact concentration of each one. These standards are to be kept under refrigeration in stoppered bottles, and must be renewed every 3 months.

9.2 Preparation of Chromatograph Calibration Curve.

Obtain the GC for each of the six final solutions prepared in Section 9.1 by using the procedure in Section 8.3.2. Prepare a chart plotting peak height obtained from the chromatogram of each solution versus the known concentration. Draw a straight line through the points derived by the least squares method.

10. Calculations

10.1 Response Factor. From the calibration curve described in Section 9.2, select the value of C_c that corresponds to H_c for each sample. Compute the response factor, R_f , for each sample as follows:

$$R_f = \frac{C_c}{H_c} \qquad \text{Eq. 107A-1}$$

where:

R_f =Chromatograph response factor, ppm/mm.

C_c =Concentration of vinyl chloride in the standard sample, ppm.

H_c =Peak height of the standard sample, mm.

10.2 Residual vinyl chloride monomer concentration (C_{rvc}) or vinyl chloride monomer concentration in resin:

$$C_{rvc} = 10 H_s R_f \qquad \text{Eq. 107A-2}$$

Where:

C_{rvc} =Concentration of residual vinyl chloride monomer, ppm.

H_s =Peak height of sample, mm.

R_f =Chromatograph response factor.

10.3 Samples containing volatile material, i.e., resin solutions, wet resin, and latexes:

$$C_{rvc} = \frac{H_s R_f (1,000)}{TS} \qquad \text{Eq. 107A-3}$$

where:

TS=Total solids in the sample, weight fraction.

10.4 Samples of solvents and in process wastewater:

$$C_{rvc} = \frac{H_s R_f}{0.888} \qquad \text{Eq. 107A-4}$$

Where:

0.888=Specific gravity of THF.

11. Bibliography

1. Communication from R. N. Wheeler, Jr.; Union Carbide Corporation. Part 61 National Emissions Standards for Hazardous Air Pollutants appendix B, Method 107—Alternate Method, September 19, 1977.

METHOD 108—DETERMINATION OF PARTICULATE AND GASEOUS ARSENIC EMISSIONS

NOTE: This method does not include all of the specifications (e.g., equipment and supplies) and procedures (e.g., sampling and analytical) essential to its performance. Some material is incorporated by reference from other methods in appendix A to 40 CFR part 60. Therefore, to obtain reliable results, persons using this method should have a thorough knowledge of at least the following additional test methods: Method 1, Method 2, Method 3, Method 5, and Method 12.

1.0 Scope and Application.

1.1 Analytes.

Analyte	**CAS No.**	**Sensitivity**
Arsenic compounds as arsenic (As)	7440-38-2	Lower limit 10 μg/ml or less.

1.2 Applicability. This method is applicable for the determination of inorganic As emissions from stationary sources as specified in an applicable subpart of the regulations.

1.3 Data Quality Objectives. Adherence to the requirements of this method will enhance the quality of the data obtained from air pollutant sampling methods.

2.0 Summary of Method

Particulate and gaseous As emissions are withdrawn isokinetically from the source and are collected on a glass mat filter and in water. The collected arsenic is then analyzed by means of atomic absorption spectrophotometry (AAS).

3.0 Definitions. [Reserved]

4.0 Interferences

Analysis for As by flame AAS is sensitive to the chemical composition and to the physical properties (e.g., viscosity, pH) of the sample. The analytical procedure includes a check for matrix effects (Section 11.5).

5.0 Safety

5.1 This method may involve hazardous materials, operations, and equipment. This test method may not address all of the safety problems associated with its use. It is the responsibility of the user to establish appropriate safety and health practices and determine the applicability of regulatory limitations prior to performing this test method.

5.2 Corrosive reagents. The following reagents are hazardous. Personal protective equipment and safe procedures that prevent chemical splashes are recommended. If contact occurs, immediately flush with copious amounts of water for at least 15 minutes. Remove clothing under shower and decontaminate. Treat residual chemical burns as thermal burns.

5.2.1 Hydrochloric Acid (HCl). Highly corrosive liquid with toxic vapors. Vapors are highly irritating to eyes, skin, nose, and lungs, causing severe damage. May cause bronchitis, pneumonia, or edema of lungs. Exposure to concentrations of 0.13 to 0.2 percent can be lethal to humans in a few minutes. Provide ventilation to limit exposure. Reacts with metals, producing hydrogen gas.

5.2.2 Hydrogen Peroxide (H_2O_2). Very harmful to eyes. 30% H_2O_2 can burn skin, nose, and lungs.

5.2.3 Nitric Acid (HNO_3). Highly corrosive to eyes, skin, nose, and lungs. Vapors are highly toxic and can cause bronchitis, pneumonia, or edema of lungs. Reaction to inhalation may be delayed as long as 30 hours and still be fatal. Provide ventilation to limit exposure. Strong oxidizer. Hazardous reaction may occur with organic materials such as solvents.

5.2.4 Sodium Hydroxide (NaOH). Causes severe damage to eyes and skin. Inhalation causes irritation to nose, throat, and lungs. Reacts exothermically with small amounts of water.

6.0 Equipment and Supplies

6.1 Sample Collection. A schematic of the sampling train used in performing this method is shown in Figure 108-1; it is similar to the Method 5 sampling train of 40 CFR part 60, appendix A. The following items are required for sample collection:

6.1.1 Probe Nozzle, Probe Liner, Pitot Tube, Differential Pressure Gauge, Filter Holder, Filter Heating System, Temperature Sensor, Metering System, Barometer, and Gas Density Determination Equipment. Same as Method 5, Sections 6.1.1.1 to 6.1.1.7, 6.1.1.9, 6.1.2, and 6.1.3, respectively.

6.1.2 Impingers. Four impingers connected in series with leak-free ground-glass fittings or any similar leak-free noncontaminating fittings. For the first, third, and fourth impingers, use the Greenburg-Smith design, modified by replacing the tip with a 1.3-cm ID (0.5-in.) glass tube extending to about 1.3 cm (0.5 in.) from the bottom of the flask. For the second impinger, use the Greenburg-Smith design with the standard tip. Modifications (e.g., flexible connections between the impingers, materials other than glass, or flexible vacuum lines to connect the filter holder to the condenser) are subject to the approval of the Administrator.

6.1.3 Temperature Sensor. Place a temperature sensor, capable of measuring temperature to within 1 °C (2 °F), at the outlet of the fourth impinger for monitoring purposes.

6.2 Sample Recovery. The following items are required for sample recovery:

6.2.1 Probe-Liner and Probe-Nozzle Brushes, Petri Dishes, Graduated Cylinder and/or Balance, Plastic Storage Containers, and Funnel and Rubber Policeman. Same as Method 5, Sections 6.2.1 and 6.2.4 to 6.2.8, respectively.

6.2.2 Wash Bottles. Polyethylene (2).

6.2.3 Sample Storage Containers. Chemically resistant, polyethylene or polypropylene for glassware washes, 500- or 1000-ml.

6.3 Analysis. The following items are required for analysis:

6.3.1 Spectrophotometer. Equipped with an electrodeless discharge lamp and a background corrector to measure absorbance at 193.7 nanometers (nm). For measuring samples having less than 10 µg As/ml, use a vapor generator accessory or a graphite furnace.

6.3.2 Recorder. To match the output of the spectrophotometer.

6.3.3 Beakers. 150 ml.

6.3.4 Volumetric Flasks. Glass 50-, 100-, 200-, 500-, and 1000-ml; and polypropylene, 50-ml.

6.3.5 Balance. To measure within 0.5 g.
6.3.6 Volumetric Pipets. 1-, 2-, 3-, 5-, 8-, and 10-ml.
6.3.7 Oven.
6.3.8 Hot Plate.

7.0 Reagents and Standards

Unless otherwise indicated, it is intended that all reagents conform to the specifications established by the Committee on Analytical Reagents of the American Chemical Society, where such specifications are available; otherwise, use the best available grade.

7.1 The following reagents are required for sample collection:

7.1.1 Filters. Same as Method 5, Section 7.1.1, except that the filters need not be unreactive to SO_2 .

7.1.2 Silica Gel, Crushed Ice, and Stopcock Grease. Same as Method 5, Sections 7.1.2, 7.1.4, and 7.1.5, respectively.

7.1.3 Water. Deionized distilled to meet ASTM D 1193-77 or 91 (incorporated by reference-see § 61.18), Type 3. When high concentrations of organic matter are not expected to be present, the $KMnO_4$ test for oxidizable organic matter may be omitted.

7.2 Sample Recovery.

7.2.1 0.1 N NaOH. Dissolve 4.00 g of NaOH in about 500 ml of water in a 1-liter volumetric flask. Then, dilute to exactly 1.0 liter with water.

7.3 Analysis. The following reagents and standards are required for analysis:

7.3.1 Water. Same as Section 7.1.3.

7.3.2 Sodium Hydroxide, 0.1 N. Same as in Section 7.2.1.

7.3.3 Sodium Borohydride ($NaBH_4$), 5 Percent Weight by Volume (W/V). Dissolve 50.0 g of $NaBH_4$ in about 500 ml of 0.1 N NaOH in a 1-liter volumetric flask. Then, dilute to exactly 1.0 liter with 0.1 N NaOH.

7.3.4 Hydrochloric Acid, Concentrated.

7.3.5 Potassium Iodide (KI), 30 Percent (W/V). Dissolve 300 g of KI in 500 ml of water in a 1 liter volumetric flask. Then, dilute to exactly 1.0 liter with water.

7.3.6 Nitric Acid, Concentrated.

7.3.7 Nitric Acid, 0.8 N. Dilute 52 ml of concentrated HNO_3 to exactly 1.0 liter with water.

7.3.8 Nitric Acid, 50 Percent by Volume (V/V). Add 50 ml concentrated HNO_3 to 50 ml water.

7.3.9 Stock Arsenic Standard, 1 mg As/ml. Dissolve 1.3203 g of primary standard grade As_2O_3 in 20 ml of 0.1 N NaOH in a 150 ml beaker. Slowly add 30 ml of concentrated HNO_3 . Heat the resulting solution and evaporate just to dryness. Transfer the residue quantitatively to a 1-liter volumetric flask, and dilute to 1.0 liter with water.

7.3.10 Arsenic Working Solution, 1.0 μg As/ml. Pipet exactly 1.0 ml of stock arsenic standard into an acid-cleaned, appropriately labeled 1-liter volumetric flask containing about 500 ml of water and 5 ml of concentrated HNO_3 . Dilute to exactly 1.0 liter with water.

7.3.11 Air. Suitable quality for AAS analysis.

7.3.12 Acetylene. Suitable quality for AAS analysis.

7.3.13 Nickel Nitrate, 5 Percent Ni (W/V). Dissolve 24.780 g of nickel nitrate hexahydrate [$Ni(NO_3)_2 6H_2O$] in water in a 100-ml volumetric flask, and dilute to 100 ml with water.

7.3.14 Nickel Nitrate, 1 Percent Ni (W/V). Pipet 20 ml of 5 percent nickel nitrate solution into a 100-ml volumetric flask, and dilute to exactly 100 ml with water.

7.3.15 Hydrogen Peroxide, 3 Percent by Volume. Pipet 50 ml of 30 percent H_2O_2 into a 500-ml volumetric flask, and dilute to exactly 500 ml with water.

8.0 Sample Collection, Preservation, Transport, and Storage

8.1 Pretest Preparation. Follow the general procedure given in Method 5, Section 8.1, except the filter need not be weighed, and the 200 ml of 0.1N NaOH and Container 4 should be tared to within 0.5 g.

8.2 Preliminary Determinations. Follow the general procedure given in Method 5, Section 8.2, except select the nozzle size to maintain isokinetic sampling rates below 28 liters/min (1.0 cfm).

8.3 Preparation of Sampling Train. Follow the general procedure given in Method 5, Section 8.3.

8.4 Leak-Check Procedures. Same as Method 5, Section 8.4.

8.5 Sampling Train Operation. Follow the general procedure given in Method 5, Section 8.5, except maintain isokinetic sampling flow rates below 28 liters/min (1.0 cfm). For each run, record the data required on a data sheet similar to the one shown in Figure 108-2.

8.6 Calculation of Percent Isokinetic. Same as Method 5, Section 8.6.

8.7 Sample Recovery. Same as Method 5, Section 8.7, except that 0.1 N NaOH is used as the cleanup solvent instead of acetone and that the impinger water is treated as follows:

8.7.1 Container Number 4 (Impinger Water). Clean each of the first three impingers and connecting glassware in the following manner:

8.7.1.1 Wipe the impinger ball joints free of silicone grease, and cap the joints.

8.7.1.2 Rotate and agitate each of the first two impingers, using the impinger contents as a rinse solution.

8.7.1.3 Transfer the liquid from the first three impingers to Container Number 4. Remove the outlet ball-joint cap, and drain the contents through this opening. Do not separate the impinger parts (inner and outer tubes) while transferring their contents to the container.

8.7.1.4 Weigh the contents of Container No. 4 to within 0.5 g. Record in the log the weight of liquid along with a notation of any color or film observed in the impinger catch. The weight of liquid is needed along with the silica gel data to calculate the stack gas moisture content.

NOTE: Measure and record the total amount of 0.1 N NaOH used for rinsing under Sections 8.7.1.5 and 8.7.1.6.

8.7.1.5 Pour approximately 30 ml of 0.1 NaOH into each of the first two impingers, and agitate the impingers. Drain the 0.1 N NaOH through the outlet arm of each impinger into Container Number 4. Repeat this operation a second time; inspect the impingers for any abnormal conditions.

8.7.1.6 Wipe the ball joints of the glassware connecting the impingers and the back half of the filter holder free of silicone grease, and rinse each piece of glassware twice with 0.1 N NaOH; transfer this rinse into Container Number 4. (DO NOT RINSE or brush the glass-fritted filter support.) Mark the height of the fluid level to determine whether leakage occurs during transport. Label the container to identify clearly its contents.

8.8 Blanks.

8.8.1 Sodium Hydroxide. Save a portion of the 0.1 N NaOH used for cleanup as a blank. Take 200 ml of this solution directly from the wash bottle being used and place it in a plastic sample container labeled “NaOH blank.”

8.8.2 Water. Save a sample of the water, and place it in a container labeled “H_2 O blank.”

8.8.3 Filter. Save two filters from each lot of filters used in sampling. Place these filters in a container labeled “filter blank.”

9.0 Quality Control

9.1 MISCELLANEOUS QUALITY CONTROL MEASURES.

Section	Quality control measure	Effect
8.4, 10.1	Sampling equipment leak-checks and calibration	Ensures accuracy and precision of sampling measurements.
10.4	Spectrophotometer calibration	Ensures linearity of spectrophotometer response to standards.
11.5	Check for matrix effects	Eliminates matrix effects.

9.2 Volume Metering System Checks. Same as Method 5, Section 9.2.

10.0 Calibration and Standardization

NOTE: Maintain a laboratory log of all calibrations.

10.1 Sampling Equipment. Same as Method 5, Section 10.0.

10.2 Preparation of Standard Solutions.

10.2.1 For the high level procedure, pipet 1, 3, 5, 8, and 10 ml of the 1.0 mg As/ml stock solution into separate 100 ml volumetric flasks, each containing 5 ml of concentrated HNO_3 . Dilute to the mark with water.

10.2.2 For the low level vapor generator procedure, pipet 1, 2, 3, and 5 ml of 1.0 μg As/ml standard solution into separate reaction tubes. Dilute to the mark with water.

10.2.3 For the low level graphite furnace procedure, pipet 1, 5, 10 and 15 ml of 1.0 μg As/ml standard solution into separate flasks along with 2 ml of the 5 percent nickel nitrate solution and 10 ml of the 3 percent H_2O_2 solution. Dilute to the mark with water.

10.3 Calibration Curve. Analyze a 0.8 N HNO_3 blank and each standard solution according to the procedures outlined in section 11.4.1. Repeat this procedure on each standard solution until two consecutive peaks agree within 3 percent of their average value. Subtract the average peak height (or peak area) of the blank—which must be less than 2 percent of recorder full scale—from the averaged peak height of each standard solution. If the blank absorbance is greater than 2 percent of full-scale, the probable cause is As contamination of a reagent or carry-over of As from a previous sample. Prepare the calibration curve by plotting the corrected peak height of each standard solution versus the corresponding final total As weight in the solution.

10.4 Spectrophotometer Calibration Quality Control. Calculate the least squares slope of the calibration curve. The line must pass through the origin or through a point no further from the origin than ±2 percent of the recorder full scale. Multiply the corrected peak height by the reciprocal of the least squares slope to determine the distance each calibration point lies from the theoretical calibration line. The difference between the calculated concentration values and the actual concentrations (e.g., 1, 3, 5, 8, and 10 mg As for the high-level procedure) must be less than 7 percent for all standards.

NOTE: For instruments equipped with direct concentration readout devices, preparation of a standard curve will not be necessary. In all cases, follow calibration and operational procedures in the manufacturers' instruction manual.

11.0 Analytical Procedure

11.1 Sample Loss Check. Prior to analysis, check the liquid level in Containers Number 2 and Number 4. Note on the analytical data sheet whether leakage occurred during transport. If a noticeable amount of leakage occurred, either void the sample or take steps, subject to the approval of the Administrator, to adjust the final results.

11.2 Sample Preparation.

11.2.1 Container Number 1 (Filter). Place the filter and loose particulate matter in a 150 ml beaker. Also, add the filtered solid material from Container Number 2 (see Section 11.2.2). Add 50 ml of 0.1 N NaOH. Then stir and warm on a hot plate at low heat (do not boil) for about 15 minutes. Add 10 ml of concentrated HNO_3 , bring to a boil, then simmer for about 15 minutes. Filter the solution through a glass fiber filter. Wash with hot water, and catch the filtrate in a clean 150 ml beaker. Boil the filtrate, and evaporate to dryness. Cool, add 5 ml of 50 percent HNO_3 , and then warm and stir. Allow to cool. Transfer to a 50-ml volumetric flask, dilute to volume with water, and mix well.

11.2.2 Container Number 2 (Probe Wash).

11.2.2.1 Filter (using a glass fiber filter) the contents of Container Number 2 into a 200 ml volumetric flask. Combine the filtered (solid) material with the contents of Container Number 1 (Filter).

11.2.2.2 Dilute the filtrate to exactly 200 ml with water. Then pipet 50 ml into a 150 ml beaker. Add 10 ml of concentrated HNO_3 , bring to a boil, and evaporate to dryness. Allow to cool, add 5 ml of 50 percent HNO_3 , and then warm and stir. Allow the solution to cool, transfer to a 50-ml volumetric flask, dilute to volume with water, and mix well.

11.2.3 Container Number 4 (Impinger Solution). Transfer the contents of Container Number 4 to a 500 ml volumetric flask, and dilute to exactly 500-ml with water. Pipet 50 ml of the solution into a 150-ml beaker. Add 10 ml of concentrated HNO_3 , bring to a boil, and evaporate to dryness. Allow to cool, add 5 ml of 50 percent HNO_3 , and then warm and stir. Allow the solution to cool, transfer to a 50-ml volumetric flask, dilute to volume with water, and mix well.

11.2.4 Filter Blank. Cut each filter into strips, and treat each filter individually as directed in Section 11.2.1, beginning with the sentence, "Add 50 ml of 0.1 N NaOH."

11.2.5 Sodium Hydroxide and Water Blanks. Treat separately 50 ml of 0.1 N NaOH and 50 ml water, as directed under Section 11.2.3, beginning with the sentence, "Pipet 50 ml of the solution into a 150-ml beaker."

11.3 Spectrophotometer Preparation. Turn on the power; set the wavelength, slit width, and lamp current. Adjust the background corrector as instructed by the manufacturer's manual for the particular atomic absorption spectrophotometer. Adjust the burner and flame characteristics as necessary.

11.4 Analysis. Calibrate the analytical equipment and develop a calibration curve as outlined in Sections 10.2 through 10.4.

11.4.1 Arsenic Samples. Analyze an appropriately sized aliquot of each diluted sample (from Sections 11.2.1 through 11.2.3) until two consecutive peak heights agree within 3 percent of their average value. If applicable, follow the procedures outlined in Section 11.4.1.1. If the sample concentration falls outside the range of the calibration curve, make an appropriate dilution with 0.8 N HNO_3 so that the final concentration falls within the range of the curve. Using the calibration curve, determine the arsenic concentration in each sample fraction.

NOTE: Because instruments vary between manufacturers, no detailed operating instructions will be given here. Instead, the instrument manufacturer's detailed operating instructions should be followed.

11.4.1.1 Arsenic Determination at Low Concentration. The lower limit of flame AAS is 10 µg As/ml. If the arsenic concentration of any sample is at a lower level, use the graphite furnace or vapor generator which is available as an accessory component. Flame, graphite furnace, or vapor generators may be used for samples whose concentrations are between 10 and 30 µg/ml. Follow the manufacturer's instructions in the use of such equipment.

11.4.1.1.1 Vapor Generator Procedure. Place a sample containing between 0 and 5 µg of arsenic in the reaction tube, and dilute to 15 ml with water. Since there is some trial and error involved in this procedure, it may be necessary to screen the samples by conventional atomic absorption until an approximate concentration is determined. After determining the approximate concentration, adjust the volume of the sample accordingly. Pipet 15 ml of concentrated HCl into each tube. Add 1 ml of 30 percent KI solution. Place the reaction tube into a 50 °C (120 °F) water bath for 5 minutes. Cool to room temperature. Connect the reaction tube to the vapor generator assembly. When the instrument response has returned to baseline, inject 5.0 ml of 5 percent $NaBH_4$, and integrate the resulting spectrophotometer signal over a 30-second time period.

11.4.1.1.2 Graphite Furnace Procedure. Dilute the digested sample so that a 5 ml aliquot contains less than 1.5 µg of arsenic. Pipet 5 ml of this digested solution into a 10-ml volumetric flask. Add 1 ml of the 1 percent nickel nitrate solution, 0.5 ml of 50 percent HNO_3 , and 1 ml of the 3 percent hydrogen peroxide and dilute to 10 ml with water. The sample is now ready for analysis.

11.4.1.2 Run a blank (0.8 N HNO_3) and standard at least after every five samples to check the spectrophotometer calibration. The peak height of the blank must pass through a point no further from the origin than ±2 percent of the recorder full scale. The difference between the measured concentration of the standard (the product of the corrected average peak height and the reciprocal of the least squares slope) and the actual concentration of the standard must be less than 7 percent, or recalibration of the analyzer is required.

11.4.1.3 Determine the arsenic concentration in the filter blank (i.e., the average of the two blank values from each lot).

11.4.2 Container Number 3 (Silica Gel). This step may be conducted in the field. Weigh the spent silica gel (or silica gel plus impinger) to the nearest 0.5 g; record this weight.

11.5 Check for matrix effects on the arsenic results. Same as Method 12, Section 11.5.

12.0 Data Analysis and Calculations

12.1 NOMENCLATURE

B_{ws} = Water in the gas stream, proportion by volume.
C_a = Concentration of arsenic as read from the standard curve, µg/ml.
C_s = Arsenic concentration in stack gas, dry basis, converted to standard conditions, g/dsm^3 (gr/dscf).
E_a = Arsenic mass emission rate, g/hr (lb/hr).
F_d = Dilution factor (equals 1 if the sample has not been diluted).
I = Percent of isokinetic sampling.
m_{bi} = Total mass of all four impingers and contents before sampling, g.
m_{fi} = Total mass of all four impingers and contents after sampling, g.
m_n = Total mass of arsenic collected in a specific part of the sampling train, µg.
m_t = Total mass of arsenic collected in the sampling train, µg.
T_m = Absolute average dry gas meter temperature (see Figure 108-2), °K (°R).
V_m = Volume of gas sample as measured by the dry gas meter, dry basis, m^3 (ft^3).
$V_{m(std)}$ = Volume of gas sample as measured by the dry gas meter, corrected to standard conditions, m^3 (ft^3).
V_n = Volume of solution in which the arsenic is contained, ml.
$V_{w(std)}$ = Volume of water vapor collected in the sampling train, corrected to standard conditions, m^3 (ft^3).
ΔH = Average pressure differential across the orifice meter (see Figure 108-2), mm H_2O (in. H_2O).

12.2 Average Dry Gas Meter Temperatures (T_m) and Average Orifice Pressure Drop (ΔH). See data sheet (Figure 108-2).

12.3 Dry Gas Volume. Using data from this test, calculate $V_{m(std)}$ according to the procedures outlined in Method 5, Section 12.3.

12.4 Volume of Water Vapor.

$$V_{w(std)} = K_2\left(m_{fi} - m_{bi}\right) \qquad \text{Eq. 108-1}$$

Where:
K_2 = 0.001334 m^3 /g for metric units.
= 0.047012 ft^3 /g for English units.

12.5 Moisture Content.

$$B_{ws} = \frac{V_{w(std)}}{V_{m(std)} + V_{w(std)}} \qquad \text{Eq. 108-2}$$

12.6 Amount of Arsenic Collected.

12.6.1 Calculate the amount of arsenic collected in each part of the sampling train, as follows:

$$m_n = C_a F_d V_n \qquad \text{Eq. 108-3}$$

12.6.2 Calculate the total amount of arsenic collected in the sampling train as follows:

$$m_t = m_{(\text{filters})} + m_{(\text{probe})} + m_{(\text{impingers})} - m_{(\text{filter blank})} - m_{(\text{NaOH blank})} - m_{(\text{water blank})} \qquad \text{Eq. 108-4}$$

12.7 Calculate the arsenic concentration in the stack gas (dry basis, adjusted to standard conditions) as follows:

$$C_s = K_3\left(m_t / V_{m(std)}\right) \qquad \text{Eq. 108-5}$$

Where:
$K_3 = 10^{-6}$ g/μg for metric units
$= 1.54 \times 10^{-5}$ gr/μg for English units

12.8 Stack Gas Velocity and Volumetric Flow Rate. Calculate the average stack gas velocity and volumetric flow rate using data obtained in this method and the equations in Sections 12.2 and 12.3 of Method 2.

12.9 Pollutant Mass Rate. Calculate the arsenic mass emission rate as follows:

$$E_a = C_s Q_{sd} \qquad Eq.\ 108\text{-}6$$

12.10 Isokinetic Variation. Same as Method 5, Section 12.11.

13.0 Method Performance

13.1 Sensitivity. The lower limit of flame AAS 10 μg As/ml. The analytical procedure includes provisions for the use of a graphite furnace or vapor generator for samples with a lower arsenic concentration.

14.0 Pollution Prevention. [Reserved]

15.0 Waste Management. [Reserved]

16.0 References.

Same as References 1 through 9 of Method 5, Section 17.0, with the addition of the following:

1. Perkin Elmer Corporation. Analytical Methods for Atomic Absorption Spectrophotometry. 303-0152. Norwalk, Connecticut. September 1976. pp. 5-6.
2. Standard Specification for Reagent Water. In: Annual Book of American Society for Testing and Materials Standards. Part 31: Water, Atmospheric Analysis. American Society for Testing and Materials. Philadelphia, PA. 1974. pp. 40-42.
3. Stack Sampling Safety Manual (Draft). U.S. Environmental Protection Agency, Office of Air Quality Planning and Standard, Research Triangle Park, NC. September 1978.

17.0 Tables, Diagrams, Flowcharts, and Validation Data

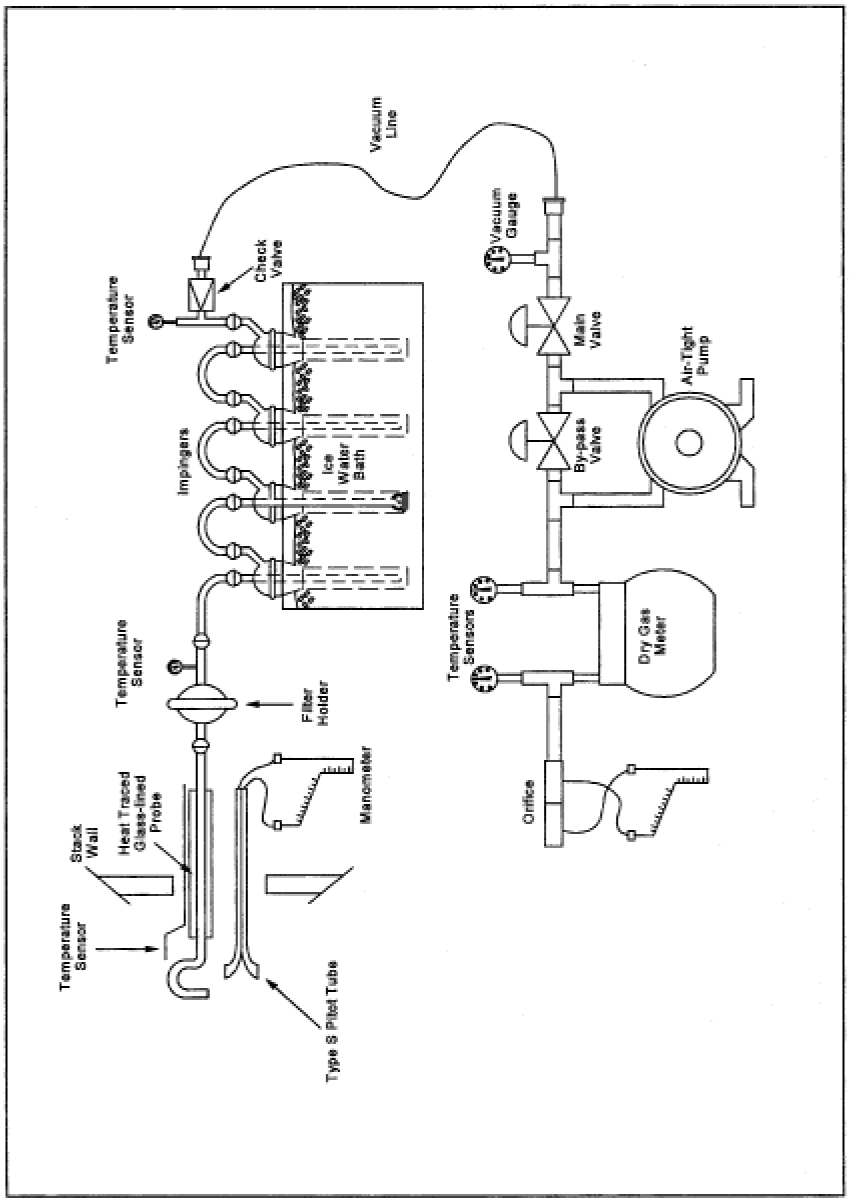

Figure 108-1. Arsenic Sampling Train

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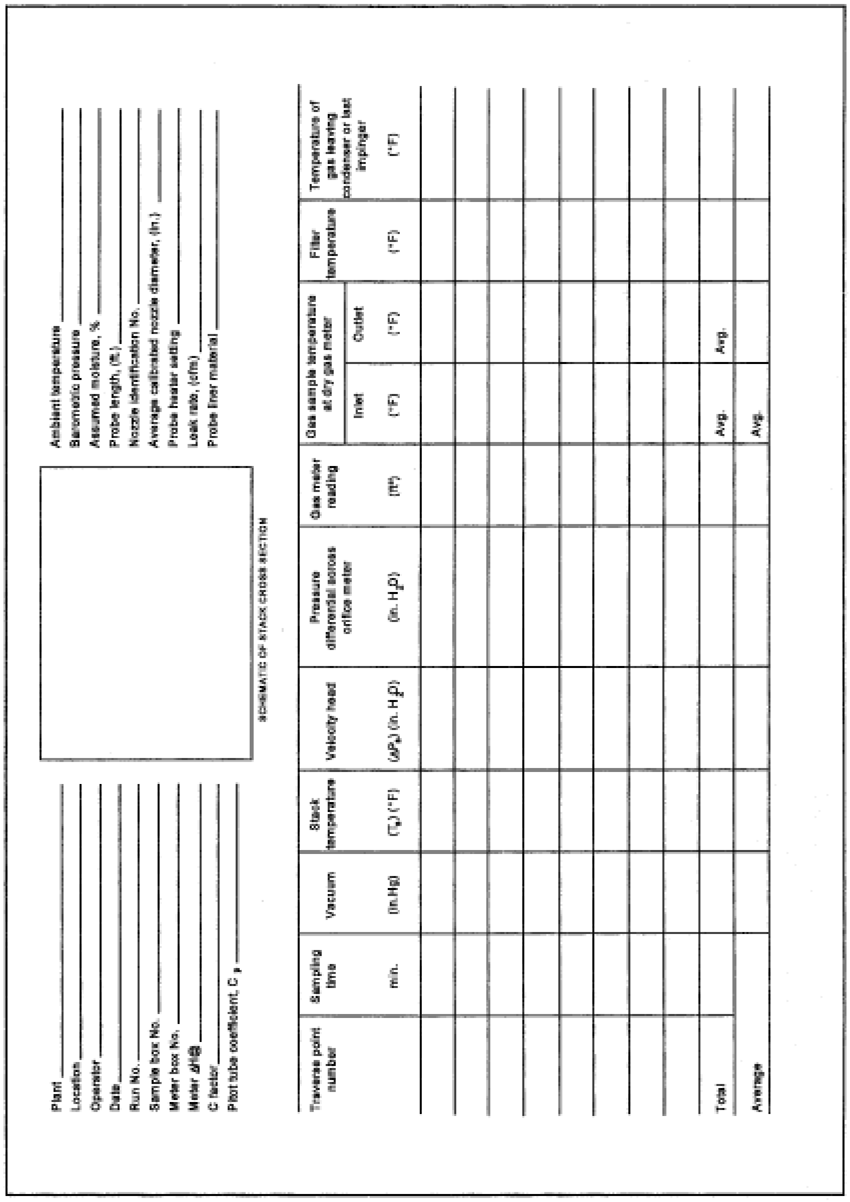

Plant ________
Location ________
Operator ________
Date ________
Run No. ________
Sample box No. ________
Meter box No. ________
Meter ΔH@ ________
C factor ________
Pitot tube coefficient, C_p ________

SCHEMATIC OF STACK CROSS SECTION

Ambient temperature ________
Barometric pressure ________
Assumed moisture, % ________
Probe length, (ft.) ________
Nozzle identification No. ________
Average calibrated nozzle diameter, (in.) ________
Probe heater setting ________
Leak rate, (cfm) ________
Probe liner material ________

Traverse point number	Sampling time min.	Vacuum (in.Hg)	Stack temperature (T_s) (°F)	Velocity head (ΔP_s) (in. H_2O)	Pressure differential across orifice meter (in. H_2O)	Gas meter reading (ft^3)	Gas sample temperature at dry gas meter Inlet (°F)	Gas sample temperature at dry gas meter Outlet (°F)	Filter temperature (°F)	Temperature of gas leaving condenser or last impinger (°F)
Total							Avg.	Avg.		
Average							Avg.			

Figure 108-2. Arsenic Field Data Sheet.

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METHOD 108A—DETERMINATION OF ARSENIC CONTENT IN ORE SAMPLES FROM NONFERROUS SMELTERS

NOTE: This method does not include all of the specifications (e.g., equipment and supplies) and procedures (e.g., sampling and analytical) essential to its performance. Some material is incorporated by reference from other methods in appendix A to 40 CFR part 60. Therefore, to obtain reliable results, persons using this method should have a thorough knowledge of Method 12.

1.0 Scope and Application

1.1 Analytes.

Analyte	CAS No.	Sensitivity
Arsenic compounds as arsenic (As)	7440-38-2	Lower limit 10 μg/ml or less.

1.2 Applicability. This method applies to the determination of inorganic As content of process ore and reverberatory matte samples from nonferrous smelters and other sources as specified in an applicable subpart of the regulations.

1.3 Data Quality Objectives. Adherence to the requirements of this method will enhance the quality of the data obtained from air pollutant sampling methods.

2.0 Summary of Method

Arsenic bound in ore samples is liberated by acid digestion and analyzed by flame atomic absorption spectrophotometry (AAS).

3.0 Definitions [Reserved]

4.0 Interferences

Analysis for As by flame AAS is sensitive to the chemical composition and to the physical properties (e.g., viscosity, pH) of the sample. The analytical procedure includes a check for matrix effects (section 11.5).

5.0 Safety

5.1 Disclaimer. This method may involve hazardous materials, operations, and equipment. This test method may not address all of the safety problems associated with its use. It is the responsibility of the user to establish appropriate safety and health practices and determine the applicability of regulatory limitations prior to performing this test method.

5.2 Corrosive Reagents. The following reagents are hazardous. Personal protective equipment and safe procedures that prevent chemical splashes are recommended. If contact occurs, immediately flush with copious amounts of water for at least 15 minutes. Remove clothing under shower and decontaminate. Treat residual chemical burns as thermal burns.

5.2.1 Hydrochloric Acid (HCl). Highly corrosive liquid with toxic vapors. Vapors are highly irritating to eyes, skin, nose, and lungs, causing severe damage. May cause bronchitis, pneumonia, or edema of lungs. Exposure to concentrations of 0.13 to 0.2 percent can be lethal to humans in a few minutes. Provide ventilation to limit exposure. Reacts with metals, producing hydrogen gas.

5.2.2 Hydrofluoric Acid (HF). Highly corrosive to eyes, skin, nose, throat, and lungs. Reaction to exposure may be delayed by 24 hours or more. Provide ventilation to limit exposure.

5.2.3 Hydrogen Peroxide ($H_2 O_2$). Very harmful to eyes. 30% $H_2 O_2$ can burn skin, nose, and lungs.

5.2.4 Nitric Acid (HNO_3). Highly corrosive to eyes, skin, nose, and lungs. Vapors are highly toxic and can cause bronchitis, pneumonia, or edema of lungs. Reaction to inhalation may be delayed as long as 30 hours and still be fatal. Provide ventilation to limit exposure. Strong oxidizer. Hazardous reaction may occur with organic materials such as solvents.

5.2.5 Sodium Hydroxide (NaOH). Causes severe damage to eyes and skin. Inhalation causes irritation to nose, throat, and lungs. Reacts exothermically with limited amounts of water.

6.0 Equipment and Supplies

6.1 Sample Collection and Preparation. The following items are required for sample collection and preparation:

6.1.1 Parr Acid Digestion Bomb. Stainless steel with vapor-tight Teflon cup and cover.

6.1.2 Volumetric Pipets. 2- and 5-ml sizes.

6.1.3 Volumetric Flask. 50-ml polypropylene with screw caps, (one needed per standard).

6.1.4 Funnel. Polyethylene or polypropylene.

6.1.5 Oven. Capable of maintaining a temperature of approximately 105 °C (221 °F).

6.1.6 Analytical Balance. To measure to within 0.1 mg.

6.2 Analysis. The following items are required for analysis:

6.2.1 Spectrophotometer and Recorder. Equipped with an electrodeless discharge lamp and a background corrector to measure absorbance at 193.7 nm. For measuring samples having less than 10 μg As/ml, use a graphite furnace or vapor generator accessory. The recorder shall match the output of the spectrophotometer.

6.2.2 Volumetric Flasks. Class A, 50-ml (one needed per sample and blank), 500-ml, and 1-liter.

6.2.3 Volumetric Pipets. Class A, 1-, 5-, 10-, and 25-ml sizes.

7.0 Reagents and Standards.

Unless otherwise indicated, it is intended that all reagents conform to the specifications established by the Committee on Analytical Reagents of the American Chemical Society, where such specifications are available; otherwise, use the best available grade.

7.1 Sample Collection and Preparation. The following reagents are required for sample collection and preparation:

7.1.1 Water. Deionized distilled to meet ASTM D 1193-77 or 91 Type 3 (incorporated by reference—See § 61.18). When high concentrations of organic matter are not expected to be present, the $KMnO_4$ test for

oxidizable organic matter may be omitted. Use in all dilutions requiring water.
7.1.2 Nitric Acid Concentrated.
7.1.3 Nitric Acid, 0.5 N. In a 1-liter volumetric flask containing water, add 32 ml of concentrated HNO_3 and dilute to volume with water.
7.1.4 Hydrofluoric Acid, Concentrated.
7.1.5 Potassium Chloride (KCl) Solution, 10 percent weight by volume (W/V). Dissolve 10 g KCl in water, add 3 ml concentrated HNO_3 , and dilute to 100 ml.
7.1.6 Filter. Teflon filters, 3-micron porosity, 47-mm size. (Available from Millipore Co., type FS, Catalog Number FSLW04700.)
7.1.7 Sodium Borohydride ($NaBH_4$), 5 Percent (W/V). Dissolve 50.0 g of $NaBH_4$ in about 500 ml of 0.1 N NaOH in a 1-liter volumetric flask. Then, dilute to exactly 1.0 liter with 0.1 N NaOH.
7.1.8 Nickel Nitrate, 5 Percent Ni (W/V). Dissolve 24.780 g of nickel nitrate hexahydrate [$Ni(NO_3)_2$ $6H_2O$] in water in a 100-ml volumetric flask, and dilute to 100 ml with water.
7.1.9 Nickel Nitrate, 1 Percent Ni (W/V). Pipet 20 ml of 5 percent nickel nitrate solution into a 100-ml volumetric flask, and dilute to 100 ml with water.
7.2 Analysis. The following reagents and standards are required for analysis:
7.2.2 Sodium Hydroxide, 0.1 N. Dissolve 2.00 g of NaOH in water in a 500-ml volumetric flask. Dilute to volume with water.
7.2.3 Nitric Acid, 0.5 N. Same as in Section 7.1.3.
7.2.4 Potassium Chloride Solution, 10 percent. Same as in Section 7.1.5.
7.2.5 Hydrochloric Acid, Concentrated.
7.2.6 Potassium Iodide (KI), 30 Percent (W/V). Dissolve 300 g of KI in about 500 ml of water in a 1-liter volumetric flask. Then, dilute to exactly 1.0 liter with water.
7.2.7 Hydrogen Peroxide, 3 Percent by Volume. Pipet 50 ml of 30 percent H_2O_2 into a 500-ml volumetric flask, and dilute to exactly 500 ml with water.
7.2.8 Stock Arsenic Standard, 1 mg As/ml. Dissolve 1.3203 g of primary grade As_2O_3 in 20 ml of 0.1 N NaOH. Slowly add 30 ml of concentrated HNO_3 , and heat in an oven at 105 °C (221 °F) for 2 hours. Allow to cool, and dilute to 1 liter with deionized distilled water.
7.2.9 Nitrous Oxide. Suitable quality for AAS analysis.
7.2.10 Acetylene. Suitable quality for AAS analysis.
7.2.11 Quality Assurance Audit Samples. When making compliance determinations, and upon availability, audit samples may be obtained from the appropriate EPA regional Office or from the responsible enforcement authority.

NOTE: The responsible enforcement authority should be notified at least 30 days prior to the test date to allow sufficient time for sample delivery.

8.0 Sample Collection, Preservation, Transport, and Storage

8.1 Sample Collection. A sample that is representative of the ore lot to be tested must be taken prior to analysis. (A portion of the samples routinely collected for metals analysis may be used provided the sample is representative of the ore being tested.)
8.2 Sample Preparation. The sample must be ground into a finely pulverized state.

9.0 QUALITY CONTROL

Section	**Quality control measure**	**Effect**
10.2	Spectrophotometer calibration	Ensure linearity of spectrophotometer response to standards.
11.5	Check for matrix effects	Eliminate matrix effects.

10.0 Calibration and Standardizations

NOTE: Maintain a laboratory log of all calibrations.

10.1 Preparation of Standard Solutions. Pipet 1, 5, 10, and 25 ml of the stock As solution into separate 100-ml volumetric flasks. Add 10 ml KCl solution and dilute to the mark with 0.5 N HNO_3 . This will give standard concentrations of 10, 50, 100, and 250 μg As/ml. For low-level arsenic samples that require the use of a graphite furnace or vapor generator, follow the procedures in Section 11.3:1. Dilute 10 ml of KCl solution to 100 ml with 0.5 N HNO_3 and use as a reagent blank.
10.2 Calibration Curve. Analyze the reagent blank and each standard solution according to the procedures outlined in Section 11.3. Repeat this procedure on each standard solution until two consecutive peaks agree within 3 percent of their average value. Subtract the average peak height (or

peak area) of the blank—which must be less than 2 percent of recorder full scale—from the averaged peak heights of each standard solution. If the blank absorbance is greater than 2 percent of full-scale, the probable cause is Hg contamination of a reagent or carry-over of As from a previous sample. Prepare the calibration curve by plotting the corrected peak height of each standard solution versus the corresponding final total As weight in the solution.

10.3 Spectrophotometer Calibration Quality Control. Calculate the least squares slope of the calibration curve. The line must pass through the origin or through a point no further from the origin than ±2 percent of the recorder full scale. Multiply the corrected peak height by the reciprocal of the least squares slope to determine the distance each calibration point lies from the theoretical calibration line. The difference between the calculated concentration values and the actual concentrations must be less than 7 percent for all standards.

NOTE: For instruments equipped with direct concentration readout devices, preparation of a standard curve will not be necessary. In all cases, follow calibration and operational procedures in the manufacturer's instruction manual.

11.0 Analytical Procedure

11.1 Sample Preparation. Weigh 50 to 500 mg of finely pulverized sample to the nearest 0.1 mg. Transfer the sample into the Teflon cup of the digestion bomb, and add 2 ml each of concentrated HNO_3 and HF. Seal the bomb immediately to prevent the loss of any volatile arsenic compounds that may form. Heat in an oven at 105 °C (221 °F) for 2 hours. Remove the bomb from the oven and allow to cool. Using a Teflon filter, quantitatively filter the digested sample into a 50-ml polypropylene volumetric flask. Rinse the bomb three times with small portions of 0.5 N HNO_3 , and filter the rinses into the flask. Add 5 ml of KCl solution to the flask, and dilute to 50 ml with 0.5 N HNO_3 .

11.2 Spectrophotometer Preparation.

11.2.1 Turn on the power; set the wavelength, slit width, and lamp current. Adjust the background corrector as instructed by the manufacturer's manual for the particular atomic absorption spectrophotometer. Adjust the burner and flame characteristics as necessary.

11.2.2 Develop a spectrophotometer calibration curve as outlined in Sections 10.2 and 10.3.

11.3 Arsenic Determination. Analyze an appropriately sized aliquot of each diluted sample (from Section 11.1) until two consecutive peak heights agree within 3 percent of their average value. If applicable, follow the procedures outlined in Section 11.3.1. If the sample concentration falls outside the range of the calibration curve, make an appropriate dilution with 0.5 N HNO_3 so that the final concentration falls within the range of the curve. Using the calibration curve, determine the As concentration in each sample.

NOTE: Because instruments vary between manufacturers, no detailed operating instructions will be given here. Instead, the instrument manufacturer's detailed operating instructions should be followed.

11.3.1 Arsenic Determination at Low Concentration. The lower limit of flame AAS is 10 µg As/ml. If the arsenic concentration of any sample is at a lower level, use the vapor generator or graphite furnace which is available as an accessory component. Flame, graphite furnace, or vapor generators may be used for samples whose concentrations are between 10 and 30 µg/ml. Follow the manufacturer's instructions in the use of such equipment.

11.3.1.1 Vapor Generator Procedure. Place a sample containing between 0 and 5 µg of arsenic in the reaction tube, and dilute to 15 ml with water. Since there is some trial and error involved in this procedure, it may be necessary to screen the samples by conventional AAS until an approximate concentration is determined. After determining the approximate concentration, adjust the volume of the sample accordingly. Pipet 15 ml of concentrated HCl into each tube. Add 1 ml of 30 percent KI solution. Place the reaction tube into a 50 °C (120 °F) water bath for 5 minutes. Cool to room temperature. Connect the reaction tube to the vapor generator assembly. When the instrument response has returned to baseline, inject 5.0 ml of 5 percent $NaBH_4$ and integrate the resulting spectrophotometer signal over a 30-second time period.

11.3.1.2 Graphite Furnace Procedure. Pipet 5 ml of the digested solution into a 10-ml volumetric flask. Add 1 ml of the 1 percent nickel nitrate solution, 0.5 ml of 50 percent HNO_3 , and 1 ml of the 3 percent H_2O_2 , and dilute to 10 ml with water. The sample is now ready to inject in the furnace for analysis.

11.4 Run a blank and standard at least after every five samples to check the spectrophotometer calibration. The peak height of the blank must pass through a point no further from the origin than ±2 percent of the recorder full scale. The difference between the measured concentration of the standard (the product of the corrected average peak height and the reciprocal of the least squares slope) and the actual concentration of the standard must be less than 7 percent, or recalibration of the analyzer is required.

11.5 Mandatory Check for Matrix Effects on the Arsenic Results. Same as Method 12, Section 11.5.

12.0 Data Analysis and Calculations

12.1 Calculate the percent arsenic in the ore sample as follows:

$$\% As = \frac{5 C_a F_d}{W} \qquad Eq.\ 108A\text{-}1$$

Where:

C_a = Concentration of As as read from the standard curve, µg/ml.
F_d = Dilution factor (equals to 1 if the sample has not been diluted).
W = Weight of ore sample analyzed, mg.
5 = (50 ml sample “ 100)/(10^3 µg/mg).

13.0 Method Performance

13.1 Sensitivity. The lower limit of flame AAS is 10 µg As/ml. The analytical procedure includes provisions for the use of a graphite furnace or vapor generator for samples with a lower arsenic concentration.

14.0 Pollution Prevention. [Reserved]

15.0 Waste Management. [Reserved]

16.0 References

Same as References 1 through 9 of Section 17.0 of Method 5, with the addition of the following:

1. Perkin Elmer Corporation. Analytical Methods of Atomic Absorption Spectrophotometry. 303-0152. Norwalk, Connecticut. September 1976. pp 5-6.
2. Ringwald, D. Arsenic Determination on Process Materials from ASARCO's Copper Smelter in Tacoma, Washington. Unpublished Report. Prepared for Emission Measurement Branch, Emission Standards and Engineering Division, U.S. Environmental Protection Agency, Research Triangle Park, North Carolina. August 1980. 35 pp.
3. Stack Sampling Safety Manual (Draft). U.S. Environmental Protection Agency, Office of Air Quality Planning and Standard, Research Triangle Park, NC. September 1978.

17.0 Tables, Diagrams, Flowcharts, and Validation Data. [Reserved]

METHOD 108B—DETERMINATION OF ARSENIC CONTENT IN ORE SAMPLES FROM NONFERROUS SMELTERS

NOTE: This method does not include all of the specifications (e.g., equipment and supplies) and procedures (e.g., sampling and analytical) essential to its performance. Some material is incorporated by reference from other methods in this appendix and in appendix A to 40 CFR part 60. Therefore, to obtain reliable results, persons using this method should have a thorough knowledge of at least the following additional test methods: Method 12 and Method 108A.

1.0 Scope and Application

1.1 Analytes.

Analyte	CAS No.	Sensitivity
Arsenic compounds as arsenic (As)	7440-38-2	Lower limit 10 µg/ml.

1.2 Applicability. This method applies to the determination of inorganic As content of process ore and reverberatory matte samples from nonferrous smelters and other sources as specified in an applicable subpart of the regulations. Samples resulting in an analytical concentration greater than 10 µg As/ml may be analyzed by this method. For lower level arsenic samples, Method 108C should be used.

1.3 Data Quality Objectives. Adherence to the requirements of this method will enhance the quality of the data obtained from air pollutant sampling methods.

2.0 Summary of Method

Arsenic bound in ore samples is liberated by acid digestion and analyzed by flame atomic absorption spectrophotometry (AAS).

3.0 Definitions [Reserved]

4.0 Interferences

Analysis for As by flame AAS is sensitive to the chemical composition and to the physical properties (e.g., viscosity, pH) of the sample. The analytical procedure includes a check for matrix effects (Section 11.4).

5.0 Safety

5.1 Disclaimer. This method may involve hazardous materials, operations, and equipment. This test method may not address all of the safety problems associated with its use. It is the responsibility of the user to establish appropriate safety and health practices and determine the applicability of regulatory limitations prior to performing this test method.

5.2 Corrosive Reagents. The following reagents are hazardous. Personal protective equipment and safe procedures that prevent chemical splashes are recommended. If contact occurs, immediately flush with copious amounts of water for at least 15 minutes. Remove clothing under shower and decontaminate. Treat residual chemical burns as thermal burns.

5.2.1 Hydrochloric acid (HCl). Highly corrosive liquid with toxic vapors. Vapors are highly irritating to eyes, skin, nose, and lungs, causing severe damage. May cause bronchitis, pneumonia, or edema of lungs. Exposure to concentrations of 0.13 to 0.2 percent can be lethal to humans in a few minutes. Provide ventilation to limit exposure. Reacts with metals, producing hydrogen gas.

5.2.2 Hydrofluoric Acid (HF). Highly corrosive to eyes, skin, nose, throat, and lungs. Reaction to exposure may be delayed by 24 hours or more. Provide ventilation to limit exposure.

5.2.3 Nitric Acid (HNO_3). Highly corrosive to eyes, skin, nose, and lungs. Vapors are highly toxic and can cause bronchitis, pneumonia, or edema of lungs. Reaction to inhalation may be delayed as long as 30 hours and still be fatal. Provide ventilation to limit exposure. Strong oxidizer. Hazardous reaction may occur with organic materials such as solvents.

5.2.4 Perchloric Acid ($HClO_4$). Corrosive to eyes, skin, nose, and throat. Provide ventilation to limit exposure. Very strong oxidizer. Keep separate from water and oxidizable materials to prevent vigorous evolution of heat, spontaneous combustion, or explosion. Heat solutions containing $HClO_4$ only in hoods specifically designed for $HClO_4$.

6.0 Equipment and Supplies

6.1 Sample Preparation. The following items are required for sample preparation:

6.1.1 Teflon Beakers. 150-ml.

6.1.2 Graduated Pipets. 5-ml disposable.

6.1.3 Graduated Cylinder. 50-ml.

6.1.4 Volumetric Flask. 100-ml.

6.1.5 Analytical Balance. To measure within 0.1 mg.

6.1.6 Hot Plate.

6.1.7 Perchloric Acid Fume Hood.

6.2 Analysis. The following items are required for analysis:

6.2.1 Spectrophotometer. Equipped with an electrodeless discharge lamp and a background corrector to measure absorbance at 193.7 nm.

6.2.2 Beaker and Watch Glass. 400-ml.

6.2.3 Volumetric Flask. 1-liter.

6.2.4 Volumetric Pipets. 1-, 5-, 10-, and 25-ml.

7.0 Reagents and Standards

Unless otherwise indicated, it is intended that all reagents conform to the specifications established by the Committee on Analytical Reagents of the American Chemical Society, where such specifications are available; otherwise, use the best available grade.

7.1 Sample Preparation. The following reagents are required for sample preparation:

7.1.1 Water. Deionized distilled to meet ASTM D 1193-77 or 91 Type 3 (incorporated by reference—see § 61.18).

7.1.2 Nitric Acid, Concentrated.

7.1.3 Hydrofluoric Acid, Concentrated.

7.1.4 Perchloric Acid, 70 Percent.

7.1.5 Hydrochloric Acid, Concentrated.

7.2 Analysis. The following reagents and standards are required for analysis:

7.2.1 Water. Same as in Section 7.1.1.

7.2.2 Stock Arsenic Standard, 1.0 mg As/ml. Dissolve 1.3203 g of primary grade $As_2 0_3$ [dried at 105 °C (221 °F)] in a 400-ml beaker with 10 ml of HNO_3 and 5 ml of HCl. Cover with a watch glass, and heat gently until dissolution is complete. Add 10 ml of HNO_3 and 25 ml of $HClO_4$, evaporate to strong fumes of $HClO_4$, and reduce to about 20 ml volume. Cool, add 100 ml of water and 100 ml of HCl, and transfer quantitatively to a 1-liter volumetric flask. Dilute to volume with water and mix.

7.2.3 Acetylene. Suitable quality for AAS analysis.

7.2.4 Air. Suitable quality for AAS analysis.

8.0 Sample Collection, Preservation, Transport, and Storage

Same as in Method 108A, Sections 8.1 and 8.2.

9.0 QUALITY CONTROL

Section	Quality control measure	Effect
10.2	Spectrophotometer calibration	Ensure linearity of spectrophotometer response to standards.
11.4	Check for matrix effects	Eliminate matrix effects.

10.0 Calibration and Standardization

NOTE: Maintain a laboratory log of all calibrations.

10.1 Preparation of Standard Solutions. Pipet 1, 5, 10, and 25 ml of the stock As solution into separate 100-ml volumetric flasks. Add 2 ml of $HClO_4$, 10 ml of HCl, and dilute to the mark with water. This will provide standard concentrations of 10, 50, 100, and 250 μg As/ml.

10.2 Calibration Curve and Spectrophotometer Calibration Quality Control. Same as Method 108A, Sections 10.2 and 10.3

11.0 Analytical Procedure

11.1 Sample Preparation. Weigh 100 to 1000 mg of finely pulverized sample to the nearest 0.1 mg. Transfer the sample to a 150-ml Teflon beaker. Dissolve the sample by adding 15 ml of HNO_3 , 10 ml of HCl, 10 ml of HF, and 10 ml of $HClO_4$ in the exact order as described, and let stand for 10 minutes. In a $HClO_4$ fume hood, heat on a hot plate until 2-3 ml of $HClO_4$ remain, then cool. Add 20 ml of water and 10 ml of HCl. Cover and warm until the soluble salts are in solution. Cool, and transfer quantitatively to a 100-ml volumetric flask. Dilute to the mark with water.

11.2 Spectrophotometer Preparation. Same as in Method 108A, Section 11.2.

11.3 Arsenic Determination. If the sample concentration falls outside the range of the calibration curve, make an appropriate dilution with 2 percent $HClO_4$ /10 percent HCl (prepared by diluting 2 ml concentrated $HClO_4$ and 10 ml concentrated HCl to 100 ml with water) so that the final concentration falls within the range of the curve. Using the calibration curve, determine the As concentration in each sample.

NOTE: Because instruments vary between manufacturers, no detailed operating instructions will be given here. Instead, the instrument manufacturer's detailed operating instructions should be followed. Run a blank and standard at least after every five samples to check the spectrophotometer calibration. The peak height of the blank must pass through a point no further from the origin than ±2 percent of the recorder full scale. The difference between the measured concentration of the standard (the product of the corrected average peak height and the reciprocal of the least squares slope) and the actual concentration of the standard must be less than 7 percent, or recalibration of the analyzer is required.

11.4 Mandatory Check for Matrix Effects on the Arsenic Results. Same as Method 12, Section 11.5.

12.0 Data Analysis and Calculations

Same as in Method 108A, Section 12.0.

13.0 Method Performance

13.1 Sensitivity. The lower limit of flame AAS is 10 μg As/ml.

14.0 Pollution Prevention [Reserved]

15.0 Waste Management [Reserved]

16.0 References

Same as in Method 108A, Section 16.0.

17.0 Tables, Diagrams, Flowcharts, and Validation Data [Reserved]

METHOD 108C—DETERMINATION OF ARSENIC CONTENT IN ORE SAMPLES FROM NONFERROUS SMELTERS (MOLYBDENUM BLUE PHOTOMETRIC PROCEDURE)

NOTE: This method does not include all of the specifications (e.g., equipment and supplies) and procedures (e.g., sampling and analytical) essential to its performance. Some material is incorporated by reference from other methods in this part. Therefore, to obtain reliable results, persons using this method should have a thorough knowledge of at least Method 108A.

1.0 Scope and Application

1.1 Analytes.

Analyte	CAS No.	Sensitivity
Arsenic compounds as arsenic (As)	7440-38-2	Lower limit 0.0002 percent As by weight.

1.2 Applicability. This method applies to the determination of inorganic As content of process ore and reverberatory matte samples from nonferrous smelters and other sources as specified in an applicable subpart of the regulations.

1.3 Data Quality Objectives. Adherence to the requirements of this method will enhance the quality of the data obtained from air pollutant sampling methods.

2.0 Summary of Method

Arsenic bound in ore samples is liberated by acid digestion and analyzed by the molybdenum blue photometric procedure.

3.0 Definitions. [Reserved]

4.0 Interferences. [Reserved]

5.0 Safety

5.1 Disclaimer. This method may involve hazardous materials, operations, and equipment. This test method may not address all of the safety problems associated with its use. It is the responsibility of the user to establish appropriate safety and health practices and determine the applicability of regulatory limitations prior to performing this test method.

5.2 Corrosive Reagents. The following reagents are hazardous. Personal protective equipment and safe procedures that prevent chemical splashes are recommended. If contact occurs, immediately flush with copious amounts of water for at least 15 minutes. Remove clothing under shower and decontaminate. Treat residual chemical burns as thermal burns.

5.2.1 Hydrochloric Acid (HCl). Highly corrosive liquid with toxic vapors. Vapors are highly irritating to eyes, skin, nose, and lungs, causing severe damage. May cause bronchitis, pneumonia, or edema of lungs. Exposure to concentrations of 0.13 to 0.2 percent can be lethal to humans in a few minutes. Provide ventilation to limit exposure. Reacts with metals, producing hydrogen gas.

5.2.2 Hydrofluoric Acid (HF). Highly corrosive to eyes, skin, nose, throat, and lungs. Reaction to exposure may be delayed by 24 hours or more. Provide ventilation to limit exposure.

5.2.3 Nitric Acid (HNO_4). Highly corrosive to eyes, skin, nose, and lungs. Vapors are highly toxic and can cause bronchitis, pneumonia, or edema of lungs. Reaction to inhalation may be delayed as long as 30 hours and still be fatal. Provide ventilation to limit exposure. Strong oxidizer. Hazardous reaction may occur with organic materials such as solvents.

5.2.4 Perchloric Acid ($HClO_4$). Corrosive to eyes, skin, nose, and throat. Provide ventilation to limit exposure. Very strong oxidizer. Keep separate from water and oxidizable materials to prevent vigorous evolution of heat, spontaneous combustion, or explosion. Heat solutions containing $HClO_4$ only in hoods specifically designed for $HClO_4$.

5.2.5 Sulfuric acid ($H_2 SO_4$). Rapidly destructive to body tissue. Will cause third degree burns. Eye damage may result in blindness. Inhalation may be fatal from spasm of the larynx, usually within 30 minutes. May cause lung tissue damage with edema. 3 mg/m^3 will cause lung damage in uninitiated. 1 mg/m^3 for 8 hours will cause lung damage or, in higher concentrations, death. Provide ventilation to limit inhalation. Reacts violently with metals and organics.

6.0 Equipment and Supplies

6.1 Sample Preparation. The following items are required for sample preparation:

6.1.1 Analytical Balance. To measure to within 0.1 mg.

6.1.2 Erlenmeyer Flask. 300-ml.

6.1.3 Hot Plate.

6.1.4 Distillation Apparatus. No. 6, in ASTM E 50-82, 86, or 90 (Reapproved 1995)(incorporated by reference—see § 61.18); detailed in Figure 108C-1.

6.1.5 Graduated Cylinder. 50-ml.

6.1.6 Perchloric Acid Fume Hood.

6.2 Analysis. The following items are required for analysis:

6.2.1 Spectrophotometer. Capable of measuring at 660 nm.

6.2.2 Volumetric Flasks. 50- and 100-ml.

7.0 Reagents and Standards

Unless otherwise indicated, it is intended that all reagents conform to the specifications established by the Committee on Analytical Reagents of the American Chemical Society, where such specifications are available; otherwise, use the best available grade.

7.1 Sample Preparation. The following reagents are required for sample preparation:

7.1.1 Water. Deionized distilled to meet ASTM D 1193-77 or 91 Type 3 (incorporated by reference—see § 61.18). When high concentrations of organic matter are not expected to be present, the $KMnO_4$ test for

oxidizable organic matter may be omitted. Use in all dilutions requiring water.
7.1.2 Nitric Acid, Concentrated.
7.1.3 Hydrofluoric Acid, Concentrated.
7.1.4 Sulfuric Acid, Concentrated.
7.1.5 Perchloric Acid, 70 Percent.
7.1.6 Hydrochloric Acid, Concentrated.
7.1.7 Dilute Hydrochloric Acid. Add one part concentrated HCl to nine parts water.
7.1.8 Hydrazine Sulfate ($(NH_2)_2 \cdot H_2SO_4$).
7.1.9 Potassium Bromide (KBr).
7.1.10 Bromine Water, Saturated.
7.2 Analysis. The following reagents and standards are required for analysis:
7.2.1 Water. Same as in Section 7.1.1.
7.2.2 Methyl Orange Solution, 1 g/liter.
7.2.3 Ammonium Molybdate Solution, 5 g/liter. Dissolve 0.5 g $(NH_4)Mo_7O_{24} \cdot 4H_2O$ in water in a 100-ml volumetric flask, and dilute to the mark. This solution must be freshly prepared.
7.2.4 Standard Arsenic Solution, 10 μg As/ml. Dissolve 0.13203 g of As_2O_3 in 100 ml HCl in a 1-liter volumetric flask. Add 200 ml of water, cool, dilute to the mark with water, and mix. Transfer 100 ml of this solution to a 1-liter volumetric flask, add 40 ml HCl, cool, dilute to the mark, and mix.
7.2.5 Hydrazine Sulfate Solution, 1 g/liter. Dissolve 0.1 g of $[(NH_2)_2 \cdot H_2SO_4]$ in water, and dilute to 100 ml in a volumetric flask. This solution must be freshly prepared.
7.2.6 Potassium Bromate ($KBrO_3$) Solution, 0.03 Percent Weight by Volume (W/V). Dissolve 0.3 g $KBrO_3$ in water, and dilute to 1 liter with water.
7.2.7 Ammonium Hydroxide (NH_4OH), Concentrated.
7.2.8 Boiling Granules.
7.2.9 Hydrochloric Acid, 50 percent by volume. Dilute equal parts concentrated HCl with water.

8.0 Sample Collection, Preservation, Transport, and Storage

Same as in Method 108A, Sections 8.1 and 8.2.

9.0 QUALITY CONTROL

Section	Quality control measure	Effect
10.2	Calibration curve preparation	Ensure linearity of spectrophotometric response to standards.

10.0 Calibration and Standardizations

NOTE: Maintain a laboratory log of all calibrations.

10.1 Preparation of Standard Solutions. Transfer 1.0, 2.0, 4.0, 8.0, 12.0, 16.0, and 20.0 ml of standard arsenic solution (10 μg/ml) to each of seven 50-ml volumetric flasks. Dilute to 20 ml with dilute HCl. Add one drop of methyl orange solution and neutralize to the yellow color with dropwise addition of NH_4OH. Just bring back to the red color by dropwise addition of dilute HCl, and add 10 ml in excess. Proceed with the color development as described in Section 11.2.
10.2 Calibration Curve. Plot the spectrophotometric readings of the calibration solutions against μg As per 50 ml of solution. Use this curve to determine the As concentration of each sample.
10.3 Spectrophotometer Calibration Quality Control. Calculate the least squares slope of the calibration curve. The line must pass through the origin or through a point no further from the origin than ±2 percent of the recorder full scale. Multiply the corrected peak height by the reciprocal of the least squares slope to determine the distance each calibration point lies from the theoretical calibration line. The difference between the calculated concentration values and the actual concentrations must be less than 7 percent for all standards.

11.0 Analytical Procedure

11.1 Sample Preparation.
11.1.1 Weigh 1.0 g of finely pulverized sample to the nearest 0.1 mg. Transfer the sample to a 300 ml Erlenmeyer flask and add 15 ml of HNO_3, 4 ml HCl, 2 ml HF, 3 ml $HClO_4$, and 15 ml H_2SO_4, in the order listed. In a $HClO_4$ fume hood, heat on a hot plate to decompose the sample. Then heat while swirling over an open flame until dense white fumes evolve. Cool, add 15 ml of water, swirl to hydrate the H_2SO_4 completely, and add several boiling granules. Cool to room temperature.
11.1.2 Add 1 g of KBr, 1 g hydrazine sulfate, and 50 ml HCl. Immediately attach the distillation head with thermometer and dip the side arm into a 50-ml graduated cylinder containing 25 ml of water and 2 ml of bromine water. Keep the graduated cylinder immersed in a beaker of cold water during distillation. Distill

until the temperature of the vapor in the flask reaches 107 °C (225 °F). When distillation is complete, remove the flask from the hot plate, and simultaneously wash down the side arm with water as it is removed from the cylinder.

11.1.3 If the expected arsenic content is in the range of 0.0020 to 0.10 percent, dilute the distillate to the 50-ml mark of the cylinder with water, stopper, and mix. Transfer a 5.0-ml aliquot to a 50-ml volumetric flask. Add 10 ml of water and a boiling granule. Place the flask on a hot plate, and heat gently until the bromine is expelled and the color of methyl orange indicator persists upon the addition of 1 to 2 drops. Cool the flask to room temperature. Neutralize just to the yellow color of the indicator with dropwise additions of NH_4 OH. Bring back to the red color by dropwise addition of dilute HCl, and add 10 ml excess. Proceed with the molybdenum blue color development as described in Section 11.2.

11.1.4 If the expected arsenic content is in the range of 0.0002 to 0.0010 percent As, transfer either the entire initial distillate or the measured remaining distillate from Section 11.1.2 to a 250-ml beaker. Wash the cylinder with two successive portions of concentrated HNO_3 , adding each portion to the distillate in the beaker. Add 4 ml of concentrated $HClO_4$, a boiling granule, and cover with a flat watch glass placed slightly to one side. Boil gently on a hot plate until the volume is reduced to approximately 10 ml. Add 3 ml of HNO_3 , and continue the evaporation until $HClO_4$ is refluxing on the beaker cover. Cool briefly, rinse the underside of the watch glass and the inside of the beaker with about 3-5 ml of water, cover, and continue the evaporation to expel all but 2 ml of the $HClO_4$.

NOTE: If the solution appears cloudy due to a small amount of antimony distilling over, add 4 ml of 50 percent HCl and 5 ml of water, cover, and warm gently until clear. If cloudiness persists, add 5 ml of HNO_3 and 2 ml H_2SO_4 . Continue the evaporation of volatile acids to solubilize the antimony until dense white fumes of H_2SO_4 appear. Retain at least 1 ml of the H_2SO_4 .

11.1.5 To the 2 ml of $HClO_4$ solution or 1 ml of H_2SO_4 solution, add 15 ml of water, boil gently for 2 minutes, and then cool. Proceed with the molybdenum blue color development by neutralizing the solution directly in the beaker just to the yellow indicator color by dropwise addition of NH_4 OH. Obtain the red color by dropwise addition of dilute HCl. Transfer the solution to a 50-ml volumetric flask. Rinse the beaker successively with 10 ml of dilute HCl, followed by several small portions of water. At this point the volume of solution in the flask should be no more than 40 ml. Continue with the color development as described in Section 11.2.

11.2 Analysis.

11.2.1 Add 1 ml of $KBrO_3$ solution to the flask and heat on a low-temperature hot plate to about 50 °C (122 °F) to oxidize the arsenic and methyl orange. Add 5.0 ml of ammonium molybdate solution to the warm solution and mix. Add 2.0 ml of hydrazine sulfate solution, dilute until the solution comes within the neck of the flask, and mix. Place the flask in a 400 ml beaker, 80 percent full of boiling water, for 10 minutes. Enough heat must be supplied to prevent the water bath from cooling much below the boiling point upon inserting the volumetric flask. Remove the flask, cool to room temperature, dilute to the mark, and mix.

11.2.2 Transfer a suitable portion of the reference solution to an absorption cell, and adjust the spectrophotometer to the initial setting using a light band centered at 660 nm. While maintaining this spectrophotometer adjustment, take the readings of the calibration solutions followed by the samples.

12.0 Data Analysis and Calculations

Same as in Method 108A, Section 12.0.

13.0 Method Performance. [Reserved]

14.0 Pollution Prevention. [Reserved]

15.0 Waste Management. [Reserved]

16.0 References

1. Ringwald, D. Arsenic Determination on Process Materials from ASARCO's Copper Smelter in Tacoma, Washington. Unpublished Report. Prepared for the Emission Measurement Branch, Technical Support Division, U.S. Environmental Protection Agency, Research Triangle Park, North Carolina. August 1980. 35 pp.

17.0 TABLES, DIAGRAMS, FLOWCHARTS, AND VALIDATION DATA

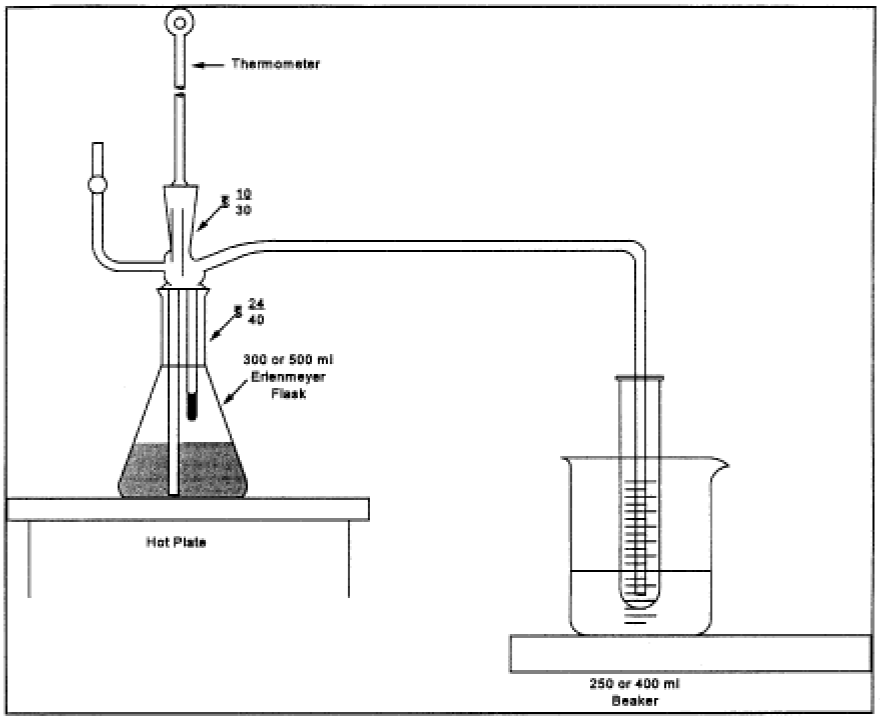

Figure 108C-1. Distillation Apparatus.

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Method 111—Determination of Polonium-210 Emissions From Stationary Sources

Note: This method does not include all of the specifications (e.g., equipment and supplies) and procedures (e.g., sampling and analytical) essential to its performance. Some material is incorporated by reference from methods in appendix A to 40 CFR part 60. Therefore, to obtain reliable results, persons using this method should have a thorough knowledge of at least the following additional test methods: Method 1, Method 2, Method 3, and Method 5.

1.0 Scope and Application

1.1 Analytes.

Analyte	CAS No.	Sensitivity
Polonium	7440-08-6	Not specified.

1.2 Applicability. This method is applicable for the determination of the polonium-210 content of particulate matter samples collected from stationary source exhaust stacks, and for the use of these data to calculate polonium-210 emissions from individual sources and from all affected sources at a facility.

1.3 Data Quality Objectives. Adherence to the requirements of this method will enhance the quality of the data obtained from air pollutant sampling methods.

2.0 Summary of Method

A particulate matter sample, collected according to Method 5, is analyzed for polonium-210 content: the polonium-210 in the sample is put in solution, deposited on a metal disc, and the radioactive disintegration rate measured. Polonium in acid solution spontaneously deposits on surfaces of metals that are more electropositive than polonium. This principle is routinely used in the radiochemical analysis of polonium-210. Data reduction procedures are provided, allowing the calculation of polonium-210 emissions from individual sources and from all affected sources at a facility, using data obtained from Methods 2 and 5 and from the analytical procedures herein.

3.0 Definitions [Reserved]

4.0 Interferences [Reserved]

5.0 Safety

5.1 Disclaimer. This method may involve hazardous materials, operations, and equipment. This test method may not address all of the safety problems associated with its use. It is the responsibility of the user of this test method to establish appropriate safety and health practices and determine the applicability of regulatory limitations prior to performing this test method.

5.2 Corrosive Reagents. The following reagents are hazardous. Personal protective equipment and safe procedures are useful in preventing chemical splashes. If contact occurs, immediately flush with copious amounts of water at least 15 minutes. Remove clothing under shower and decontaminate. Treat residual chemical burns as thermal burns.

5.2.1 Hydrochloric Acid (HCl). Highly corrosive liquid with toxic vapors. Vapors are highly irritating to eyes, skin, nose, and lungs, causing severe damage. May cause bronchitis, pneumonia, or edema of lungs. Exposure to concentrations of 0.13 to 0.2 percent can be lethal to humans in a few minutes. Provide ventilation to limit exposure. Reacts with metals, producing hydrogen gas.

5.2.2 Hydrofluoric Acid (HF). Highly corrosive to eyes, skin, nose, throat, and lungs. Reaction to exposure may be delayed by 24 hours or more. Provide ventilation to limit exposure.

5.2.3 Nitric Acid (HNO_3). Highly corrosive to eyes, skin, nose, and lungs. Vapors cause bronchitis, pneumonia, or edema of lungs. Reaction to inhalation may be delayed as long as 30 hours and still be fatal. Provide ventilation to limit exposure. Strong oxidizer. Hazardous reaction may occur with organic materials such as solvents.

5.2.4 Perchloric Acid ($HClO_4$). Corrosive to eyes, skin, nose, and throat. Provide ventilation to limit exposure. Keep separate from water and oxidizable materials to prevent vigorous evolution of heat, spontaneous combustion, or explosion. Heat solutions containing $HClO_4$ only in hoods specifically designed for $HClO_4$.

6.0 Equipment and Supplies

6.1 Alpha Spectrometry System. Consisting of a multichannel analyzer, biasing electronics, silicon surface barrier detector, vacuum pump and chamber.

6.2 Constant Temperature Bath at 85 °C (185 °F).

6.3 Polished Silver Discs. 3.8 cm diameter, 0.4 mm thick with a small hole near the edge.

6.4 Glass Beakers. 400 ml, 150 ml.

6.5 Hot Plate, Electric.

6.6 Fume Hood.

6.7 Teflon Beakers, 150 ml.

6.8 Magnetic Stirrer.

6.9 Stirring Bar.

6.10 Hooks. Plastic or glass, to suspend plating discs.

6.11 Internal Proportional Counter. For measuring alpha particles.

6.12 Nucleopore Filter Membranes. 25 mm diameter, 0.2 micrometer pore size or equivalent.

6.13 Planchets. Stainless steel, 32 mm diameter with 1.5 mm lip.

6.14 Transparent Plastic Tape. 2.5 cm wide with adhesive on both sides.

6.15 Epoxy Spray Enamel.

6.16 Suction Filter Apparatus. For 25 mm diameter filter.

6.17 Wash Bottles, 250 ml capacity.

6.18 Graduated Cylinder, plastic, 25 ml capacity.

6.19 Volumetric Flasks, 100 ml, 250 ml.

7.0 Reagents and Standards

Unless otherwise indicated, it is intended that all reagents conform to the specifications established by the Committee on Analytical Reagents of the American Chemical Society, where such specifications are available; otherwise, use the best available grade.

7.1 Ascorbic Acid.

7.2 Ammonium Hydroxide (NH_4 OH), 15 M.

7.3 Water. Deionized distilled, to conform to ASTM D 1193-77 or 91 (incorporated by reference—see § 61.18), Type 3. Use in all dilutions requiring water.

7.4 Ethanol (C_2 H_5 OH), 95 percent.

7.5 Hydrochloric Acid, 12 M.

7.6 Hydrochloric Acid, 1 M. Dilute 83 ml of the 12 M HCl to 1 liter with distilled water.

7.7 Hydrofluoric Acid, 29 M.

7.8 Hydrofluoric Acid, 3 M. Dilute 52 ml of the 29 M HF to 500 ml with distilled water. Use a plastic graduated cylinder and storage bottle.

7.9 Lanthanum Carrier, 0.1 mg La^{+3} /ml. Dissolve 0.078 gram lanthanum nitrate, $La(NO_3)_3 \cdot 6H_2O$ in 250 ml of 1 M HCl.

7.10 Nitric Acid, 16 M.
7.11 Perchloric Acid, 12 M.
7.12 Polonium-209 Solution.
7.13 Silver Cleaner. Any mild abrasive commercial silver cleaner.
7.14 Degreaser.
7.15 Standard Solution. Standardized solution of an alpha-emitting actinide element, such as plutonium-239 or americium-241.

8.0 Sample Collection, Preservation, Transport, and Storage. [Reserved]

9.0 Quality Control

9.1 General Requirement.

9.1.1 All analysts using this method are required to demonstrate their ability to use the method and to define their respective accuracy and precision criteria.

9.2 MISCELLANEOUS QUALITY CONTROL MEASURES

Section	**Quality control measure**	**Effect**
10.1	Standardization of alpha spectrometry system	Ensure precision of sample analyses.
10.3	Standardization of internal proportional counter	Ensure precise sizing of sample aliquot.
11.1, 11.2	Determination of procedure background and instrument background	Minimize background effects.

10.0 Calibration and Standardization

10.1 Standardization of Alpha Spectrometry System.

10.1.1 Add a quantity of the actinide standard solution to a 100 ml volumetric flask so that the final concentration when diluted to a volume of 100 ml will be approximately 1_p Ci/ml.

10.1.2 Add 10 ml of 16 M HNO_3 and dilute to 100 ml with water.

10.1.3 Add 20 ml of 1 M HCl to each of six 150 ml beakers. Add 1.0 ml of lanthanum carrier, 0.1 mg lanthanum per ml, to the acid solution in each beaker.

10.1.4 Add 1.0 ml of the 1 pCi/ml working solution (from Section 10.1.1) to each beaker. Add 5.0 ml of 3 M HF to each beaker.

10.1.5 Cover beakers and allow solutions to stand for a minimum of 30 minutes. Filter the contents of each beaker through a separate filter membrane using the suction filter apparatus. After each filtration, wash the filter membrane with 10 ml of distilled water and 5 ml of ethanol, and allow the filter membrane to air dry on the filter apparatus.

10.1.6 Carefully remove the filter membrane and mount it, filtration side up, with double-side tape on the inner surface of a planchet. Place planchet in an alpha spectrometry system and count each planchet for 1000 minutes.

10.1.7 Calculate the counting efficiency of the detector for each aliquot of the 1 pCi/ml actinide working solution using Eq. 111-1 in Section 12.2.

10.1.8 Determine the average counting efficiency of the detector, E_c , by calculating the average of the six determinations.

10.2 Preparation of Standardized Solution of Polonium-209.

10.2.1 Add a quantity of the Po-209 solution to a 100 ml volumetric flask so that the final concentration when diluted to a 100 ml volume will be approximately 1 pCi/ml.

10.2.2 Follow the procedures outlined in Sections 10.1.2 through 10.1.6, except substitute 1.0 ml of polonium-209 tracer solution (Section 10.2.1) and 3.0 ml of 15 M ammonium hydroxide for the 1 pCi/ml actinide working solution and the 3 M HF, respectively.

10.2.3 Calculate the activity of each aliquot of the polonium-209 tracer solution using Eq. 111-2 in Section 12.3.

10.2.4 Determine the average activity of the polonium-209 tracer solution, F, by averaging the results of the six determinations.

10.3 Standardization of Internal Proportional Counter

10.3.1 Add a quantity of the actinide standard solution to a 100 ml volumetric flask so that the final concentration when diluted to a 100 ml volume will be approximately 100 pCi/ml.

10.3.2 Follow the procedures outlined in Sections 10.1.2 through 10.1.6, except substitute the 100 pCi/ml actinide working solution for the 1 pCi/ml solution, place the planchet in an internal proportional counter (instead of an alpha spectrometry system), and count for 100 minutes (instead of 1000 minutes).

10.3.3 Calculate the counting efficiency of the internal proportional counter for each aliquot of the 100 pCi/ml actinide working solution using Eq. 111-3 in 12.4.

10.3.4 Determine the average counting efficiency of the internal proportional counter, E_I , by averaging the results of the six determinations.

11.0 ANALYTICAL PROCEDURE

NOTE: Perform duplicate analyses of all samples, including background counts and Method 5 samples. Duplicate measurements are considered acceptable when the difference between them is less than two standard deviations as described in EPA 600/4-77-001 or subsequent revisions.

11.1 Determination of Procedure Background. Background counts used in all equations are determined by performing the specific analysis required using the analytical reagents only. All procedure background counts and sample counts for the internal proportional counter should utilize a counting time of 100 minutes; for the alpha spectrometry system, 1000 minutes. These background counts should be performed no less frequently than once per 10 sample analyses.

11.2 Determination of Instrument Background. Instrument backgrounds of the internal proportional counter and the alpha spectrometry system should be determined on a weekly basis. Instrument background should not exceed procedure background. If this occurs, it may be due to a malfunction or contamination, and should be corrected before use.

11.4 Sample Preparation. Treat the Method 5 samples [i.e., the glass fiber filter (Container No. 1) and the acetone rinse (Container No. 2)] as follows:

11.4.1 Container No. 1. Transfer the filter and any loose particulate matter from the sample container to a 150-ml Teflon beaker.

11.4.2 Container No. 2. Note the level of liquid in the container, and confirm on the analysis sheet whether leakage occurred during transport. If a noticeable amount of leakage has occurred, either void the sample or use methods, subject to the approval of the Administrator, to correct the final results. Transfer the contents to a 400-ml glass beaker. Add polonium-209 tracer solution to the glass beaker in an amount approximately equal to the amount of polonium-210 expected in the total particulate sample. Record the activity of the tracer solution added. Add 16 M nitric acid to the beaker to digest and loosen the residue.

11.4.3 Transfer the contents of the glass beaker to the Teflon beaker containing the glass fiber filter. Rinse the glass beaker with 16 M HNO_3 . If necessary, reduce the volume in the beaker by evaporation until all of the nitric acid HNO_3 from the glass beaker has been transferred to the Teflon beaker.

11.4.4 Add 30 ml of 29 M HF to the Teflon beaker and evaporate to near dryness on a hot plate in a properly operating hood.

NOTE: Do not allow the residue to go to dryness and overheat; this will result in loss of polonium.

11.4.5 Repeat step 11.4.4 until the filter is dissolved.

11.4.6 Add 100 ml of 16 M HNO_3 to the residue in the Teflon beaker and evaporate to near dryness.

NOTE: Do not allow the residue to go to dryness.

11.4.7 Add 50 ml of 16 M HNO_3 and 10 ml of 12 M perchloric acid to the Teflon beaker and heat until dense fumes of perchloric acid are evolved.

11.4.8 Repeat steps 11.4.4 to 11.4.7 as necessary until sample is completely dissolved.

11.4.9 Add 10 ml of 12 M HCl to the Teflon beaker and evaporate to dryness. Repeat additions and evaporations several times.

11.4.10 Transfer the sample to a 250-ml volumetric flask and dilute to volume with 3 M HCl.

11.5 Sample Screening. To avoid contamination of the alpha spectrometry system, check each sample as follows:

11.5.1 Add 20 ml of 1 M HCl, 1 ml of the lanthanum carrier solution (0.1 mg La/ml), a 1 ml aliquot of the sample solution from Section 11.4.10, and 3 ml of 15 M ammonium hydroxide to a 250-ml beaker in the order listed. Allow this solution to stand for a minimum of 30 minutes.

11.5.2 Filter the solution through a filter membrane using the suction filter apparatus. Wash the filter membrane with 10 ml of water and 5 ml of ethanol, and allow the filter membrane to air dry on the filter apparatus.

11.5.3 Carefully remove the filter membrane and mount it, filtration side up, with double-side tape on the inner surface of a planchet. Place the planchet in an internal proportional counter, and count for 100 minutes.

11.5.4 Calculate the activity of the sample using Eq. 111-4 in Section 12.5.

11.5.5 Determine the aliquot volume of the sample solution from Section 11.4.10 to be analyzed for polonium-210, such that the aliquot contains an activity between 1 and 4 picocuries. Use Eq. 111-5 in Section 12.6.

11.6 Preparation of Silver Disc for Spontaneous Electrodeposition.

11.6.1 Clean both sides of the polished silver disc with silver cleaner and with degreaser.

11.6.2 Place disc on absorbent paper and spray one side with epoxy spray enamel. This should be carried out in a well-ventilated area, with the disc lying flat to keep paint on one side only. Allow paint to dry for 24 hours before using disc for deposition.

11.7 Sample Analysis.

11.7.1 Add the aliquot of sample solution from Section 11.4.10 to be analyzed for polonium-210, the volume of which was determined in Section 11.5.5, to a suitable 200-ml container to be placed in a constant temperature bath.

NOTE: Aliquot volume may require a larger container.

11.7.2 If necessary, bring the volume to 100 ml with 1 M HCl. If the aliquot volume exceeds 100 ml, use total aliquot.

11.7.3 Add 200 mg of ascorbic acid and heat solution to 85 °C (185 °F) in a constant temperature bath.

11.7.4 Suspend a silver disc in the heated solution using a glass or plastic rod with a hook inserted through the hole in the disc. The disc should be totally immersed in the solution, and the solution must be stirred constantly, at all times during the plating operation. Maintain the disc in solution for 3 hours.

11.7.5 Remove the silver disc, rinse with deionized distilled water, and allow to air dry at room temperature.

11.7.6 Place the disc, with deposition side (unpainted side) up, on a planchet and secure with double-side plastic tape. Place the planchet with disc in alpha spectrometry system and count for 1000 minutes.

12.0 Data Analysis and Calculations.

12.1 Nomenclature.

A = Picocuries of polonium-210 in the Method 5 sample (from Section 12.8).
A_A = Picocuries of actinide added.
A_L = Volume of sample aliquot used, in ml (specified in Section 11.5.1 as 1 ml).
A_S = Aliquot to be analyzed, in ml.
B_B = Procedure background counts measured in polonium-209 spectral region.
B_T = Polonium-209 tracer counts in sample.
C_T = Total counts in polonium-210 spectral region.
D = Decay correction for time “t” (in days) from sample collection to sample counting, given by: $D=e^{-0.005t}$
E_C = Average counting efficiency of detector (from Section 10.1.8), as counts per disintegration.
E_{Ci} = Counting efficiency of the detector for aliquot i of the actinide working solution, counts per disintegration.
E_I = Average counting efficiency of the internal proportional counter, as determined in Section 10.3.4, counts per disintegration.
E_{Ii} = Counting efficiency of the internal proportional counter for aliquot i of the 100 pCi/ml actinide working solution, counts per disintegration.
E_Y = The fraction of polonium-209 recovered on the planchet (from Section 12.7).
F= Average activity of polonium-209 in sample (from Section 10.2.4), in pCi.
F_i = activity of aliquot i of the polonium-209 tracer solution, in pCi.
L = Dilution factor (unitless). This is the volume of sample solution prepared (specified as 250 ml in Section 11.1.10) divided by the volume of the aliquot of sample solution analyzed for polonium-210 (from Section 11.7.1).
M_i = Phosphorous rock processing rate of the source being tested, during run i, Mg/hr.
M_k = Phosphate rock processed annually by source k, in Mg/yr.
n = Number of calciners at the elemental phosphorus plant.
P = Total activity of sample solution from Section 11.4.10, in pCi (see Eq. 111-4).
Q_{sd} = Volumetric flow rate of effluent stream, as determined by Method 2, in dscm/hr.
S = Annual polonium-210 emissions from the entire facility, in curies/yr.
$V_{m(std)}$ = Volume of air sample, as determined by Method 5, in dscm.
X_k = Emission rate from source k, from Section 12.10, in curies/Mg.

10^{-12} = Curies per picocurie.
2.22 = Disintegrations per minute per picocurie.
250 = Volume of solution from Section 11.4.10, in ml.

12.2 Counting Efficiency. Calculate the counting efficiency of the detector for each aliquot of the 1 pCi/ml actinide working solution using Eq. 111-1.

$$E_{Ci} = \frac{C_S - C_B}{2.22\ A_A T} \qquad Eq.\ 111\text{-}1$$

Where:
C_B = Background counts in same peak area as C_S .
C_S = Gross counts in actinide peak.
T = Counting time in minutes, specified in Section 10.1.6 as 1000 minutes.

12.3 Polonium-209 Tracer Solution Activity. Calculate the activity of each aliquot of the polonium-209 tracer solution using Eq. 111-2.

$$F_i = \frac{C_S - C_B}{2.22\ \mathrm{E}_{Ci} T} \qquad Eq.\ 111\text{-}2$$

Where:
C_B = Background counts in the 4.88 MeV region of spectrum the in the counting time T.
C_S = Gross counts of polonium-209 in the 4.88 MeV region of the spectrum in the counting time T.
T = Counting time, specified in Section 10.1.6 as 1000 minutes.

12.4 Control Efficiency of Internal Proportional Counter. Calculate the counting efficiency of the internal proportional counter for each aliquot of the 100 pCi/ml actinide working solution using Eq. 111-3.

$$E_{Ii} = \frac{C_S - C_B}{2.22\ A_A T} \qquad Eq.\ 111\text{-}3$$

Where:
C_B = Gross counts of procedure background.
C_S = Gross counts of standard.
T = Counting time in minutes, specified in Section 10.3.2 as 100 minutes.

12.5 Calculate the activity of the sample using Eq. 111-4.

$$P = \frac{250\ (C_S - C_B)}{2.22\ \overline{\mathrm{E}}_I A_I T} \qquad Eq.\ 111\text{-}4$$

Where:
C_B = Total counts of procedure background. (See Section 11.1).
C_S = Total counts of screening sample.
T = Counting time for sample and background (which must be equal), in minutes (specified in Section 11.5.3 as 100 minutes).

12.6 Aliquot Volume. Determine the aliquot volume of the sample solution from Section 11.4.10 to be analyzed for polonium-210 , such that the aliquot contains an activity between 1 and 4 picocuries using Eq. 111-5.

$$A_s = \frac{250\ (\text{desired picocuries in aliquot})}{\mathrm{P}} \qquad Eq.\ 111\text{-}5$$

12.7 Polonium-209 Recovery. Calculate the fraction of polonium-209 recovered on the planchet, E_Y , using Eq. 111-6.

$$E_Y = \frac{B_T - B_B}{2.22\ \overline{\mathrm{F}}\ \overline{E_C}\, T} \qquad Eq.\ 111\text{-}6$$

Where:
T = Counting time, specified in Section 11.1 as 1000 minutes.

12.8 Polonium-210 Activity. Calculate the activity of polonium-210 in the Method 5 sample (including glass fiber filter and acetone rinse) using Eq. 111-7.

$$A = \frac{\left(C_T - C_B\right) \mathrm{L}}{2.22\ \mathrm{E_y}\ \overline{E_C}\ T\ D} \qquad Eq.\ 111\text{-}7$$

Where:

C_B = Procedure background counts in polonium-210 spectral region.

T = Counting time, specified in Section 11.1 as 1000 minutes for all alpha spectrometry sample and background counts.

12.9 Emission Rate from Each Stack.

12.9.1 For each test run, i, on a stack, calculate the measured polonium-210 emission rate, R_{Si} , using Eq. 111-8.

$$R_{Si} = \frac{\left(10^{-12}\right) A\, \mathrm{Q_{sd}}}{V_{m(std)} M_i} \qquad Eq.\ 111\text{-}8$$

12.9.2 Determine the average polonium-210 emission rate from the stack, R_S , by taking the sum of the measured emission rates for all runs, and dividing by the number of runs performed.

12.9.3 Repeat steps 12.9.1 and 12.9.2 for each stack of each calciner.

12.10 Emission Rate from Each Source. Determine the total polonium-210 emission rate, X_k , from each source, k, by taking the sum of the average emission rates from all stacks to which the source exhausts.

12.11 Annual Polonium-210 Emission Rate from Entire Facility. Determine the annual elemental phosphorus plant emissions of polonium-210, S, using Eq. 111-9.

$$S = \frac{\sum_{k=1}^{n} \left(X_k M_k\right)}{n} \qquad Eq.\ 111\text{-}9$$

13.0 Method Performance. [Reserved]

14.0 Pollution Prevention. [Reserved]

15.0 Waste Management. [Reserved]

16.0 References

1. Blanchard, R.L. “Rapid Determination of Lead-210 and Polonium-210 in Environmental Samples by Deposition on Nickel.” Anal. Chem., 38 :189, pp. 189-192. February 1966.

17.0 Tables, Diagrams, Flowcharts, and Validation Data [Reserved]

METHOD 114—TEST METHODS FOR MEASURING RADIONUCLIDE EMISSIONS FROM STATIONARY SOURCES

1. Purpose and Background

This method provides the requirements for: (1) Stack monitoring and sample collection methods appropriate for radionuclides; (2) radiochemical methods which are used in determining the amounts of radionuclides collected by the stack sampling and; (3) quality assurance methods which are conducted in conjunction with these measurements. These methods are appropriate for emissions for stationary sources. A list of references is provided.

Many different types of facilities release radionuclides into air. These radionuclides differ in the chemical and physical forms, half-lives and type of radiation emitted. The appropriate combination of sample extraction, collection and analysis for an individual radionuclide is dependent upon many interrelated factors including the mixture of other radionuclides present. Because of this wide range of conditions, no single method for monitoring or sample collection and analysis of a radionuclide is applicable to all types of facilities. Therefore, a series of methods based on “principles of measurement” are described for monitoring and sample collection and analysis which are applicable to the measurement of radionuclides found in effluent streams at stationary sources. This approach provides the user with the flexibility to choose the most appropriate combination of monitoring and sample collection and analysis methods which are applicable to the effluent stream to be measured.

2. Stack Monitoring and Sample Collection Methods

Monitoring and sample collection methods are described based on “principles of monitoring and sample collection” which are applicable to the measurement of radionuclides from effluent streams at stationary sources. Radionuclides of most elements will be in the particulate form in these effluent streams and can be readily collected using a suitable filter media. Radionuclides of hydrogen, oxygen, carbon, nitrogen, the noble gases and in some circumstances iodine will be in the gaseous form. Radionuclides of these elements will require either the use of an in-line or off-line monitor to directly measure the radionuclides, or suitable sorbers, condensers or bubblers to collect the radionuclides.

2.1 Radionuclides as Particulates. The extracted effluent stream is passed through a filter media to remove the particulates. The filter must have a high efficiency for removal of sub-micron particles. The guidance in ANSI/HPS N13.1-1999 (section 6.6.2 Filter media) shall be followed in using filter media to collect particulates (incorporated by reference—see § 61.18 of this part).

2.2 Radionuclides as Gases.

2.2.1 The Radionuclide Tritium (H-3). Tritium in the form of water vapor is collected from the extracted effluent sample by sorption, condensation or dissolution techniques. Appropriate collectors may include silica gel, molecular sieves, and ethylene glycol or water bubblers.

Tritium in the gaseous form may be measured directly in the sample stream using Method B-1, collected as a gas sample or may be oxidized using a metal catalyst to tritiated water and collected as described above.

2.2.2 Radionuclides of Iodine. Iodine is collected from an extracted sample by sorption or dissolution techniques. Appropriate collectors may include charcoal, impregnated charcoal, metal zeolite and caustic solutions.

2.2.3 Radionuclides of Argon, Krypton and Xenon. Radionuclides of these elements are either measured directly by an in-line or off-line monitor, or are collected from the extracted sample by low temperature sorption techniques, Appropriate sorbers may include charcoal or metal zeolite.

2.2.4 Radionuclides of Oxygen, Carbon, Nitrogen and Radon. Radionuclides of these elements are measured directly using an in-line or off-line monitor. Radionuclides of carbon in the form of carbon dioxide may be collected by dissolution in caustic solutions.

2.3 Definition of Terms

In-line monitor means a continuous measurement system in which the detector is placed directly in or adjacent to the effluent stream. This may involve either gross radioactivity measurements or specific radionuclide measurements. Gross measurements shall be made in conformance with the conditions specified in Methods A-4, B-2 and G-4.

Off-line monitor means a measurement system in which the detector is used to continuously measure an extracted sample of the effluent stream. This may involve either gross radioactivity measurements or specific radionuclide measurements. Gross measurements shall be made in conformance with the conditions specified in Methods A-4, B-2 and G-4.

Sample collection means a procedure in which the radionuclides are removed from an extracted sample of the effluent using a collection media. These collection media include filters, absorbers, bubblers and condensers. The collected sample is analyzed using the methods described in Section 3.

3. Radionuclide Analysis Methods

A series of methods based on “principles of measurement” are described which are applicable to the analysis of radionuclides collected from airborne effluent streams at stationary sources. These methods are applicable only under the conditions stated and within the limitations described. Some methods specify that only a single radionuclide be present in the sample or the chemically separated sample. This condition should be interpreted to mean that no other radionuclides are present in quantities which would interfere with the measurement.

Also identified (Table 1) are methods for a selected list of radionuclides. The listed radionuclides are those which are most commonly used and which have the greatest potential for causing dose to members of the public. Use of methods based on principles of measurement other than those described in this section must be approved in advance of use by the Administrator. For radionuclides not listed in Table 1, any of the described methods may be used provided the user can demonstrate that the applicability conditions of the method have been met.

The type of method applicable to the analysis of a radionuclide is dependent upon the type of radiation emitted, i.e., alpha, beta or gamma. Therefore, the methods described below are grouped according to principles of measurements for the analysis of alpha, beta and gamma emitting radionuclides.

3.1 Methods for Alpha Emitting Radionuclides

3.1.1 Method A-1, Radiochemistry-Alpha Spectrometry.

Principle: The element of interest is separated from other elements, and from the sample matrix using radiochemical techniques. The procedure may involve precipitation, ion exchange, or solvent extraction. Carriers (elements chemically similar to the element of interest) may be used. The element is deposited on a planchet in a very thin film by electrodeposition or by coprecipitation on a very small amount of carrier, such as lanthanum fluoride. The deposited element is then counted with an alpha spectrometer.

The activity of the nuclide of interest is measured by the number of alpha counts in the appropriate energy region. A correction for chemical yield and counting efficiency is made using a standardized radioactive nuclide (tracer) of the same element. If a radioactive tracer is not available for the element of interest, a predetermined chemical yield factor may be used.

Applicability: This method is applicable for determining the activity of any alpha-emitting radionuclide, regardless of what other radionuclides are present in the sample provided the chemical separation step produces a very thin sample and removes all other radionuclides which could interfere in the spectral region of interest. APHA-605(2), ASTM-D-3972(13).

3.1.2 Method A-2, Radiochemistry-Alpha Counting.

Principle: The element of interest is separated from other elements, and from the sample matrix using radiochemistry. The procedure may involve precipitation, ion exchange, or solvent extraction. Carriers (elements chemically similar to the element of interest) may be used. The element is deposited on a planchet in a thin film and counted with an alpha counter. A correction for chemical yield (if necessary) is made. The alpha count rate measures the total activity of all emitting radionuclides of the separated element.

Applicability: This method is applicable for the measurement of any alpha-emitting radionuclide, provided no other alpha emitting radionuclide is present in the separated sample. It may also be applicable for determining compliance, when other radionuclides of the separated element are present, provided that the calculated emission rate is assigned to the radionuclide which could be present in the sample that has the highest dose conversion factor. IDO-12096(18).

3.1.3 Method A-3, Direct Alpha Spectrometry.

Principle: The sample, collected on a suitable filter, is counted directly on an alpha spectrometer. The sample must be thin enough and collected on the surface of the filter so that any absorption of alpha particle energy in the sample or the filter, which would degrade the spectrum, is minimal.

Applicability: This method is applicable to simple mixtures of alpha emitting radionuclides and only when the amount of particulates collected on the filter paper are relatively small and the alpha spectra is adequately resolved. Resolutions should be 50 keV (FWHM) or better, ASTM-D-3084(16).

3.1.4 Method A-4, Direct Alpha Counting (Gross alpha determination).

Principle: The sample, collected on a suitable filter, is counted with an alpha counter. The sample must be thin enough so that self-absorption is not significant and the filter must be of such a nature that the particles are retained on the surface.

Applicability: Gross alpha determinations may be used to measure emissions of specific radionuclides only (1) when it is known that the sample contains only a single radionuclide, or the identity and isotopic ratio of the radionuclides in the sample are well-known, and (2) measurements using either Method A-1, A-2 or A-5 have shown that this method provides a reasonably accurate measurement of the emission rate. Gross alpha measurements are applicable to unidentified mixtures of radionuclides only for the purposes and under the conditions described in section 3.7. APHA-601(3), ASTM-D-1943(10).

3.1.5 Method A-5, Chemical Determination of Uranium.

Principle: Uranium may be measured chemically by either colorimetry or fluorometry. In both procedures, the sample is dissolved, the uranium is oxidized to the hexavalent form and extracted into a suitable solvent. Impurities are removed from the solvent layer. For colorimetry, dibenzoylmethane is added, and the uranium is measured by the absorbance in a colorimeter. For fluorometry, a portion of the solution is fused with a sodium fluoride-lithium fluoride flux and the uranium is determined by the ultraviolet activated fluorescence of the fused disk in a fluorometer.

Applicability: This method is applicable to the measurements of emission rates of uranium when the isotopic ratio of the uranium radionuclides is well known. ASTM-E-318(15), ASTM-D-2907(14).

3.1.6 Method A-6, Radon-222—Continuous Gas Monitor.

Principle: Radon-222 is measured directly in a continuously extracted sample stream by passing the air stream through a calibrated scintillation cell. Prior to the scintillation cell, the air stream is treated to remove particulates and excess moisture. The alpha particles from radon-222 and its decay products strike a zinc sulfide coating on the inside of the scintillation cell producing light pulses. The light pulses are detected by a photomultiplier tube which generates electrical pulses. These pulses are processed by the system electronics and the read out is in pCi/l of radon-222.

Applicability: This method is applicable to the measurement of radon-222 in effluent streams which do not contain significant quantities of radon-220. Users of this method should calibrate the monitor in a radon calibration chamber at least twice per year. The background of the monitor should also be checked periodically by operating the instrument in a low radon environment. EPA 520/1-89-009(24).

3.1.7 Method A-7, Radon-222-Alpha Track Detectors

Principle: Radon-222 is measured directly in the effluent stream using alpha track detectors (ATD). The alpha particles emitted by radon-222 and its decay products strike a small plastic strip and produce submicron damage tracks. The plastic strip is placed in a caustic solution that accentuates the damage tracks which are counted using a microscope or automatic counting system. The number of tracks per unit area is correlated to the radon concentration in air using a conversion factor derived from data generated in a radon calibration facility.

Applicability: Prior approval from EPA is required for use of this method. This method is only applicable to effluent streams which do not contain significant quantities of radon-220, unless special detectors are used to discriminate against radon-220. This method may be used only when ATDs have been demonstrated to produce data comparable to data obtained with Method A-6. Such data should be submitted to EPA when requesting approval for the use of this method. EPA 520/1-89-009(24).

3.2 Methods for Gaseous Beta Emitting Radionuclides.

3.2.1 Method B-1, Direct Counting in Flow-Through Ionization Chambers.

Principle: An ionization chamber containing a specific volume of gas which flows at a given flow rate through the chamber is used. The sample (effluent stream sample) acts as the counting gas for the chamber. The activity of the radionuclide is determined from the current measured in the ionization chamber.

Applicability: This method is applicable for measuring the activity of a gaseous beta-emitting radionuclide in an effluent stream that is suitable as a counting gas, when no other beta-emitting nuclides are present. DOE/EP-0096(17), NCRP-58(23).

3.2.2 Method B-2, Direct Counting With In-line or Off-line Beta Detectors.

Principle: The beta detector is placed directly in the effluent stream (in-line) or an extracted sample of the effluent stream is passed through a chamber containing a beta detector (off-line). The activities of the radionuclides present in the effluent stream are determined from the beta count rate, and a knowledge of the radionuclides present and the relationship of the gross beta count rate and the specific radionuclide concentration.

Applicability: This method is applicable only to radionuclides with maximum beta particle energies greater then 0.2 MeV. This method may be used to measure emissions of specific radionuclides only when it is known that the sample contains only a single radionuclide or the identity and isotopic ratio of the radionuclides in the effluent stream are well known. Specific radionuclide analysis of periodic grab samples may be used to identify the types and quantities of radionuclides present and to establish the relationship between specific radionuclide analyses and gross beta count rates.

This method is applicable to unidentified mixtures of gaseous radionuclides only for the purposes and under the conditions described in section 3.7.

3.3 Methods for Non-Gaseous Beta Emitting Radionuclides.

3.3.1 Method B-3, Radiochemistry-Beta Counting.

Principle: The element of interest is separated from other elements, and from the sample matrix by radiochemistry. This may involve precipitation, distillation, ion exchange, or solvent extraction. Carriers (elements chemically similar to the element of interest) may be used. The element is deposited on a planchet, and counted with a beta counter. Corrections for chemical yield, and decay (if necessary) are made. The beta count rate determines the total activity of all radionuclides of the separated element. This method may also involve the radiochemical separation and counting of a daughter element, after a suitable period of ingrowth, in which case it is specific for the parent nuclide.

Applicability: This method is applicable for measuring the activity of any beta-emitting radionuclide, with a maximum energy greater than 0.2 MeV, provided no other radionuclide is present in the separated sample. APHA-608(5).

3.3.2 Method B-4, Direct Beta Counting (Gross beta determination).

Principle: The sample, collected on a suitable filter, is counted with a beta counter. The sample must be thin enough so that self-absorption corrections can be made.

Applicability: Gross beta measurements are applicable only to radionuclides with maximum beta particle energies greater than 0.2 MeV. Gross beta measurements may be used to measure emissions of specific radionuclides only (1) when it is known that the sample contains only a single radionuclide, and (2) measurements made using Method B-3 show reasonable agreement with the gross beta measurement. Gross beta measurements are applicable to mixtures of radionuclides only for the purposes and under the conditions described in section 3.7. APHA-602(4), ASTM-D-1890(11).

3.3.3 Method B-5, Liquid Scintillation Spectrometry.

Principle: An aliquot of a collected sample or the result of some other chemical separation or processing technique is added to a liquid scintillation "cocktail" which is viewed by photomultiplier tubes in a liquid scintillation spectrometer. The spectrometer is adjusted to establish a channel or "window" for the pulse energy appropriate to the nuclide of interest. The activity of the nuclide of interest is measured by the counting rate in the appropriate energy channel. Corrections are made for chemical yield where separations are made.

Applicability: This method is applicable to any beta-emitting nuclide when no other radionuclide is present in the sample or the separated sample provided that it can be incorporated in the scintillation cocktail. This method is also applicable for samples which contain more than one radionuclide but only when the energies of the beta particles are sufficiently separated so that they can be resolved by the spectrometer. This method is most applicable to the measurement of low-energy beta emitters such as tritium and carbon-14. APHA-609(6), EML-LV-539-17(19).

3.4 Gamma Emitting Radionuclides

3.4.1 Method G-1, High Resolution Gamma Spectrometry.

Principle: The sample is counted with a high resolution gamma detector, usually either a Ge(Li) or a high purity Ge detector, connected to a multichannel analyzer or computer. The gamma emitting radionuclides in the sample are measured from the gamma count rates in the energy regions characteristic of the individual radionuclide. Corrections are made for counts contributed by other radionuclides to the spectral regions of the radionuclides of interest. Radiochemical separations may be made prior to counting but are usually not necessary.

Applicability: This method is applicable to the measurement of any gamma emitting radionuclide with gamma energies greater than 20 keV. It can be applied to complex mixtures of radionuclides. The samples counted may be in the form of particulate filters, absorbers, liquids or gases. The method may also be applied to the analysis of gaseous gamma emitting radionuclides directly in an effluent stream by passing the stream through a chamber or cell containing the detector. ASTM-3649(9), IDO-12096(18).

3.4.2 Method G-2, Low Resolution Gamma Spectrometry.

Principle: The sample is counted with a low resolution gamma detector, a thallium activated sodium iodide crystal. The detector is coupled to a photomultiplier tube and connected to a multichannel analyzer. The gamma emitting radionuclides in the sample are measured from the gamma count rates in the energy regions characteristic of the individual radionuclides. Corrections are made for counts contributed by other radionuclides to the spectral regions of the radionuclides of interest. Radiochemical separation may be used prior to counting to obtain less complex gamma spectra if needed.

Applicability: This method is applicable to the measurement of gamma emitting radionuclides with energies greater than 100 keV. It can be applied only to relatively simple mixtures of gamma emitting radionuclides. The samples counted may be in the form of particulate filters, absorbers, liquids or gas. The method can be applied to the analysis of gaseous radionuclides directly in an effluent stream by passing the gas stream through a chamber or cell containing the detector. ASTM-D-2459(12), EMSL-LV-0539-17(19).

3.4.3 Method G-3, Single Channel Gamma Spectrometry.

Principle: The sample is counted with a thallium activated sodium iodide crystal. The detector is coupled to a photomultiplier tube connected to a single channel analyzer. The activity of a gamma emitting radionuclide is determined from the gamma counts in the energy range for which the counter is set.

Applicability: This method is applicable to the measurement of a single gamma emitting radionuclide. It is not applicable to mixtures of radionuclides. The samples counted may be in the form of particulate filters, absorbers, liquids or gas. The method can be applied to the analysis of gaseous radionuclides directly in an effluent stream by passing the gas stream through a chamber or cell containing the detector.

3.4.4 Method G-4, Gross Gamma Counting.

Principle: The sample is counted with a gamma detector usually a thallium activated sodium iodine crystal. The detector is coupled to a photomultiplier tube and gamma rays above a specific threshold energy level are counted.

Applicability: Gross gamma measurements may be used to measure emissions of specific radionuclides only when it is known that the sample contains a single radionuclide or the identity and isotopic ratio of the radionuclides in the effluent stream are well known. When gross gamma measurements are used to determine emissions of specific radionuclides periodic measurements using Methods G-1 or G-2 should be made to demonstrate that the gross gamma measurements provide reliable emission data. This method may be applied to analysis of gaseous radionuclides directly in an effluent stream by placing the detector directly in or adjacent to the effluent stream or passing an extracted sample of the effluent stream through a chamber or cell containing the detector.

3.5 Counting Methods. All of the above methods with the exception of Method A-5 involve counting the radiation emitted by the radionuclide. Counting methods applicable to the measurement of alpha, beta and gamma radiations are listed below. The equipment needed and the counting principles involved are described in detail in ASTM-3648(8).

3.5.1 Alpha Counting:

- Gas Flow Proportional Counters. The alpha particles cause ionization in the counting gas and the resulting electrical pulses are counted. These counters may be windowless or have very thin windows.
- Scintillation Counters. The alpha particles transfer energy to a scintillator resulting in a production of light photons which strike a photomultiplier tube converting the light photons to electrical pulses which are counted. The counters may involve the use of solid scintillation materials such as zinc sulfide or liquid scintillation solutions.
- Solid-State Counters. Semiconductor materials, such as silicon surface-barrier p-n junctions, act as solid ionization chambers. The alpha particles interact which the detector producing electron hole pairs. The charged pair is collected by an applied electrical field and the resulting electrical pulses are counted.
- Alpha Spectrometers. Semiconductor detectors used in conjunction with multichannel analyzers for energy discrimination.

3.5.2 Beta Counting:

- Ionization Chambers. These chambers contain the beta-emitting nuclide in gaseous form. The ionization current produced is measured.
- Geiger-Muller (GM) Counters-or Gas Flow Proportional Counters. The beta particles cause ionization in the counting gas and the resulting electrical pulses are counted. Proportional gas flow counters which are heavily shielded by lead or other metal, and provided with an anti-coincidence shield to reject cosmic rays, are called low background beta counters.
- Scintillation Counters. The beta particles transfer energy to a scintillator resulting in a production of light photons, which strike a photomultiplier tube converting the light photon to electrical pulses which are counted. This may involve the use of anthracene crystals, plastic scintillator, or liquid scintillation solutions with organic phosphors.
- Liquid Scintillation Spectrometers. Liquid scintillation counters which use two photomultiplier tubes in coincidence to reduce background counts. This counter may also electronically discriminate among pulses of a given range of energy.

3.5.3 Gamma Counting:

- Low-Resolution Gamma Spectrometers. The gamma rays interact with thallium activated sodium iodide or cesium iodide crystal resulting in the release of light photons which strike a photomultiplier tube converting the light pulses to electrical pulses proportional to the energy of the gamma ray. Multi-channel analyzers are used to separate and store the pulses according to the energy absorbed in the crystal.
- High-Resolution gamma Spectrometers. Gamma rays interact with a lithium-drifted (Ge(Li)) or high-purity germanium (HPGe) semiconductor detectors resulting in a production of electron-hole pairs. The charged pair is collected by an applied electrical field. A very stable low noise preamplifier amplifies the pulses of electrical charge resulting from the gamma photon interactions. Multichannel analyzers or computers are used to separate and store the pulses according to the energy absorbed in the crystal.
- Single Channel Analyzers. Thallium activated sodium iodide crystals used with a single window analyzer. Pulses from the photomultiplier tubes are separated in a single predetermined energy range.

3.5.4 Calibration of Counters. Counters are calibrated for specific radionuclide measurements using a standard of the radionuclide under either identical or very similar conditions as the sample to be counted. For gamma spectrometers a series of standards covering the energy range of interest may be used to construct a calibration curve relating gamma energy to counting efficiency.

In those cases where a standard is not available for a radionuclide, counters may be calibrated using a standard with energy characteristics as similar as possible to the radionuclide to be measured. For gross alpha and beta measurements of the unidentified mixtures of radionuclides, alpha counters are calibrated with a natural uranium standard and beta counters with a cesium-137 standard. The standard must contain the same weight and distribution of solids as the samples, and be mounted in an identical manner. If the samples contain variable amounts of solids, calibration curves relating weight of solids present to counting efficiency are prepared. Standards other than those prescribed may be used provided it can be shown that such standards are more applicable to the radionuclide mixture measured.

3.6 Radiochemical Methods for Selected Radionuclides. Methods for a selected list of radionuclides are listed in Table 1. The radionuclides listed are those which are most commonly used and which have the greatest potential for causing doses to members of the public. For radionuclides not listed in Table 1, methods based on any of the applicable "principles of measurement" described in section 3.1 through 3.4 may be used.

3.7 Applicability of Gross Alpha and Beta Measurements to Unidentified Mixtures of Radionuclides. Gross alpha and beta measurements may be used as a screening measurement as a part of an emission measurement program to identify the need to do specific radionuclide analyses or to confirm or verify that unexpected radionuclides are not being released in significant quantities.

Gross alpha (Method A-4) or gross beta (Methods B-2 or B-4) measurements may also be used for the purpose of comparing the measured concentrations in the effluent stream with the limiting "Concentration Levels for Environmental Compliance" in table 2 of appendix E. For unidentified mixtures, the measured concentration value shall be compared with the lowest environmental concentration limit for any radionuclide which is not known to be absent from the effluent stream.

Table 1—List of Approved Methods for Specific Radionuclides

Radionuclide	Approved methods of analysis
Am-241	A-1, A-2, A-3, A-4
Ar-41	B-1, B-2, G-1, G-2, G-3, G-4
Ba-140	G-1, G-2, G-3, G-4
Br-82	G-1, G-2, G-3, G-4
C-11	B-1, B-2, G-1, G-2, G-3, G-4
C-14	B-5
Ca-45	B-3, B-4, B-5
Ce-144	G-1, G-2, G-3, G-4
Cm-244	A-1, A-2, A-3, A-4
Co-60	G-1, G-2, G-3, G-4
Cr-51	G-1, G-2, G-3, G-4
Cs-134	G-1, G-2, G-3, G-4
Cs-137	G-1, G-2, G-3, G-4
Fe-55	B-5, G-1
Fe-59	G-1, G-2, G-3, G-4
Ga-67	G-1, G-2, G-3, G-4
H-3 (H_2O)	B-5
H-3 (gas)	B-1
I-123	G-1, G-2, G-3, G-4
I-125	G-1
I-131	G-1, G-2, G-3, G-4
In-113m	G-1, G-2, G-3, G-4
Ir-192	G-1, G-2, G-3, G-4

Kr-85	B-1, B-2, B-5, G-1, G-2, G-3, G-4
Kr-87	B-1, B-2, G-1, G-2, G-3, G-4
Kr-88	B-1, B-2, G-1, G-2, G-3, G-4
Mn-54	G-1, G-2, G-3, G-4
Mo-99	G-1, G-2, G-3, G-4
N-13	B-1, B-2, G-1, G-2, G-3, G-4
O-15	B-1, B-2, G-1, G-2, G-3, G-4
P-32	B-3, B-4, B-5
Pm-147	B-3, B-4, B-5
Po-210	A-1, A-2, A-3, A-4
Pu-238	A-1, A-2, A-3, A-4
Pu-239	A-1, A-2, A-3, A-4
Pu-240	A-1, A-2, A-3, A-4
Ra-226	A-1, A-2, G-1, G-2
S-35	B-5
Se-75	G-1, G-2, G-3, G-4
Sr-90	B-3, B-4, B-5
Tc-99	B-3, B-4, B-5
Te-201	G-1, G-2, G-3, G-4
Uranium (total alpha)	A-1, A-2, A-3, A-4
Uranium (Isotopic)	A-1, A-3
Uranium (Natural)	A-5
Xe-133	G-1
Yb-169	G-1, G-2, G-3, G-4
Zn-65	G-1, G-2, G-3, G-4

4. Quality Assurance Methods

Each facility required to measure their radionuclide emissions shall conduct a quality assurance program in conjunction with the radionuclide emission measurements. This program shall assure that the emission measurements are representative, and are of known precision and accuracy and shall include administrative controls to assure prompt response when emission measurements indicate unexpectedly large emissions. The program shall consist of a system of policies, organizational responsibilities, written procedures, data quality specifications, audits, corrective actions and reports. This quality assurance program shall include the following program elements:

4.1 The organizational structure, functional responsibilities, levels of authority and lines of communications for all activities related to the emissions measurement program shall be identified and documented.

4.2 Administrative controls shall be prescribed to ensure prompt response in the event that emission levels increase due to unplanned operations.

4.3 The sample collection and analysis procedures used in measuring the emissions shall be described including where applicable:

4.3.1 Identification of sampling sites and number of sampling points, including the rationale for site selections.
4.3.2 A description of sampling probes and representativeness of the samples.
4.3.3 A description of any continuous monitoring system used to measure emissions, including the sensitivity of the system, calibration procedures and frequency of calibration.
4.3.4 A description of the sample collection systems for each radionuclide measured, including frequency of collection, calibration procedures and frequency of calibration.
4.3.5 A description of the laboratory analysis procedures used for each radionuclide measured, including frequency of analysis, calibration procedures and frequency of calibration.
4.3.6 A description of the sample flow rate measurement systems or procedures, including calibration procedures and frequency of calibration.
4.3.7 A description of the effluent flow rate measurement procedures, including frequency of measurements, calibration procedures and frequency of calibration.
4.4 The objectives of the quality assurance program shall be documented and shall state the required precision, accuracy and completeness of the emission measurement data including a description of the procedures used to assess these parameters. Accuracy is the degree of agreement of a measurement with a true or known value. Precision is a measure of the agreement among individual measurements of the same parameters under similar conditions. Completeness is a measure of the amount of valid data obtained compared to the amount expected under normal conditions.
4.5 A quality control program shall be established to evaluate and track the quality of the emissions measurement data against preset criteria. The program should include where applicable a system of replicates, spiked samples, split samples, blanks and control charts. The number and frequency of such quality control checks shall be identified.
4.6 A sample tracking system shall be established to provide for positive identification of samples and data through all phases of the sample collection, analysis and reporting system. Sample handling and preservation procedures shall be established to maintain the integrity of samples during collection, storage and analysis.
4.7 Regular maintenance, calibration and field checks shall be performed for each sampling system in use by satisfying the requirements found in Table 2: Maintenance, Calibration and Field Check Requirements.

Table 2—Maintenance, Calibration and Field Check Requirements

Sampling system components	**Frequency of activity**
Cleaning of thermal anemometer elements	As required by application.
Inspect pitot tubes for contaminant deposits	At least annually.
Inspect pitot tube systems for leaks	At least annually.
Inspect sharp-edged nozzles for damage	At least annually or after maintenance that could cause damage.
Check nozzles for alignment, presence of deposits, or other potentially degrading factors	Annually.
Check transport lines of HEPA-filtered applications to determine if cleaning is required	Annually.
Clean transport lines	Visible deposits for HEPA-filtered applications. Mean mass of deposited material exceeds 1g/m^{2}for other applications.
Inspect or test the sample transport system for leaks	At least annually.
Check mass flow meters of sampling systems with a secondary or transfer standard	At least quarterly.
Inspect rotameters of sampling systems for	At the start of each sampling period.

presence of foreign matter	
Check response of stack flow rate systems	At least quarterly.
Calibration of flow meters of sampling systems	At least annually.
Calibration of effluent flow measurement devices	At least annually.
Calibration of timing devices	At least annually.

4.8 Periodic internal and external audits shall be performed to monitor compliance with the quality assurance program. These audits shall be performed in accordance with written procedures and conducted by personnel who do not have responsibility for performing any of the operations being audited.

4.9 A corrective action program shall be established including criteria for when corrective action is needed, what corrective actions will be taken and who is responsible for taking the corrective action.

4.10 Periodic reports to responsible management shall be prepared on the performance of the emissions measurements program. These reports should include assessment of the quality of the data, results of audits and description of corrective actions.

4.11 The quality assurance program should be documented in a quality assurance project plan that should address each of the above requirements.

5. References

(1) American National Standards Institute “Guide to Sampling Airborne Radioactive Materials in Nuclear Facilities”, ANSI-N13.1-1969, American National Standards Institute, New York, New York (1969).
(2) American Public Health Association, “Methods of Air Sampling”, 2nd Edition, Method 605, “Tentative Method of Analysis for Plutonium Content of Atmospheric Particulate Matter”. American Public Health Association, New York, NY (1977).
(3) Ibid, Method 601, “Tentative Method of Analysis for Gross Alpha Radioactivity Content of the Atmosphere”.
(4) Ibid, Method 602, “Tentative Method of the Analysis for Gross Beta Radioactivity Content of the Atmosphere”.
(5) Ibid, Method 608, “Tentative Method of Analysis for Strontium-90 Content of Atmospheric Particulate Matter”.
(6) Ibid, Method 609, “Tentative Method of Analysis for Tritium Content of the Atmosphere”.
(7) Ibid, Method 603, “Tentative Method of Analysis for Iodine-131 Content of the Atmosphere”.
(8) American Society for Testing and Materials, 1986 Annual Book ASTM Standards, Designation D-3648-78, “Standard Practices for the Measurement of Radioactivity”. American Society for Testing and Materials, Philadelphia, PA (1986).
(9) Ibid, Designation D-3649-85, “Standard Practice for High Resolution Gamma Spectrometry”.
(10) Ibid, Designation D-1943-81, “Standard Test Method for Alpha Particle Radioactivity of Water”.
(11) Ibid, Designation D-1890-81, “Standard Test Method for Beta Particle Radioactivity of Water”.
(12) Ibid, Designation D-2459-72, “Standard Test Method for Gamma Spectrometry of Water”.
(13) Ibid, Designation D-3972-82, “Standard Test Method for Isotopic Uranium in Water by Radiochemistry”.
(14) Ibid, Designation D-2907-83, “Standard Test Methods for Microquantities of Uranium in Water by Fluorometry”.
(15) Ibid, Designation E-318, “Standard Test Method for Uranium in Aqueous Solutions by Colorimetry”.
(16) Ibid, Designation D-3084-75, “Standard Practice for Alpha Spectrometry of Water”.
(17) Corley, J.P. and C.D. Corbit, “A Guide for Effluent Radiological Measurements at DOE Installations”, DOE/EP-0096, Pacific Northwest Laboratories, Richland, Washington (1983).
(18) Department of Energy, “RESL Analytical Chemistry Branch Procedures Manual”, IDO-12096, U.S. Department of Energy, Idaho Falls, Idaho (1982).
(19) Environmental Protection Agency, “Radiochemical Analytical Procedures for Analysis of Environmental Samples”, EMSL-LV-0539-17, U.S. Environmental Protection Agency, Environmental Monitoring and Support Laboratory, Las Vegas, Nevada (1979).
(20) Environmental Protection Agency, “Radiochemistry Procedures Manual”, EPA 520/5-84-006, Eastern

Environmental Radiation Facility, Montgomery, Alabama (1984).
(21) National Council on Radiation Protection and Measurements, NCRP Report No. 50, “Environmental Radiation Measurements”, National Council on Radiation Protection and Measurement, Bethesda, Maryland (1976).
(22) Ibid, Report No. 47, “Tritium Measurement Techniques”. (1976).
(23) Ibid, Report No. 58 “A Handbook of Radioactivity Measurement Procedures” (1985).
(24) Environmental Protection Agency, “Indoor Radon and Radon Decay Product Measurement Protocols”, EPA 520/1-89-009, U.S. Environmental Protection Agency, Washington, DC (1989).

Method 115—Monitoring for Radon-222 Emissions

This appendix describes the monitoring methods which must be used in determining the radon-222 emissions from underground uranium mines, uranium mill tailings piles, phosphogypsum stacks, and other piles of waste material emitting radon.

1. Radon-222 Emissions from Underground Uranium Mine Vents

1.1 Sampling Frequency and Calculation of Emissions. Radon-222 emissions from underground uranium mine vents shall be determined using one of the following methods:

1.1.1 Continuous Measurement. These measurements shall be made and the emissions calculated as follows:

(a) The radon-222 concentration shall be continuously measured at each mine vent whenever the mine ventilation system is operational.

(b) Each mine vent exhaust flow rate shall be measured at least 4 times per year.

(c) A weekly radon-222 emission rate for the mine shall be calculated and recorded weekly as follows:

$$A_w = C_1 Q_1 T_1 + C_2 Q_2 T_2 + \ldots C_i Q_i T_i$$

Where:

A_w =Total radon-222 emitted from the mine during week (Ci)
C_i =Average radon-222 concentration in mine vent i(Ci/m^3)
Q_i =Volumetric flow rate from mine vent i(m^3 /hr)
T_i =Hours of mine ventilation system operation during week for mine vent i(hr)

(d) The annual radon-222 emission rate is the sum of the weekly emission rates during a calendar year.

1.1.2 Periodic Measurement. This method is applicable only to mines that continuously operate their ventilation system except for extended shutdowns. Mines which start up and shut down their ventilation system frequently must use the continuous measurement method describe in Section 1.1.1 above. Emission rates determined using periodic measurements shall be measured and calculated as follows:

(a) The radon-222 shall be continuously measured at each mine vent for at least one week every three months.

(b) Each mine vent exhaust flow rate shall be measured at least once during each of the radon-222 measurement periods.

(c) A weekly radon-222 emission rate shall be calculated for each weekly period according to the method described in Section 1.1.1. In this calculation T=168 hr.

(d) The annual radon-222 emission rate from the mine should be calculated as follows:

$$A_y = \frac{52 - W_s}{n} \quad (A_{w1} + A_{w2} + \cdots A_{wi})$$

Where:

A_y =Annual radon-222 emission rate from the mine(Ci)
A_{wi} =Weekly radon-222 emission rate during the measurement period i (Ci)
n=Number of weekly measurement periods per year
W_s =Number of weeks during the year that the mine ventilation system is shut down in excess of 7 consecutive days, i.e. the sum of the number of weeks each shut down exceeds 7 days

1.2 Test Methods and Procedures

Each underground mine required to test its emissions, unless an equivalent or alternative method has been approved by the Administrator, shall use the following test methods:

1.2.1 Test Method 1 of appendix A to part 60 shall be used to determine velocity traverses. The sampling point in the duct shall be either the centroid of the cross section or the point of average velocity.

1.2.2 Test Method 2 of appendix A to part 60 shall be used to determine velocity and volumetric flow rates.

1.2.3 Test Methods A-6 or A-7 of appendix B, Method 114 to part 61 shall be used for the analysis of radon-222. Use of Method A-7 requires prior approval of EPA based on conditions described in appendix B.

1.2.4 A quality assurance program shall be conducted in conformance with the programs described for Continuous Radon Monitors and Alpha Track Detectors in EPA 520/1-89-009. (2)

2. Radon-222 Emissions from Uranium Mill Tailings Piles

2.1 Measurement and Calculation of Radon Flux from Uranium Mill Tailings Piles.

2.1.1 Frequency of Flux Measurement. A single set of radon flux measurements may be made, or if the owner or operator chooses, more frequent measurements may be made over a one year period. These measurements may involve quarterly, monthly or weekly intervals. All radon measurements shall be made as described in paragraphs 2.1.2 through 2.1.6 except that for measurements made over a one year period, the requirement of paragraph 2.1.4(c) shall not apply. The mean radon flux from the pile shall be the arithmetic mean of the mean radon flux for each measurement period. The weather conditions, moisture content of the tailings and area of the pile covered by water existing at the time of the measurement shall be chosen so as to provide measurements representative of the long term radon flux from the pile and shall be subject to EPA review and approval.

2.1.2 Distribution of Flux Measurements. The distribution and number of radon flux measurements required on a pile will depend on clearly defined areas of the pile (called regions) that can have significantly different radon fluxes due to surface conditions. The mean radon flux shall be determined for each individual region of the pile. Regions that shall be considered for operating mill tailings piles are:

(a) Water covered areas,
(b) Water saturated areas (beaches),
(c) Dry top surface areas, and
(d) Sides, except where earthen material is used in dam construction.

For mill tailings after disposal the pile shall be considered to consist of only one region.

2.1.3 Number of Flux Measurements. Radon flux measurements shall be made within each region on the pile, except for those areas covered with water. Measurements shall be made at regularly spaced locations across the surface of the region, realizing that surface roughness will prohibit measurements in some areas of a region. The minimum number of flux measurements considered necessary to determine a representative mean radon flux value for each type of region on an operating pile is:

(a) Water covered area—no measurements required as radon flux is assumed to be zero,
(b) Water saturated beaches—100 radon flux measurements,
(c) Loose and dry top surface—100 radon flux measurements,
(d) Sides—100 radon flux measurements, except where earthern material is used in dam construction.

For a mill tailings pile after disposal which consists of only one region a minimum of 100 measurements are required.

2.1.4 Restrictions to Radon Flux Measurements. The following restrictions are placed on making radon flux measurements:

(a) Measurements shall not be initiated within 24 hours of a rainfall.
(b) If a rainfall occurs during the 24 hour measurements period, the measurement is invalid if the seal around the lip of the collector has washed away or if the collector is surrounded by water.
(c) Measurements shall not be performed if the ambient temperature is below 35 °F or if the ground is frozen.

2.1.5 Areas of Pile Regions. The approximate area of each region of the pile shall be determined in units of square meters.

2.1.6 Radon Flux Measurement. Measuring radon flux involves the adsorption of radon on activated charcoal in a large-area collector. The radon collector is placed on the surface of the pile area to be measured and allowed to collect radon for a time period of 24 hours. The radon collected on the charcoal is measured by gamma-ray spectroscopy. The detailed measurement procedure provided in appendix A of EPA 520/5-85-0029(1) shall be used to measure the radon flux on uranium mill tailings, except the surface of the tailings shall not be penetrated by the lip of the radon collector as directed in the procedure, rather the collector shall be carefully positioned on a flat surface with soil or tailings used to seal the edge.

2.1.7 Calculations. The mean radon flux for each region of the pile and for the total pile shall be calculated and reported as follows:

(a) The individual radon flux calculations shall be made as provided in appendix A EPA 86 (1). The mean radon flux for each region of the pile shall be calculated by summing all individual flux measurements for the region and dividing by the total number of flux measurements for the region.

(b) The mean radon flux for the total uranium mill tailings pile shall be calculated as follows.

$$J_s = \frac{J_1A_1 + \cdots J_2A_2 \cdots J_iA_i}{A_t}$$

Where:

J_s =Mean flux for the total pile (pCi/m^2 -s)
J_i =Mean flux measured in region i (pCi/m^2 -s)
A_i =Area of region i (m^2)
A_t =Total area of the pile (m^2)

2.1.8 Reporting. The results of individual flux measurements, the approximate locations on the pile, and the mean radon flux for each region and the mean radon flux for the total stack shall be included in the emission test report. Any condition or unusual event that occurred during the measurements that could significantly affect the results should be reported.

3.0 Radon-222 Emissions from Phosphogypsum Stacks.

3.1 Measurement and Calculation of the Mean Radon Flux. Radon flux measurements shall be made on phosphogypsum stacks as described below:

3.1.1 Frequency of Measurements. A single set of radon flux measurements may be made after the phosphogypsum stack becomes inactive, or if the owner or operator chooses, more frequent measurements may be made over a one year period. These measurements may involve quarterly, monthly or weekly intervals. All radon measurements shall be made as described in paragraphs 3.1.2 through 3.1.6 except that for measurements made over a one year period, the requirement of paragraph 3.1.4(c) shall not apply. For measurements made over a one year period, the radon flux shall be the arithmetic mean of the mean radon flux for each measurement period.

3.1.2 Distribution and Number of Flux Measurements. The distribution and number of radon flux measurements required on a stack will depend on clearly defined areas of the stack (called regions) that can have significantly different radon fluxes due to surface conditions. The mean radon flux shall be determined for each individual region of the stack. Regions that shall be considered are:

(a) Water covered areas,
(b) Water saturated areas (beaches),
(c) Loose and dry top surface areas,
(d) Hard-packed roadways, and
(e) Sides.

3.1.3 Number of Flux Measurements. Radon flux measurements shall be made within each region on the phosphogypsum stack, except for those areas covered with water. Measurements shall be made at regularly spaced locations across the surface of the region, realizing that surface roughness will prohibit measurements in some areas of a region. The minimum number of flux measurements considered necessary to determine a representative mean radon flux value for each type of region is:

(a) Water covered area—no measurements required as radon flux is assumed to be zero,
(b) Water saturated beaches—50 radon flux measurements,
(c) Loose and dry top surface—100 radon flux measurements,
(d) Hard-packed roadways—50 radon flux measurements, and
(e) Sides—100 radon flux measurements.

A minimum of 300 measurements are required. A stack that has no water cover can be considered to consist of two regions, top and sides, and will require a minimum of only 200 measurements.

3.1.4 Restrictions to Radon Flux Measurements. The following restrictions are placed on making radon flux measurements:

(a) Measurements shall not be initiated within 24 hours of a rainfall.
(b) If a rainfall occurs during the 24 hour measurement period, the measurement is invalid if the seal around the lip of the collector has washed away or if the collector is surrounded by water.
(c) Measurements shall not be performed if the ambient temperature is below 35 °F or if the ground is frozen.

3.1.5 Areas of Stack Regions. The approximate area of each region of the stack shall be determined in units of square meters.

3.1.6 Radon Flux Measurements. Measuring radon flux involves the adsorption of radon on activated charcoal in a large-area collector. The radon collector is placed on the surface of the stack area to be measured and allowed to collect radon for a time period of 24 hours. The radon collected on the charcoal is measured by gamma-ray spectroscopy. The detailed measurement procedure provided in appendix A of EPA 520/5-85-0029(1) shall be used to measure the radon flux on phosphogypsum stacks, except the surface of the phosphogypsum shall not be penetrated by the lip of the radon collector as directed in the procedure, rather the collector shall be carefully positioned on a flat surface with soil or phosphogypsum used to seal the edge.

3.1.7 Calculations. The mean radon flux for each region of the phosphogypsum stack and for the total stack shall be calculated and reported as follows:

(a) The individual radon flux calculations shall be made as provided in appendix A EPA 86 (1). The mean radon flux for each region of the stack shall be calculated by summing all individual flux measurements for the region and dividing by the total number of flux measurements for the region.

(b) The mean radon flux for the total phosphogypsum stack shall be calculated as follows.

$$J_s = \frac{J_1A_1 + J_2A_2 + \cdots J_iA_i}{A_t}$$

Where:

J_s =Mean flux for the total stack (pCi/m^2 -s)
J_i =Mean flux measured in region i (pCi/m^2 -s)
A_i =Area of region i (m^2)
A_t =Total area of the stack

3.1.8 Reporting. The results of individual flux measurements, the approximate locations on the stack, and the mean radon flux for each region and the mean radon flux for the total stack shall be included in the emission test report. Any condition or unusual event that occurred during the measurements that could significantly affect the results should be reported.

4.0 Quality Assurance Procedures for Measuring Rn-222 Flux

A. SAMPLING PROCEDURES

Records of field activities and laboratory measurements shall be maintained. The following information shall be recorded for each charcoal canister measurement:

(a) Site
(b) Name of pile
(c) Sample location
(d) Sample ID number
(e) Date and time on
(f) Date and time off
(g) Observations of meteorological conditions and comments

Records shall include all applicable information associated with determining the sample measurement, calculations, observations, and comments.

B. SAMPLE CUSTODY

Custodial control of all charcoal samples exposed in the field shall be maintained in accordance with EPA chain-of-custody field procedures. A control record shall document all custody changes that occur between the field and laboratory personnel.

C. CALIBRATION PROCEDURES AND FREQUENCY

The radioactivity of two standard charcoal sources, each containing a carefully determined quantity of radium-226 uniformly distributed through 180g of activated charcoal, shall be measured. An efficiency factor is computed by dividing the average measured radioactivity of the two standard charcoal sources, minus the background, in cpm by the known radioactivity of the charcoal sources in dpm. The same two standard charcoal sources shall be counted at the beginning and at the end of each day's counting as a check of the radioactivity counting equipment. A background count using unexposed charcoal should also be made at the beginning and at the end of each counting day to check for inadvertent contamination of the detector or other changes affecting the background. The unexposed charcoal comprising the blank is changed with each new batch of charcoal used.

D. INTERNAL QUALITY CONTROL CHECKS AND FREQUENCY

The charcoal from every tenth exposed canister shall be recounted. Five percent of the samples analyzed shall be either blanks (charcoal having no radioactivity added) or samples spiked with known quantities of radium-226.

E. DATA PRECISION, ACCURACY, AND COMPLETENESS

The precision, accuracy, and completeness of measurements and analyses shall be within the following limits for samples measuring greater than 1.0 pCi/m^2 −s.

(a) Precision: 10%

(b) Accuracy: ±10%

(c) Completeness: at least 85% of the measurements must yield useable results.

5.0 REFERENCES

(1) Hartley, J.N. and Freeman, H.D., “Radon Flux Measurements on Gardinier and Royster phosphogypsum Piles Near Tampa and Mulberry, Florida,” U.S. Environmental Protection Agency Report, EPA 520/5-85-029, January 1986.

(2) Environmental Protection Agency, “Indoor Radon and Radon Decay Product Measurement Protocols”, EPA 520/1-89-009, U.S. Environmental Protection Agency, Washington, DC. (1989).

[38 FR 8826, Apr. 6, 1973]

EDITORIAL NOTES: 1. For FEDERAL REGISTER citations to appendix B see the List of CFR Sections Affected, which appears in the Finding Aids section of the printed volume and at www.fdsys.gov .

2. At 65 FR 62161, Oct. 17, 2000, appendix B to part 61 was amended by revising Methods 101, 101A, 102, 103, 104, 105, 106, 107, 107A, 108, 108A, 108B, 108C, and 111. However, because the amendment contains no revised text for Method 107A, this part of the revision could not be incorporated.

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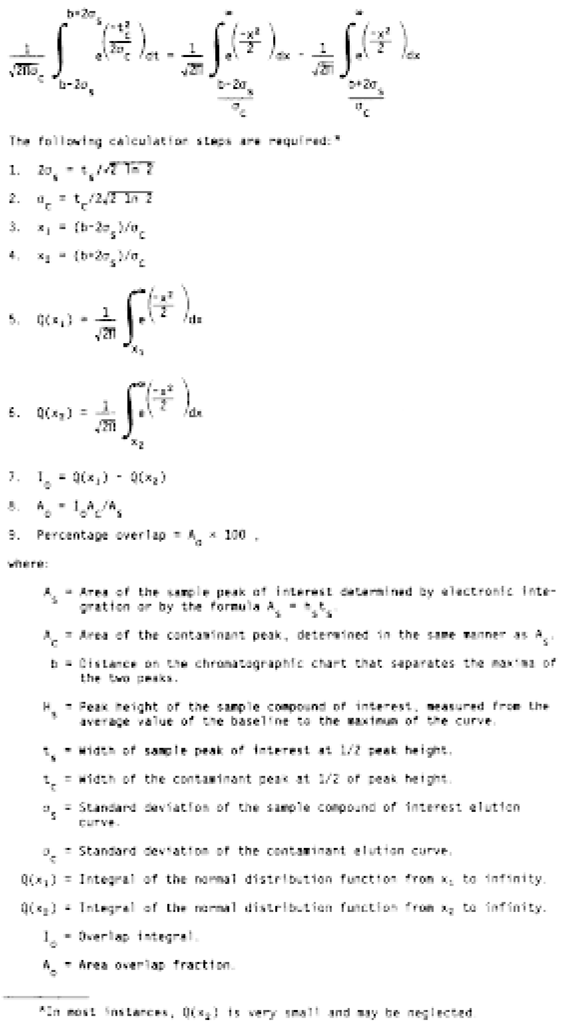
Appendix C to Part 61—Quality Assurance Procedures

Procedure 1—Determination of Adequate Chromatographic Peak Resolution

In this method of dealing with resolution, the extent to which one chromatographic peak overlaps another is determined.

For convenience, consider the range of the elution curve of each compound as running from -2σ to $+2\sigma$. This range is used in other resolution criteria, and it contains 95.45 percent of the area of a normal curve. If two peaks are separated by a known distance, b, one can determine the fraction of the area of one curve that lies within the range of the other. The extent to which the elution curve of a contaminant compound overlaps the curve of a compound that is under analysis is found by integrating the contaminant curve over the limits $b-2\sigma_s$ to $b+2\sigma_s$, where σ_s is the standard deviation of the sample curve. This calculation can be simplified in several ways. Overlap can be determined for curves of unit area; then actual areas can be introduced. Desired integration can be resolved into two integrals of the normal distribution function for which there are convenient calculation programs and tables. An example would be Program 15 in Texas Instruments Program Manual ST1, 1975, Texas Instruments, Inc., Dallas, Texas 75222.



$$\frac{1}{\sqrt{2\pi}\sigma_c}\int_{b-2\sigma_s}^{b+2\sigma_s} e^{\left(\frac{-t^2}{2\sigma_c^2}\right)}dt = \frac{1}{\sqrt{2\pi}}\int_{\frac{b-2\sigma_s}{\sigma_c}}^{\infty} e^{\left(\frac{-x^2}{2}\right)}dx - \frac{1}{\sqrt{2\pi}}\int_{\frac{b+2\sigma_s}{\sigma_c}}^{\infty} e^{\left(\frac{-x^2}{2}\right)}dx$$

The following calculation steps are required:*

1. $2\sigma_s = t_s/\sqrt{2\ln 2}$
2. $\sigma_c = t_c/2\sqrt{2\ln 2}$
3. $x_1 = (b-2\sigma_s)/\sigma_c$
4. $x_2 = (b+2\sigma_s)/\sigma_c$
5. $Q(x_1) = \frac{1}{\sqrt{2\pi}}\int_{x_1}^{\infty} e^{\left(\frac{-x^2}{2}\right)}dx$
6. $Q(x_2) = \frac{1}{\sqrt{2\pi}}\int_{x_2}^{\infty} e^{\left(\frac{-x^2}{2}\right)}dx$
7. $I_o = Q(x_1) - Q(x_2)$
8. $A_o = I_o A_c / A_s$
9. Percentage overlap = $A_o \times 100$.

where:

A_s = Area of the sample peak of interest determined by electronic integration or by the formula $A_s = h_s t_s$.

A_c = Area of the contaminant peak, determined in the same manner as A_s.

b = Distance on the chromatographic chart that separates the maxima of the two peaks.

H_s = Peak height of the sample compound of interest, measured from the average value of the baseline to the maximum of the curve.

t_s = Width of sample peak of interest at 1/2 peak height.

t_c = Width of the contaminant peak at 1/2 of peak height.

σ_s = Standard deviation of the sample compound of interest elution curve.

σ_c = Standard deviation of the contaminant elution curve.

$Q(x_1)$ = Integral of the normal distribution function from x_1 to infinity.

$Q(x_2)$ = Integral of the normal distribution function from x_2 to infinity.

I_o = Overlap integral.

A_o = Area overlap fraction.

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*In most instances, $Q(x_2)$ is very small and may be neglected.

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In judging the suitability of alternate GC columns or the effects of altering chromatographic conditions, one can employ the area overlap as the resolution parameter with a specific maximum permissible value. The use of Gaussian functions to describe chromatographic elution curves is widespread. However, some elution curves are highly asymmetric. In cases where the sample peak is followed by a contaminant that has a leading edge that rises sharply but the curve then tails off, it may be possible to define an effective width for t_c as "twice the distance from the leading edge to a perpendicular line through the maxim of the contaminant curve, measured along a perpendicular bisection of that line."

Procedure 2—Procedure for Field Auditing GC Analysis

Responsibilities of audit supervisor and analyst at the source sampling site include the following:

A. The audit supervisor verifies that audit cylinders are stored in a safe location both before and after the audit to prevent vandalism.

B. At the beginning and conclusion of the audit, the analyst records each cylinder number and pressure. An audit cylinder is never analyzed when the pressure drops below 200 psi.

C. During the audit, the analyst performs a minimum of two consecutive analyses of each audit cylinder gas. The audit must be conducted to coincide with the analysis of source test samples, normally immediately after GC calibration and prior to sample analyses.

D. At the end of audit analyses, the audit supervisor requests the calculated concentrations from the analyst and compares the results with the actual audit concentrations. If each measured concentration agrees with the respective actual concentration within ±10 percent, he directs the analyst to begin analyzing source samples. Audit supervisor judgment and/or supervisory policy determine action when agreement is not within ±10 percent. When a consistent bias in excess of 10 percent is found, it may be possible to proceed with the sample analysis, with a corrective factor to be applied to the results at a later time. However, every attempt should be made to locate the cause of the discrepancy, as it may be misleading. The audit supervisor records each cylinder number, cylinder pressure (at the end of the audit), and all calculated concentrations. The individual being audited must not under any circumstance be told actual audit concentrations until calculated concentrations have been submitted to the audit supervisor.

FIELD AUDIT REPORT

Part A— To be filled out by organization supplying audit cylinders.

1. Organization supplying audit sample(s) and shipping address
2. Audit supervisor, organization, and phone number
3. Shipping instructions: Name, Address, Attention
4. Guaranteed arrival date for cylinders
5. Planned shipping date for cylinders
6. Details on audit cylinders from last analysis

	Low conc.	**High conc.**
a. Date of last analysis		
b. Cylinder number		
c. Cylinder pressure, psi		
d. Audit gas(es)/balance gas		
e. Audit gas(es), ppm		
f. Cylinder construction		

Part B —To be filled out by audit supervisor.

1. Process sampled
2. Audit location
3. Name of individual audit
4. Audit date
5. Audit results:

	Low conc. cylinder	**High conc. cylinder**
a. Cylinder number		
b. Cylinder pressure before audit, psi		
c. Cylinder pressure after audit, psi		
d. Measured concentration, ppm Injection #1* Injection #2* Average		
e. Actual audit concentration, ppm (Part A, 6e)		
f. Audit accuracy:[1]		
Low Conc. Cylinder		
High Conc. Cylinder		
Percent [1]accuracy=		
Measured Conc.−Actual Conc.		
__________________ ×100		
Actual Conc.		
g. Problems detected (if any)		

[1] Results of two consecutive injections that meet the sample analysis criteria of the test method.

[47 FR 39178, Sept. 7, 1982]

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Appendix D to Part 61—Methods for Estimating Radionuclide Emissions

1. Purpose and Background

Facility owners or operators may estimate radionuclide emissions to the atmosphere for dose calculations instead of measuring emissions. Particulate emissions from mill tailings piles should be estimated using the procedures listed in reference re #2. All other emissions may be estimated by using the “Procedures” listed below, or using the method described in reference #1.

2. Procedure

To estimate emissions to the atmosphere:

(a) Determine the amount (in curies) used at facilities for the period under consideration. Radioactive materials in sealed packages that remain unopened, and have not leaked during the assessment period should not be included in the calculation.

(b) Multiply the amount used by the following factors which depend on the physical state of the radionuclide. They are:

(i) 1 for gases;

(ii) 10^{-3} for liquids or particulate solids; and

(iii) 10^{-6} for solids.

If any nuclide is heated to a temperature of 100 degrees Celsius or more, boils at a temperature of 100 degrees Celsius or less, or is intentionally dispersed into the environment, it must be considered to be a gas.

(c) If a control device is installed between the place of use and the point of release, multiply emissions from (b) by an adjustment factor. These are presented in Table 1.

Table 1—Adjustment to Emission Factors for Effluent Controls

Controls	Types of radionuclides controlled	Adjustment factor to emissions	Comments and conditions
HEPA filters	Particulates	0.01	Not applicable to gaseous radionuclides; periodic testing is prudent to ensure high removal efficiency.
Fabric filter	Particulates	0.1	Monitoring would be prudent to guard against tears in filter.
Sintered metal	Particulates	1	Insufficient data to make recommendation.
Activated carbon filters	Iodine gas	0.1	Efficiency is time dependent; monitoring is necessary to ensure effectiveness.
Douglas bags: Held one week or longer for decay	Xenon	0.5/wk	Based on xenon half-life of 5.3 days;
Douglas bags: Released within one week	Xenon	1	Provides no reduction of exposure to general public.
Venturi scrubbers	Particulates Gases	0.05 1	Although venturis may remove gases, variability in gaseous removal efficiency dictates adjustment factor for particulates only.
Packed bed scrubbers	Gases	0.1	Not applicable to particulates.
Electrostatic precipitators	Particulates	0.05	Not applicable for gaseous radionuclides

Xenon traps	Xenon	0.1	Efficiency is time dependent; monitoring is necessary to ensure effectiveness.
Fume hoods	All	1	Provides no reduction to general public exposures.
Vent stacks	All	1	Generally provides no reduction of exposure to general public.

References

(1) Environmental Protection Agency, “A Guide for Determining Compliance with the Clean Air Act Standards for Radionuclides Emissions from NRC-Licensed and Non-DOE Federal Facilities”, EPA 520/1-89-002, January 1989.

(2) Nuclear Regulatory Commission, “Methods for Estimating Radioactive and Toxic Airborne Source Terms for Uranium Milling Operations”, U.S. Nuclear Regulatory Commission Regulatory Guide 3.59, March 1987.

[54 FR 51711, Dec. 15, 1989]

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Appendix E to Part 61—Compliance Procedures Methods for Determining Compliance With Subpart I

1. Purpose and Background

This Appendix provides simplified procedures to reduce the burden on Nuclear Regulatory Commission (NRC) licensees, and non-Department of Energy Federal facilities in determining compliance with 40 CFR part 61, subpart I. The procedures consist of a series of increasingly more stringent steps, depending on the facility's potential to exceed the standard.

First, a facility can be found in compliance if the quantity of radioactive material possessed during the year is less than that listed in a table of annual possession quantities. A facility will also be in compliance if the average annual radionuclide emission concentration is less than that listed in a table of air concentration levels. If the facility is not in compliance by these tables, it can establish compliance by estimating a dose using screening procedure developed by the National Council on Radiation Protection and Measurements with a radiological source term derived using EPA approved emission factors. These procedures are described in a “Guide for Determining Compliance with the Clean Air Act Standards for Radionuclide Emissions From NRC-Licensed and Non-DOE Federal Facilities.”

A user-friendly computer program called COMPLY has been developed to reduce the burden on the regulated community. The Agency has also prepared a “User's Guide for the COMPLY Code” to assist the regulated community in using the code, and in handling more complex situations such as multiple release points. The basis for these compliance procedures are provided in “Background Information Document: Procedures Approved for Demonstrating Compliance with 40 CFR Part 61, Subpart I”. The compliance model is the highest level in the COMPLY computer code and provides for the most realistic assessment of dose by allowing the use of site-specific information.

2. Table of Annual Possession Quantity

(a) Table 1 may be used for determining if facilities are in compliance with the standard. The possession table can only be used if the following conditions are met:

(i) No person lives within 10 meters of any release point; and

(ii) No milk, meat, or vegetables are produced within 100 meters of any release point.

(b) Procedures described in Reference (1) shall be used to determine compliance or exemption from reporting by use of Table 2.

Table 1—Annual Possession Quantities for Environmental Compliance

[Annual Possession Quantities (Ci/yr)]

Radionuclide	**Gaseous form***	**Liquid/powder forms**	**Solid form***
Ac-225	9.6E−05	9.6E−02	9.6E+01
Ac-227	1.6E−07	1.6E−04	1.6E−01
Ac-228	3.4E−03	3.4E+00	3.4E+03

Ag-106	1.6E+00	1.6E+03	1.6E+06
Ag-106m	2.6E−03	2.6E+00	2.6E+03
Ag-108m	6.5E−06	6.5E−03	6.5E+00
Ag-110m	9.4E−05	9.4E−02	9.4E+01
Ag-111	6.7E−02	6.7E+01	6.7E+04
Al-26	4.0E−06	4.0E−03	4.0E+00
Am-241	2.3E−06	2.3E−03	2.3E+00
Am-242	1.8E−02	1.8E+01	1.8E+04
Am-242m	2.5E−06	2.5E−03	2.5E+00
Am-243	2.3E−06	2.3E−03	2.3E+00
Am-244	4.6E−02	4.6E+01	4.6E+04
Am-245	7.0E+00	7.0E+03	7.0E+06
Am-246	9.8E−01	9.8E+02	9.8E+05
Ar-37	1.4E+06		
Ar-41	1.4E+00		
As-72	2.9E−02	2.9E+01	2.9E+04
As-73	6.0E−02	6.0E+01	6.0E+04
As-74	4.3E−03	4.3E+00	4.3E+03
As-76	8.8E−02	8.8E+01	8.8E+04
As-77	7.9E−01	7.9E+02	7.9E+05
At-211	1.0E−02	1.0E+01	1.0E+04
Au-193	4.2E−01	4.2E+02	4.2E+05
Au-194	3.5E−02	3.5E+01	3.5E+04
Au-195	3.3E−03	3.3E+00	3.3E+03
Au-198	4.6E−02	4.6E+01	4.6E+04
Au-199	1.5E−01	1.5E+02	1.5E+05
Ba-131	1.0E−02	1.0E+01	1.0E+04
Ba-133	4.9E−05	4.9E−02	4.9E+01
Ba-133m	9.3E−02	9.3E+01	9.3E+04
Ba-135m	5.8E−01	5.8E+02	5.8E+05
Ba-139	4.7E+00	4.7E+03	4.7E+06
Ba-140	2.1E−03	2.1E+00	2.1E+03
Ba-141	1.3E+00	1.3E+03	1.3E+06
Ba-142	1.1E+00	1.1E+03	1.1E+06

Be-7	2.3E−02	2.3E+01	2.3E+04
Be-10	3.0E−03	3.0E+00	3.0E+03
Bi-206	3.1E−03	3.1E+00	3.1E+03
Bi-207	8.4E−06	8.4E−03	8.4E+00
Bi-210	4.2E−03	4.2E+00	4.2E+03
Bi-212	4.7E−02	4.7E+01	4.7E+04
Bi-213	6.0E−02	6.0E+01	6.0E+04
Bi-214	1.4E−01	1.4E+02	1.4E+05
Bk-249	7.0E−04	7.0E−01	7.0E+02
Bk-250	1.0E−01	1.0E+02	1.0E+05
Br-77	7.5E−02	7.5E+01	7.5E+04
Br-80	1.2E+01	1.2E+04	1.2E+07
Br-80m	1.5E+00	1.5E+03	1.5E+06
Br-82	1.6E−02	1.6E+01	1.6E+04
Br-83	9.9E+00	9.9E+03	9.9E+06
Br-84	5.6E−01	5.6E+02	5.6E+05
C-11	1.3E+00	1.3E+03	1.3E+06
C-14	2.9E−01	2.9E+02	2.9E+05
Ca-41	2.7E−02	2.7E+01	2.7E+04
Ca-45	5.8E−02	5.8E+01	5.8E+04
Ca-47	1.1E−02	1.1E+01	1.1E+04
Cd-109	5.0E−03	5.0E+00	5.0E+03
Cd-113	3.3E−04	3.3E−01	3.3E+02
Cd-113m	4.4E−04	4.4E−01	4.4E+02
Cd-115	5.4E−02	5.4E+01	5.4E+04
Cd-115m	1.0E−02	1.0E+01	1.0E+04
Cd-117	5.6E−02	5.6E+01	5.6E+04
Cd-117m	1.3E−01	1.3E+02	1.3E+05
Ce-139	2.6E−03	2.6E+00	2.6E+03
Ce-141	1.8E−02	1.8E+01	1.8E+04
Ce-143	1.0E−01	1.0E+02	1.0E+05
Ce-144	1.7E−03	1.7E+00	1.7E+03
Cf-248	2.0E−05	2.0E−02	2.0E+01
Cf-249	1.7E−06	1.7E−03	1.7E+00

Cf-250	4.0E−06	4.0E−03	4.0E+00
Cf-251	1.7E−06	1.7E−03	1.7E+00
Cf-252	6.4E−06	6.4E−03	6.4E+00
Cf-253	3.3E−04	3.3E−01	3.3E+02
Cf-254	3.6E−06	3.6E−03	3.6E+00
Cl-36	1.9E−04	1.9E−01	1.9E+02
Cl-38	6.5E−01	6.5E+02	6.5E+05
Cm-242	6.0E−05	6.0E−02	6.0E+01
Cm-243	3.3E−06	3.3E−03	3.3E+00
Cm-244	4.2E−06	4.2E−03	4.2E+00
Cm-245	2.3E−06	2.3E−03	2.3E+00
Cm-246	2.3E−06	2.3E−03	2.3E+00
Cm-247	2.3E−06	2.3E−03	2.3E+00
Cm-248	6.4E−07	6.4E−04	6.4E−01
Cm-249	4.6E+00	4.6E+03	4.6E+06
Cm-250	1.1E−07	1.1E−04	1.1E−01
Co-56	2.4E−04	2.4E−01	2.4E+02
Co-57	1.6E−03	1.6E+00	1.6E+03
Co-58	9.0E−04	9.0E−01	9.0E+02
Co-58m	1.7E−01	1.7E+02	1.7E+05
Co-60	1.6E−05	1.6E−02	1.6E+01
Co-60m	4.0E+00	4.0E+03	4.0E+06
Co-61	3.8E+00	3.8E+03	3.8E+06
Cr-49	9.0E−01	9.0E+02	9.0E+05
Cr-51	6.3E−02	6.3E+01	6.3E+04
Cs-129	1.5E−01	1.5E+02	1.5E+05
Cs-131	2.8E−01	2.8E+02	2.8E+05
Cs-132	1.3E−02	1.3E+01	1.3E+04
Cs-134	5.2E−05	5.2E−02	5.2E+01
Cs-134m	3.2E−01	3.2E+02	3.2E+05
Cs-135	2.4E−02	2.4E+01	2.4E+04
Cs-136	2.1E−03	2.1E+00	2.1E+03
Cs-137	2.3E−05	2.3E−02	2.3E+01
Cs-138	4.4E−01	4.4E+02	4.4E+05

Cu-61	4.0E−01	4.0E+02	4.0E+05
Cu-64	5.2E−01	5.2E+02	5.2E+05
Cu-67	1.5E−01	1.5E+02	1.5E+05
Dy-157	4.4E−01	4.4E+02	4.4E+05
Dy-165	5.6E+00	5.6E+03	5.6E+06
Dy-166	8.1E−02	8.1E+01	8.1E+04
Er-169	4.0E−01	4.0E+02	4.0E+05
Er-171	3.6E−01	3.6E+02	3.6E+05
Es-253	2.6E−04	2.6E−01	2.6E+02
Es-254	2.3E−05	2.3E−02	2.3E+01
Es-254m	1.8E−03	1.8E+00	1.8E+03
Eu-152	1.6E−05	1.6E−02	1.6E+01
Eu-152m	3.5E−01	3.5E+02	3.5E+05
Eu-154	2.0E−05	2.0E−02	2.0E+01
Eu-155	5.2E−04	5.2E−01	5.2E+02
Eu-156	3.2E−03	3.2E+00	3.2E+03
F-18	5.6E−01	5.6E+02	5.6E+05
Fe-52	4.9E−02	4.9E+01	4.9E+04
Fe-55	1.4E−01	1.4E+02	1.4E+05
Fe-59	1.3E−03	1.3E+00	1.3E+03
Fm-254	1.8E−02	1.8E+01	1.8E+04
Fm-255	4.0E−03	4.0E+00	4.0E+03
Fr-223	1.4E−01	1.4E+02	1.4E+05
Ga-66	5.6E−02	5.6E+01	5.6E+04
Ga-67	1.1E−01	1.1E+02	1.1E+05
Ga-68	7.6E−01	7.6E+02	7.6E+05
Ga-72	3.6E−02	3.6E+01	3.6E+04
Gd-152	4.4E−06	4.4E−03	4.4E+00
Gd-153	2.0E−03	2.0E+00	2.0E+03
Gd-159	6.8E−01	6.8E+02	6.8E+05
Ge-68	2.3E−04	2.3E−01	2.3E+02
Ge-71	2.6E+00	2.6E+03	2.6E+06
Ge-77	1.0E−01	1.0E+02	1.0E+05
H-3	1.5E+01	1.5E+04	1.5E+07

Hf-181	2.5E−03	2.5E+00	2.5E+03
Hg-193m	9.5E−02	9.5E+01	9.5E+04
Hg-197	2.4E−01	2.4E+02	2.4E+05
Hg-197m	2.5E−01	2.5E+02	2.5E+05
Hg-203	5.2E−03	5.2E+00	5.2E+03
Ho-166	2.8E−01	2.8E+02	2.8E+05
Ho-166m	6.0E−06	6.0E−03	6.0E+00
I-123	4.9E−01	4.9E+02	4.9E+05
I-124	9.3E−03	9.3E+00	9.3E+03
I-125	6.2E−03	6.2E+00	6.2E+03
I-126	3.7E−03	3.7E+00	3.7E+03
I-128	9.3E+00	9.3E+03	9.3E+06
I-129	2.6E−04	2.6E−01	2.6E+02
I-130	4.6E−02	4.6E+01	4.6E+04
I-131	6.7E−03	6.7E+00	6.7E+03
I-132	2.0E−01	2.0E+02	2.0E+05
I-133	6.7E−02	6.7E+01	6.7E+04
I-134	3.2E−01	3.2E+02	3.2E+05
I-135	1.2E−01	1.2E+02	1.2E+05
In-111	4.9E−02	4.9E+01	4.9E+04
In-113m	2.1E+00	2.1E+03	2.1E+06
In-114m	4.9E−03	4.9E+00	4.9E+03
In-115	2.7E−04	2.7E−01	2.7E+02
In-115m	1.4E+00	1.4E+03	1.4E+06
In-116m	3.5E−01	3.5E+02	3.5E+05
In-117	1.3E+00	1.3E+03	1.3E+06
In-117m	7.6E−02	7.6E+01	7.6E+04
Ir-190	3.5E−03	3.5E+00	3.5E+03
Ir-192	9.7E−04	9.7E−01	9.7E+02
Ir-194	2.5E−01	2.5E+02	2.5E+05
Ir-194m	1.5E−04	1.5E−01	1.5E+02
K-40	6.8E−05	6.8E−02	6.8E+01
K-42	2.9E−01	2.9E+02	2.9E+05
K-43	6.0E−02	6.0E+01	6.0E+04

K-44	4.9E−01	4.9E+02	4.9E+05
Kr-79	7.0E+00		
Kr-81	1.8E+02		
Kr-83m	2.0E+04		
Kr-85	8.4E+02		
Kr-85m	1.1E+01		
Kr-87	2.0E+00		
Kr-88	4.2E−01		
La-140	1.6E−02	1.6E+01	1.6E+04
La-141	1.1E+00	1.1E+03	1.1E+06
La-142	2.3E−01	2.3E+02	2.3E+05
Lu-177	1.4E−01	1.4E+02	1.4E+05
Lu-177m	3.5E−04	3.5E−01	3.5E+02
Mg-28	2.1E−02	2.1E+01	2.1E+04
Mn-52	3.5E−03	3.5E+00	3.5E+03
Mn-52m	5.2E−01	5.2E+02	5.2E+05
Mn-53	5.7E−02	5.7E+01	5.7E+04
Mn-54	2.5E−04	2.5E−01	2.5E+02
Mn-56	2.5E−01	2.5E+02	2.5E+05
Mo-93	1.5E−03	1.5E+00	1.5E+03
Mo-99**	5.7E−02	5.7E+01	5.7E+04
Mo-101	8.4E−01	8.4E+02	8.4E+05
Na-22	3.2E−05	3.2E−02	3.2E+01
Na-24	2.6E−02	2.6E+01	2.6E+04
Nb-90	2.5E−02	2.5E+01	2.5E+04
Nb-93m	1.2E−02	1.2E+01	1.2E+04
Nb-94	6.0E−06	6.0E−03	6.0E+00
Nb-95	2.3E−03	2.3E+00	2.3E+03
Nb-95m	2.0E−02	2.0E+01	2.0E+04
Nb-96	2.5E−02	2.5E+01	2.5E+04
Nb-97	1.0E+00	1.0E+03	1.0E+06
Nd-147	3.0E−02	3.0E+01	3.0E+04
Nd-149	1.1E+00	1.1E+03	1.1E+06
Ni-56	2.0E−03	2.0E+00	2.0E+03

Ni-57	2.1E−02	2.1E+01	2.1E+04
Ni-59	2.2E−02	2.2E+01	2.2E+04
Ni-63	1.4E−01	1.4E+02	1.4E+05
Ni-65	7.0E−01	7.0E+02	7.0E+05
Np-235	3.0E−02	3.0E+01	3.0E+04
Np-237	1.8E−06	1.8E−03	1.8E+00
Np-238	1.9E−02	1.9E+01	1.9E+04
Np-239	1.0E−01	1.0E+02	1.0E+05
Np-240	6.5E−01	6.5E+02	6.5E+05
Np-240m	4.7E+00	4.7E+03	4.7E+06
Os-185	9.2E−04	9.2E−01	9.2E+02
Os-191m	9.0E−01	9.0E+02	9.0E+05
Os-191	3.8E−02	3.8E+01	3.8E+04
Os-193	2.9E−01	2.9E+02	2.9E+05
P-32	1.7E−02	1.7E+01	1.7E+04
P-33	1.2E−01	1.2E+02	1.2E+05
Pa-230	6.3E−04	6.3E−01	6.3E+02
Pa-231	8.3E−07	8.3E−04	8.3E−01
Pa-233	9.3E−03	9.3E+00	9.3E+03
Pa-234	9.3E−02	9.3E+01	9.3E+04
Pb-203	8.3E−02	8.3E+01	8.3E+04
Pb-205	1.2E−02	1.2E+01	1.2E+04
Pb-209	1.1E+01	1.1E+04	1.1E+07
Pb-210	5.5E−05	5.5E−02	5.5E+01
Pb-211	1.2E−01	1.2E+02	1.2E+05
Pb-212	6.0E−03	6.0E+00	6.0E+03
Pb-214	1.2E−01	1.2E+02	1.2E+05
Pd-103	2.1E−01	2.1E+02	2.1E+05
Pd-107	8.2E−02	8.2E+01	8.2E+04
Pd-109	9.4E−01	9.4E+02	9.4E+05
Pm-143	7.6E−04	7.6E−01	7.6E+02
Pm-144	1.1E−04	1.1E−01	1.1E+02
Pm-145	5.2E−04	5.2E−01	5.2E+02
Pm-146	4.4E−05	4.4E−02	4.4E+01

Pm-147	2.6E−02	2.6E+01	2.6E+04
Pm-148	1.7E−02	1.7E+01	1.7E+04
Pm-148m	7.6E−04	7.6E−01	7.6E+02
Pm-149	2.8E−01	2.8E+02	2.8E+05
Pm-151	1.2E−01	1.2E+02	1.2E+05
Po-210	9.3E−05	9.3E−02	9.3E+01
Pr-142	2.8E−01	2.8E+02	2.8E+05
Pr-143	1.0E−01	1.0E+02	1.0E+05
Pr-144	1.5E+01	1.5E+04	1.5E+07
Pt-191	6.4E−02	6.4E+01	6.4E+04
Pt-193	2.1E−02	2.1E+01	2.1E+04
Pt-193m	4.8E−01	4.8E+02	4.8E+05
Pt-195m	1.4E−01	1.4E+02	1.4E+05
Pt-197	1.1E+00	1.1E+03	1.1E+06
Pt-197m	3.6E+00	3.6E+03	3.6E+06
Pu-236	7.0E−06	7.0E−03	7.0E+00
Pu-237	2.3E−02	2.3E+01	2.3E+04
Pu-238	2.7E−06	2.7E−03	2.7E+00
Pu-239	2.5E−06	2.5E−03	2.5E+00
Pu-240	2.5E−06	2.5E−03	2.5E+00
Pu-241	1.3E−04	1.3E−01	1.3E+02
Pu-242	2.5E−06	2.5E−03	2.5E+00
Pu-243	3.8E+00	3.8E+03	3.8E+06
Pu-244	2.4E−06	2.4E−03	2.4E+00
Pu-245	2.1E−01	2.1E+02	2.1E+05
Pu-246	4.8E−03	4.8E+00	4.8E+03
Ra-223	1.3E−04	1.3E−01	1.3E+02
Ra-224	3.2E−04	3.2E−01	3.2E+02
Ra-225	1.3E−04	1.3E−01	1.3E+02
Ra-226	5.5E−06	5.5E−03	5.5E+00
Ra-228	1.3E−05	1.3E−02	1.3E+01
Rb-81	4.2E−01	4.2E+02	4.2E+05
Rb-83	1.4E−03	1.4E+00	1.4E+03
Rb-84	2.0E−03	2.0E+00	2.0E+03

Rb-86	1.7E−02	1.7E+01	1.7E+04
Rb-87	1.0E−02	1.0E+01	1.0E+04
Rb-88	1.7E+00	1.7E+03	1.7E+06
Rb-89	6.4E−01	6.4E+02	6.4E+05
Re−184	1.8E−03	1.8E+00	1.8E+03
Re-184m	3.6E−04	3.6E−01	3.6E+02
Re-186	1.9E−01	1.9E+02	1.9E+05
Re-187	9.3E+00	9.3E+03	9.3E+06
Re-188	3.7E−01	3.7E+02	3.7E+05
Rh-103m	1.7E+02	1.7E+05	1.7E+08
Rh-105	3.4E−01	3.4E+02	3.4E+05
Ru-97	8.3E−02	8.3E+01	8.3E+04
Ru-103	3.1E−03	3.1E+00	3.1E+03
Ru-105	2.9E−01	2.9E+02	2.9E+05
Ru-106	5.9E−04	5.9E−01	5.9E+02
S-35	7.5E−02	7.5E+01	7.5E+04
Sb-117	2.0E+00	2.0E+03	2.0E+06
Sb-122	3.9E−02	3.9E+01	3.9E+04
Sb-124	6.0E−04	6.0E−01	6.0E+02
Sb-125	1.4E−04	1.4E−01	1.4E+02
Sb-126	1.8E−03	1.8E+00	1.8E+03
Sb-126m	7.6E−01	7.6E+02	7.6E+05
Sb-127	2.0E−02	2.0E+01	2.0E+04
Sb-129	1.8E−01	1.8E+02	1.8E+05
Sc-44	1.4E−01	1.4E+02	1.4E+05
Sc-46	4.0E−04	4.0E−01	4.0E+02
Sc-47	1.1E−01	1.1E+02	1.1E+05
Sc-48	1.1E−02	1.1E+01	1.1E+04
Sc-49	1.0E+01	1.0E+04	1.0E+07
Se-73	1.6E−01	1.6E+02	1.6E+05
Se-75	1.1E−03	1.1E+00	1.1E+03
Se-79	6.9E−03	6.9E+00	6.9E+03
Si-31	4.7E+00	4.7E+03	4.7E+06
Si-32	7.2E−04	7.2E−01	7.2E+02

Sm-147	1.4E−05	1.4E−02	1.4E+01
Sm-151	3.5E−02	3.5E+01	3.5E+04
Sm-153	2.4E−01	2.4E+02	2.4E+05
Sn-113	1.9E−03	1.9E+00	1.9E+03
Sn-117m	2.3E−02	2.3E+01	2.3E+04
Sn-119m	2.8E−02	2.8E+01	2.8E+04
Sn-123	1.8E−02	1.8E+01	1.8E+04
Sn-125	7.2E−03	7.2E+00	7.2E+03
Sn-126	4.7E−06	4.7E−03	4.7E+00
Sr-82	1.9E−03	1.9E+00	1.9E+03
Sr-85	1.9E−03	1.9E+00	1.9E+03
Sr-85m	1.5E+00	1.5E+03	1.5E+06
Sr-87m	1.2E+00	1.2E+03	1.2E+06
Sr-89	2.1E−02	2.1E+01	2.1E+04
Sr-90	5.2E−04	5.2E−01	5.2E+02
Sr-91	1.2E−01	1.2E+02	1.2E+05
Sr-92	2.5E−01	2.5E+02	2.5E+05
Ta-182	4.4E−04	4.4E−01	4.4E+02
Tb-157	2.2E−03	2.2E+00	2.2E+03
Tb-160	8.4E−04	8.4E−01	8.4E+02
Tc-95	9.0E−02	9.0E+01	9.0E+04
Tc-95m	1.4E−03	1.4E+00	1.4E+03
Tc-96	5.6E−03	5.6E+00	5.6E+03
Tc-96m	7.0E−01	7.0E+02	7.0E+05
Tc-97	1.5E−03	1.5E+00	1.5E+03
Tc-97m	7.2E−02	7.2E+01	7.2E+04
Tc-98	6.4E−06	6.4E−03	6.4E+00
Tc-99	9.0E−03	9.0E+00	9.0E+03
Tc-99m	1.4E+00	1.4E+03	1.4E+06
Tc-101	3.8E+00	3.8E+03	3.8E+06
Te-121	6.0E−03	6.0E+00	6.0E+03
Te-121m	5.3E−04	5.3E−01	5.3E+02
Te-123	1.2E−03	1.2E+00	1.2E+03
Te-123m	2.7E−03	2.7E+00	2.7E+03

Te-125m	1.5E−02	1.5E+01	1.5E+04
Te-127	2.9E+00	2.9E+03	2.9E+06
Te-127m	7.3E−03	7.3E+00	7.3E+03
Te-129	6.5E+00	6.5E+03	6.5E+06
Te-129m	6.1E−03	6.1E+00	6.1E+03
Te-131	9.4E−01	9.4E+02	9.4E+05
Te-131m	1.8E−02	1.8E+01	1.8E+04
Te-132	6.2E−03	6.2E+00	6.2E+03
Te-133	1.2E+00	1.2E+03	1.2E+06
Te-133m	2.9E−01	2.9E+02	2.9E+05
Te-134	4.4E−01	4.4E+02	4.4E+05
Th-226	3.0E−02	3.0E+01	3.0E+04
Th-227	6.4E−05	6.4E−02	6.4E+01
Th-228	2.9E−06	2.9E−03	2.9E+00
Th-229	4.9E−07	4.9E−04	4.9E−01
Th-230	3.2E−06	3.2E−03	3.2E+00
Th-231	8.4E−01	8.4E+02	8.4E+05
Th-232	6.0E−07	6.0E−04	6.0E−01
Th-234	2.0E−02	2.0E+01	2.0E+04
Ti-44	5.2E−06	5.2E−03	5.2E+00
Ti-45	4.0E−01	4.0E+02	4.0E+05
Tl-200	4.4E−02	4.4E+01	4.4E+04
Tl-201	1.8E−01	1.8E+02	1.8E+05
Tl-202	1.0E−02	1.0E+01	1.0E+04
Tl-204	2.5E−02	2.5E+01	2.5E+04
Tm-170	2.4E−02	2.4E+01	2.4E+04
Tm-171	5.9E−02	5.9E+01	5.9E+04
U-230	5.0E−05	5.0E−02	5.0E+01
U-231	1.4E−01	1.4E+02	1.4E+05
U-232	1.3E−06	1.3E−03	1.3E+00
U-233	7.6E−06	7.6E−03	7.6E+00
U-234	7.6E−06	7.6E−03	7.6E+00
U-235	7.0E−06	7.0E−03	7.0E+00
U-236	8.4E−06	8.4E−03	8.4E+00

U-237	4.7E−02	4.7E+01	4.7E+04
U-238	8.6E−06	8.6E−03	8.6E+00
U-239	8.3E+00	8.3E+03	8.3E+06
U-240	1.8E−01	1.8E+02	1.8E+05
V-48	1.4E−03	1.4E+00	1.4E+03
V-49	1.3E+00	1.3E+03	1.3E+06
W-181	1.1E−02	1.1E+01	1.1E+04
W-185	1.6E−01	1.6E+02	1.6E+05
W-187	1.1E−01	1.1E+02	1.1E+05
W-188	1.0E−02	1.0E+01	1.0E+04
Xe-122	7.6E−02	7.6E+01	7.6E+04
Xe-123	1.6E+00	1.6E+03	1.6E+06
Xe-125	6.0E−01		
Xe-127	7.0E+00		
Xe-129m	7.6E+01		
Xe-131m	2.2E+02		
Xe-133	5.2E+01		
Xe-133m	6.0E+01		
Xe-135	7.6E+00		
Xe-135m	4.2E+00		
Xe-138	9.9E−01		
Y-86	2.8E−02	2.8E+01	2.8E+04
Y-87	2.3E−02	2.3E+01	2.3E+04
Y-88	2.5E−04	2.5E−01	2.5E+02
Y-90	1.1E−01	1.1E+02	1.1E+05
Y-90m	4.3E−01	4.3E+02	4.3E+05
Y-91	1.8E−02	1.8E+01	1.8E+04
Y-91m	1.6E+00	1.6E+03	1.6E+06
Y-92	7.0E−01	7.0E+02	7.0E+05
Y-93	3.8E−01	3.8E+02	3.8E+05
Yb-169	5.5E−03	5.5E+00	5.5E+03
Yb-175	2.1E−01	2.1E+02	2.1E+05
Zn-62	8.6E−02	8.6E+01	8.6E+04
Zn-65	4.4E−04	4.4E−01	4.4E+02

Zn-69	2.7E+01	2.7E+04	2.7E+07
Zn-69m	2.0E−01	2.0E+02	2.0E+05
Zr-86	2.4E−02	2.4E+01	2.4E+04
Zr-88	2.7E−04	2.7E−01	2.7E+02
Zr-89	1.6E−02	1.6E+01	1.6E+04
Zr-93	2.8E−03	2.8E+00	2.8E+03
Zr-95	6.4E−04	6.4E−01	6.4E+02
Zr-97	4.6E−02	4.6E+01	4.6E+04

*Radionuclides boiling at 100 °C or less, or exposed to a temperature of 100 °C, must be considered a gas. Capsules containing radionuclides in liquid or powder form can be considered to be solids.

**Mo-99 contained in a generator to produce Technetium-99 can be assumed to be a solid.

3. Table of Concentration Levels

(a) Table 2 may be used for determining if facilities are in compliance with the standard.

1. The concentration table as applied to emission estimates can only be used if all releases are from point sources and concentrations have been measured at the stack or vent using EPA-approved methods, and the distance between each stack or vent and the nearest resident is greater than 3 times the diameter of the stack or vent. Procedures provided in Ref. (1) shall be used to determine compliance or exemption from reporting by use of Table 2.

2. The concentration table may be used to determine compliance with the standard based on environmental measurements provided these measurements are made in conformance with the requirements of § 61.107(b)(5).

4. NCRP Screening Model

The procedures described in Reference (4) may be used to determine doses to members of the general public from emissions of radionuclides to the atmosphere. Both the total dose from all radionuclides emitted, and the dose caused by radioactive iodine must be considered in accordance with the procedures in Ref. (1).

5. The COMPLY Computer Code

The COMPLY computer code may be used to determine compliance with subpart I. The compliance model in the COMPLY computer code may be used to determine the dose to members of the general public from emissions of radionuclides to the atmosphere. The EPA may add radionuclides to all or any part of COMPLY to cover radionuclides that may be used by the regulated community.

Table 2—Concentration Levels for Environmental Compliance

Radionuclide	**Concentration (Ci/m^3)**	**Radionuclide**	**Concentration (Ci/m^3)**
Ac-225	9.1E−14	Bi-207	1.0E−14
Ac-227	1.6E−16	Bi-210	2.9E−13
Ac-228	3.7E−12	Bi-212	5.6E−11
Ag-106	1.9E−09	Bi-213	7.1E−11
Ag-106m	1.2E−12	Bi-214	1.4E−10
Ag-108m	7.1E−15	Bk-249	5.6E−13
Ag-110m	9.1E−14	Bk-250	9.1E−11
Ag-111	2.5E−12	Br-77	4.2E−11
Al-26	4.8E−15	Br-80	1.4E−08
Am-241	1.9E−15	Br-80m	1.8E−09

Am-242	1.5E−11	Br-82	1.2E−11
Am-242m	2.0E−15	Br-83	1.2E−08
Am-243	1.8E−15	Br-84	6.7E−10
Am-244	4.0E−11	C-11	1.5E−09
Am-245	8.3E−09	C-14	1.0E−11
Am-246	1.2E−09	Ca-41	4.2E−13
Ar-37	1.6E−03	Ca-45	1.3E−12
Ar-41	1.7E−09	Ca-47	2.4E−12
As-72	2.4E−11	Cd-109	5.9E−13
As-73	1.1E−11	Cd-113	9.1E−15
As-74	2.2E−12	Cd-113m	1.7E−14
As-76	5.0E−11	Cd-115	1.6E−11
As-77	1.6E−10	Cd-115m	8.3E−13
At-211	1.1E−11	Cd-117	6.7E−11
Au-193	3.8E−10	Cd-117m	1.6E−10
Au-194	3.2E−11	Ce-139	2.6E−12
Au-195	3.1E−12	Ce-141	6.3E−12
Au-198	2.1E−11	Ce-143	3.0E−11
Au-199	4.8E−11	Ce-144	6.2E−13
Ba-131	7.1E−12	Cf-248	1.8E−14
Ba-133	5.9E−14	Cf-249	1.4E−15
Ba-133m	5.9E−11	Cf-250	3.2E−15
Ba-135m	1.8E−10	Cf-251	1.4E−15
Ba-139	5.6E−09	Cf-252	5.6E−15
Ba-140	1.3E−12	Cf-253	3.1E−13
Ba-141	1.4E−09	Cf-254	3.0E−15
Ba-142	1.3E−09	Cl-36	2.7E−15
Be-7	2.3E−11	Cl-38	7.7E−10
Be-10	1.6E−12	Cm-242	5.3E−14
Bi-206	2.3E−12	Cm-243	2.6E−15
Cm-244	3.3E−15	Eu-156	1.9E−12
Cm-245	1.8E−15	F-18	6.7E−10
Cm-246	1.9E−15	Fe-52	5.6E−11
Cm-247	1.9E−15	Fe-55	9.1E−12

Cm-248	5.0E−16	Fe-59	6.7E−13
Cm-249	3.7E−09	Fm-254	2.0E−11
Cm-250	9.1E−17	Fm-255	4.3E−12
Co-56	1.8E−13	Fr-223	3.3E−11
Co-57	1.3E−12	Ga-66	6.2E−11
Co-58	6.7E−13	Ga-67	7.1E−11
Co-58m	1.2E−10	Ga-68	9.1E−10
Co-60	1.7E−14	Ga-72	3.8E−11
Co-60m	.4.3E−09	Gd-152	5.0E−15
Co-61	4.5E−09	Gd-153	2.1E−12
Cr-49	1.1E−09	Gd-159	2.9E−10
Cr-51	3.1E−11	Ge-68	2.0E−13
Cs-129	1.4E−10	Ge-71	2.4E−10
Cs-131	3.3E−11	Ge-77	1.0E−10
Cs-132	4.8E−12	H-3	1.5E−09
Cs-134	2.7E−14	Hf-181	1.9E−12
Cs-134m	1.7E−10	Hg-193m	1.0E−10
Cs-135	4.0E−13	Hg-197	8.3E−11
Cs-136	5.3E−13	Hg-197m	1.1E−10
Cs-137	1.9E−14	Hg-203	1.0E−12
Cs-138	5.3E−10	Ho-166	7.1E−11
Cu-61	4.8E−10	Ho-166m	7.1E−15
Cu-64	5.3E−10	I-123	4.3E−10
Cu-67	5.0E−11	I-124	6.2E−13
Dy-157	5.0E−10	I-125	1.2E−13
Dy-165	6.7E−09	I-126	1.1E−13
Dy-166	1.1E−11	I-128	1.1E−08
Er-169	2.9E−11	I-129	9.1E−15
Er-171	4.0E−10	I-130	4.5E−11
Es-253	2.4E−13	I-131	2.1E−13
Es-254	2.0E−14	I-132	2.3E−10
Es-254m	1.8E−12	I-133	2.0E−11
Eu-152	2.0E−14	I-134	3.8E−10
Eu-152m	3.6E−10	I-135	1.2E−10

Eu-154	2.3E−14	In-111	3.6E−11
Eu-155	5.9E−13	In-113m	2.5E−09
In-114m	9.1E−13	Nb-95	2.2E−12
In-115	7.1E−14	Nb-95m	1.4E−11
In-115m	1.6E−09	Nb-96	2.4E−11
In-116m	4.2E−10	Nb-97	1.2E−09
In-117	1.6E−09	Nd-147	7.7E−12
In-117m	9.1E−11	Nd-149	7.1E−10
Ir-190	2.6E−12	Ni-56	1.7E−12
Ir-192	9.1E−13	Ni-57	1.8E−11
Ir-194	1.1E−10	Ni-59	1.5E−11
Ir-194m	1.7E−13	Ni-63	1.4E−11
K-40	2.7E−14	Ni-65	8.3E−10
K-42	2.6E−10	Np-235	2.5E−11
K-43	6.2E−11	Np-237	1.2E−15
K-44	5.9E−10	Np-238	1.4E−11
Kr-79	8.3E−09	Np-239	3.8E−11
Kr-81	2.1E−07	Np-240	7.7E−10
Kr-83m	2.3E−05	Np-240m	5.6E−09
Kr-85	1.0E−06	Os-185	1.0E−12
Kr-85m	1.3E−08	Os-191m	2.9E−10
Kr-87	2.4E−09	Os-191	1.1E−11
Kr-88	5.0E−10	Os-193	9.1E−11
La-140	1.2E−11	P-32	3.3E−13
La-141	7.7E−10	P-33	2.4E−12
La-142	2.7E−10	Pa-230	3.2E−13
Lu-177	2.4E−11	Pa-231	5.9E−16
Lu-177m	3.6E−13	Pa-233	4.8E−12
Mg-28	1.5E−11	Pa-234	1.1E−10
Mn-52	2.8E−12	Pb-203	6.2E−11
Mn-52m	6.2E−10	Pb-205	5.6E−12
Mn-53	1.5E−11	Pb-209	1.3E−08
Mn-54	2.8E−13	Pb-2I0	2.8E−15
Mn-56	2.9E−10	Pb-211	1.4E−10

Mo-93	1.1E−12	Pb-212	6.3E−12
Mo-99	1.4E−11	Pb-214	1.2E−10
Mo-101	1.0E−09	Pd-103	3.8E−11
Na-22	2.6E−14	Pd-107	3.1E−11
Na-24	2.6E−11	Pd-109	4.8E−10
Nb-90	2.6E−11	Pm-143	9.1E−13
Nb-93m	1.0E−11	Pm-144	1.3E−13
Nb-94	7.1E−15	Pm-145	6.2E−13
Pm-146	5.3E−14	Re-184m	3.7E−13
Pm-147	1.1E−11	Re-186	1.8E−11
Pm-148	5.0E−12	Re-187	2.6E−10
Pm-148m	6.7E−13	Re-188	1.7E−10
Pm-149	4.2E−11	Rh-103m	2.1E−07
Pm-151	7.1E−11	Rh-105	1.3E−10
Po-210	7.1E−15	Ru-97	6.7E−11
Pr-142	1.1E−10	Ru-103	2.6E−12
Pr-143	7.1E−12	Ru-105	2.8E−10
Pr-144	1.8E−08	Ru-106	3.4E−13
Pt-191	4.3E−11	S-35	1.3E−12
Pt-193	1.8E−11	Sb-117	2.4E−09
Pt-193m	4.8E−11	Sb-122	1.4E−11
Pt-195m	3.2E−11	Sb-124	5.3E−13
Pt-197	4.0E−10	Sb-125	1.6E−13
Pt-197m	2.6E−09	Sb-126	1.4E−12
Pu-236	5.9E−15	Sb-126m	9.1E−10
Pu-237	1.9E−11	Sb-127	7.1E−12
Pu-238	2.1E−15	Sb-129	7.7E−11
Pu-239	2.0E−15	Sc-44	1.7E−10
Pu-240	2.0E−15	Sc-46	4.2E−13
Pu-241	1.0E−13	Sc-47	3.8E−11
Pu-242	2.0E−15	Sc-48	9.1E−12
Pu-243	4.2E−09	Sc-49	1.2E−08
Pu-244	2.0E−15	Se-73	1.7E−10
Pu-245	2.1E−10	Se-75	1.7E−13

Pu-246	2.2E−12	Se-79	1.1E−13
Ra-223	4.2E−14	Si-31	5.6E−09
Ra-224	1.5E−13	Si-32	3.4E−14
Ra-225	5.0E−14	Sm-147	1.4E−14
Ra-226	3.3E−15	Sm-151	2.1E−11
Ra-228	5.9E−15	Sm-153	5.9E−11
Rb-81	5.0E−10	Sn-113	1.4E−12
Rb-83	3.4E−13	Sn-117m	5.6E−12
Rb-84	3.6E−13	Sn-119m	5.3E−12
Rb-86	5.6E−13	Sn-123	1.1E−12
Rb-87	1.6E−13	Sn-125	1.7E−12
Rb-88	2.1E−09	Sn-126	5.3E−15
Rb-89	7.1E−10	Sr-82	6.2E−13
Re-184	1.5E−12	Sr-85	1.8E−12
Sr-85m	1.6E−09	Th-232	6.2E−16
Sr-87m	1.4E−09	Th-234	2.2E−12
Sr-89	1.8E−12	Ti-44	6.2E−15
Sr-90	1.9E−14	Ti-45	4.8E−10
Sr-91	9.1E−11	Tl-200	4.5E−11
Sr-92	2.9E−10	Tl-201	1.0E−10
Ta-182	4.5E−13	Tl-202	5.0E−12
Tb-157	2.5E−12	Tl-204	1.2E−12
Tb-160	7.7E−13	Tm-170	3.3E−12
Tc-95	1.0E−10	Tm-171	2.6E−11
Tc-95m	1.4E−12	U-230	1.5E−14
Tc-96	5.6E−12	U-231	4.2E−11
Tc-96m	6.7E−10	U-232	1.3E−15
Tc-97	.7.1E−13	U-233	7.1E−15
Tc-97m	7.1E−12	U-234	7.7E−15
Tc-98	6.7E−15	U-235	7.1E−15
Tc-99	1.4E−13	U-236	7.7E−15
Tc-99m	1.7E−09	U-237	1.0E−11
Tc-101	4.5E−09	U-238	8.3E−15
Te-121	1.0E−12	U-239	4.3E−09

Te-121m	1.2E−13	U-240	1.3E−10
Te-123	1.4E−13	V-48	1.0E−12
Te-123m	2.0E−13	V-49	1.6E−10
Te-125m	3.6E−13	W-181	6.7E−12
Te-127	1.0E−09	W-185	2.6E−12
Te-127m	1.5E−13	W-187	7.7E−11
Te-129	7.7E−09	W-188	5.3E−13
Te-129m	1.4E−13	Xe-122	9.1E−11
Te-131	9.1E−11	Xe-123	1.6E−09
Te-131m	1.0E−12	Xe-125	1.1E−11
Te-132	7.1E−13	Xe-127	8.3E−09
Te-133	9.1E−10	Xe-129m	9.1E−08
Te-133m	2.2E−10	Xe-131m	2.6E−07
Te-134	5.3E−10	Xe-133	6.2E−08
Th-226	3.4E−11	Xe-133m	7.1E−08
Th-227	3.8E−14	Xe-135	9.1E−09
Th-228	3.1E−15	Xe-135m	5.0E−09
Th-229	5.3E−16	Xe-138	1.2E−09
Th-230	3.4E−15	Y-86	3.0E−11
Th-231	2.9E−10	Y-87	1.7E−11
Y-88	2.7E−13	Zn-65	9.1E−14
Y-90	1.3E−11	Zn-69	3.2E−08
Y-90m	1.9E−10	Zn-69m	1.7E−10
Y-91	2.1E−12	Zr-86	2.4E−11
Y-91m	1.3E−09	Zr-88	3.1E−13
Y-92	8.3E−10	Zr-89	1.3E−11
Y-93	2.9E−10	Zr-93	2.6E−12
Yb-169	3.7E−12	Zr-95	6.7E−13
Yb-175	4.3E−11	Zr-97	3.8E−11
Zn-62	9.1E−11		

6. References

(1) Environmental Protection Agency, “A Guide for Determining Compliance with the Clean Air Act Standards for Radionuclides Emissions from NRC-Licensed and Non-DOE Federal Facilities”, EPA 520/1-89-002, October 1989.
(2) Environmental Protection Agency, “User's Guide for the COMPLY Code”, EPA 520/1-89-003, October 1989.
(3) Environmental Protection Agency, “Background Information Document: Procedures Approved for

Demonstrating Compliance with 40 CFR Part 61, Subpart I", EPA 520/1-89-001, January 1989.

(4) National Council on Radiation Protection and Measurement, "Screening Techniques for Determining Compliance with Environmental Standards" NCRP Commentary No. 3, Revision of January 1989 with addendum of October, 1989.

[54 FR 51711, Dec. 15, 1989]

Indiana Department of Environmental Management
Office of Air Quality

Attachment H to a Part 70 Operating Permit

Source Background and Description

Source Name:	Ohio Valley Resources, LLC
Source Location:	300-400 East CR 350 North, Rockport, Indiana 47635
County:	Spencer
SIC Code:	2873
Permit No.:	T 147-32322-00062
Permit Reviewer:	David Matousek

40 CFR 63, Subpart DDDDD

Subpart DDDDD — National Emission Standards for Hazardous Air Pollutants for Major Sources: Industrial, Commercial, and Institutional Boilers and Process Heaters

Source: 76 FR 15664, Mar. 21, 2011, unless otherwise noted.

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What This Subpart Covers

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§ 63.7480 What is the purpose of this subpart?

This subpart establishes national emission limitations and work practice standards for hazardous air pollutants (HAP) emitted from industrial, commercial, and institutional boilers and process heaters located at major sources of HAP. This subpart also establishes requirements to demonstrate initial and continuous compliance with the emission limitations and work practice standards.

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§ 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, except as specified in § 63.7491. For purposes of this subpart, a major source of HAP is as defined in § 63.2, except that for oil and natural gas production facilities, a major source of HAP is as defined in § 63.7575.

[78 FR 7162, Jan. 31, 2013]

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§ 63.7490 What is the affected source of this subpart?

(a) This subpart applies to new, reconstructed, and existing affected sources as described in paragraphs (a)(1) and (2) of this section.

(1) The affected source of this subpart is the collection at a major source of all existing industrial, commercial, and institutional boilers and process heaters within a subcategory 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, as defined in § 63.7575, located at a major source.

(b) A boiler or process heater is new if you commence construction of the boiler or process heater after June 4, 2010, 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 June 4, 2010, 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.

(e) An existing electric utility steam generating unit (EGU) that meets the applicability requirements of this subpart after the effective date of this final rule due to a change (e.g., fuel switch) is considered to be an existing source under this subpart.

[76 FR 15664, Mar. 21, 2011, as amended at 78 FR 7162, Jan. 31, 2013]

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§ 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 (n) of this section are not subject to this subpart.

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

(b) A recovery boiler or furnace covered by subpart MM of this part.

(c) A boiler or process heater that is used specifically for research and development, including test steam boilers used to provide steam for testing the propulsion systems on military vessels. This does not include units that provide heat or steam to a process at a research and development facility.

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

(e) A refining kettle covered by subpart X of this part.

(f) An ethylene cracking furnace covered by subpart YY of this part.

(g) Blast furnace stoves as described in EPA-453/R-01-005 (incorporated by reference, see § 63.14).

(h) Any boiler or process heater that is part of the affected source subject to another subpart of this part, such as boilers and process heaters used as control devices to comply with subparts JJJ, OOO, PPP, and U of this part.

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

(j) Temporary boilers as defined in this subpart.

(k) Blast furnace gas fuel-fired boilers and process heaters as defined in this subpart.

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

(m) A unit that burns hazardous waste covered by Subpart EEE of this part. A unit that is exempt from Subpart EEE as specified in § 63.1200(b) is not covered by Subpart EEE.

[76 FR 15664, Mar. 21, 2011, as amended at 78 FR 7162, Jan. 31, 2013]

EDITORIAL NOTE: At 78 FR 7162, Jan. 31, 2013, § 63.7491 was amended by revising paragraph (n). However, there is no paragraph (n) to revise.

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§ 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 January 31, 2013, 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 January 31, 2016, except as provided in § 63.6(i).

(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 source must be in compliance with this subpart upon startup.
(2) Any existing boiler or process heater at the existing source must be in compliance with this subpart within 3 years after the source 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.

(e) If you own or operate an industrial, commercial, or institutional boiler or process heater and would be subject to this subpart except for the exemption in § 63.7491(l) for commercial and industrial solid waste incineration units covered by part 60, subpart CCCC or subpart DDDD, and you cease combusting solid waste, you must be in compliance with this subpart on the effective date of the switch from waste to fuel.

(f) If you own or operate an existing EGU that becomes subject to this subpart after January 31, 2013, you must be in compliance with the applicable existing source provisions of this subpart on the effective date such unit becomes subject to this subpart.

(g) If you own or operate an existing industrial, commercial, or institutional boiler or process heater and would be subject to this subpart except for a exemption in § 63.7491(i) that becomes subject to this subpart after January 31, 2013, you must be in compliance with the applicable existing source provisions of this subpart within 3 years after such unit becomes subject to this subpart.

[76 FR 15664, Mar. 21, 2011, as amended at 78 FR 7162, Jan. 31, 2013]
EDITORIAL NOTE: At 78 FR 7162, Jan. 31, 2013, § 63.7495 was amended by adding paragraph (e). However, there is already a paragraph (e).

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Emission Limitations and Work Practice Standards

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§ 63.7499 What are the subcategories of boilers and process heaters?

The subcategories of boilers and process heaters, as defined in § 63.7575 are:

(a) Pulverized coal/solid fossil fuel units.

(b) Stokers designed to burn coal/solid fossil fuel.

(c) Fluidized bed units designed to burn coal/solid fossil fuel.

(d) Stokers/sloped grate/other units designed to burn kiln dried biomass/bio-based solid.

(e) Fluidized bed units designed to burn biomass/bio-based solid.

(f) Suspension burners designed to burn biomass/bio-based solid.

(g) Fuel cells designed to burn biomass/bio-based solid.

(h) Hybrid suspension/grate burners designed to burn wet biomass/bio-based solid.

(i) Stokers/sloped grate/other units designed to burn wet biomass/bio-based solid.

(j) Dutch ovens/pile burners designed to burn biomass/bio-based solid.

(k) Units designed to burn liquid fuel that are non-continental units.

(l) Units designed to burn gas 1 fuels.

(m) Units designed to burn gas 2 (other) gases.

(n) Metal process furnaces.

(o) Limited-use boilers and process heaters.

(p) Units designed to burn solid fuel.

(q) Units designed to burn liquid fuel.

(r) Units designed to burn coal/solid fossil fuel.

(s) Fluidized bed units with an integrated fluidized bed heat exchanger designed to burn coal/solid fossil fuel.

(t) Units designed to burn heavy liquid fuel.

(u) Units designed to burn light liquid fuel.

[76 FR 15664, Mar. 21, 2011, as amended at 78 FR 7162, Jan. 31, 2013]

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§ 63.7500 What emission limitations, work practice standards, and operating limits must I meet?

(a) You must meet the requirements in paragraphs (a)(1) through (3) of this section, except as provided in paragraphs (b), through (e) of this section. You must meet these requirements at all times the affected unit is operating, except as provided in paragraph (f) of this section.

(1) You must meet each emission limit and work practice standard in Tables 1 through 3, and 11 through 13 to this subpart that applies to your boiler or process heater, for each boiler or process heater at your source, except as provided under § 63.7522. The output-based emission limits, in units of pounds per million Btu of steam output, in Tables 1 or 2 to this subpart are an alternative applicable only to boilers and process heaters that generate steam. The output-based emission limits, in units of pounds per megawatt-hour, in Tables 1 or 2 to this subpart are an alternative applicable only to boilers that generate electricity. If you operate a new boiler or process heater, you can choose to comply with alternative limits as discussed in paragraphs (a)(1)(i) through (a)(1)(iii) of this section, but on or after January 31, 2016, you must comply with the emission limits in Table 1 to this subpart.

(i) If your boiler or process heater commenced construction or reconstruction after June 4, 2010 and before May 20, 2011, you may comply with the emission limits in Table 1 or 11 to this subpart until January 31, 2016.

(ii) If your boiler or process heater commenced construction or reconstruction after May 20, 2011 and before December 23, 2011, you may comply with the emission limits in Table 1 or 12 to this subpart until January 31, 2016.

(iii) If your boiler or process heater commenced construction or reconstruction after December 23, 2011 and before January 31, 2013, you may comply with the emission limits in Table 1 or 13 to this subpart until January 31, 2016.

(2) You must meet each operating limit in Table 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 Table 4 to this subpart, or you wish to establish and monitor an alternative operating limit or an alternative monitoring parameter, you must apply to the EPA Administrator for approval of alternative monitoring under § 63.8(f).

(3) At all times, you must operate and maintain any affected source (as defined in § 63.7490), including associated air pollution control equipment and monitoring equipment, in a manner consistent with safety and good air pollution control practices for minimizing emissions. Determination of whether such operation and maintenance procedures are being used will be based on information available to the Administrator that may include, but is not limited to, monitoring results, review of operation and maintenance procedures, review of operation and maintenance records, and inspection of the source.

(b) As provided in § 63.6(g), EPA may approve use of an alternative to the work practice standards in this section.

(c) Limited-use boilers and process heaters must complete a tune-up every 5 years as specified in § 63.7540. They are not subject to the emission limits in Tables 1 and 2 or 11 through 13 to this subpart, the annual tune-up, or the energy assessment requirements in Table 3 to this subpart, or the operating limits in Table 4 to this subpart.

(d) Boilers and process heaters with a heat input capacity of less than or equal to 5 million Btu per hour in the units designed to burn gas 2 (other) fuels subcategory or units designed to burn light liquid fuels subcategory must complete a tune-up every 5 years as specified in § 63.7540.

(e) Boilers and process heaters in the units designed to burn gas 1 fuels subcategory with a heat input capacity of less than or equal to 5 million Btu per hour must complete a tune-up every 5 years as specified in § 63.7540. Boilers and process heaters in the units designed to burn gas 1 fuels subcategory with a heat input capacity greater than 5 million Btu per hour and less than 10 million Btu per hour must complete a tune-up every 2 years as specified in § 63.7540. Boilers and process heaters in the units designed to burn gas 1 fuels subcategory are not subject to the emission limits in Tables 1 and 2 or 11 through 13 to this subpart, or the operating limits in Table 4 to this subpart.

(f) These standards apply at all times the affected unit is operating, except during periods of startup and shutdown during which time you must comply only with Table 3 to this subpart.

[76 FR 15664, Mar. 21, 2011, as amended at 78 FR 7162, Jan. 31, 2013]

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§ 63.7501 Affirmative Defense for Violation of Emission Standards During Malfunction.

In response to an action to enforce the standards set forth in § 63.7500 you may assert an affirmative defense to a claim for civil penalties for violations of such standards that are caused by malfunction, as defined at § 63.2. Appropriate penalties may be assessed if you fail to meet your burden of proving all of the requirements in the affirmative defense. The affirmative defense shall not be available for claims for injunctive relief.

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

(1) The violation:

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

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

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

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

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

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

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

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

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

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

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

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

(b) *Report.* The owner or operator seeking to assert an affirmative defense shall submit a written report to the Administrator with all necessary supporting documentation, that it has met the requirements set forth in § 63.7500 of this section. This affirmative defense report shall be included in the first periodic compliance, deviation report or excess emission report otherwise required after the initial occurrence of the violation of the relevant standard (which may be the end of any applicable averaging period). If such compliance, deviation report or excess emission report is due less than 45 days after the initial occurrence of the violation, the affirmative defense report may be included in the second compliance, deviation report or excess emission report due after the initial occurrence of the violation of the relevant standard.

[78 FR 7163, Jan. 31, 2013]

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General Compliance Requirements

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§ 63.7505 What are my general requirements for complying with this subpart?

(a) You must be in compliance with the emission limits, work practice standards, and operating limits in this subpart. These limits apply to you at all times the affected unit is operating except for the periods noted in § 63.7500(f).

(b) [Reserved]

(c) You must demonstrate compliance with all applicable emission limits using performance stack testing, fuel analysis, or continuous monitoring systems (CMS), including a continuous emission monitoring system (CEMS), continuous opacity monitoring system (COMS), continuous parameter monitoring system (CPMS), or particulate matter continuous parameter monitoring system (PM CPMS), where applicable. You may demonstrate compliance with the applicable emission limit for hydrogen chloride (HCl), mercury, or total selected metals (TSM) using fuel analysis if the emission rate calculated according to § 63.7530(c) is less than the applicable emission limit. (For gaseous fuels, you may not use fuel analyses to comply with the TSM alternative standard or the HCl standard.) Otherwise, you must demonstrate compliance for HCl, mercury, or TSM using performance testing, if subject to an applicable emission limit listed in Tables 1, 2, or 11 through 13 to this subpart.

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

(1) For each CMS required in this section (including CEMS, COMS, or CPMS), you must develop, and submit to the Administrator for approval upon request, a site-specific monitoring plan that addresses design, data collection, and the quality assurance and quality control elements outlined in § 63.8(d) and the elements described in paragraphs (d)(1)(i) through (iii) of this section. You must submit this site-specific monitoring plan, if requested, at least 60 days before your initial performance evaluation of your CMS. This requirement to develop and submit a site specific monitoring plan does not apply to affected sources with existing CEMS or COMS operated according to the performance specifications under appendix B to part 60 of this chapter and that meet the requirements of § 63.7525. Using the process described in § 63.8(f)(4), you may request approval of alternative monitoring system quality assurance and quality control procedures in place of those specified in this paragraph and, if approved, include the alternatives in your site-specific monitoring plan.

(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, accuracy audits, analytical drift).

(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)(ii), (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) (as applicable in Table 10 to this subpart), (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.

[76 FR 15664, Mar. 21, 2011, as amended at 78 FR 7164, Jan. 31, 2013]

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Testing, Fuel Analyses, and Initial Compliance Requirements

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§ 63.7510 What are my initial compliance requirements and by what date must I conduct them?

(a) For each boiler or process heater that is required or that you elect to demonstrate compliance with any of the applicable emission limits in Tables 1 or 2 or 11 through 13 of this subpart through performance testing, your initial compliance requirements include all the following:

(1) Conduct performance tests according to § 63.7520 and Table 5 to this subpart.

(2) 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, except as specified in paragraphs (a)(2)(i) through (iii) of this section.

(i) For each boiler or process heater that burns a single type of fuel, you are not required 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. For purposes of this subpart, units that use a supplemental fuel only for startup, unit shutdown, and transient flame stability purposes still qualify as units that burn a single type of fuel, and the supplemental fuel is not subject to the fuel analysis requirements under § 63.7521 and Table 6 to this subpart.

(ii) When natural gas, refinery gas, or other gas 1 fuels are co-fired with other fuels, you are not required to conduct a fuel analysis of those fuels according to § 63.7521 and Table 6 to this subpart. If gaseous fuels other than natural gas, refinery gas, or other gas 1 fuels are co-fired with other fuels and those gaseous fuels are subject to another subpart of this part, part 60, part 61, or part 65, you are not required to conduct a fuel analysis of those fuels according to § 63.7521 and Table 6 to this subpart.

(iii) You are not required to conduct a chlorine fuel analysis for any gaseous fuels. You must conduct a fuel analysis for mercury on gaseous fuels unless the fuel is exempted in paragraphs (a)(2)(i) and (ii) of this section.

(3) Establish operating limits according to § 63.7530 and Table 7 to this subpart.

(4) Conduct CMS performance evaluations according to § 63.7525.

(b) For each boiler or process heater that you elect to demonstrate compliance with the applicable emission limits in Tables 1 or 2 or 11 through 13 to this subpart 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. The fuels described in paragraph (a)(2)(i) and (ii) of this section are exempt from these fuel analysis and operating limit requirements. The fuels described in paragraph (a)(2)(ii) of this section are exempt from the chloride fuel analysis and operating limit requirements. Boilers and process heaters that use a CEMS for mercury or HCl are exempt from the performance testing and operating limit requirements specified in paragraph (a) of this section for the HAP for which CEMS are used.

(c) If your boiler or process heater is subject to a carbon monoxide (CO) limit, your initial compliance demonstration for CO is to conduct a performance test for CO according to Table 5 to this subpart or conduct a performance evaluation of your continuous CO monitor, if applicable, according to § 63.7525(a). Boilers and process heaters that use a CO CEMS to comply with the applicable alternative CO CEMS emission standard listed in Tables 12, or 11 through 13 to this subpart, as specified in § 63.7525(a), are exempt from the initial CO performance testing and oxygen concentration operating limit requirements specified in paragraph (a) of this section.

(d) If your boiler or process heater is subject to a PM limit, your initial compliance demonstration for PM is to conduct a performance test in accordance with § 63.7520 and Table 5 to this subpart.

(e) For existing affected sources (as defined in § 63.7490), you must complete the initial compliance demonstration, as specified in paragraphs (a) through (d) of this section, 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, except as specified in paragraph (j) of this section. You must complete an initial tune-up by following the procedures described in § 63.7540(a)(10)(i) through (vi) no later than the compliance date specified in § 63.7495, except as specified in paragraph (j) of this section. You must complete the one-time energy assessment specified in Table 3 to this subpart no later than the compliance date specified in § 63.7495, except as specified in paragraph (j) of this section.

(f) For new or reconstructed affected sources (as defined in § 63.7490), you must complete the initial compliance demonstration with the emission limits no later than July 30, 2013 or within 180 days after startup of the source, whichever is later. If you are demonstrating compliance with an emission limit in Tables 11 through 13 to this subpart that is less stringent (that is, higher) than the applicable emission limit in Table 1 to this subpart, you must demonstrate compliance with the applicable emission limit in Table 1 no later than July 29, 2016.

(g) For new or reconstructed affected sources (as defined in § 63.7490), you must demonstrate initial compliance with the applicable work practice standards in Table 3 to this subpart within the applicable annual, biennial, or 5-year schedule as specified in § 63.7540(a) following the initial compliance date specified in § 63.7495(a). Thereafter, you are required to complete the applicable annual, biennial, or 5-year tune-up as specified in § 63.7540(a).

(h) For affected sources (as defined in § 63.7490) that ceased burning solid waste consistent with § 63.7495(e) and for which the initial compliance date has passed, you must demonstrate compliance within 60 days of the effective date of the waste-to-fuel switch. If you have not conducted your compliance demonstration for this subpart within the previous 12 months, you must complete all compliance demonstrations for this subpart before you commence or recommence combustion of solid waste.

(i) For an existing EGU that becomes subject after January 31, 2013, you must demonstrate compliance within 180 days after becoming an affected source.

(j) For existing affected sources (as defined in § 63.7490) that have not operated between the effective date of the rule and the compliance date that is specified for your source in § 63.7495, you must complete the initial compliance demonstration, if subject to the emission limits in Table 2 to this subpart, as specified in paragraphs (a) through (d) of this section, no later than 180 days after the re-start of the affected source and according to the applicable provisions in § 63.7(a)(2) as cited in Table 10 to this subpart. You must complete an initial tune-up by following the procedures described in § 63.7540(a)(10)(i) through (vi) no later than 30 days after the re-start of the affected source and, if applicable, complete the one-time energy assessment specified in Table 3 to this subpart, no later than the compliance date specified in § 63.7495.

[78 FR 7164, Jan. 31, 2013]

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§ 63.7515 When must I conduct subsequent performance tests, fuel analyses, or tune-ups?

(a) You must conduct all applicable performance tests according to § 63.7520 on an annual basis, except as specified in paragraphs (b) through (e), (g), and (h) of this section. Annual performance tests must be completed no more than 13 months after the previous performance test, except as specified in paragraphs (b) through (e), (g), and (h) of this section.

(b) If your performance tests for a given pollutant for at least 2 consecutive years show that your emissions are at or below 75 percent of the emission limit (or, in limited instances as specified in Tables 1 and 2 or 11 through 13 to this subpart, at or below the emission limit) for the pollutant, and if there are no changes in the operation of the individual boiler or process heater or air pollution control equipment that could increase emissions, you may choose to conduct performance tests for the pollutant every third year. Each such performance test must be conducted no more than 37 months after the previous performance test. If you elect to demonstrate compliance using emission averaging under § 63.7522, you must continue to conduct performance tests annually. The requirement to test at maximum chloride input level is waived unless the stack test is conducted for HCl. The requirement to test at maximum mercury input level is waived unless the stack test is conducted for mercury. The requirement to test at maximum TSM input level is waived unless the stack test is conducted for TSM.

(c) If a performance test shows emissions exceeded the emission limit or 75 percent of the emission limit (as specified in Tables 1 and 2 or 11 through 13 to this subpart) for a pollutant, you must conduct annual performance tests for that pollutant until all performance tests over a consecutive 2-year period meet the required level (at or below 75 percent of the emission limit, as specified in Tables 1 and 2 or 11 through 13 to this subpart).

(d) If you are required to meet an applicable tune-up work practice standard, you must conduct an annual, biennial, or 5-year performance tune-up according to § 63.7540(a)(10), (11), or (12), respectively. Each annual tune-up specified in § 63.7540(a)(10) must be no more than 13 months after the previous tune-up. Each biennial tune-up specified in § 63.7540(a)(11) must be conducted no more than 25 months after the previous tune-up. Each 5-year tune-up specified in § 63.7540(a)(12) must be conducted no more than 61 months after the previous tune-up. For a new or reconstructed affected source (as defined in § 63.7490), the first annual, biennial, or 5-year tune-up must be no later than 13 months, 25 months, or 61 months, respectively, after the initial startup of the new or reconstructed affected source.

(e) If you demonstrate compliance with the mercury, HCl, or TSM based on fuel analysis, you must conduct a monthly fuel analysis according to § 63.7521 for each type of fuel burned that is subject to an emission limit in Tables 1, 2, or 11 through 13 to this subpart. You may comply with this monthly requirement by completing the fuel analysis any time within the calendar month as long as the analysis is separated from the previous analysis by at least 14 calendar days. 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. If each of 12 consecutive monthly fuel analyses demonstrates 75 percent or less of the compliance level, you may decrease the fuel analysis frequency to quarterly for that fuel. If any quarterly sample exceeds 75 percent of the compliance level or you begin burning a new type of fuel, you must return to monthly monitoring for that fuel, until 12 months of fuel analyses are again less than 75 percent of the compliance level.

(f) You must report the results of performance tests and the associated fuel analyses within 60 days after the completion of the performance tests. This report must also verify that the operating limits for each boiler or process heater have not changed or provide documentation of revised operating limits established according to § 63.7530 and Table 7 to this subpart, as applicable. The reports for all subsequent performance tests must include all applicable information required in § 63.7550.

(g) For affected sources (as defined in § 63.7490) that have not operated since the previous compliance demonstration and more than one year has passed since the previous compliance demonstration, you must complete the subsequent compliance demonstration, if subject to the emission limits in Tables 1, 2, or 11 through 13 to this subpart, no later than 180 days after the re-start of the affected source and according to the applicable provisions in § 63.7(a)(2) as cited in Table 10 to this subpart. You must complete a subsequent tune-up by following the procedures described in § 63.7540(a)(10)(i) through (vi) and the schedule described in § 63.7540(a)(13) for units that are not operating at the time of their scheduled tune-up.

(h) If your affected boiler or process heater is in the unit designed to burn light liquid subcategory and you combust ultra low sulfur liquid fuel, you do not need to conduct further performance tests if the pollutants measured during the initial compliance performance tests meet the emission limits in Tables 1 or 2 of this subpart providing you demonstrate ongoing compliance with the emissions limits by monitoring and recording the type of fuel combusted on a monthly basis. If you intend to use a fuel other than ultra low sulfur liquid fuel, natural gas, refinery gas, or other gas 1 fuel, you must conduct new performance tests within 60 days of burning the new fuel type.

(i) If you operate a CO CEMS that meets the Performance Specifications outlined in § 63.7525(a)(3) of this subpart to demonstrate compliance with the applicable alternative CO CEMS emission standard listed in Tables 1, 2, or 11 through 13 to this subpart, you are not required to conduct CO performance tests and are not subject to the oxygen concentration operating limit requirement specified in § 63.7510(a).

[78 FR 7165, Jan. 31, 2013]

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§ 63.7520 What stack 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 stack test plan according to the requirements in § 63.7(c). You shall conduct all performance tests under such conditions as the Administrator specifies to you based on the representative performance of each boiler or process heater for the period being tested. Upon request, you shall make available to the Administrator such records as may be necessary to determine the conditions of the performance tests.

(b) You must conduct each performance test according to the requirements in Table 5 to this subpart.

(c) 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 representative operating load conditions while burning the type of fuel or mixture of fuels that has the highest content of chlorine and mercury, and TSM if you are opting to comply with the TSM alternative standard and you must demonstrate initial compliance and establish your operating limits based on these performance tests. These requirements could result in the need to conduct more than one performance test. Following each performance test and until the next performance test, you must comply with the operating limit for operating load conditions specified in Table 4 to this subpart.

(d) You must conduct a minimum of three separate test runs for each performance test required in this section, as specified in § 63.7(e)(3). Each test run must comply with the minimum applicable sampling times or volumes specified in Tables 1 and 2 or 11 through 13 to this subpart.

(e) To determine compliance with the emission limits, you must use the F-Factor methodology and equations in sections 12.2 and 12.3 of EPA Method 19 at 40 CFR part 60, appendix A-7 of this chapter to convert the measured particulate matter (PM) concentrations, the measured HCl concentrations, the measured mercury concentrations, and the measured TSM concentrations that result from the performance test to pounds per million Btu heat input emission rates.

(f) Except for a 30-day rolling average based on CEMS (or sorbent trap monitoring system) data, if measurement results for any pollutant are reported as below the method detection level (e.g., laboratory analytical results for one or more sample components are below the method defined analytical detection level), you must use the method detection level as the measured emissions level for that pollutant in calculating compliance. The measured result for a multiple component analysis (e.g., analytical values for multiple Method 29 fractions both for individual HAP metals and for total HAP metals) may include a combination of method detection level data and analytical data reported above the method detection level.

[76 FR 15664, Mar. 21, 2011, as amended at 78 FR 7166, Jan. 31, 2013]

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§ 63.7521 What fuel analyses, fuel specification, and procedures must I use?

(a) For solid and liquid fuels, you must conduct fuel analyses for chloride and mercury according to the procedures in paragraphs (b) through (e) of this section and Table 6 to this subpart, as applicable. For solid fuels and liquid fuels, you must also conduct fuel analyses for TSM if you are opting to comply with the TSM alternative standard. For gas 2 (other) fuels, you must conduct fuel analyses for mercury according to the procedures in paragraphs (b) through (e) of this section and Table 6 to this subpart, as applicable. (For gaseous fuels, you may not use fuel analyses to comply with the TSM alternative standard or the HCl standard.) For purposes of complying with this section, a fuel gas system that consists of multiple gaseous fuels collected and mixed with each other is considered a single fuel type and sampling and analysis is only required on the combined fuel gas system that will feed the boiler or process heater. Sampling and analysis of the individual gaseous streams prior to combining is not required. You are not required to conduct fuel analyses for fuels used for only startup, unit shutdown, and transient flame stability purposes. You are required to conduct fuel analyses only for fuels and units that are subject to emission limits for mercury, HCl, or TSM in Tables 1 and 2 or 11 through 13 to this subpart. Gaseous and liquid fuels are exempt from the sampling requirements in paragraphs (c) and (d) of this section and Table 6 to this subpart.

(b) You must develop a site-specific fuel monitoring plan according to the following procedures and requirements in paragraphs (b)(1) and (2) of this section, if you are required to conduct fuel analyses as specified in § 63.7510.

(1) If you intend to use an alternative analytical method other than those required by Table 6 to this subpart, you must submit the fuel analysis plan to the Administrator for review and approval no later than 60 days before the date that you intend to conduct the initial compliance demonstration described in § 63.7510.

(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 anticipated fuel type, the notification of whether you or a fuel supplier will be conducting the fuel analysis.

(iii) For each anticipated 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 anticipated fuel type, the analytical methods from Table 6, with the expected minimum detection levels, to be used for the measurement of 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 you are proposing to use. Methods in Table 6 shall be used until the requested alternative is approved.

(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, or the methods listed in Table 6 to this subpart, or use an automated sampling mechanism that provides representative composite fuel samples for each fuel type that includes both coarse and fine material.

(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. You must collect all the material (fines and coarse) in the full cross-section. You must transfer the sample to a clean plastic bag.

(ii) Each composite sample will consist of a minimum of three samples collected at approximately equal one-hour intervals during the testing period for sampling during performance stack testing. For monthly sampling, each composite sample shall be collected at approximately equal 10-day intervals during the month.

(2) If sampling from a fuel pile or truck, you must collect fuel samples according to paragraphs (c)(2)(i) through (iii) of this section.

(i) For each composite sample, you must select a minimum of five sampling locations uniformly spaced over the surface of the pile.

(ii) At each sampling site, you must dig into the pile to a uniform depth of approximately 18 inches. You must insert a clean shovel into the hole and withdraw a sample, making sure that large pieces do not fall off during sampling; use the same shovel to collect all samples.

(iii) You must transfer all samples to a clean plastic bag for further processing.

(d) You must prepare each composite sample according to the procedures in paragraphs (d)(1) through (7) of this section.

(1) You must thoroughly mix and pour the entire composite sample over a clean plastic sheet.

(2) You must break large sample pieces (e.g., larger than 3 inches) into smaller sizes.

(3) You must make a pie shape with the entire composite sample and subdivide it into four equal parts.

(4) You must separate one of the quarter samples as the first subset.

(5) If this subset is too large for grinding, you must repeat the procedure in paragraph (d)(3) of this section with the quarter sample and obtain a one-quarter subset from this sample.

(6) You must grind the sample in a mill.

(7) You must 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) You must determine the concentration of pollutants in the fuel (mercury and/or chlorine and/or TSM) 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, for use in Equations 7, 8, and 9 of this subpart.

(f) To demonstrate that a gaseous fuel other than natural gas or refinery gas qualifies as an other gas 1 fuel, as defined in § 63.7575, you must conduct a fuel specification analyses for mercury according to the procedures in paragraphs (g) through (i) of this section and Table 6 to this subpart, as applicable, except as specified in paragraph (f)(1) through (4) of this section.

(1) You are not required to conduct the fuel specification analyses in paragraphs (g) through (i) of this section for natural gas or refinery gas.

(2) You are not required to conduct the fuel specification analyses in paragraphs (g) through (i) of this section for gaseous fuels that are subject to another subpart of this part, part 60, part 61, or part 65.

(3) You are not required to conduct the fuel specification analyses in paragraphs (g) through (i) of this section on gaseous fuels for units that are complying with the limits for units designed to burn gas 2 (other) fuels.

(4) You are not required to conduct the fuel specification analyses in paragraphs (g) through (i) of this section for gas streams directly derived from natural gas at natural gas production sites or natural gas plants.

(g) You must develop and submit a site-specific fuel analysis plan for other gas 1 fuels to the EPA Administrator for review and approval according to the following procedures and requirements in paragraphs (g)(1) and (2) of this section.

(1) If you intend to use an alternative analytical method other than those required by Table 6 to this subpart, you must submit the fuel analysis plan to the Administrator for review and approval no later than 60 days before the date that you intend to conduct the initial compliance demonstration described in § 63.7510.

(2) You must include the information contained in paragraphs (g)(2)(i) through (vi) of this section in your fuel analysis plan.

(i) The identification of all gaseous fuel types other than those exempted from fuel specification analysis under (f)(1) through (3) of this section anticipated to be burned in each boiler or process heater.

(ii) For each anticipated fuel type, the notification of whether you or a fuel supplier will be conducting the fuel specification analysis.

(iii) For each anticipated fuel type, a detailed description of the sample location and specific procedures to be used for collecting and preparing the samples if your procedures are different from the sampling methods contained in Table 6 to this subpart. 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. If multiple boilers or process heaters are fueled by a common fuel stream it is permissible to conduct a single gas specification at the common point of gas distribution.

(iv) For each anticipated fuel type, the analytical methods from Table 6 to this subpart, with the expected minimum detection levels, to be used for the measurement of 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 you are proposing to use. Methods in Table 6 to this subpart shall be used until the requested alternative is approved.

(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.

(h) You must obtain a single fuel sample for each fuel type according to the sampling procedures listed in Table 6 for fuel specification of gaseous fuels.

(i) You must determine the concentration in the fuel of mercury, in units of microgram per cubic meter, dry basis, of each sample for each other gas 1 fuel type according to the procedures in Table 6 to this subpart.

[78 FR 7167, Jan. 31, 2013]

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§ 63.7522 Can I use emissions averaging to comply with this subpart?

(a) As an alternative to meeting the requirements of § 63.7500 for PM (or TSM), HCl, or mercury on a boiler or process heater-specific basis, if you have more than one existing boiler or process heater in any subcategories located at your facility, you may demonstrate compliance by emissions averaging, if your averaged emissions are not more than 90 percent of the applicable emission limit, according to the procedures in this section. You may not include new boilers or process heaters in an emissions average.

(b) For a group of two or more existing boilers or process heaters in the same subcategory that each vent to a separate stack, you may average PM (or TSM), HCl, or mercury emissions among existing units to demonstrate compliance with the limits in Table 2 to this subpart as specified in paragraph (b)(1) through (3) of this section, if you satisfy the requirements in paragraphs (c) through (g) of this section.

(1) You may average units using a CEMS or PM CPMS for demonstrating compliance.

(2) For mercury and HCl, averaging is allowed as follows:

(i) You may average among units in any of the solid fuel subcategories.

(ii) You may average among units in any of the liquid fuel subcategories.

(iii) You may average among units in a subcategory of units designed to burn gas 2 (other) fuels.

(iv) You may not average across the units designed to burn liquid, units designed to burn solid fuel, and units designed to burn gas 2 (other) subcategories.

(3) For PM (or TSM), averaging is only allowed between units within each of the following subcategories and you may not average across subcategories:

(i) Units designed to burn coal/solid fossil fuel.

(ii) Stokers/sloped grate/other units designed to burn kiln dried biomass/bio-based solids.

(iii) Stokers/sloped grate/other units designed to burn wet biomass/bio-based solids.

(iv) Fluidized bed units designed to burn biomass/bio-based solid.

(v) Suspension burners designed to burn biomass/bio-based solid.

(vi) Dutch ovens/pile burners designed to burn biomass/bio-based solid.

(vii) Fuel Cells designed to burn biomass/bio-based solid.

(viii) Hybrid suspension/grate burners designed to burn wet biomass/bio-based solid.

(ix) Units designed to burn heavy liquid fuel.

(x) Units designed to burn light liquid fuel.

(xi) Units designed to burn liquid fuel that are non-continental units.

(xii) Units designed to burn gas 2 (other) gases.

(c) For each existing boiler or process heater 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 January 31, 2013 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 January 31, 2013.

(d) The averaged emissions rate from the existing boilers and process heaters participating in the emissions averaging option must not exceed 90 percent of the limits in Table 2 to this subpart at all times the affected units are operating following the compliance date specified in § 63.7495.

(e) You must demonstrate initial compliance according to paragraph (e)(1) or (2) of this section using the maximum rated heat input capacity or maximum steam generation capacity of each unit and the results of the initial performance tests or fuel analysis.

(1) You must use Equation 1a or 1b or 1c of this section to demonstrate that the PM (or TSM), HCl, or mercury emissions from all existing units participating in the emissions averaging option for that pollutant do not exceed the emission limits in Table 2 to this subpart. Use Equation 1a if you are complying with the emission limits on a heat input basis, use Equation 1b if you are complying with the emission limits on a steam generation (output) basis, and use Equation 1c if you are complying with the emission limits on a electric generation (output) basis.

$$AveWeightedEmissions = 1.1 \times \sum_{i=1}^{n} (Er \times Hm) \div \sum_{i=1}^{n} Hm \qquad \text{(Eq.1a)}$$

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Where:

AveWeightedEmissions = Average weighted emissions for PM (or TSM), HCl, or mercury, in units of pounds per million Btu of heat input.

Er = Emission rate (as determined during the initial compliance demonstration) of PM (or TSM), HCl, or mercury from unit, i, in units of pounds per million Btu of heat input. Determine the emission rate for PM (or TSM), HCl, or mercury by performance testing according to Table 5 to this subpart, or by fuel analysis for HCl or mercury or TSM using the applicable equation in § 63.7530(c).

Hm = Maximum rated heat input capacity of unit, i, in units of million Btu per hour.

n = Number of units participating in the emissions averaging option.

1.1 = Required discount factor.

$$AveWeightedEmissions = 1.1 \times \sum_{i=1}^{n} (Er \times So) \div \sum_{i=1}^{n} So \qquad \text{(Eq.1b)}$$

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Where:

AveWeightedEmissions = Average weighted emissions for PM (or TSM), HCl, or mercury, in units of pounds per million Btu of steam output.

Er = Emission rate (as determined during the initial compliance demonstration) of PM (or TSM), HCl, or mercury from unit, i, in units of pounds per million Btu of steam output. Determine the emission rate for PM (or TSM), HCl, or mercury by performance testing according to Table 5 to this subpart, or by fuel analysis for HCl or mercury or TSM using the applicable equation in § 63.7530(c). If you are taking credit for energy conservation measures from a unit according to § 63.7533, use the adjusted emission level for that unit, Eadj, determined according to § 63.7533 for that unit.

So = Maximum steam output capacity of unit, i, in units of million Btu per hour, as defined in § 63.7575.

n = Number of units participating in the emissions averaging option.

1.1 = Required discount factor.

$$AveWeightedEmissions = 1.1 \times \sum_{i=1}^{n} (Er \times Eo) \div \sum_{i=1}^{n} Eo \qquad \text{(Eq.1c)}$$

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Where:

AveWeightedEmissions = Average weighted emissions for PM (or TSM), HCl, or mercury, in units of pounds per megawatt hour.

Er = Emission rate (as determined during the initial compliance demonstration) of PM (or TSM), HCl, or mercury from unit, i, in units of pounds per megawatt hour. Determine the emission rate for PM (or TSM), HCl, or mercury by performance testing according to Table 5 to this subpart, or by fuel analysis for HCl or mercury or TSM using the applicable equation in § 63.7530(c). If you are taking credit for energy conservation measures from a unit according to § 63.7533, use the adjusted emission level for that unit, Eadj, determined according to § 63.7533 for that unit.

Eo = Maximum electric generating output capacity of unit, i, in units of megawatt hour, as defined in § 63.7575.

n = Number of units participating in the emissions averaging option.

1.1 = Required discount factor.

(2) If you are not capable of determining the maximum rated heat input capacity of one or more boilers that generate steam, you may use Equation 2 of this section as an alternative to using Equation 1a of this section to demonstrate that the PM (or TSM), HCl, or mercury emissions from all existing units participating in the emissions averaging option do not exceed the emission limits for that pollutant in Table 2 to this subpart that are in pounds per million Btu of heat input.

$$AveWeightedEmissions = 1.1 \times \sum_{i=1}^{n} (Er \times Sm \times Cfi) \div \sum_{i=1}^{n} (Sm \times Cfi) \qquad \text{(Eq. 2)}$$

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Where:

AveWeightedEmissions = 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 determined during the most recent compliance demonstration) of PM (or TSM), HCl, or mercury from unit, i, in units of pounds per million Btu of heat input. Determine the emission rate for PM (or TSM), HCl, or mercury by performance testing according to Table 5 to this subpart, or by fuel analysis for HCl or mercury or TSM using the applicable equation in § 63.7530(c).

Sm = Maximum steam generation capacity by unit, i, in units of pounds per hour.

Cfi = Conversion factor, calculated from the most recent compliance test, in units of million Btu of heat input per pounds of steam generated for unit, i.

1.1 = Required discount factor.

(f) After the initial compliance demonstration described in paragraph (e) of this section, you must demonstrate 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. If the affected source elects to collect monthly data for up the 11 months preceding the first monthly period, these additional data points can be used to compute the 12-month rolling average in paragraph (f)(3) of this section.

(1) For each calendar month, you must use Equation 3a or 3b or 3c of this section to calculate the average weighted emission rate for that month. Use Equation 3a and the actual heat input for the month for each existing unit participating in the emissions averaging option if you are complying with emission limits on a heat input basis. Use Equation 3b and the actual steam generation for the month if you are complying with the emission limits on a steam generation (output) basis. Use Equation 3c and the actual steam generation for the month if you are complying with the emission limits on a electrical generation (output) basis.

$$AveWeightedEmissions = 1.1 \times \sum_{i=1}^{n} (Er \times Hb) \div \sum_{i=1}^{n} Hb \qquad \text{(Eq. 3a)}$$

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Where:

AveWeightedEmissions = Average weighted emission level for PM (or TSM), HCl, or mercury, in units of pounds per million Btu of heat input, for that calendar month.

Er = Emission rate (as determined during the most recent compliance demonstration) of PM (or TSM), HCl, or mercury from unit, i, in units of pounds per million Btu of heat input. Determine the emission rate for PM (or TSM), HCl, or mercury by performance testing according to Table 5 to this subpart, or by fuel analysis for HCl or mercury or TSM according to Table 6 to this subpart.

Hb = The heat input for that calendar month to unit, i, in units of million Btu.

n = Number of units participating in the emissions averaging option.

1.1 = Required discount factor.

$$AveWeightedEmissions = 1.1 \times \sum_{i=1}^{n} (Er \times So) \div \sum_{i=1}^{n} So \qquad \text{(Eq. 3b)}$$

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Where:

AveWeightedEmissions = Average weighted emission level for PM (or TSM), HCl, or mercury, in units of pounds per million Btu of steam output, for that calendar month.

Er = Emission rate (as determined during the most recent compliance demonstration) of PM (or TSM), HCl, or mercury from unit, i, in units of pounds per million Btu of steam output. Determine the emission rate for PM (or TSM), HCl, or mercury by performance testing according to Table 5 to this subpart, or by fuel analysis for HCl or mercury or TSM according to Table 6 to this subpart. If you are taking credit for energy conservation measures from a unit according to § 63.7533, use the adjusted emission level for that unit, E_{adj} , determined according to § 63.7533 for that unit.

So = The steam output for that calendar month from unit, i, in units of million Btu, as defined in § 63.7575.

n = Number of units participating in the emissions averaging option.

1.1 = Required discount factor.

$$AveWeightedEmissions = 1.1 \times \sum_{i=1}^{n} (Er \times Eo) \div \sum_{i=1}^{n} Eo \qquad \text{(Eq. 3c)}$$

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Where:

AveWeightedEmissions = Average weighted emission level for PM (or TSM), HCl, or mercury, in units of pounds per megawatt hour, for that calendar month.

Er = Emission rate (as determined during the most recent compliance demonstration) of PM (or TSM), HCl, or mercury from unit, i, in units of pounds per megawatt hour. Determine the emission rate for PM (or TSM), HCl, or mercury by performance testing according to Table 5 to this subpart, or by fuel analysis for HCl or mercury or TSM according to Table 6 to this subpart. If you are taking credit for energy conservation measures from a unit according to § 63.7533, use the adjusted emission level for that unit, E_{adj} , determined according to § 63.7533 for that unit.

Eo = The electric generating output for that calendar month from unit, i, in units of megawatt hour, as defined in § 63.7575.

n = Number of units participating in the emissions averaging option.

1.1 = Required discount factor.

(2) If you are not capable of monitoring heat input, you may use Equation 4 of this section as an alternative to using Equation 3a of this section to calculate the average weighted emission rate using the actual steam generation from the boilers participating in the emissions averaging option.

$$AveWeightedEmissions = 1.1 \times \sum_{i=1}^{n} \left(Er \times Sa \times Cfi\right) \div \sum_{i=1}^{n} \left(Sa \times Cfi\right) \quad \text{(Eq. 4)}$$

[View or download PDF]

Where:

AveWeightedEmissions = average weighted emission level for PM (or TSM), HCl, or mercury, in units of pounds per million Btu of heat input for that calendar month.

Er = Emission rate (as determined during the most recent compliance demonstration of PM (or TSM), HCl, or mercury from unit, i, in units of pounds per million Btu of heat input. Determine the emission rate for PM (or TSM), HCl, or mercury by performance testing according to Table 5 to this subpart, or by fuel analysis for HCl or mercury or TSM according to Table 6 to this subpart.

Sa = Actual steam generation for that calendar month by boiler, i, in units of pounds.

Cfi = Conversion factor, as calculated during the most recent compliance test, in units of million Btu of heat input per pounds of steam generated for boiler, i.

1.1 = Required discount factor.

(3) Until 12 monthly weighted average emission rates have been accumulated, calculate and report only the average weighted emission rate determined under paragraph (f)(1) or (2) of this section for each calendar month. After 12 monthly weighted average emission rates have been accumulated, for each subsequent calendar month, use Equation 5 of this section to calculate the 12-month rolling average of the monthly weighted average emission rates for the current calendar month and the previous 11 calendar months.

$$Eavg = \sum_{i=1}^{n} ERi \div 12 \quad \text{(Eq. 5)}$$

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Where:

Eavg = 12-month rolling average emission rate, (pounds per million Btu heat input)

ERi = Monthly weighted average, for calendar month “i” (pounds per million Btu heat input), as calculated by paragraph (f)(1) or (2) of this section.

(g) You must develop, and submit upon request to the applicable Administrator for review and approval, an implementation plan for emission averaging according to the following procedures and requirements in paragraphs (g)(1) through (4) of this section.

(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 boilers and process heaters in the averaging group, including for each either the applicable HAP emission level or the control technology installed as of January 31, 2013 and the date on which you are requesting emission averaging to commence;

(ii) The process parameter (heat input or steam generated) that will be monitored for each averaging group;

(iii) The specific control technology or pollution prevention measure to be used for each emission boiler or process heater in the averaging group and the date of its installation or application. If the pollution prevention measure reduces or eliminates emissions from multiple boilers or process heaters, the owner or operator must identify each boiler or process heater;

(iv) The test plan for the measurement of PM (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 consistent with § 63.7500 and Table 4, 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 Administrator, 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 load conditions. Following each compliance demonstration and until the next compliance demonstration, you must comply with the operating limit for operating load conditions specified in Table 4 to this subpart.

(3) The Administrator 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 Administrator 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 unit in the same subcategories.

(h) For a group of two or more existing affected units, each of which vents through a single common stack, you may average PM (or TSM), HCl, or mercury emissions to demonstrate compliance with the limits for that pollutant in Table 2 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 units in the same subcategories, 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 unit for purposes of this subpart and comply with the requirements of this subpart as if the group were a single unit.

(j) For all other groups of units subject to the common stack requirements of paragraph (h) of this section, including situations where the exhaust of affected units are each individually controlled and then sent to a common stack, 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 vent to the common stack. The emission limits that the group must comply with are determined by the use of Equation 6 of this section.

$$En=\sum_{i=1}^{n}\left(ELi\times Hi\right)\div\sum_{i=1}^{n}Hi \qquad \text{(Eq. 6)}$$

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Where:

En = HAP emission limit, pounds per million British thermal units (lb/MMBtu), parts per million (ppm), or nanograms per dry standard cubic meter (ng/dscm).

ELi = Appropriate emission limit from Table 2 to this subpart for unit i, in units of lb/MMBtu, ppm or ng/dscm.

Hi = Heat input from unit i, MMBtu.

(2) Conduct performance tests according to procedures specified in § 63.7520 in the common stack. If affected units and non-affected units vent to the common stack, the non-affected units must be shut down or vented to a different stack during the performance test unless the facility determines to demonstrate compliance with the non-affected units venting to the stack; and

(3) Meet the applicable operating limit specified in § 63.7540 and Table 8 to this subpart for each emissions control system (except that, if each unit 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) The common stack of a group of two or more existing boilers or process heaters in the same subcategories 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.

[76 FR 15664, Mar. 21, 2011, as amended at 78 FR 7168, Jan. 31, 2013]

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§ 63.7525 What are my monitoring, installation, operation, and maintenance requirements?

(a) If your boiler or process heater is subject to a CO emission limit in Tables 1, 2, or 11 through 13 to this subpart, you must install, operate, and maintain an oxygen analyzer system, as defined in § 63.7575, or install, certify, operate and maintain continuous emission monitoring systems for CO and oxygen according to the procedures in paragraphs (a)(1) through (7) of this section.

(1) Install the CO CEMS and oxygen analyzer by the compliance date specified in § 63.7495. The CO and oxygen levels shall be monitored at the same location at the outlet of the boiler or process heater.

(2) To demonstrate compliance with the applicable alternative CO CEMS emission standard listed in Tables 1, 2, or 11 through 13 to this subpart, you must install, certify, operate, and maintain a CO CEMS and an oxygen analyzer according to the applicable procedures under Performance Specification 4, 4A, or 4B at 40 CFR part 60, appendix B, the site-specific monitoring plan developed according to § 63.7505(d), and the requirements in § 63.7540(a)(8) and paragraph (a) of this section. Any boiler or process heater that has a CO CEMS that is compliant with Performance Specification 4, 4A, or 4B at 40 CFR part 60, appendix B, a site-specific monitoring plan developed according to § 63.7505(d), and the requirements in § 63.7540(a)(8) and paragraph (a) of this section must use the CO CEMS to comply with the applicable alternative CO CEMS emission standard listed in Tables 1, 2, or 11 through 13 to this subpart.

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

(ii) During each relative accuracy test run of the CO CEMS, you must be collect emission data for CO concurrently (or within a 30- to 60-minute period) by both the CO CEMS and by Method 10, 10A, or 10B at 40 CFR part 60, appendix A-4. The relative accuracy testing must be at representative operating conditions.

(iii) You must follow the quality assurance procedures (e.g., quarterly accuracy determinations and daily calibration drift tests) of Procedure 1 of appendix F to part 60. The measurement span value of the CO CEMS must be two times the applicable CO emission limit, expressed as a concentration.

(iv) Any CO CEMS that does not comply with § 63.7525(a) cannot be used to meet any requirement in this subpart to demonstrate compliance with a CO emission limit listed in Tables 1, 2, or 11 through 13 to this subpart.

(v) For a new unit, complete the initial performance evaluation no later than July 30, 2013, or 180 days after the date of initial startup, whichever is later. For an existing unit, complete the initial performance evaluation no later than July 29, 2016.

(3) Complete a minimum of one cycle of CO and oxygen CEMS operation (sampling, analyzing, and data recording) for each successive 15-minute period. Collect CO and oxygen data concurrently. Collect at least four CO and oxygen CEMS data values representing the four 15-minute periods in an hour, or at least two 15-minute data values during an hour when CEMS calibration, quality assurance, or maintenance activities are being performed.

(4) Reduce the CO CEMS data as specified in § 63.8(g)(2).

(5) Calculate one-hour arithmetic averages, corrected to 3 percent oxygen from each hour of CO CEMS data in parts per million CO concentration. The one-hour arithmetic averages required shall be used to calculate the 30-day or 10-day rolling average emissions. Use Equation 19-19 in section 12.4.1 of Method 19 of 40 CFR part 60, appendix A-7 for calculating the average CO concentration from the hourly values.

(6) For purposes of collecting CO data, operate the CO CEMS as specified in § 63.7535(b). You must use all the data collected during all periods in calculating data averages and assessing compliance, except that you must exclude certain data as specified in § 63.7535(c). Periods when CO data are unavailable may constitute monitoring deviations as specified in § 63.7535(d).

(7) Operate an oxygen trim system with the oxygen level set no lower than the lowest hourly average oxygen concentration measured during the most recent CO performance test as the operating limit for oxygen according to Table 7 to this subpart.

(b) If your boiler or process heater is in the unit designed to burn coal/solid fossil fuel subcategory or the unit designed to burn heavy liquid subcategory and has an average annual heat input rate greater than 250 MMBtu per hour from solid fossil fuel and/or heavy liquid, and you demonstrate compliance with the PM limit instead of the alternative TSM limit, you must install, certify, maintain, and operate a PM CPMS monitoring emissions discharged to the atmosphere and record the output of the system as specified in paragraphs (b)(1) through (4) of this section. As an alternative to use of a PM CPMS to demonstrate compliance with the PM limit, you may choose to use a PM CEMS. If you choose to use a PM CEMS to demonstrate compliance with the PM limit instead of the alternative TSM limit, you must install, certify, maintain, and operate a PM CEMS monitoring emissions discharged to the atmosphere and record the output of the system as specified in paragraph (b)(5) through (8) of this section. For other boilers or process heaters, you may elect to use a PM CPMS or PM CEMS operated in accordance with this section in lieu of using other CMS for monitoring PM compliance (e.g., bag leak detectors, ESP secondary power, PM scrubber pressure). Owners of boilers and process heaters who elect to comply with the alternative TSM limit are not required to install a PM CPMS.

(1) Install, certify, operate, and maintain your PM CPMS according to the procedures in your approved site-specific monitoring plan developed in accordance with § 63.7505(d), the requirements in § 63.7540(a)(9), and paragraphs (b)(1)(i) through (iii) of this section.

(i) The operating principle of the PM CPMS must be based on in-stack or extractive light scatter, light scintillation, beta attenuation, or mass accumulation detection of PM in the exhaust gas or representative exhaust gas sample. The reportable measurement output from the PM CPMS must be expressed as milliamps.

(ii) The PM CPMS must have a cycle time (i.e., period required to complete sampling, measurement, and reporting for each measurement) no longer than 60 minutes.

(iii) The PM CPMS must be capable of detecting and responding to PM concentrations of no greater than 0.5 milligram per actual cubic meter.

(2) For a new unit, complete the initial performance evaluation no later than July 30, 2013, or 180 days after the date of initial startup, whichever is later. For an existing unit, complete the initial performance evaluation no later than July 29, 2016.

(3) Collect PM CPMS hourly average output data for all boiler or process heater operating hours except as indicated in § 63.7535(a) through (d). Express the PM CPMS output as milliamps.

(4) Calculate the arithmetic 30-day rolling average of all of the hourly average PM CPMS output data collected during all boiler or process heater operating hours (milliamps).

(5) Install, certify, operate, and maintain your PM CEMS according to the procedures in your approved site-specific monitoring plan developed in accordance with § 63.7505(d), the requirements in § 63.7540(a)(9), and paragraphs (b)(5)(i) through (iv) of this section.

(i) You shall conduct a performance evaluation of the PM CEMS according to the applicable requirements of § 60.8(e), and Performance Specification 11 at 40 CFR part 60, appendix B of this chapter.

(ii) During each PM correlation testing run of the CEMS required by Performance Specification 11 at 40 CFR part 60, appendix B of this chapter, you shall collect PM and oxygen (or carbon dioxide) data concurrently (or within a 30-to 60-minute period) by both the CEMS and conducting performance tests using Method 5 at 40 CFR part 60, appendix A-3 or Method 17 at 40 CFR part 60, appendix A-6 of this chapter.

(iii) You shall perform quarterly accuracy determinations and daily calibration drift tests in accordance with Procedure 2 at 40 CFR part 60, appendix F of this chapter. You must perform Relative Response Audits annually and perform Response Correlation Audits every 3 years.

(iv) Within 60 days after the date of completing each CEMS relative accuracy test audit or performance test conducted to demonstrate compliance with this subpart, you must submit the relative accuracy test audit data and performance test data to the EPA by successfully submitting the data electronically into the EPA's Central Data Exchange by using the Electronic Reporting Tool (see *http://www.epa.gov/ttn/chief/ert/erttool.html/*).

(6) For a new unit, complete the initial performance evaluation no later than July 30, 2013, or 180 days after the date of initial startup, whichever is later. For an existing unit, complete the initial performance evaluation no later than July 29, 2016.

(7) Collect PM CEMS hourly average output data for all boiler or process heater operating hours except as indicated in § 63.7535(a) through (d).

(8) Calculate the arithmetic 30-day rolling average of all of the hourly average PM CEMS output data collected during all boiler or process heater operating hours.

(c) If you have an applicable opacity operating limit in this rule, and are not otherwise required or elect to install and operate a PM CPMS, PM CEMS, or a bag leak detection system, you must install, operate, certify and maintain each COMS according to the procedures in paragraphs (c)(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 Performance Specification 1 at appendix B to part 60 of this chapter.

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

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

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

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

(6) You must operate and maintain each COMS according to the requirements in the monitoring plan and the requirements of § 63.8(e). You must identify periods the COMS is out of control including any periods that the COMS fails to pass a daily calibration drift assessment, a quarterly performance audit, or an annual zero alignment audit. Any 6-minute period for which the monitoring system is out of control and data are not available for a required calculation constitutes a deviation from the monitoring requirements.

(7) You must determine and record all the 6-minute averages (and daily block averages as applicable) collected for periods during which the COMS is not out of control.

(d) If you have an operating limit that requires the use of a CMS other than a PM CPMS or COMS, you must install, operate, and maintain each CMS according to the procedures in paragraphs (d)(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 every 15-minutes. You must have a minimum of four successive cycles of operation, one representing each of the four 15-minute periods in an hour, to have a valid hour of data.

(2) You must operate the monitoring system as specified in § 63.7535(b), and comply with the data calculation requirements specified in § 63.7535(c).

(3) Any 15-minute period for which the monitoring system is out-of-control and data are not available for a required calculation constitutes a deviation from the monitoring requirements. Other situations that constitute a monitoring deviation are specified in § 63.7535(d).

(4) You must determine the 30-day rolling average of all recorded readings, except as provided in § 63.7535(c).

(5) You must record the results of each inspection, calibration, and validation check.

(e) If you have an operating limit that requires the use of a flow monitoring system, you must meet the requirements in paragraphs (d) and (e)(1) through (4) of this section.

(1) You must install the flow sensor and other necessary equipment in a position that provides a representative flow.

(2) You must use a flow sensor with a measurement sensitivity of no greater than 2 percent of the design flow rate.

(3) You must minimize, consistent with good engineering practices, the effects of swirling flow or abnormal velocity distributions due to upstream and downstream disturbances.

(4) You must conduct a flow monitoring system performance evaluation in accordance with your monitoring plan at the time of each performance test but no less frequently than annually.

(f) If you have an operating limit that requires the use of a pressure monitoring system, you must meet the requirements in paragraphs (d) and (f)(1) through (6) of this section.

(1) Install the pressure sensor(s) in a position that provides a representative measurement of the pressure (*e.g.* , PM scrubber pressure drop).

(2) Minimize or eliminate pulsating pressure, vibration, and internal and external corrosion consistent with good engineering practices.

(3) Use a pressure sensor with a minimum tolerance of 1.27 centimeters of water or a minimum tolerance of 1 percent of the pressure monitoring system operating range, whichever is less.

(4) Perform checks at least once each process operating day to ensure pressure measurements are not obstructed (*e.g.* , check for pressure tap pluggage daily).

(5) Conduct a performance evaluation of the pressure monitoring system in accordance with your monitoring plan at the time of each performance test but no less frequently than annually.

(6) If at any time the measured pressure exceeds the manufacturer's specified maximum operating pressure range, conduct a performance evaluation of the pressure monitoring system in accordance with your monitoring plan and confirm that the pressure monitoring system continues to meet the performance requirements in you monitoring plan. Alternatively, install and verify the operation of a new pressure sensor.

(g) If you have an operating limit that requires a pH monitoring system, you must meet the requirements in paragraphs (d) and (g)(1) through (4) of this section.

(1) Install 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) Conduct a performance evaluation of the pH monitoring system in accordance with your monitoring plan at least once each process operating day.

(4) Conduct a performance evaluation (including a two-point calibration with one of the two buffer solutions having a pH within 1 of the pH of the operating limit) of the pH monitoring system in accordance with your monitoring plan at the time of each performance test but no less frequently than quarterly.

(h) If you have an operating limit that requires a secondary electric power monitoring system for an electrostatic precipitator (ESP) operated with a wet scrubber, you must meet the requirements in paragraphs (h)(1) and (2) of this section.

(1) Install sensors to measure (secondary) voltage and current to the precipitator collection plates.

(2) Conduct a performance evaluation of the electric power monitoring system in accordance with your monitoring plan at the time of each performance test but no less frequently than annually.

(i) If you have an operating limit that requires the use of a monitoring system to measure sorbent injection rate (e.g., weigh belt, weigh hopper, or hopper flow measurement device), you must meet the requirements in paragraphs (d) and (i)(1) through (2) of this section.

(1) Install the system in a position(s) that provides a representative measurement of the total sorbent injection rate.

(2) Conduct a performance evaluation of the sorbent injection rate monitoring system in accordance with your monitoring plan at the time of each performance test but no less frequently than annually.

(j) If you are not required to use a PM CPMS and 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 the bag leak detection system as specified in paragraphs (j)(1) through (6) of this section.

(1) You must install a bag leak detection sensor(s) in a position(s) that will be representative of the relative or absolute PM loadings for each exhaust stack, roof vent, or compartment (e.g., for a positive pressure fabric filter) of the fabric filter.

(2) Conduct a performance evaluation of the bag leak detection system in accordance with your monitoring plan and consistent with the guidance provided in EPA-454/R-98-015 (incorporated by reference, see § 63.14).

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

(4) Use a bag leak detection system equipped with a device to record continuously the output signal from the sensor.

(5) Use a bag leak detection system equipped with a system that will alert plant operating personnel when an increase in relative PM emissions over a preset level is detected. The alert must easily recognizable (e.g., heard or seen) by plant operating personnel.

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

(k) For each unit that meets the definition of limited-use boiler or process heater, you must keep fuel use records for the days the boiler or process heater was operating.

(l) For each unit for which you decide to demonstrate compliance with the mercury or HCl emissions limits in Tables 1 or 2 or 11 through 13 of this subpart by use of a CEMS for mercury or HCl, you must install, certify, maintain, and operate a CEMS measuring emissions discharged to the atmosphere and record the output of the system as specified in paragraphs (l)(1) through (8) of this section. For HCl, this option for an affected unit takes effect on the date a final performance specification for a HCl CEMS is published in the FEDERAL REGISTER or the date of approval of a site-specific monitoring plan.

(1) Notify the Administrator one month before starting use of the CEMS, and notify the Administrator one month before stopping use of the CEMS.

(2) Each CEMS shall be installed, certified, operated, and maintained according to the requirements in § 63.7540(a)(14) for a mercury CEMS and § 63.7540(a)(15) for a HCl CEMS.

(3) For a new unit, you must complete the initial performance evaluation of the CEMS by the latest of the dates specified in paragraph (l)(3)(i) through (iii) of this section.

(i) No later than July 30, 2013.

(ii) No later 180 days after the date of initial startup.

(iii) No later 180 days after notifying the Administrator before starting to use the CEMS in place of performance testing or fuel analysis to demonstrate compliance.

(4) For an existing unit, you must complete the initial performance evaluation by the latter of the two dates specified in paragraph (l)(4)(i) and (ii) of this section.

(i) No later than July 29, 2016.

(ii) No later 180 days after notifying the Administrator before starting to use the CEMS in place of performance testing or fuel analysis to demonstrate compliance.

(5) Compliance with the applicable emissions limit shall be determined based on the 30-day rolling average of the hourly arithmetic average emissions rates using the continuous monitoring system outlet data. The 30-day rolling arithmetic average emission rate (lb/MMBtu) shall be calculated using the equations in EPA Reference Method 19 at 40 CFR part 60, appendix A-7, but substituting the mercury or HCl concentration for the pollutant concentrations normally used in Method 19.

(6) Collect CEMS hourly averages for all operating hours on a 30-day rolling average basis. Collect at least four CMS data values representing the four 15-minute periods in an hour, or at least two 15-minute data values during an hour when CMS calibration, quality assurance, or maintenance activities are being performed.

(7) The one-hour arithmetic averages required shall be expressed in lb/MMBtu and shall be used to calculate the boiler 30-day and 10-day rolling average emissions.

(8) You are allowed to substitute the use of the PM, mercury or HCl CEMS for the applicable fuel analysis, annual performance test, and operating limits specified in Table 4 to this subpart to demonstrate compliance with the PM, mercury or HCl emissions limit, and if you are using an acid gas wet scrubber or dry sorbent injection control technology to comply with the HCl emission limit, you are allowed to substitute the use of a sulfur dioxide (SO_2) CEMS for the applicable fuel analysis, annual performance test, and operating limits specified in Table 4 to this subpart to demonstrate compliance with HCl emissions limit.

(m) If your unit is subject to a HCl emission limit in Tables 1, 2, or 11 through 13 of this subpart and you have an acid gas wet scrubber or dry sorbent injection control technology and you use an SO_2 CEMS, you must install the monitor at the outlet of the boiler or process heater, downstream of all emission control devices, and you must install, certify, operate, and maintain the CEMS according to part 75 of this chapter.

(1) The SO_2 CEMS must be installed by the compliance date specified in § 63.7495.

(2) For on-going quality assurance (QA), the SO_2 CEMS must meet the applicable daily, quarterly, and semiannual or annual requirements in sections 2.1 through 2.3 of appendix B to part 75 of this chapter, with the following addition: You must perform the linearity checks required in section 2.2 of appendix B to part 75 of this chapter if the SO_2 CEMS has a span value of 30 ppm or less.

(3) For a new unit, the initial performance evaluation shall be completed no later than July 30, 2013, or 180 days after the date of initial startup, whichever is later. For an existing unit, the initial performance evaluation shall be completed no later than July 29, 2016.

(4) For purposes of collecting SO_2 data, you must operate the SO_2 CEMS as specified in § 63.7535(b). You must use all the data collected during all periods in calculating data averages and assessing compliance, except that you must exclude certain data as specified in § 63.7535(c). Periods when SO_2 data are unavailable may constitute monitoring deviations as specified in § 63.7535(d).

(5) Collect CEMS hourly averages for all operating hours on a 30-day rolling average basis.

(6) Use only unadjusted, quality-assured SO_2 concentration values in the emissions calculations; do not apply bias adjustment factors to the part 75 SO_2 data and do not use part 75 substitute data values.

[76 FR 15664, Mar. 21, 2011, as amended at 78 FR 7171, Jan. 31, 2013]

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§ 63.7530 How do I demonstrate initial compliance with the emission limitations, fuel specifications and work practice standards?

(a) You must demonstrate initial compliance with each emission limit that applies to you by conducting initial performance tests and fuel analyses and establishing operating limits, as applicable, according to § 63.7520, paragraphs (b) and (c) of this section, and Tables 5 and 7 to this subpart. The requirement to conduct a fuel analysis is not applicable for units that burn a single type of fuel, as specified by § 63.7510(a)(2)(i). If applicable, you must also install, operate, and maintain all applicable CMS (including CEMS, COMS, and CPMS) according to § 63.7525.

(b) If you demonstrate compliance through performance testing, you must establish each site-specific operating limit in Table 4 to this subpart that applies to you according to the requirements in § 63.7520, Table 7 to this subpart, and paragraph (b)(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 (b)(1) through (3) of this section, as applicable, and as specified in § 63.7510(a)(2). (Note that § 63.7510(a)(2) exempts certain fuels from the fuel analysis requirements.) However, if you switch fuel(s) and cannot show that the new fuel(s) does (do) not increase the chlorine, mercury, or TSM input into the unit through the results of fuel analysis, then you must repeat the performance test to demonstrate compliance while burning the new fuel(s).

(1) You must establish the maximum chlorine fuel input (Clinput) during the initial fuel analysis according to the procedures in paragraphs (b)(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 fuel analysis for hydrogen chloride, you must determine the fraction of the total heat input for each fuel type burned (Qi) based on the fuel mixture that has the highest content of chlorine, and the average chlorine concentration of each fuel type burned (Ci).

(iii) You must establish a maximum chlorine input level using Equation 7 of this section.

$$Clinput = \sum_{i=1}^{n} (Ci \times Qi) \quad \text{(Eq. 7)}$$

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Where:

Clinput = Maximum amount of chlorine entering the boiler or process heater through fuels burned in units of pounds per million Btu.

Ci = Arithmetic average concentration of chlorine in fuel type, i, analyzed according to § 63.7521, in units of pounds per million Btu.

Qi = 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 Qi.

n = Number of different fuel types burned in your boiler or process heater for the mixture that has the highest content of chlorine.

(2) You must establish the maximum mercury fuel input level (Mercuryinput) during the initial fuel analysis using the procedures in paragraphs (b)(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 mercury.

(ii) During the compliance demonstration for mercury, you must determine the fraction of total heat input for each fuel burned (Qi) based on the fuel mixture that has the highest content of mercury, and the average mercury concentration of each fuel type burned (HGi).

(iii) You must establish a maximum mercury input level using Equation 8 of this section.

$$Mercuryinput = \sum_{i=1}^{n} (HGi \times Qi) \qquad \text{(Eq. 8)}$$

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Where:

Mercuryinput = Maximum amount of mercury entering the boiler or process heater through fuels burned in units of pounds per million Btu.

HGi = Arithmetic average concentration of mercury in fuel type, i, analyzed according to § 63.7521, in units of pounds per million Btu.

Qi = 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 Qi.

n = Number of different fuel types burned in your boiler or process heater for the mixture that has the highest content of mercury.

(3) If you opt to comply with the alternative TSM limit, you must establish the maximum TSM fuel input (TSMinput) for solid or liquid fuels during the initial fuel analysis according to the procedures in paragraphs (b)(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 TSM.

(ii) During the fuel analysis for TSM, you must determine the fraction of the total heat input for each fuel type burned (Qi) based on the fuel mixture that has the highest content of TSM, and the average TSM concentration of each fuel type burned (TSMi).

(iii) You must establish a maximum TSM input level using Equation 9 of this section.

$$TSMinput = \sum_{i=1}^{n} (TSMi \times Qi) \qquad \text{(Eq. 9)}$$

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Where:

TSMinput = Maximum amount of TSM entering the boiler or process heater through fuels burned in units of pounds per million Btu.

TSMi = Arithmetic average concentration of TSM in fuel type, i, analyzed according to § 63.7521, in units of pounds per million Btu.

Qi = Fraction of total heat input from 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 testing, it is not necessary to determine the value of this term. Insert a value of “1” for Qi.

n = Number of different fuel types burned in your boiler or process heater for the mixture that has the highest content of TSM.

(4) You must establish parameter operating limits according to paragraphs (b)(4)(i) through (ix) of this section. As indicated in Table 4 to this subpart, you are not required to establish and comply with the operating parameter limits when you are using a CEMS to monitor and demonstrate compliance with the applicable emission limit for that control device parameter.

(i) For a wet acid gas scrubber, you must establish the minimum scrubber effluent pH and liquid flow rate as defined in § 63.7575, as your operating limits during the performance test during which you demonstrate compliance with your applicable limit. If you use a wet scrubber and you conduct separate performance tests for HCl and mercury emissions, you must establish one set of minimum scrubber effluent pH, liquid flow rate, 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 flow rate operating limit at the higher of the minimum values established during the performance tests.

(ii) For any particulate control device (e.g., ESP, particulate wet scrubber, fabric filter) for which you use a PM CPMS, you must establish your PM CPMS operating limit and determine compliance with it according to paragraphs (b)(4)(ii)(A) through (F) of this section.

(A) Determine your operating limit as the average PM CPMS output value recorded during the most recent performance test run demonstrating compliance with the filterable PM emission limit or at the PM CPMS output value corresponding to 75 percent of the emission limit if your PM performance test demonstrates compliance below 75 percent of the emission limit. You must verify an existing or establish a new operating limit after each repeated performance test. You must repeat the performance test annually and reassess and adjust the site-specific operating limit in accordance with the results of the performance test.

(*1*) Your PM CPMS must provide a 4-20 milliamp output and the establishment of its relationship to manual reference method measurements must be determined in units of milliamps.

(*2*) Your PM CPMS operating range must be capable of reading PM concentrations from zero to a level equivalent to at least two times your allowable emission limit. If your PM CPMS is an auto-ranging instrument capable of multiple scales, the primary range of the instrument must be capable of reading PM concentration from zero to a level equivalent to two times your allowable emission limit.

(*3*) During the initial performance test or any such subsequent performance test that demonstrates compliance with the PM limit, record and average all milliamp output values from the PM CPMS for the periods corresponding to the compliance test runs (e.g., average all your PM CPMS output values for three corresponding 2-hour Method 5I test runs).

(B) If the average of your three PM performance test runs are below 75 percent of your PM emission limit, you must calculate an operating limit by establishing a relationship of PM CPMS signal to PM concentration using the PM CPMS instrument zero, the average PM CPMS values corresponding to the three compliance test runs, and the average PM concentration from the Method 5 or performance test with the procedures in paragraphs (b)(4)(ii)(B)(*1*) through (*4*) of this section.

(*1*) Determine your instrument zero output with one of the following procedures:

(*i*) Zero point data for *in-situ* instruments should be obtained by removing the instrument from the stack and monitoring ambient air on a test bench.

(*ii*) Zero point data for *extractive* instruments should be obtained by removing the extractive probe from the stack and drawing in clean ambient air.

(*iii*) The zero point may also be established by performing manual reference method measurements when the flue gas is free of PM emissions or contains very low PM concentrations (e.g., when your process is not operating, but the fans are operating or your source is combusting only natural gas) and plotting these with the compliance data to find the zero intercept.

(*iv*) If none of the steps in paragraphs (b)(4)(ii)(B)(*1*)(*i*) through (*iii*) of this section are possible, you must use a zero output value provided by the manufacturer.

(*2*) Determine your PM CPMS instrument average in milliamps, and the average of your corresponding three PM compliance test runs, using equation 10.

$$\bar{x} = \frac{1}{n}\sum_{i=1}^{n} X_1, \bar{y} = \frac{1}{n}\sum_{i=1}^{n} Y_1 \qquad \text{(Eq. 10)}$$

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Where:

X_1 = the PM CPMS data points for the three runs constituting the performance test,

Y_1 = the PM concentration value for the three runs constituting the performance test, and

n = the number of data points.

(*3*) With your instrument zero expressed in milliamps, your three run average PM CPMS milliamp value, and your three run average PM concentration from your three compliance tests, determine a relationship of lb/MMBtu per milliamp with equation 11.

$$R = \frac{Y_1}{(X_1 - z)} \qquad \text{(Eq. 11)}$$

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Where:

R = the relative lb/MMBtu per milliamp for your PM CPMS,

Y_1 = the three run average lb/MMBtu PM concentration,

X_1 = the three run average milliamp output from you PM CPMS, and

z = the milliamp equivalent of your instrument zero determined from (B)(i).

(*4*) Determine your source specific 30-day rolling average operating limit using the lb/MMBtu per milliamp value from Equation 11 in equation 12, below. This sets your operating limit at the PM CPMS output value corresponding to 75 percent of your emission limit.

$$O_l = z + \frac{0.75(L)}{R} \qquad \text{(Eq. 12)}$$

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Where:

O_l = the operating limit for your PM CPMS on a 30-day rolling average, in milliamps.

L = your source emission limit expressed in lb/MMBtu,

z = your instrument zero in milliamps, determined from (B)(i), and

R = the relative lb/MMBtu per milliamp for your PM CPMS, from Equation 11.

(C) If the average of your three PM compliance test runs is at or above 75 percent of your PM emission limit you must determine your 30-day rolling average operating limit by averaging the PM CPMS milliamp output corresponding to your three PM performance test runs that demonstrate compliance with the emission limit using equation 13 and you must submit all compliance test and PM CPMS data according to the reporting requirements in paragraph (b)(4)(ii)(F) of this section.

$$O_h = \frac{1}{n}\sum_{i=1}^{n} X_1 \qquad \text{(Eq. 13)}$$

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Where:

X_1 = the PM CPMS data points for all runs i,

n = the number of data points, and

O_h = your site specific operating limit, in milliamps.

(D) To determine continuous compliance, you must record the PM CPMS output data for all periods when the process is operating and the PM CPMS is not out-of-control. You must demonstrate continuous compliance by using all quality-assured hourly average data collected by the PM CPMS for all operating hours to calculate the arithmetic average operating parameter in units of the operating limit (milliamps) on a 30-day rolling average basis, updated at the end of each new operating hour. Use Equation 14 to determine the 30-day rolling average.

$$30-\text{day}=\frac{\sum_{i=1}^{n} Hpvi}{n} \qquad \text{(Eq. 14)}$$

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Where:

30-day = 30-day average.

Hpvi = is the hourly parameter value for hour i

n = is the number of valid hourly parameter values collected over the previous 720 operating hours.

(E) Use EPA Method 5 of appendix A to part 60 of this chapter to determine PM emissions. For each performance test, conduct three separate runs under the conditions that exist when the affected source is operating at the highest load or capacity level reasonably expected to occur. Conduct each test run to collect a minimum sample volume specified in Tables 1, 2, or 11 through 13 to this subpart, as applicable, for determining compliance with a new source limit or an existing source limit. Calculate the average of the results from three runs to determine compliance. You need not determine the PM collected in the impingers (“back half”) of the Method 5 particulate sampling train to demonstrate compliance with the PM standards of this subpart. This shall not preclude the permitting authority from requiring a determination of the “back half” for other purposes.

(F) For PM performance test reports used to set a PM CPMS operating limit, the electronic submission of the test report must also include the make and model of the PM CPMS instrument, serial number of the instrument, analytical principle of the instrument (e.g. beta attenuation), span of the instruments primary analytical range, milliamp value equivalent to the instrument zero output, technique by which this zero value was determined, and the average milliamp signals corresponding to each PM compliance test run.
(iii) For a particulate wet scrubber, you must establish the minimum pressure drop and liquid flow rate as defined in § 63.7575, as your operating limits during the three-run performance test during which you demonstrate compliance with your applicable limit. If you use a wet scrubber and you conduct separate performance tests for PM and TSM emissions, you must establish one set of minimum scrubber liquid flow rate 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 flow rate and pressure drop operating limits at the higher of the minimum values established during the performance tests.

(iii) For an electrostatic precipitator (ESP) operated with a wet scrubber, you must establish the minimum total secondary electric power input, as defined in § 63.7575, as your operating limit during the three-run performance test during which you demonstrate compliance with your applicable limit. (These operating limits do not apply to ESP that are operated as dry controls without a wet scrubber.)

(iv) For a dry scrubber, you must establish the minimum sorbent injection rate for each sorbent, as defined in § 63.7575, as your operating limit during the three-run performance test during which you demonstrate compliance with your applicable limit.

(v) For activated carbon injection, you must establish the minimum activated carbon injection rate, as defined in § 63.7575, as your operating limit during the three-run performance test during which you demonstrate compliance with your applicable limit.

(vi) The operating limit for boilers or process heaters with fabric filters that demonstrate continuous compliance through bag leak detection systems is that a bag leak detection system be installed according to the requirements in § 63.7525, and that each fabric filter must be operated such that the bag leak detection system alert is not activated more than 5 percent of the operating time during a 6-month period.

(vii) For a minimum oxygen level, if you conduct multiple performance tests, you must set the minimum oxygen level at the lower of the minimum values established during the performance tests.

(viii) The operating limit for boilers or process heaters that demonstrate continuous compliance with the HCl emission limit using a SO_2 CEMS is to install and operate the SO_2 according to the requirements in § 63.7525(m) establish a maximum SO_2 emission rate equal to the highest hourly average SO_2 measurement during the most recent three-run performance test for HCl.

(c) 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 (c)(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 t-statistic test described in Equation 15 of this section.

$$P90 = mean + (SD \times t) \qquad \text{(Eq. 15)}$$

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Where:

P90 = 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 mean of pollutant concentration in the fuel samples analyzed according to § 63.7521, in units of pounds per million Btu. SD is calculated as the sample standard deviation divided by the square root of the number of samples.

t = t distribution critical value for 90th percentile ($t_{0.1}$) probability for the appropriate degrees of freedom (number of samples minus one) as obtained from a t-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 16 of this section must not exceed the applicable emission limit for HCl.

$$HCl = \sum_{i=1}^{n} (Ci90 \times Qi \times 1.028) \qquad \text{(Eq. 16)}$$

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Where:

HCl = HCl emission rate from the boiler or process heater in units of pounds per million Btu.

Ci90 = 90th percentile confidence level concentration of chlorine in fuel type, i, in units of pounds per million Btu as calculated according to Equation 11 of this section.

Qi = 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 Qi.

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 mercury, the mercury emission rate that you calculate for your boiler or process heater using Equation 17 of this section must not exceed the applicable emission limit for mercury.

$$Mercury = \sum_{i=1}^{n} \left(Hgi90 \times Qi \right) \quad \text{(Eq. 17)}$$

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Where:

Mercury = Mercury emission rate from the boiler or process heater in units of pounds per million Btu.

Hgi90 = 90th percentile confidence level concentration of mercury in fuel, i, in units of pounds per million Btu as calculated according to Equation 11 of this section.

Qi = 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 Qi.

n = Number of different fuel types burned in your boiler or process heater for the mixture that has the highest mercury content.

(5) To demonstrate compliance with the applicable emission limit for TSM for solid or liquid fuels, the TSM emission rate that you calculate for your boiler or process heater from solid fuels using Equation 18 of this section must not exceed the applicable emission limit for TSM.

$$Metals = \sum_{i=1}^{n} \left(TSM90i \times Qi \right) \quad \text{(Eq. 18)}$$

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Where:

Metals = TSM emission rate from the boiler or process heater in units of pounds per million Btu.

TSMi90 = 90th percentile confidence level concentration of TSM in fuel, i, in units of pounds per million Btu as calculated according to Equation 11 of this section.

Qi = Fraction of total heat input from fuel type, i, based on the fuel mixture that has the highest TSM 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 Qi.

n = Number of different fuel types burned in your boiler or process heater for the mixture that has the highest TSM content.

(d) If you own or operate an existing unit with a heat input capacity of less than 10 million Btu per hour or a unit in the unit designed to burn gas 1 subcategory, you must submit a signed statement in the Notification of Compliance Status report that indicates that you conducted a tune-up of the unit.

(e) You must include with the Notification of Compliance Status a signed certification that the energy assessment was completed according to Table 3 to this subpart and is an accurate depiction of your facility at the time of the assessment.

(f) You must submit the Notification of Compliance Status containing the results of the initial compliance demonstration according to the requirements in § 63.7545(e).

(g) If you elect to demonstrate that a gaseous fuel meets the specifications of another gas 1 fuel as defined in § 63.7575, you must conduct an initial fuel specification analyses according to § 63.7521(f) through (i) and according to the frequency listed in § 63.7540(c) and maintain records of the results of the testing as outlined in § 63.7555(g). For samples where the initial mercury specification has not been exceeded, you will include a signed certification with the Notification of Compliance Status that the initial fuel specification test meets the gas specification outlined in the definition of other gas 1 fuels.

(h) If you own or operate a unit subject to emission limits in Tables 1 or 2 or 11 through 13 to this subpart, you must meet the work practice standard according to Table 3 of this subpart. During startup and shutdown, you must only follow the work practice standards according to item 5 of Table 3 of this subpart.

(i) If you opt to comply with the alternative SO_2 CEMS operating limit in Tables 4 and 8 to this subpart, you may do so only if your affected boiler or process heater:

(1) Has a system using wet scrubber or dry sorbent injection and SO_2 CEMS installed on the unit; and

(2) At all times, you operate the wet scrubber or dry sorbent injection for acid gas control on the unit consistent with § 63.7500(a)(3); and

(3) You establish a unit-specific maximum SO_2 operating limit by collecting the minimum hourly SO_2 emission rate on the SO_2 CEMS during the paired 3-run test for HCl. The maximum SO_2 operating limit is equal to the highest hourly average SO_2 concentration measured during the most recent HCl performance test.

[76 FR 15664, Mar. 21, 2013, as amended at 78 FR 7174, Jan. 31, 2013]

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§ 63.7533 Can I use efficiency credits earned from implementation of energy conservation measures to comply with this subpart?

(a) If you elect to comply with the alternative equivalent output-based emission limits, instead of the heat input-based limits listed in Table 2 to this subpart, and you want to take credit for implementing energy conservation measures identified in an energy assessment, you may demonstrate compliance using efficiency credits according to the procedures in this section. You may use this compliance approach for an existing affected boiler for demonstrating initial compliance according to § 63.7522(e) and for demonstrating monthly compliance according to § 63.7522(f). Owners or operators using this compliance approach must establish an emissions benchmark, calculate and document the efficiency credits, develop an Implementation Plan, comply with the general reporting requirements, and apply the efficiency credit according to the procedures in paragraphs (b) through (f) of this section. You cannot use this compliance approach for a new or reconstructed affected boiler. Additional guidance from the Department of Energy on efficiency credits is available at: *http://www.epa.gov/ttn/atw/boiler/boilerpg.html* .

(b) For each existing affected boiler for which you intend to apply emissions credits, establish a benchmark from which emission reduction credits may be generated by determining the actual annual fuel heat input to the affected boiler before initiation of an energy conservation activity to reduce energy demand (*i.e.,* fuel usage) according to paragraphs (b)(1) through (4) of this section. The benchmark shall be expressed in trillion Btu per year heat input.

(1) The benchmark from which efficiency credits may be generated shall be determined by using the most representative, accurate, and reliable process available for the source. The benchmark shall be established for a one-year period before the date that an energy demand reduction occurs, unless it can be demonstrated that a different time period is more representative of historical operations.

(2) Determine the starting point from which to measure progress. Inventory all fuel purchased and generated on-site (off-gases, residues) in physical units (MMBtu, million cubic feet, etc.).

(3) Document all uses of energy from the affected boiler. Use the most recent data available.

(4) Collect non-energy related facility and operational data to normalize, if necessary, the benchmark to current operations, such as building size, operating hours, etc. If possible, use actual data that are current and timely rather than estimated data.

(c) Efficiency credits can be generated if the energy conservation measures were implemented after January 1, 2008 and if sufficient information is available to determine the appropriate value of credits.

(1) The following emission points cannot be used to generate efficiency credits:

(i) Energy conservation measures implemented on or before January 1, 2008, unless the level of energy demand reduction is increased after January 1, 2008, in which case credit will be allowed only for change in demand reduction achieved after January 1, 2008.

(ii) Efficiency credits on shut-down boilers. Boilers that are shut down cannot be used to generate credits unless the facility provides documentation linking the permanent shutdown to energy conservation measures identified in the energy assessment. In this case, the bench established for the affected boiler to which the credits from the shutdown will be applied must be revised to include the benchmark established for the shutdown boiler.

(2) For all points included in calculating emissions credits, the owner or operator shall:

(i) Calculate annual credits for all energy demand points. Use Equation 19 to calculate credits. Energy conservation measures that meet the criteria of paragraph (c)(1) of this section shall not be included, except as specified in paragraph (c)(1)(i) of this section.

(3) Credits are generated by the difference between the benchmark that is established for each affected boiler, and the actual energy demand reductions from energy conservation measures implemented after January 1, 2008. Credits shall be calculated using Equation 19 of this section as follows:

(i) The overall equation for calculating credits is:

$$ECredits = \left(\sum_{i=1}^{n} EIS_{iactual} \right) \div EI_{baseline} \quad \text{(Eq. 19)}$$

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Where:

ECredits = Energy Input Savings for all energy conservation measures implemented for an affected boiler, expressed as a decimal fraction of the baseline energy input.

$EIS_{iactual}$ = Energy Input Savings for each energy conservation measure, i, implemented for an affected boiler, million Btu per year.

$EI_{baseline}$ = Energy Input baseline for the affected boiler, million Btu per year.

n = Number of energy conservation measures included in the efficiency credit for the affected boiler.

(ii) [Reserved]

(d) The owner or operator shall develop, and submit for approval upon request by the Administrator, an Implementation Plan containing all of the information required in this paragraph for all boilers to be included in an efficiency credit approach. The Implementation Plan shall identify all existing affected boilers to be included in applying the efficiency credits. The Implementation Plan shall include a description of the energy conservation measures implemented and the energy savings generated from each measure and an explanation of the criteria used for determining that savings. If requested, you must submit the implementation plan for efficiency credits to the Administrator for review and approval no later than 180 days before the date on which the facility intends to demonstrate compliance using the efficiency credit approach.

(e) The emissions rate as calculated using Equation 20 of this section from each existing boiler participating in the efficiency credit option must be in compliance with the limits in Table 2 to this subpart at all times the affected unit is operating, following the compliance date specified in § 63.7495.

(f) You must use Equation 20 of this section to demonstrate initial compliance by demonstrating that the emissions from the affected boiler participating in the efficiency credit compliance approach do not exceed the emission limits in Table 2 to this subpart.

$$E_{adj} = E_m \times (1 - ECredits) \quad \text{(Eq. 20)}$$

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Where:

E_{adj} = Emission level adjusted by applying the efficiency credits earned, lb per million Btu steam output (or lb per MWh) for the affected boiler.

E_m = Emissions measured during the performance test, lb per million Btu steam output (or lb per MWh) for the affected boiler.

ECredits = Efficiency credits from Equation 19 for the affected boiler.

(g) As part of each compliance report submitted as required under § 63.7550, you must include documentation that the energy conservation measures implemented continue to generate the credit for use in demonstrating compliance with the emission limits.

[76 FR 15664, Mar. 21, 2011, as amended at 78 FR 7178, Jan. 21, 2013]

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Continuous Compliance Requirements

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§ 63.7535 Is there a minimum amount of monitoring data I must obtain?

(a) You must monitor and collect data according to this section and the site-specific monitoring plan required by § 63.7505(d).

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

(c) You may not use data recorded during monitoring system malfunctions or out-of-control periods, repairs associated with monitoring system malfunctions or out-of-control periods, or required monitoring system quality assurance or control activities in data averages and calculations used to report emissions or operating levels. You must record and make available upon request results of CMS performance audits and dates and duration of periods when the CMS is out of control to completion of the corrective actions necessary to return the CMS to operation consistent with your site-specific monitoring plan. You must use all the data collected during all other periods in assessing compliance and the operation of the control device and associated control system.

(d) Except for periods of monitoring system malfunctions, repairs associated with monitoring system malfunctions, and required monitoring system quality assurance or quality control activities (including, as applicable, system accuracy audits, calibration checks, and required zero and span adjustments), failure to collect required data is a deviation of the monitoring requirements. In calculating monitoring results, do not use any data collected during periods when the monitoring system is out of control as specified in your site-specific monitoring plan, while conducting repairs associated with periods when the monitoring system is out of control, or while conducting required monitoring system quality assurance or quality control activities. You must calculate monitoring results using all other monitoring data collected while the process is operating. You must report all periods when the monitoring system is out of control in your annual report.

[76 FR 15664, Mar. 21, 2011, as amended at 78 FR 7179, Jan. 31, 2013]

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§ 63.7540 How do I demonstrate continuous compliance with the emission limitations, fuel specifications and work practice standards?

(a) You must demonstrate continuous compliance with each emission limit in Tables 1 and 2 or 11 through 13 to this subpart, the work practice standards in Table 3 to this subpart, and the operating limits in Table 4 to this subpart that applies to you according to the methods specified in Table 8 to this subpart and paragraphs (a)(1) through (19) of this section.

(1) Following the date on which the initial compliance demonstration is completed or is required to be completed under §§ 63.7 and 63.7510, whichever date comes first, operation above the established maximum or below the established minimum operating limits shall constitute a deviation of established operating limits listed in Table 4 of this subpart except during performance tests conducted to determine compliance with the emission limits or to establish new operating limits. Operating limits must be confirmed or reestablished during performance tests.

(2) As specified in § 63.7550(c), 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 result in either of the following:

(i) Lower emissions of HCl, mercury, and TSM than the applicable emission limit for each pollutant, if you demonstrate compliance through fuel analysis.

(ii) Lower fuel input of chlorine, mercury, and TSM than the maximum values calculated during the last performance test, if you demonstrate compliance through performance testing.

(3) If you demonstrate compliance with an applicable HCl emission limit through fuel analysis for a solid or liquid fuel and you plan to burn a new type of solid or liquid fuel, you must recalculate the HCl emission rate using Equation 12 of § 63.7530 according to paragraphs (a)(3)(i) through (iii) of this section. You are not required to conduct fuel analyses for the fuels described in § 63.7510(a)(2)(i) through (iii). You may exclude the fuels described in § 63.7510(a)(2)(i) through (iii) when recalculating the HCl emission rate.

(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 12 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 7 of § 63.7530. If the results of recalculating the maximum chlorine input using Equation 7 of § 63.7530 are greater 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(b). In recalculating the maximum chlorine input and establishing the new operating limits, you are not required to conduct fuel analyses for and include the fuels described in § 63.7510(a)(2)(i) through (iii).

(5) 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 13 of § 63.7530 according to the procedures specified in paragraphs (a)(5)(i) through (iii) of this section. You are not required to conduct fuel analyses for the fuels described in § 63.7510(a)(2)(i) through (iii). You may exclude the fuels described in § 63.7510(a)(2)(i) through (iii) when recalculating the mercury emission rate.

(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 13 of § 63.7530. The recalculated mercury emission rate must be less than the applicable emission limit.

(6) 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 8 of § 63.7530. If the results of recalculating the maximum mercury input using Equation 8 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(b). You are not required to conduct fuel analyses for the fuels described in § 63.7510(a)(2)(i) through (iii). You may exclude the fuels described in § 63.7510(a)(2)(i) through (iii) when recalculating the mercury emission rate.

(7) 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 alert and complete corrective actions as soon as practical, and operate and maintain the fabric filter system such that the periods which would cause an alert are no 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 alert, the time corrective action was initiated and completed, and a brief description of the cause of the alert and the corrective action taken. You must also record the percent of the operating time during each 6-month period that the conditions exist for an alert. In calculating this operating time percentage, if inspection of the fabric filter demonstrates that no corrective action is required, no alert time is counted. If corrective action is required, each alert shall be counted as a minimum of 1 hour. If you take longer than 1 hour to initiate corrective action, the alert time shall be counted as the actual amount of time taken to initiate corrective action.

(8) To demonstrate compliance with the applicable alternative CO CEMS emission limit listed in Tables 1, 2, or 11 through 13 to this subpart, you must meet the requirements in paragraphs (a)(8)(i) through (iv) of this section.

(i) Continuously monitor CO according to §§ 63.7525(a) and 63.7535.

(ii) Maintain a CO emission level below or at your applicable alternative CO CEMS-based standard in Tables 1 or 2 or 11 through 13 to this subpart at all times the affected unit is operating.

(iii) Keep records of CO levels according to § 63.7555(b).

(iv) You must record and make available upon request results of CO CEMS performance audits, dates and duration of periods when the CO CEMS is out of control to completion of the corrective actions necessary to return the CO CEMS to operation consistent with your site-specific monitoring plan.

(9) The owner or operator of a boiler or process heater using a PM CPMS or a PM CEMS to meet requirements of this subpart shall install, certify, operate, and maintain the PM CPMS or PM CEMS in accordance with your site-specific monitoring plan as required in § 63.7505(d).

(10) If your boiler or process heater has a heat input capacity of 10 million Btu per hour or greater, you must conduct an annual tune-up of the boiler or process heater to demonstrate continuous compliance as specified in paragraphs (a)(10)(i) through (vi) of this section. This frequency does not apply to limited-use boilers and process heaters, as defined in § 63.7575, or units with continuous oxygen trim systems that maintain an optimum air to fuel ratio.

(i) As applicable, inspect the burner, and clean or replace any components of the burner as necessary (you may delay the burner inspection until the next scheduled unit shutdown). Units that produce electricity for sale may delay the burner inspection until the first outage, not to exceed 36 months from the previous inspection. At units where entry into a piece of process equipment or into a storage vessel is required to complete the tune-up inspections, inspections are required only during planned entries into the storage vessel or process equipment;

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

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

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

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

(vi) Maintain on-site and submit, if requested by the Administrator, an annual report containing the information in paragraphs (a)(10)(vi)(A) through (C) of this section,

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

(B) A description of any corrective actions taken as a part of the tune-up; and

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

(11) If your boiler or process heater has a heat input capacity of less than 10 million Btu per hour (except as specified in paragraph (a)(12) of this section), you must conduct a biennial tune-up of the boiler or process heater as specified in paragraphs (a)(10)(i) through (vi) of this section to demonstrate continuous compliance.

(12) If your boiler or process heater has a continuous oxygen trim system that maintains an optimum air to fuel ratio, or a heat input capacity of less than or equal to 5 million Btu per hour and the unit is in the units designed to burn gas 1; units designed to burn gas 2 (other); or units designed to burn light liquid subcategories, or meets the definition of limited-use boiler or process heater in § 63.7575, you must conduct a tune-up of the boiler or process heater every 5 years as specified in paragraphs (a)(10)(i) through (vi) of this section to demonstrate continuous compliance. You may delay the burner inspection specified in paragraph (a)(10)(i) of this section until the next scheduled or unscheduled unit shutdown, but you must inspect each burner at least once every 72 months.

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

(14) If you are using a CEMS measuring mercury emissions to meet requirements of this subpart you must install, certify, operate, and maintain the mercury CEMS as specified in paragraphs (a)(14)(i) and (ii) of this section.

(i) Operate the mercury CEMS in accordance with performance specification 12A of 40 CFR part 60, appendix B or operate a sorbent trap based integrated monitor in accordance with performance specification 12B of 40 CFR part 60, appendix B. The duration of the performance test must be the maximum of 30 unit operating days or 720 hours. For each day in which the unit operates, you must obtain hourly mercury concentration data, and stack gas volumetric flow rate data.

(ii) If you are using a mercury CEMS, you must install, operate, calibrate, and maintain an instrument for continuously measuring and recording the mercury mass emissions rate to the atmosphere according to the requirements of performance specifications 6 and 12A of 40 CFR part 60, appendix B, and quality assurance procedure 6 of 40 CFR part 60, appendix F.

(15) If you are using a CEMS to measure HCl emissions to meet requirements of this subpart, you must install, certify, operate, and maintain the HCl CEMS as specified in paragraphs (a)(15)(i) and (ii) of this section. This option for an affected unit takes effect on the date a final performance specification for an HCl CEMS is published in the FEDERAL REGISTER or the date of approval of a site-specific monitoring plan.

(i) Operate the continuous emissions monitoring system in accordance with the applicable performance specification in 40 CFR part 60, appendix B. The duration of the performance test must be the maximum of 30 unit operating days or 720 hours. For each day in which the unit operates, you must obtain hourly HCl concentration data, and stack gas volumetric flow rate data.

(ii) If you are using a HCl CEMS, you must install, operate, calibrate, and maintain an instrument for continuously measuring and recording the HCl mass emissions rate to the atmosphere according to the requirements of the applicable performance specification of 40 CFR part 60, appendix B, and the quality assurance procedures of 40 CFR part 60, appendix F.

(16) 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 9 of § 63.7530. If the results of recalculating the maximum TSM input using

Equation 9 of § 63.7530 are higher than the maximum total selected 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(b). You are not required to conduct fuel analyses for the fuels described in § 63.7510(a)(2)(i) through (iii). You may exclude the fuels described in § 63.7510(a)(2)(i) through (iii) when recalculating the TSM emission rate.

(17) If you demonstrate compliance with an applicable TSM emission limit through fuel analysis for solid or liquid fuels, and you plan to burn a new type of fuel, you must recalculate the TSM emission rate using Equation 14 of § 63.7530 according to the procedures specified in paragraphs (a)(5)(i) through (iii) of this section. You are not required to conduct fuel analyses for the fuels described in § 63.7510(a)(2)(i) through (iii). You may exclude the fuels described in § 63.7510(a)(2)(i) through (iii) when recalculating the TSM emission rate.

(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 14 of § 63.7530. The recalculated TSM emission rate must be less than the applicable emission limit.

(18) If you demonstrate continuous PM emissions compliance with a PM CPMS you will use a PM CPMS to establish a site-specific operating limit corresponding to the results of the performance test demonstrating compliance with the PM limit. You will conduct your performance test using the test method criteria in Table 5 of this subpart. You will use the PM CPMS to demonstrate continuous compliance with this operating limit. You must repeat the performance test annually and reassess and adjust the site-specific operating limit in accordance with the results of the performance test.

(i) To determine continuous compliance, you must record the PM CPMS output data for all periods when the process is operating and the PM CPMS is not out-of-control. You must demonstrate continuous compliance by using all quality-assured hourly average data collected by the PM CPMS for all operating hours to calculate the arithmetic average operating parameter in units of the operating limit (milliamps) on a 30-day rolling average basis, updated at the end of each new boiler or process heater operating hour.

(ii) For any deviation of the 30-day rolling PM CPMS average value from the established operating parameter limit, you must:

(A) Within 48 hours of the deviation, visually inspect the air pollution control device (APCD);

(B) If inspection of the APCD identifies the cause of the deviation, take corrective action as soon as possible and return the PM CPMS measurement to within the established value; and

(C) Within 30 days of the deviation or at the time of the annual compliance test, whichever comes first, conduct a PM emissions compliance test to determine compliance with the PM emissions limit and to verify or re-establish the CPMS operating limit. You are not required to conduct additional testing for any deviations that occur between the time of the original deviation and the PM emissions compliance test required under this paragraph.

(iii) PM CPMS deviations from the operating limit leading to more than four required performance tests in a 12-month operating period constitute a separate violation of this subpart.

(19) If you choose to comply with the PM filterable emissions limit by using PM CEMS you must install, certify, operate, and maintain a PM CEMS and record the output of the PM CEMS as specified in paragraphs (a)(19)(i) through (vii) of this section. The compliance limit will be expressed as a 30-day rolling average of the numerical emissions limit value applicable for your unit in Tables 1 or 2 or 11 through 13 of this subpart.

(i) Install and certify your PM CEMS according to the procedures and requirements in Performance Specification 11—Specifications and Test Procedures for Particulate Matter Continuous Emission Monitoring Systems at Stationary Sources in Appendix B to part 60 of this chapter, using test criteria outlined in Table V of this rule. The reportable measurement output from the PM CEMS must be expressed in units of the applicable emissions limit (e.g., lb/MMBtu, lb/MWh).

(ii) Operate and maintain your PM CEMS according to the procedures and requirements in Procedure 2—Quality Assurance Requirements for Particulate Matter Continuous Emission Monitoring Systems at Stationary Sources in Appendix F to part 60 of this chapter.

(A) You must conduct the relative response audit (RRA) for your PM CEMS at least once annually.

(B) You must conduct the relative correlation audit (RCA) for your PM CEMS at least once every 3 years.

(iii) Collect PM CEMS hourly average output data for all boiler operating hours except as indicated in paragraph (i) of this section.

(iv) Calculate the arithmetic 30-day rolling average of all of the hourly average PM CEMS output data collected during all nonexempt boiler or process heater operating hours.

(v) You must collect data using the PM CEMS at all times the unit is operating and at the intervals specified this paragraph (a), except for periods of monitoring system malfunctions, repairs associated with monitoring system malfunctions, and required monitoring system quality assurance or quality control activities.

(vi) You must use all the data collected during all boiler or process heater operating hours in assessing the compliance with your operating limit except:

(A) Any data collected during monitoring system malfunctions, repairs associated with monitoring system malfunctions, or required monitoring system quality assurance or control activities conducted during monitoring system malfunctions in calculations and report any such periods in your annual deviation report;

(B) Any data collected during periods when the monitoring system is out of control as specified in your site-specific monitoring plan, repairs associated with periods when the monitoring system is out of control, or required monitoring system quality assurance or control activities conducted during out of control periods in calculations used to report emissions or operating levels and report any such periods in your annual deviation report;

(C) Any data recorded during periods of startup or shutdown.

(vii) You must record and make available upon request results of PM CEMS system performance audits, dates and duration of periods when the PM CEMS is out of control to completion of the corrective actions necessary to return the PM CEMS to operation consistent with your site-specific monitoring plan.

(b) You must report each instance in which you did not meet each emission limit and operating limit in Tables 1 through 4 or 11 through 13 to this subpart that apply to you. These instances are deviations from the emission limits or operating limits, respectively, in this subpart. These deviations must be reported according to the requirements in § 63.7550.

(c) If you elected to demonstrate that the unit meets the specification for mercury for the unit designed to burn gas 1 subcategory, you must follow the sampling frequency specified in paragraphs (c)(1) through (4) of this section and conduct this sampling according to the procedures in § 63.7521(f) through (i).

(1) If the initial mercury constituents in the gaseous fuels are measured to be equal to or less than half of the mercury specification as defined in § 63.7575, you do not need to conduct further sampling.

(2) If the initial mercury constituents are greater than half but equal to or less than 75 percent of the mercury specification as defined in § 63.7575, you will conduct semi-annual sampling. If 6 consecutive semi-annual fuel analyses demonstrate 50 percent or less of the mercury specification, you do not need to conduct further sampling. If any semi-annual sample exceeds 75 percent of the mercury specification, you must return to monthly sampling for that fuel, until 12 months of fuel analyses again are less than 75 percent of the compliance level.

(3) If the initial mercury constituents are greater than 75 percent of the mercury specification as defined in § 63.7575, you will conduct monthly sampling. If 12 consecutive monthly fuel analyses demonstrate 75 percent or less of the mercury specification, you may decrease the fuel analysis frequency to semi-annual for that fuel.

(4) If the initial sample exceeds the mercury specification as defined in § 63.7575, each affected boiler or process heater combusting this fuel is not part of the unit designed to burn gas 1 subcategory and must be in compliance with the emission and operating limits for the appropriate subcategory. You may elect to conduct additional monthly sampling while complying with these emissions and operating limits to demonstrate that the fuel qualifies as another gas 1 fuel. If 12 consecutive monthly fuel analyses samples are at or below the mercury specification as defined in § 63.7575, each affected boiler or process heater combusting the fuel can elect to switch back into the unit designed to burn gas 1 subcategory until the mercury specification is exceeded.

(d) For startup and shutdown, you must meet the work practice standards according to item 5 of Table 3 of this subpart.

[78 FR 7179, Jan. 31, 2013]

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§ 63.7541 How do I demonstrate continuous compliance under the emissions 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 units 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) and (ii) of this section.

(i) For each existing unit 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 units participating in the emissions averaging option where each unit in the group is equipped with a dry control system and vented to a common stack that does not receive emissions from non-affected units, maintain opacity at or below the applicable limit at the common stack.

(3) For each existing unit participating in the emissions averaging option that is equipped with a wet scrubber, maintain the 30-day rolling average parameter values at or above the operating limits established during the most recent performance test.

(4) For each existing unit participating in the emissions averaging option that has an approved alternative operating parameter, maintain the 30-day rolling average parameter values consistent with the approved monitoring plan.

(5) For each existing unit participating in the emissions averaging option venting to a common stack configuration containing affected units from other subcategories, maintain the appropriate operating limit for each unit as specified in Table 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 is a deviation.

[76 FR 15664, Mar. 21, 2013, as amended at 78 FR 7182, Jan. 31, 2013]

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Notification, Reports, and Records

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§ 63.7545 What notifications must I submit and when?

(a) You must submit to the Administrator 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 January 31, 2013, you must submit an Initial Notification not later than 120 days after January 31, 2013.

(c) As specified in § 63.9(b)(4) and (5), if you startup your new or reconstructed affected source on or after January 31, 2013, 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 60 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, you must submit a Notification of Compliance Status according to § 63.9(h)(2)(ii). For the initial compliance demonstration for each boiler or process heater, 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 all performance test and/or other initial compliance demonstrations for all boiler or process heaters at the facility according to § 63.10(d)(2). The Notification of Compliance Status report must contain all the information specified in paragraphs (e)(1) through (8), as applicable. If you are not required to conduct an initial compliance demonstration as specified in § 63.7530(a), the Notification of Compliance Status must only contain the information specified in paragraphs (e)(1) and (8).

(1) A description of the affected unit(s) including identification of which subcategories the unit is in, the design heat input capacity of the unit, a description of the add-on controls used on the unit to comply with this subpart, description of the fuel(s) burned, including whether the fuel(s) were a secondary material determined by you or the EPA through a petition process to be a non-waste under § 241.3 of this chapter, whether the fuel(s) were a secondary material processed from discarded non-hazardous secondary materials within the meaning of § 241.3 of this chapter, and justification for the selection of fuel(s) burned during the compliance demonstration.

(2) Summary of the results of all performance tests and fuel analyses, and calculations conducted to demonstrate initial compliance including all established operating limits, and including:

(i) Identification of whether you are complying with the PM emission limit or the alternative TSM emission limit.

(ii) Identification of whether you are complying with the output-based emission limits or the heat input-based (i.e., lb/MMBtu or ppm) emission limits,

(3) A summary of the maximum CO emission levels recorded during the performance test to show that you have met any applicable emission standard in Tables 1, 2, or 11 through 13 to this subpart, if you are not using a CO CEMS to demonstrate compliance.

(4) Identification of whether you plan to demonstrate compliance with each applicable emission limit through performance testing, a CEMS, or fuel analysis.

(5) Identification of whether you plan to demonstrate compliance by emissions averaging and identification of whether you plan to demonstrate compliance by using efficiency credits through energy conservation:

(i) If you plan to demonstrate compliance by emission averaging, report the emission level that was being achieved or the control technology employed on January 31, 2013.

(ii) [Reserved]

(6) A signed certification that you have met all applicable emission limits and work practice standards.

(7) If you had a deviation from any emission limit, work practice standard, or operating limit, 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.

(8) In addition to the information required in § 63.9(h)(2), your notification of compliance status must include the following certification(s) of compliance, as applicable, and signed by a responsible official:

(i) “This facility complies with the required initial tune-up according to the procedures in § 63.7540(a)(10)(i) through (vi).”

(ii) “This facility has had an energy assessment performed according to § 63.7530(e).”

(iii) Except for units that burn only natural gas, refinery gas, or other gas 1 fuel, or units that qualify for a statutory exemption as provided in section 129(g)(1) of the Clean Air Act, include the following: “No secondary materials that are solid waste were combusted in any affected unit.”

(f) If you operate a unit designed to burn natural gas, refinery gas, or other gas 1 fuels that is subject to this subpart, and you intend to use a fuel other than natural gas, refinery gas, gaseous fuel subject to another subpart of this part, part 60, 61, or 65, or other gas 1 fuel to fire the affected unit during a period of natural gas curtailment or supply interruption, as defined in § 63.7575, you must submit a notification of alternative fuel use within 48 hours of the declaration of each period of natural gas curtailment or supply interruption, as defined in § 63.7575. The notification must include the information specified in paragraphs (f)(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.

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

(1) The name of the owner or operator of the affected source, as defined in § 63.7490, the location of the source, the boiler(s) or process heater(s) that will commence burning solid waste, and the date of the notice.

(2) The currently applicable subcategories under this subpart.

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

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

(h) If you have switched fuels or made a physical change to the boiler and the fuel switch or physical change resulted in the applicability of a different subcategory, you must provide notice of the date upon which you switched fuels or made the physical change within 30 days of the switch/change. The notification must identify:

(1) The name of the owner or operator of the affected source, as defined in § 63.7490, the location of the source, the boiler(s) and process heater(s) that have switched fuels, were physically changed, and the date of the notice.

(2) The currently applicable subcategory under this subpart.

(3) The date upon which the fuel switch or physical change occurred.

[76 FR 15664, Mar. 21, 2011, as amended at 78 FR 7183, Jan. 31, 2013]

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§ 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, according to paragraph (h) of this section, by the date in Table 9 to this subpart and according to the requirements in paragraphs (b)(1) through (4) of this section. For units that are subject only to a requirement to conduct an annual, biennial, or 5-year tune-up according to § 63.7540(a)(10), (11), or (12), respectively, and not subject to emission limits or operating limits, you may submit only an annual, biennial, or 5-year compliance report, as applicable, as specified in paragraphs (b)(1) through (4) of this section, instead of a semi-annual compliance report.

(1) The first compliance report must cover the period beginning on the compliance date that is specified for each boiler or process heater in § 63.7495 and ending on July 31 or January 31, whichever date is the first date that occurs at least 180 days (or 1, 2, or 5 years, as applicable, if submitting an annual, biennial, or 5-year compliance report) after the compliance date that is specified for your source in § 63.7495.

(2) The first compliance report must be postmarked or submitted 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 each boiler or process heater in § 63.7495. The first annual, biennial, or 5-year compliance report must be postmarked or submitted no later than January 31.

(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. Annual, biennial, and 5-year compliance reports must cover the applicable 1-, 2-, or 5-year periods from January 1 to December 31.

(4) Each subsequent compliance report must be postmarked or submitted no later than July 31 or January 31, whichever date is the first date following the end of the semiannual reporting period. Annual, biennial, and 5-year compliance reports must be postmarked or submitted no later than January 31.

(c) A compliance report must contain the following information depending on how the facility chooses to comply with the limits set in this rule.

(1) If the facility is subject to a the requirements of a tune up they must submit a compliance report with the information in paragraphs (c)(5)(i) through (iv) and (xiv) of this section.

(2) If a facility is complying with the fuel analysis they must submit a compliance report with the information in paragraphs (c)(5)(i) through (iv), (vi), (x), (xi), (xiii), (xv) and paragraph (d) of this section.

(3) If a facility is complying with the applicable emissions limit with performance testing they must submit a compliance report with the information in (c)(5)(i) through (iv), (vi), (vii), (ix), (xi), (xiii), (xv) and paragraph (d) of this section.

(4) If a facility is complying with an emissions limit using a CMS the compliance report must contain the information required in paragraphs (c)(5)(i) through (vi), (xi), (xiii), (xv) through (xvii), and paragraph (e) of this section.

(5)(i) Company and Facility name and address.

(ii) Process unit information, emissions limitations, and operating parameter limitations.

(iii) Date of report and beginning and ending dates of the reporting period.

(iv) The total operating time during the reporting period.

(v) If you use a CMS, including CEMS, COMS, or CPMS, you must include the monitoring equipment manufacturer(s) and model numbers and the date of the last CMS certification or audit.

(vi) The total fuel use by each individual boiler or process heater subject to an emission limit within the reporting period, including, but not limited to, a description of the fuel, whether the fuel has received a non-waste determination by the EPA or your basis for concluding that the fuel is not a waste, and the total fuel usage amount with units of measure.

(vii) If you are conducting performance tests once every 3 years consistent with § 63.7515(b) or (c), the date of the last 2 performance tests and a statement as to whether there have been any operational changes since the last performance test that could increase emissions.

(viii) A statement indicating that you burned no new types of fuel in an individual boiler or process heater subject to an emission limit. Or, if you did burn a new type of fuel and are subject to a HCl emission limit, you must submit the calculation of chlorine input, using Equation 7 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 12 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 and are subject to a mercury emission limit, you must submit the calculation of mercury input, using Equation 8 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 13 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). If you burned a new type of fuel and are subject to a TSM emission limit, you must submit the calculation of TSM input, using Equation 9 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 14 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).

(ix) If you wish to burn a new type of fuel in an individual boiler or process heater subject to an emission limit and you cannot demonstrate compliance with the maximum chlorine input operating limit using Equation 7 of § 63.7530 or the maximum mercury input operating limit using Equation 8 of § 63.7530, or the maximum TSM input operating limit using Equation 9 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.

(x) A summary of any monthly fuel analyses conducted to demonstrate compliance according to §§ 63.7521 and 63.7530 for individual boilers or process heaters subject to emission limits, and any fuel specification analyses conducted according to §§ 63.7521(f) and 63.7530(g).

(xi) If there are no deviations from any emission limits or operating limits in this subpart that apply to you, a statement that there were no deviations from the emission limits or operating limits during the reporting period.

(xii) If there were no deviations from the monitoring requirements including 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 deviations and no periods during which the CMS were out of control during the reporting period.

(xiii) If a malfunction occurred during the reporting period, the report must include the number, duration, and a brief description for each type of malfunction which occurred during the reporting period and which caused or may have caused any applicable emission limitation to be exceeded. The report must also include a description of actions taken by you during a malfunction of a boiler, process heater, or associated air pollution control device or CMS to minimize emissions in accordance with § 63.7500(a)(3), including actions taken to correct the malfunction.

(xiv) Include the date of the most recent tune-up for each unit subject to only the requirement to conduct an annual, biennial, or 5-year tune-up according to § 63.7540(a)(10), (11), or (12) respectively. Include the date of the most recent burner inspection if it was not done annually, biennially, or on a 5-year period and was delayed until the next scheduled or unscheduled unit shutdown.

(xv) If you plan to demonstrate compliance by emission averaging, certify the emission level achieved or the control technology employed is no less stringent than the level or control technology contained in the notification of compliance status in § 63.7545(e)(5)(i).

(xvi) For each reporting period, the compliance reports must include all of the calculated 30 day rolling average values based on the daily CEMS (CO and mercury) and CPMS (PM CPMS output, scrubber pH, scrubber liquid flow rate, scrubber pressure drop) data.

(xvii) 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.

(d) For each deviation from an emission limit or operating limit in this subpart that occurs at an individual boiler or process heater where you are not using a CMS to comply with that emission limit or operating limit, the compliance report must additionally contain the information required in paragraphs (d)(1) through (3) of this section.

(1) A description of the deviation and which emission limit or operating limit from which you deviated.

(2) Information on the number, duration, and cause of deviations (including unknown cause), as applicable, and the corrective action taken.

(3) If the deviation occurred during an annual performance test, provide the date the annual performance test was completed.

(e) For each deviation from an emission limit, operating limit, and monitoring requirement in this subpart occurring at an individual boiler or process heater where you are using a CMS to comply with that emission limit or operating limit, the compliance report must additionally contain the information required in paragraphs (e)(1) through (9) of this section. This includes any deviations from your site-specific monitoring plan as required in § 63.7505(d).

(1) The date and time that each deviation 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.

(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 characterization of the total duration of the deviations during the reporting period into those that are due to control equipment problems, process problems, other known causes, and other unknown causes.

(7) A summary of the total duration of CMS's 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) A brief description of the source for which there was a deviation.

(9) 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)-(g) [Reserved]

(h) You must submit the reports according to the procedures specified in paragraphs (h)(1) through (3) of this section.

(1) Within 60 days after the date of completing each performance test (defined in § 63.2) as required by this subpart you must submit the results of the performance tests, including any associated fuel analyses, required by this subpart and the compliance reports required in § 63.7550(b) to the EPA's WebFIRE database by using the Compliance and Emissions Data Reporting Interface (CEDRI) that is accessed through the EPA's Central Data Exchange (CDX) (*www.epa.gov/cdx*). Performance test data must be submitted in the file format generated through use of the EPA's Electronic Reporting Tool (ERT) (see *http://www.epa.gov/ttn/chief/ert/index.html*). Only data collected using test methods on the ERT Web site are subject to this requirement for submitting reports electronically to WebFIRE. Owners or operators who claim that some of the information being submitted for performance tests is confidential business information (CBI) must submit a complete ERT file including information claimed to be CBI on a compact disk or other commonly used electronic storage media (including, but not limited to, flash drives) to the EPA. The electronic media must be clearly marked as CBI and mailed to U.S. EPA/OAPQS/CORE CBI Office, Attention: WebFIRE Administrator, MD C404-02, 4930 Old Page Rd., Durham, NC 27703. The same ERT file with the CBI omitted must be submitted to the EPA via CDX as described earlier in this paragraph. At the discretion of the Administrator, you must also submit these reports, including the confidential business information, to the Administrator in the format specified by the Administrator. For any performance test conducted using test methods that are not listed on the ERT Web site, the owner or operator shall submit the results of the performance test in paper submissions to the Administrator.

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

(3) You must submit all reports required by Table 9 of this subpart electronically using CEDRI that is accessed through the EPA's Central Data Exchange (CDX) (*www.epa.gov/cdx*). However, if the reporting form specific to this subpart is not available in CEDRI at the time that the report is due the report you must submit the report to the Administrator at the appropriate address listed in § 63.13. At the discretion of the Administrator, you must also submit these reports, to the Administrator in the format specified by the Administrator.

[78 FR 7183, Jan. 31, 2013]

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§ 63.7555 What records must I keep?

(a) You must keep records according to paragraphs (a)(1) and (2) 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) Records of performance tests, fuel analyses, or other compliance demonstrations and performance evaluations as required in § 63.10(b)(2)(viii).

(b) For each CEMS, COMS, and continuous monitoring system you must keep records according to paragraphs (b)(1) through (5) of this section.

(1) Records described in § 63.10(b)(2)(vii) 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.

(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, pH, and operating load, to show continuous compliance with each emission limit and operating limit that applies to you.

(d) For each boiler or process heater subject to an emission limit in Tables 1, 2, or 11 through 13 to this subpart, you must also keep the applicable records in paragraphs (d)(1) through (11) of this section.

(2) If you combust non-hazardous secondary materials that have been determined not to be solid waste pursuant to § 241.3(b)(1) and (2) of this chapter, you must keep a record that documents how the secondary material meets each of the legitimacy criteria under § 241.3(d)(1) of this chapter. If you combust a fuel that has been processed from a discarded non-hazardous secondary material pursuant to § 241.3(b)(4) of this chapter, you must keep records as to how the operations that produced the fuel satisfy the definition of processing in § 241.2 of this chapter. If the fuel received a non-waste determination pursuant to the petition process submitted under § 241.3(c) of this chapter, you must keep a record that documents how the fuel satisfies the requirements of the petition process. For operating units that combust non-hazardous secondary materials as fuel per § 241.4 of this chapter, you must keep records documenting that the material is listed as a non-waste under § 241.4(a) of this chapter. Units exempt from the incinerator standards under section 129(g)(1) of the Clean Air Act because they are qualifying facilities burning a homogeneous waste stream do not need to maintain the records described in this paragraph (d)(2).

(3) For units in the limited use subcategory, you must keep a copy of the federally enforceable permit that limits the annual capacity factor to less than or equal to 10 percent and fuel use records for the days the boiler or process heater was operating.

(4) A copy of all calculations and supporting documentation of maximum chlorine fuel input, using Equation 7 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 12 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.

(5) A copy of all calculations and supporting documentation of maximum mercury fuel input, using Equation 8 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 13 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.

(6) If, consistent with § 63.7515(b), you choose to stack test less frequently than annually, you must keep a record that documents that your emissions in the previous stack test(s) were less than 75 percent of the applicable emission limit (or, in specific instances noted in Tables 1 and 2 or 11 through 13 to this subpart, less than the applicable emission limit), and document that there was no change in source operations including fuel composition and operation of air pollution control equipment that would cause emissions of the relevant pollutant to increase within the past year.

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

(8) Records of actions taken during periods of malfunction to minimize emissions in accordance with the general duty to minimize emissions in § 63.7500(a)(3), including corrective actions to restore the malfunctioning boiler or process heater, air pollution control, or monitoring equipment to its normal or usual manner of operation.

(9) A copy of all calculations and supporting documentation of maximum TSM fuel input, using Equation 9 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 14 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.

(10) You must maintain records of the calendar date, time, occurrence and duration of each startup and shutdown.

(11) You must maintain records of the type(s) and amount(s) of fuels used during each startup and shutdown.

(e) If you elect to average emissions consistent with § 63.7522, you must additionally keep a copy of the emission averaging implementation plan required in § 63.7522(g), all calculations required under § 63.7522, including monthly records of heat input or steam generation, as applicable, and monitoring records consistent with § 63.7541.

(f) If you elect to use efficiency credits from energy conservation measures to demonstrate compliance according to § 63.7533, you must keep a copy of the Implementation Plan required in § 63.7533(d) and copies of all data and calculations used to establish credits according to § 63.7533(b), (c), and (f).

(g) If you elected to demonstrate that the unit meets the specification for mercury for the unit designed to burn gas 1 subcategory, you must maintain monthly records (or at the frequency required by § 63.7540(c)) of the calculations and results of the fuel specification for mercury in Table 6.

(h) If you operate a unit in the unit designed to burn gas 1 subcategory that is subject to this subpart, and you use an alternative fuel other than natural gas, refinery gas, gaseous fuel subject to another subpart under this part, other gas 1 fuel, or gaseous fuel subject to another subpart of this part or part 60, 61, or 65, you must keep records of the total hours per calendar year that alternative fuel is burned and the total hours per calendar year that the unit operated during periods of gas curtailment or gas supply emergencies.

(i) You must maintain records of the calendar date, time, occurrence and duration of each startup and shutdown.

(j) You must maintain records of the type(s) and amount(s) of fuels used during each startup and shutdown.

[76 FR 15664, Mar. 21, 2011 as amended at 78 FR 715, Jan. 31, 2013]

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§ 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, or they must be accessible from on site (for example, through a computer network), 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.

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Other Requirements and Information

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§ 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.

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§ 63.7570 Who implements and enforces this subpart?

(a) This subpart can be implemented and enforced by the EPA, or an Administrator such as your state, local, or tribal agency. If the EPA Administrator has delegated authority to your state, local, or tribal agency, then that agency (as well as the 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 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, and alternative analytical methods requested under § 63.7521(b)(2).

(4) Approval of major change to monitoring under § 63.8(f) and as defined in § 63.90, and approval of alternative operating parameters under § 63.7500(a)(2) and § 63.7522(g)(2).

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

[76 FR 15664, Mar. 21, 2011 as amended at 78 FR 7186, Jan. 31, 2013]

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§ 63.7575 What definitions apply to this subpart?

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

10-day rolling average means the arithmetic mean of the previous 240 hours of valid operating data. Valid data excludes hours during startup and shutdown, data collected during periods when the monitoring system is out of control as specified in your site-specific monitoring plan, while conducting repairs associated with periods when the monitoring system is out of control, or while conducting required monitoring system quality assurance or quality control activities, and periods when this unit is not operating. The 240 hours should be consecutive, but not necessarily continuous if operations were intermittent.

30-day rolling average means the arithmetic mean of the previous 720 hours of valid operating data. Valid data excludes hours during startup and shutdown, data collected during periods when the monitoring system is out of control as specified in your site-specific monitoring plan, while conducting repairs associated with periods when the monitoring system is out of control, or while conducting required monitoring system quality assurance or quality control activities, and periods when this unit is not operating. The 720 hours should be consecutive, but not necessarily continuous if operations were intermittent.

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

Annual 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.

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

Average annual heat input rate means total heat input divided by the hours of operation for the 12 months preceding the compliance demonstration.

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

Benchmark means the fuel heat input for a boiler or process heater for the one-year period before the date that an energy demand reduction occurs, unless it can be demonstrated that a different time period is more representative of historical operations.

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

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

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 annual gas volume 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. Controlled flame combustion refers to a steady-state, or near steady-state, process wherein fuel and/or oxidizer feed rates are controlled. A device combusting solid waste, as defined in § 241.3 of this chapter, is not a boiler unless the device is exempt from the definition of a solid waste incineration unit as provided in section 129(g)(1) of the Clean Air Act. Waste heat boilers are excluded from this definition.

Boiler system means the boiler and associated components, such as, the feed water system, the combustion air system, the fuel system (including burners), blowdown system, combustion control systems, steam systems, and condensate return systems.

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

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

Coal 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, nursing homes, research centers, institutions of higher education, elementary and secondary schools, libraries, religious establishments, governmental buildings, hotels, restaurants, and laundries to provide electricity, steam, and/or hot water.

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

Cost-effective energy conservation measure means a measure that is implemented to improve the energy efficiency of the boiler or facility that has a payback (return of investment) period of 2 years or less.

Daily block average means the arithmetic mean of all valid emission concentrations or parameter levels recorded when a unit is operating measured over the 24-hour period from 12 a.m. (midnight) to 12 a.m. (midnight), except for periods of startup and shutdown or downtime.

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

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

(2) A deviation is not always a violation.

Dioxins/furans means tetra- through octa-chlorinated dibenzo-p-dioxins and dibenzofurans.

Distillate oil means fuel oils that contain 0.05 weight percent nitrogen or less and comply with the specifications for fuel oil numbers 1 and 2, as defined by the American Society of Testing and Materials in ASTM D396 (incorporated by reference, see § 63.14) or diesel fuel oil numbers 1 and 2, as defined by the American Society for Testing and Materials in ASTM D975 (incorporated by reference, see § 63.14), kerosene, and biodiesel as defined by the American Society of Testing and Materials in ASTM D6751-11b (incorporated by reference, see § 60.14).

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

Dutch oven means a unit having a refractory-walled cell connected to a conventional boiler setting. Fuel materials are introduced through an opening in the roof of the dutch oven and burn in a pile on its floor. Fluidized bed boilers are not part of the dutch oven design category.

Efficiency credit means emission reductions above those required by this subpart. Efficiency credits generated may be used to comply with the emissions limits. Credits may come from pollution prevention projects that result in reduced fuel use by affected units. Boilers that are shut down cannot be used to generate credits unless the facility provides documentation linking the permanent shutdown to implementation of the energy conservation measures identified in the energy assessment.

Electric utility steam generating unit (EGU) means a fossil fuel-fired combustion unit of more than 25 megawatts electric (MWe) 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 MWe output to any utility power distribution system for sale is considered an electric utility steam generating unit. To be “capable of combusting” fossil fuels, an EGU would need to have these fuels allowed in their operating permits and have the appropriate fuel handling facilities on-site or otherwise available (e.g., coal handling equipment, including coal storage area, belts and conveyers, pulverizers, etc.; oil storage facilities). In addition, fossil fuel-fired EGU means any EGU that fired fossil fuel for more than 10.0 percent of the average annual heat input in any 3 consecutive calendar years or for more than 15.0 percent of the annual heat input during any one calendar year after April 16, 2012.

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

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

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

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

(3) The energy assessment for facilities with affected boilers and process heaters with a combined heat input capacity greater than 1.0 TBtu/year will be up to 24 on-site technical labor hours in length for the first TBtu/yr plus 8 on-site technical labor hours for every additional 1.0 TBtu/yr not to exceed 160 on-site technical hours, but may be longer at the discretion of the owner or operator of the affected source. The boiler system(s), process heater(s), and any on-site energy use system(s) accounting for at least 20

percent of the energy (e.g., steam, process heat, hot water, or electricity) production, as applicable, will be evaluated to identify energy savings opportunities.

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

Energy management practices means the set of practices and procedures designed to manage energy use that are demonstrated by the facility's energy policies, a facility energy manager and other staffing responsibilities, energy performance measurement and tracking methods, an energy saving goal, action plans, operating procedures, internal reporting requirements, and periodic review intervals used at the facility.

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

Energy use system includes the following systems located on-site that use energy (steam, hot water, or electricity) provided by the affected boiler or process heater: process heating; compressed air systems; machine drive (motors, pumps, fans); process cooling; facility heating, ventilation, and air-conditioning systems; hot water systems; building envelop; and lighting; or other systems that use steam, hot water, process heat, or electricity provided by the affected boiler or process heater. Energy use systems are only those systems using energy clearly produced by affected boilers and process heaters.

Equivalent means the following only as this term is used in Table 6 to this subpart:

(1) An equivalent sample collection procedure means a published voluntary consensus standard or practice (VCS) or EPA method that includes collection of a minimum of three composite fuel samples, with each composite consisting of a minimum of three increments collected at approximately equal intervals over the test period.

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

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

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

(5) An equivalent procedure for determining fuel moisture content means a published VCS or EPA method to obtain moisture content. If the sample analysis plan calls for determining 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, HCl) 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 this subpart for the same purpose.

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

Federally enforceable means all limitations and conditions that are enforceable by the EPA Administrator, including, but not limited to, the requirements of 40 CFR parts 60, 61, 63, and 65, requirements within any applicable state implementation plan, and any permit requirements established under 40 CFR 52.21 or under 40 CFR 51.18 and 40 CFR 51.24.

Fluidized bed boiler means a boiler utilizing a fluidized bed combustion process that is not a pulverized coal boiler.

Fluidized bed boiler with an integrated fluidized bed heat exchanger means a boiler utilizing a fluidized bed combustion where the entire tube surface area is located outside of the furnace section at the exit of the cyclone section and exposed to the flue gas stream for conductive heat transfer. This design applies only to boilers in the unit designed to burn coal/solid fossil fuel subcategory that fire coal refuse.

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

Fuel cell means a boiler type in which the fuel is dropped onto suspended fixed grates and is fired in a pile. The refractory-lined fuel cell uses combustion air preheating and positioning of secondary and tertiary air injection ports to improve boiler efficiency. Fluidized bed, dutch oven, pile burner, hybrid suspension grate, and suspension burners are not part of the fuel cell subcategory.

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

Gaseous fuel includes, but is not limited to, natural gas, process gas, landfill gas, coal derived gas, refinery gas, and biogas. Blast furnace gas and process gases that are regulated under another subpart of this part, or part 60, part 61, or part 65 of this chapter, are 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, returned condensate, or exhaust gases from other sources such as gas turbines, internal combustion engines, kilns, etc.

Heavy liquid includes residual oil and any other liquid fuel not classified as a light liquid.

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

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

MMBtu/hr heat input capacity threshold for hot water boilers. Hot water heater also means a tankless unit that provides on demand hot water.

Hybrid suspension grate boiler means a boiler designed with air distributors to spread the fuel material over the entire width and depth of the boiler combustion zone. The biomass fuel combusted in these units exceeds a moisture content of 40 percent on an as-fired annual heat input basis. The drying and much of the combustion of the fuel takes place in suspension, and the combustion is completed on the grate or floor of the boiler. Fluidized bed, dutch oven, and pile burner designs are not part of the hybrid suspension grate boiler design category.

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

Light liquid includes distillate oil, biodiesel, or vegetable oil.

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

Liquid fuel includes, but is not limited to, light liquid, heavy liquid, any form of liquid fuel derived from petroleum, used oil, liquid biofuels, biodiesel, vegetable oil, and comparable fuels as defined under 40 CFR 261.38.

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

Major source for oil and natural gas production facilities, as used in this subpart, shall have the same meaning as in § 63.2, except that:

(1) Emissions from any oil or gas exploration or production well (with its associated equipment, as defined in this section), and emissions from any pipeline compressor station or pump station shall not be aggregated with emissions from other similar units to determine whether such emission points or stations are major sources, even when emission points are in a contiguous area or under common control;

(2) Emissions from processes, operations, or equipment that are not part of the same facility, as defined in this section, shall not be aggregated; and

(3) For facilities that are production field facilities, only HAP emissions from glycol dehydration units and storage vessels with the potential for flash emissions shall be aggregated for a major source determination. For facilities that are not production field facilities, HAP emissions from all HAP emission units shall be aggregated for a major source determination.

Metal process furnaces are a subcategory of process heaters, as defined in this subpart, which include natural gas-fired annealing furnaces, preheat furnaces, reheat furnaces, aging furnaces, heat treat furnaces, and homogenizing furnaces.

Million Btu (MMBtu) means one million British thermal units.

Minimum activated carbon injection rate means load fraction multiplied by the lowest hourly average activated carbon injection rate measured according to Table 7 to this subpart during the most recent performance test demonstrating compliance with the applicable emission limit.

Minimum oxygen level means the lowest hourly average oxygen level measured according to Table 7 to this subpart during the most recent performance test demonstrating compliance with the applicable emission limit.

Minimum pressure drop means the lowest hourly 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 the lowest hourly average sorbent liquid pH measured at the inlet to 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 liquid flow rate means the lowest hourly average liquid flow rate (e.g., to the PM scrubber or to the acid gas scrubber) measured according to Table 7 to this subpart during the most recent performance stack test demonstrating compliance with the applicable emission limit.

Minimum scrubber pressure drop means the lowest hourly average scrubber pressure drop measured according to Table 7 to this subpart during the most recent performance test demonstrating compliance with the applicable emission limit.

Minimum sorbent injection rate means:

(1) The load fraction multiplied by the lowest hourly average sorbent injection rate for each sorbent measured according to Table 7 to this subpart during the most recent performance test demonstrating compliance with the applicable emission limits; or

(2) For fluidized bed combustion, the lowest average ratio of sorbent to sulfur measured during the most recent performance test.

Minimum total secondary electric power means the lowest hourly average total secondary electric power determined from the values of secondary voltage and secondary current to the electrostatic precipitator measured according to Table 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) Liquefied petroleum gas, as defined in ASTM D1835 (incorporated by reference, see § 63.14); 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 35 and 41 megajoules (MJ) per dry standard cubic meter (950 and 1,100 Btu per dry standard cubic foot); or

(4) Propane or propane derived synthetic natural gas. Propane means a colorless gas derived from petroleum and natural gas, with the molecular structure $C_3 H_8$.

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

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

Other combustor means a unit designed to burn solid fuel that is not classified as a dutch oven, fluidized bed, fuel cell, hybrid suspension grate boiler, pulverized coal boiler, stoker, sloped grate, or suspension boiler as defined in this subpart.

Other gas 1 fuel means a gaseous fuel that is not natural gas or refinery gas and does not exceed a maximum concentration of 40 micrograms/cubic meters of mercury.

Oxygen analyzer system means all equipment required to determine the oxygen content of a gas stream and used to monitor oxygen in the boiler or process heater flue gas, boiler or process heater, firebox, or other appropriate location. This definition includes oxygen trim systems. The source owner or operator must install, calibrate, maintain, and operate the oxygen analyzer system in accordance with the manufacturer's recommendations.

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

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

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

Pile burner means a boiler design incorporating a design where the anticipated biomass fuel has a high relative moisture content. Grates serve to support the fuel, and underfire air flowing up through the grates provides oxygen for combustion, cools the grates, promotes turbulence in the fuel bed, and fires the fuel. The most common form of pile burning is the dutch oven.

Process heater means an enclosed device using controlled flame, and the unit's primary purpose is to transfer heat indirectly to a process material (liquid, gas, or solid) or to a heat transfer material (e.g., glycol or a mixture of glycol and water) for use in a process unit, instead of generating steam. Process heaters are devices in which the combustion gases do not come into direct contact with process materials. A device combusting solid waste, as defined in § 241.3 of this chapter, is not a process heater unless the device is exempt from the definition of a solid waste incineration unit as provided in section 129(g)(1) of the Clean Air Act. Process heaters do not include units used for comfort heat or space heat, food preparation for on-site consumption, or autoclaves. Waste heat process heaters are excluded from this definition.

Pulverized coal boiler means a boiler in which pulverized coal or other solid fossil fuel is introduced into an air stream that carries the coal to the combustion chamber of the boiler where it is fired in suspension.

Qualified energy assessor means:

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

(i) Boiler combustion management.

(ii) Boiler thermal energy recovery, including

(A) Conventional feed water economizer,

(B) Conventional combustion air preheater, and

(C) Condensing economizer.

(iii) Boiler blowdown thermal energy recovery.

(iv) Primary energy resource selection, including

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

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

(v) Insulation issues.

(vi) Steam trap and steam leak management.

(vi) Condensate recovery.

(viii) Steam end-use management.

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

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

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

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

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

(v) Boiler-steam turbine cogeneration systems.

(vi) Industry specific steam end-use systems.

Refinery gas means any gas that is generated at a petroleum refinery and is combusted. Refinery gas includes natural gas when the natural gas is combined and combusted in any proportion with a gas generated at a refinery. Refinery gas includes gases generated from other facilities when that gas is combined and combusted in any proportion with gas generated at a refinery.

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

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

(1) A dwelling containing four or fewer families; or

(2) A single unit residence dwelling that has since been converted or subdivided into condominiums or apartments.

Residual oil means crude oil, fuel oil that does not comply with the specifications under the definition of distillate oil, and all fuel oil numbers 4, 5, and 6, as defined by the American Society of Testing and Materials in ASTM D396-10 (incorporated by reference, *see* § 63.14(b)).

Responsible official means responsible official as defined in § 70.2.

Secondary material means the material as defined in § 241.2 of this chapter.

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

Sloped grate means a unit where the solid fuel is fed to the top of the grate from where it slides downwards; while sliding the fuel first dries and then ignites and burns. The ash is deposited at the bottom of the grate. Fluidized bed, dutch oven, pile burner, hybrid suspension grate, suspension burners, and fuel cells are not considered to be a sloped grate design.

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

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

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

Steam output means:

(1) For a boiler that produces steam for process or heating only (no power generation), the energy content in terms of MMBtu of the boiler steam output,

(2) For a boiler that cogenerates process steam and electricity (also known as combined heat and power), the total energy output, which is the sum of the energy content of the steam exiting the turbine and sent to process in MMBtu and the energy of the electricity generated converted to MMBtu at a rate of 10,000 Btu per kilowatt-hour generated (10 MMBtu per megawatt-hour), and

(3) For a boiler that generates only electricity, the alternate output-based emission limits would be calculated using Equations 21 through 25 of this section, as appropriate:

(i) For emission limits for boilers in the unit designed to burn solid fuel subcategory use Equation 21 of this section:

$$EL_{OBE} = EL_T \times 12.7 \text{ MMBtu/Mwh} \quad \text{(Eq. 21)}$$

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Where:

EL_{OBE} = Emission limit in units of pounds per megawatt-hour.

EL_T = Appropriate emission limit from Table 1 or 2 of this subpart in units of pounds per million Btu heat input.

(ii) For PM and CO emission limits for boilers in one of the subcategories of units designed to burn coal use Equation 22 of this section:

$$EL_{OBE} = EL_T \times 12.2 \text{ MMBtu/Mwh} \quad \text{(Eq. 22)}$$

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Where:

EL_{OBE} = Emission limit in units of pounds per megawatt-hour.

EL_T = Appropriate emission limit from Table 1 or 2 of this subpart in units of pounds per million Btu heat input.

(iii) For PM and CO emission limits for boilers in one of the subcategories of units designed to burn biomass use Equation 23 of this section:

$$EL_{OBE} = EL_T \times 13.9 \text{ MMBtu/Mwh} \quad \text{(Eq. 23)}$$

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Where:

EL_{OBE} = Emission limit in units of pounds per megawatt-hour.

EL_T = Appropriate emission limit from Table 1 or 2 of this subpart in units of pounds per million Btu heat input.

(iv) For emission limits for boilers in one of the subcategories of units designed to burn liquid fuels use Equation 24 of this section:

$EL_{OBE} = EL_T \times 13.8 \text{ MMBtu/Mwh} \quad \text{(Eq. 24)}$

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Where:

EL_{OBE} = Emission limit in units of pounds per megawatt-hour.

EL_T = Appropriate emission limit from Table 1 or 2 of this subpart in units of pounds per million Btu heat input.

(v) For emission limits for boilers in the unit designed to burn gas 2 (other) subcategory, use Equation 25 of this section:

$EL_{OBE} = EL_T \times 10.4 \text{ MMBtu/Mwh} \quad \text{(Eq. 25)}$

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Where:

EL_{OBE} = Emission limit in units of pounds per megawatt-hour.

EL_T = Appropriate emission limit from Table 1 or 2 of this subpart in units of pounds per million Btu heat input.

Stoker means a unit consisting of a mechanically operated fuel feeding mechanism, a stationary or moving grate to support the burning of fuel and admit under-grate air to the fuel, an overfire air system to complete combustion, and an ash discharge system. This definition of stoker includes air swept stokers. There are two general types of stokers: Underfeed and overfeed. Overfeed stokers include mass feed and spreader stokers. Fluidized bed, dutch oven, pile burner, hybrid suspension grate, suspension burners, and fuel cells are not considered to be a stoker design.

Stoker/sloped grate/other unit designed to burn kiln dried biomass means the unit is in the units designed to burn biomass/bio-based solid subcategory that is either a stoker, sloped grate, or other combustor design and is not in the stoker/sloped grate/other units designed to burn wet biomass subcategory.

Stoker/sloped grate/other unit designed to burn wet biomass means the unit is in the units designed to burn biomass/bio-based solid subcategory that is either a stoker, sloped grate, or other combustor design and any of the biomass/bio-based solid fuel combusted in the unit exceeds 20 percent moisture on an annual heat input basis.

Suspension burner means a unit designed to fire dry biomass/biobased solid particles in suspension that are conveyed in an airstream to the furnace like pulverized coal. The combustion of the fuel material is completed on a grate or floor below. The biomass/biobased fuel combusted in the unit shall not exceed 20 percent moisture on an annual heat input basis. Fluidized bed, dutch oven, pile burner, and hybrid suspension grate units are not part of the suspension burner subcategory.

Temporary boiler means any gaseous or liquid fuel boiler that is designed to, and is capable of, being carried or moved from one location to another by means of, for example, wheels, skids, carrying handles, dollies, trailers, or platforms. A boiler is not a temporary boiler if any one of the following conditions exists:

(1) The equipment is attached to a foundation.

(2) The boiler or a replacement remains at a location within the facility and performs the same or similar function for more than 12 consecutive months, unless the regulatory agency approves an extension. An extension may be granted by the regulating agency upon petition by the owner or operator of a unit specifying the basis for such a request. Any temporary boiler that replaces a temporary boiler at a location and performs the same or similar function will be included in calculating the consecutive time period.

(3) The equipment is located at a seasonal facility and operates during the full annual operating period of the seasonal facility, remains at the facility for at least 2 years, and operates at that facility for at least 3 months each year.

(4) The equipment is moved from one location to another within the facility but continues to perform the same or similar function and serve the same electricity, steam, and/or hot water system in an attempt to circumvent the residence time requirements of this definition.

Total selected metals (TSM) means the sum of the following metallic hazardous air pollutants: arsenic, beryllium, cadmium, chromium, lead, manganese, nickel and selenium.

Traditional fuel means the fuel as defined in § 241.2 of this chapter.

Tune-up means adjustments made to a boiler or process heater in accordance with the procedures outlined in § 63.7540(a)(10).

* * * * *

Ultra low sulfur liquid fuel means a distillate oil that has less than or equal to 15 ppm sulfur.

Unit designed to burn biomass/bio-based solid subcategory includes any boiler or process heater that burns at least 10 percent biomass or bio-based solids on an annual heat input basis in combination with solid fossil fuels, liquid fuels, or gaseous fuels.

Unit designed to burn coal/solid fossil fuel subcategory includes any boiler or process heater that burns any coal or other solid fossil fuel alone or at least 10 percent coal or other solid fossil fuel on an annual heat input basis in combination with liquid fuels, gaseous fuels, or less than 10 percent biomass and bio-based solids on an annual heat input basis.

Unit designed to burn gas 1 subcategory includes any boiler or process heater that burns only natural gas, refinery gas, and/or other gas 1 fuels. Gaseous fuel boilers and process heaters that burn liquid fuel for periodic testing of liquid fuel, maintenance, or operator training, not to exceed a combined total of 48 hours during any calendar year, are included in this definition. Gaseous fuel boilers and process heaters that burn liquid fuel during periods of gas curtailment or gas supply interruptions of any duration are also included in this definition.

Unit designed to burn gas 2 (other) subcategory includes any boiler or process heater that is not in the unit designed to burn gas 1 subcategory and burns any gaseous fuels either alone or in combination with less than 10 percent coal/solid fossil fuel, and less than 10 percent biomass/bio-based solid fuel on an annual heat input basis, and no liquid fuels. Gaseous fuel boilers and process heaters that are not in the unit designed to burn gas 1 subcategory and that burn liquid fuel for periodic testing of liquid fuel, maintenance, or operator training, not to exceed a combined total of 48 hours during any calendar year, are included in this definition. Gaseous fuel boilers and process heaters that are not in the unit designed to burn gas 1 subcategory and that burn liquid fuel during periods of gas curtailment or gas supply interruption of any duration are also included in this definition.

Unit designed to burn heavy liquid subcategory means a unit in the unit designed to burn liquid subcategory where at least 10 percent of the heat input from liquid fuels on an annual heat input basis comes from heavy liquids.

Unit designed to burn light liquid subcategory means a unit in the unit designed to burn liquid subcategory that is not part of the unit designed to burn heavy liquid subcategory.

Unit designed to burn liquid subcategory includes any boiler or process heater that burns any liquid fuel, but less than 10 percent coal/solid fossil fuel and less than 10 percent biomass/bio-based solid fuel on an annual heat input basis, either alone or in combination with gaseous fuels. Units in the unit design to burn gas 1 or unit designed to burn gas 2 (other) subcategories that burn liquid fuel for periodic testing of liquid fuel, maintenance, or operator training, not to exceed a combined total of 48 hours during any calendar year are not included in this definition. Units in the unit design to burn gas 1 or unit designed to burn gas 2 (other) subcategories during periods of gas curtailment or gas supply interruption of any duration are also not included in this definition.

Unit designed to burn liquid fuel that is a non-continental unit means an industrial, commercial, or institutional boiler or process heater meeting the definition of the unit designed to burn liquid subcategory located in the State of Hawaii, the Virgin Islands, Guam, American Samoa, the Commonwealth of Puerto Rico, or the Northern Mariana Islands.

Unit designed to burn solid fuel subcategory means any boiler or process heater that burns only solid fuels or at least 10 percent solid fuel on an annual heat input basis in combination with liquid fuels or gaseous fuels.

Vegetable oil means oils extracted from vegetation.

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

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

Waste heat process heater means an enclosed device that recovers normally unused energy (i.e., hot exhaust gas) and converts it to usable heat. Waste heat process heaters are also referred to as recuperative process heaters. This definition includes both fired and unfired waste heat process heaters.

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 or to absorb and neutralize acid gases, such as hydrogen chloride. A wet scrubber creates an aqueous stream or slurry as a byproduct of the emissions control process.

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

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Table 1 to Subpart DDDDD of Part 63—Emission Limits for New or Reconstructed Boilers and Process Heaters

As stated in § 63.7500, you must comply with the following applicable emission limits:

[Units with heat input capacity of 10 million Btu per hour or greater]

If your boiler or process heater is in this subcategory . . .	**For the following pollutants . . .**	**The emissions must not exceed the following emission limits, except during startup and shutdown . . .**	**Or the emissions must not exceed the following alternative output-based limits, except during startup and shutdown . . .**	**Using this specified sampling volume or test run duration . . .**
1. Units in all subcategories designed to burn solid fuel.	a. HCl	2.2E-02 lb per MMBtu of heat input	2.5E-02 lb per MMBtu of steam output or 0.28 lb per MWh	For M26A, collect a minimum of 1 dscm per run; for M26 collect a minimum of 120 liters per run.
	b. Mercury	8.0E-07 [a]lb per MMBtu of heat input	8.7E-07 [a]lb per MMBtu of steam output or 1.1E-05 [a]lb per MWh	For M29, collect a minimum of 4 dscm per run; for M30A or M30B, collect a minimum sample as specified in the method; for ASTM D6784 [b]collect a minimum of 4 dscm.

If your boiler or process heater is in this subcategory . . .	**For the following pollutants . . .**	**The emissions must not exceed the following emission limits, except during startup and shutdown . . .**	**Or the emissions must not exceed the following alternative output-based limits, except during startup and shutdown . . .**	**Using this specified sampling volume or test run duration . . .**
2. Units designed to burn coal/solid fossil fuel	a. Filterable PM (or TSM)	1.1E-03 lb per MMBtu of heat input; or (2.3E-05 lb per MMBtu of heat input)	1.1E-03 lb per MMBtu of steam output or 1.4E-02 lb per MWh; or (2.7E-05 lb per MMBtu of steam output or 2.9E-04 lb per MWh)	Collect a minimum of 3 dscm per run.
3. Pulverized coal boilers designed to burn coal/solid fossil fuel	a. Carbon monoxide (CO) (or CEMS)	130 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (320 ppm by volume on a dry basis corrected to 3 percent oxygen, 30-day rolling average)	0.11 lb per MMBtu of steam output or 1.4 lb per MWh; 3-run average	1 hr minimum sampling time.
4. Stokers designed to burn coal/solid fossil fuel	a. CO (or CEMS)	130 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (340 ppm by volume on a dry basis corrected to 3 percent oxygen, 30-day rolling average)	0.12 lb per MMBtu of steam output or 1.4 lb per MWh; 3-run average	1 hr minimum sampling time.
5. Fluidized bed units designed to burn coal/solid fossil fuel	a. CO (or CEMS)	130 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (230 ppm by volume on a dry basis corrected to 3 percent oxygen, 30-day rolling average)	0.11 lb per MMBtu of steam output or 1.4 lb per MWh; 3-run average	1 hr minimum sampling time.
6. Fluidized bed units with an integrated heat exchanger designed to burn coal/solid fossil fuel	a. CO (or CEMS)	140 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (150 ppm by volume on a dry basis corrected to 3 percent oxygen, 30-day rolling average)	1.2E-01 lb per MMBtu of steam output or 1.5 lb per MWh; 3-run average	1 hr minimum sampling time.

If your boiler or process heater is in this subcategory . . .	**For the following pollutants . . .**	**The emissions must not exceed the following emission limits, except during startup and shutdown . . .**	**Or the emissions must not exceed the following alternative output-based limits, except during startup and shutdown . . .**	**Using this specified sampling volume or test run duration . . .**
7. Stokers/sloped grate/others designed to burn wet biomass fuel	a. CO (or CEMS)	620 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (390 ppm by volume on a dry basis corrected to 3 percent oxygen, 30-day rolling average)	5.8E-01 lb per MMBtu of steam output or 6.8 lb per MWh; 3-run average	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	3.0E-02 lb per MMBtu of heat input; or (2.6E-05 lb per MMBtu of heat input)	3.5E-02 lb per MMBtu of steam output or 4.2E-01 lb per MWh; or (2.7E-05 lb per MMBtu of steam output or 3.7E-04 lb per MWh)	Collect a minimum of 2 dscm per run.
8. Stokers/sloped grate/others designed to burn kiln-dried biomass fuel	a. CO	460 ppm by volume on a dry basis corrected to 3 percent oxygen	4.2E-01 lb per MMBtu of steam output or 5.1 lb per MWh	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	3.0E-02 lb per MMBtu of heat input; or (4.0E-03 lb per MMBtu of heat input)	3.5E-02 lb per MMBtu of steam output or 4.2E-01 lb per MWh; or (4.2E-03 lb per MMBtu of steam output or 5.6E-02 lb per MWh)	Collect a minimum of 2 dscm per run.
9. Fluidized bed units designed to burn biomass/bio-based solids	a. CO (or CEMS)	230 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (310 ppm by volume on a dry basis corrected to 3 percent oxygen, 30-day rolling average)	2.2E-01 lb per MMBtu of steam output or 2.6 lb per MWh; 3-run average	1 hr minimum sampling time.

If your boiler or process heater is in this subcategory . . .	**For the following pollutants . . .**	**The emissions must not exceed the following emission limits, except during startup and shutdown . . .**	**Or the emissions must not exceed the following alternative output-based limits, except during startup and shutdown . . .**	**Using this specified sampling volume or test run duration . . .**
	b. Filterable PM (or TSM)	9.8E-03 lb per MMBtu of heat input; or (8.3E-05 [a]lb per MMBtu of heat input)	1.2E-02 lb per MMBtu of steam output or 0.14 lb per MWh; or (1.1E-04 [a]lb per MMBtu of steam output or 1.2E-03 [a]lb per MWh)	Collect a minimum of 3 dscm per run.
10. Suspension burners designed to burn biomass/bio-based solids	a. CO (or CEMS)	2,400 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (2,000 ppm by volume on a dry basis corrected to 3 percent oxygen, 10-day rolling average)	1.9 lb per MMBtu of steam output or 27 lb per MWh; 3-run average	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	3.0E-02 lb per MMBtu of heat input; or (6.5E-03 lb per MMBtu of heat input)	3.1E-02 lb per MMBtu of steam output or 4.2E-01 lb per MWh; or (6.6E-03 lb per MMBtu of steam output or 9.1E-02 lb per MWh)	Collect a minimum of 2 dscm per run.
11. Dutch Ovens/Pile burners designed to burn biomass/bio-based solids	a. CO (or CEMS)	330 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (520 ppm by volume on a dry basis corrected to 3 percent oxygen, 10-day rolling average)	3.5E-01 lb per MMBtu of steam output or 3.6 lb per MWh; 3-run average	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	3.2E-03 lb per MMBtu of heat input; or (3.9E-05 lb per MMBtu of heat input)	4.3E-03 lb per MMBtu of steam output or 4.5E-02 lb per MWh; or (5.2E-05 lb per MMBtu of steam output or 5.5E-04 lb per MWh)	Collect a minimum of 3 dscm per run.

If your boiler or process heater is in this subcategory . . .	**For the following pollutants . . .**	**The emissions must not exceed the following emission limits, except during startup and shutdown . . .**	**Or the emissions must not exceed the following alternative output-based limits, except during startup and shutdown . . .**	**Using this specified sampling volume or test run duration . . .**
12. Fuel cell units designed to burn biomass/bio-based solids	a. CO	910 ppm by volume on a dry basis corrected to 3 percent oxygen	1.1 lb per MMBtu of steam output or 1.0E+01 lb per MWh	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	2.0E-02 lb per MMBtu of heat input; or (2.9E-05 [a]lb per MMBtu of heat input)	3.0E-02 lb per MMBtu of steam output or 2.8E-01 lb per MWh; or (5.1E-05 lb per MMBtu of steam output or 4.1E-04 lb per MWh)	Collect a minimum of 2 dscm per run.
13. Hybrid suspension grate boiler designed to burn biomass/bio-based solids	a. CO (or CEMS)	1,100 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (900 ppm by volume on a dry basis corrected to 3 percent oxygen, 30-day rolling average)	1.4 lb per MMBtu of steam output or 12 lb per MWh; 3-run average	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	2.6E-02 lb per MMBtu of heat input; or (4.4E-04 lb per MMBtu of heat input)	3.3E-02 lb per MMBtu of steam output or 3.7E-01 lb per MWh; or (5.5E-04 lb per MMBtu of steam output or 6.2E-03 lb per MWh)	Collect a minimum of 3 dscm per run.
14. Units designed to burn liquid fuel	a. HCl	4.4E-04 lb per MMBtu of heat input	4.8E-04 lb per MMBtu of steam output or 6.1E-03 lb per MWh	For M26A: Collect a minimum of 2 dscm per run; for M26, collect a minimum of 240 liters per run.
	b. Mercury	4.8E-07 [a]lb per MMBtu of heat input	5.3E-07 [a]lb per MMBtu of steam output or 6.7E-06 [a]lb per MWh	For M29, collect a minimum of 4 dscm per run; for M30A or M30B, collect a minimum sample as specified in the method; for ASTM D6784 [b]collect a minimum of 4 dscm.

If your boiler or process heater is in this subcategory . . .	**For the following pollutants . . .**	**The emissions must not exceed the following emission limits, except during startup and shutdown . . .**	**Or the emissions must not exceed the following alternative output-based limits, except during startup and shutdown . . .**	**Using this specified sampling volume or test run duration . . .**
15. Units designed to burn heavy liquid fuel	a. CO	130 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average	0.13 lb per MMBtu of steam output or 1.4 lb per MWh; 3-run average	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	1.3E-02 lb per MMBtu of heat input; or (7.5E-05 lb per MMBtu of heat input)	1.5E-02 lb per MMBtu of steam output or 1.8E-01 lb per MWh; or (8.2E-05 lb per MMBtu of steam output or 1.1E-03 lb per MWh)	Collect a minimum of 3 dscm per run.
16. Units designed to burn light liquid fuel	a. CO	130 ppm by volume on a dry basis corrected to 3 percent oxygen	0.13 lb per MMBtu of steam output or 1.4 lb per MWh	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	1.1E-03 [a]lb per MMBtu of heat input; or (2.9E-05 lb per MMBtu of heat input)	1.2E-03 [a]lb per MMBtu of steam output or 1.6E-02 [a]lb per MWh; or (3.2E-05 lb per MMBtu of steam output or 4.0E-04 lb per MWh)	Collect a minimum of 3 dscm per run.
17. Units designed to burn liquid fuel that are non-continental units	a. CO	130 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average based on stack test	0.13 lb per MMBtu of steam output or 1.4 lb per MWh; 3-run average	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	2.3E-02 lb per MMBtu of heat input; or (8.6E-04 lb per MMBtu of heat input)	2.5E-02 lb per MMBtu of steam output or 3.2E-01 lb per MWh; or (9.4E-04 lb per MMBtu of steam output or 1.2E-02 lb per MWh)	Collect a minimum of 4 dscm per run.
18. Units designed to burn gas 2 (other) gases	a. CO	130 ppm by volume on a dry basis corrected to 3 percent oxygen	0.16 lb per MMBtu of steam output or 1.0 lb per MWh	1 hr minimum sampling time.

If your boiler or process heater is in this subcategory . . .	**For the following pollutants . . .**	**The emissions must not exceed the following emission limits, except during startup and shutdown . . .**	**Or the emissions must not exceed the following alternative output-based limits, except during startup and shutdown . . .**	**Using this specified sampling volume or test run duration . . .**
	b. HCl	1.7E-03 lb per MMBtu of heat input	2.9E-03 lb per MMBtu of steam output or 1.8E-02 lb per MWh	For M26A, Collect a minimum of 2 dscm per run; for M26, collect a minimum of 240 liters per run.
	c. Mercury	7.9E-06 lb per MMBtu of heat input	1.4E-05 lb per MMBtu of steam output or 8.3E-05 lb per MWh	For M29, collect a minimum of 3 dscm per run; for M30A or M30B, collect a minimum sample as specified in the method; for ASTM D6784 [b]collect a minimum of 3 dscm.
	d. Filterable PM (or TSM)	6.7E-03 lb per MMBtu of heat input; or (2.1E-04 lb per MMBtu of heat input)	1.2E-02 lb per MMBtu of steam output or 7.0E-02 lb per MWh; or (3.5E-04 lb per MMBtu of steam output or 2.2E-03 lb per MWh)	Collect a minimum of 3 dscm per run.

[a] If you are conducting stack tests to demonstrate compliance and your performance tests for this pollutant for at least 2 consecutive years show that your emissions are at or below this limit, you can skip testing according to § 63.7515 if all of the other provisions of § 63.7515 are met. For all other pollutants that do not contain a footnote “a”, your performance tests for this pollutant for at least 2 consecutive years must show that your emissions are at or below 75 percent of this limit in order to qualify for skip testing.

[b] Incorporated by reference, see § 63.14.

[c] If your affected source is a new or reconstructed affected source that commenced construction or reconstruction after June 4, 2010, and before January 31, 2013, you may comply with the emission limits in Tables 11, 12 or 13 to this subpart until January 31, 2016. On and after January 31, 2016, you must comply with the emission limits in Table 1 to this subpart.

[78 FR 7193, Jan. 31, 2013]

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Table 2 to Subpart DDDDD of Part 63—Emission Limits for Existing Boilers and Process Heaters

As stated in § 63.7500, you must comply with the following applicable emission limits:

[Units with heat input capacity of 10 million Btu per hour or greater]

If your boiler or process heater is in this subcategory . . .	**For the following pollutants . . .**	**The emissions must not exceed the following emission limits, except during startup and shutdown . . .**	**The emissions must not exceed the following alternative output-based limits, except during startup and shutdown . . .**	**Using this specified sampling volume or test run duration . . .**
1. Units in all subcategories designed to burn solid fuel	a. HCl	2.2E-02 lb per MMBtu of heat input	2.5E-02 lb per MMBtu of steam output or 0.27 lb per MWh	For M26A, Collect a minimum of 1 dscm per run; for M26, collect a minimum of 120 liters per run.
	b. Mercury	5.7E-06 lb per MMBtu of heat input	6.4E-06 lb per MMBtu of steam output or 7.3E-05 lb per MWh	For M29, collect a minimum of 3 dscm per run; for M30A or M30B, collect a minimum sample as specified in the method; for ASTM D6784 [b]collect a minimum of 3 dscm.
2. Units design to burn coal/solid fossil fuel	a. Filterable PM (or TSM)	4.0E-02 lb per MMBtu of heat input; or (5.3E-05 lb per MMBtu of heat input)	4.2E-02 lb per MMBtu of steam output or 4.9E-01 lb per MWh; or (5.6E-05 lb per MMBtu of steam output or 6.5E-04 lb per MWh)	Collect a minimum of 2 dscm per run.
3. Pulverized coal boilers designed to burn coal/solid fossil fuel	a. CO (or CEMS)	130 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (320 ppm by volume on a dry basis corrected to 3 percent oxygen, 30-day rolling average)	0.11 lb per MMBtu of steam output or 1.4 lb per MWh; 3-run average	1 hr minimum sampling time.
4. Stokers designed to burn coal/solid fossil fuel	a. CO (or CEMS)	160 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (340 ppm by volume on a dry basis corrected to 3 percent oxygen, 30-day rolling average)	0.14 lb per MMBtu of steam output or 1.7 lb per MWh; 3-run average	1 hr minimum sampling time.

If your boiler or process heater is in this subcategory . . .	**For the following pollutants . . .**	**The emissions must not exceed the following emission limits, except during startup and shutdown . . .**	**The emissions must not exceed the following alternative output-based limits, except during startup and shutdown . . .**	**Using this specified sampling volume or test run duration . . .**
5. Fluidized bed units designed to burn coal/solid fossil fuel	a. CO (or CEMS)	130 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (230 ppm by volume on a dry basis corrected to 3 percent oxygen, 30-day rolling average)	0.12 lb per MMBtu of steam output or 1.4 lb per MWh; 3-run average	1 hr minimum sampling time.
6. Fluidized bed units with an integrated heat exchanger designed to burn coal/solid fossil fuel	a. CO (or CEMS)	140 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (150 ppm by volume on a dry basis corrected to 3 percent oxygen, 30-day rolling average)	1.3E-01 lb per MMBtu of steam output or 1.5 lb per MWh; 3-run average	1 hr minimum sampling time.
7. Stokers/sloped grate/others designed to burn wet biomass fuel	a. CO (or CEMS)	1,500 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (720 ppm by volume on a dry basis corrected to 3 percent oxygen, 30-day rolling average)	1.4 lb per MMBtu of steam output or 17 lb per MWh; 3-run average	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	3.7E-02 lb per MMBtu of heat input; or (2.4E-04 lb per MMBtu of heat input)	4.3E-02 lb per MMBtu of steam output or 5.2E-01 lb per MWh; or (2.8E-04 lb per MMBtu of steam output or 3.4E-04 lb per MWh)	Collect a minimum of 2 dscm per run.
8. Stokers/sloped grate/others designed to burn kiln-dried biomass fuel	a. CO	460 ppm by volume on a dry basis corrected to 3 percent oxygen	4.2E-01 lb per MMBtu of steam output or 5.1 lb per MWh	1 hr minimum sampling time.

If your boiler or process heater is in this subcategory . . .	**For the following pollutants . . .**	**The emissions must not exceed the following emission limits, except during startup and shutdown . . .**	**The emissions must not exceed the following alternative output-based limits, except during startup and shutdown . . .**	**Using this specified sampling volume or test run duration . . .**
	b. Filterable PM (or TSM)	3.2E-01 lb per MMBtu of heat input; or (4.0E-03 lb per MMBtu of heat input)	3.7E-01 lb per MMBtu of steam output or 4.5 lb per MWh; or (4.6E-03 lb per MMBtu of steam output or 5.6E-02 lb per MWh)	Collect a minimum of 1 dscm per run.
9. Fluidized bed units designed to burn biomass/bio-based solid	a. CO (or CEMS)	470 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (310 ppm by volume on a dry basis corrected to 3 percent oxygen, 30-day rolling average)	4.6E-01 lb per MMBtu of steam output or 5.2 lb per MWh; 3-run average	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	1.1E-01 lb per MMBtu of heat input; or (1.2E-03 lb per MMBtu of heat input)	1.4E-01 lb per MMBtu of steam output or 1.6 lb per MWh; or (1.5E-03 lb per MMBtu of steam output or 1.7E-02 lb per MWh)	Collect a minimum of 1 dscm per run.
10. Suspension burners designed to burn biomass/bio-based solid	a. CO (or CEMS)	2,400 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (2,000 ppm by volume on a dry basis corrected to 3 percent oxygen, 10-day rolling average)	1.9 lb per MMBtu of steam output or 27 lb per MWh; 3-run average	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	5.1E-02 lb per MMBtu of heat input; or (6.5E-03 lb per MMBtu of heat input)	5.2E-02 lb per MMBtu of steam output or 7.1E-01 lb per MWh; or (6.6E-03 lb per MMBtu of steam output or 9.1E-02 lb per MWh)	Collect a minimum of 2 dscm per run.

If your boiler or process heater is in this subcategory . . .	**For the following pollutants . . .**	**The emissions must not exceed the following emission limits, except during startup and shutdown . . .**	**The emissions must not exceed the following alternative output-based limits, except during startup and shutdown . . .**	**Using this specified sampling volume or test run duration . . .**
11. Dutch Ovens/Pile burners designed to burn biomass/bio-based solid	a. CO (or CEMS)	770 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (520 ppm by volume on a dry basis corrected to 3 percent oxygen, 10-day rolling average)	8.4E-01 lb per MMBtu of steam output or 8.4 lb per MWh; 3-run average	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	2.8E-01 lb per MMBtu of heat input; or (2.0E-03 lb per MMBtu of heat input)	3.9E-01 lb per MMBtu of steam output or 3.9 lb per MWh; or (2.8E-03 lb per MMBtu of steam output or 2.8E-02 lb per MWh)	Collect a minimum of 1 dscm per run.
12. Fuel cell units designed to burn biomass/bio-based solid	a. CO	1,100 ppm by volume on a dry basis corrected to 3 percent oxygen	2.4 lb per MMBtu of steam output or 12 lb per MWh	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	2.0E-02 lb per MMBtu of heat input; or (5.8E-03 lb per MMBtu of heat input)	5.5E-02 lb per MMBtu of steam output or 2.8E-01 lb per MWh; or (1.6E-02 lb per MMBtu of steam output or 8.1E-02 lb per MWh)	Collect a minimum of 2 dscm per run.
13. Hybrid suspension grate units designed to burn biomass/bio-based solid	a. CO (or CEMS)	2,800 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (900 ppm by volume on a dry basis corrected to 3 percent oxygen, 30-day rolling average)	2.8 lb per MMBtu of steam output or 31 lb per MWh; 3-run average	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	4.4E-01 lb per MMBtu of heat input; or (4.5E-04 lb per MMBtu of heat input)	5.5E-01 lb per MMBtu of steam output or 6.2 lb per MWh; or (5.7E-04 lb per MMBtu of steam output or 6.3E-03 lb per MWh)	Collect a minimum of 1 dscm per run.

If your boiler or process heater is in this subcategory . . .	For the following pollutants . . .	The emissions must not exceed the following emission limits, except during startup and shutdown . . .	The emissions must not exceed the following alternative output-based limits, except during startup and shutdown . . .	Using this specified sampling volume or test run duration . . .
14. Units designed to burn liquid fuel	a. HCl	1.1E-03 lb per MMBtu of heat input	1.4E-03 lb per MMBtu of steam output or 1.6E-02 lb per MWh	For M26A, collect a minimum of 2 dscm per run; for M26, collect a minimum of 240 liters per run.
	b. Mercury	2.0E-06 lb per MMBtu of heat input	2.5E-06 lb per MMBtu of steam output or 2.8E-05 lb per MWh	For M29, collect a minimum of 3 dscm per run; for M30A or M30B collect a minimum sample as specified in the method, for ASTM D6784 [b]collect a minimum of 2 dscm.
15. Units designed to burn heavy liquid fuel	a. CO	130 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average	0.13 lb per MMBtu of steam output or 1.4 lb per MWh; 3-run average	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	6.2E-02 lb per MMBtu of heat input; or (2.0E-04 lb per MMBtu of heat input)	7.5E-02 lb per MMBtu of steam output or 8.6E-01 lb per MWh; or (2.5E-04 lb per MMBtu of steam output or 2.8E-03 lb per MWh)	Collect a minimum of 1 dscm per run.
16. Units designed to burn light liquid fuel	a. CO	130 ppm by volume on a dry basis corrected to 3 percent oxygen	0.13 lb per MMBtu of steam output or 1.4 lb per MWh	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	7.9E-03 lb per MMBtu of heat input; or (6.2E-05 lb per MMBtu of heat input)	9.6E-03 lb per MMBtu of steam output or 1.1E-01 lb per MWh; or (7.5E-05 lb per MMBtu of steam output or 8.6E-04 lb per MWh)	Collect a minimum of 3 dscm per run.
17. Units designed to burn liquid fuel that are non-continental units	a. CO	130 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average based on stack test	0.13 lb per MMBtu of steam output or 1.4 lb per MWh; 3-run average	1 hr minimum sampling time.

If your boiler or process heater is in this subcategory . . .	**For the following pollutants . . .**	**The emissions must not exceed the following emission limits, except during startup and shutdown . . .**	**The emissions must not exceed the following alternative output-based limits, except during startup and shutdown . . .**	**Using this specified sampling volume or test run duration . . .**
	b. Filterable PM (or TSM)	2.7E-01 lb per MMBtu of heat input; or (8.6E-04 lb per MMBtu of heat input)	3.3E-01 lb per MMBtu of steam output or 3.8 lb per MWh; or (1.1E-03 lb per MMBtu of steam output or 1.2E-02 lb per MWh)	Collect a minimum of 2 dscm per run.
18. Units designed to burn gas 2 (other) gases	a. CO	130 ppm by volume on a dry basis corrected to 3 percent oxygen	0.16 lb per MMBtu of steam output or 1.0 lb per MWh	1 hr minimum sampling time.
	b. HCl	1.7E-03 lb per MMBtu of heat input	2.9E-03 lb per MMBtu of steam output or 1.8E-02 lb per MWh	For M26A, collect a minimum of 2 dscm per run; for M26, collect a minimum of 240 liters per run.
	c. Mercury	7.9E-06 lb per MMBtu of heat input	1.4E-05 lb per MMBtu of steam output or 8.3E-05 lb per MWh	For M29, collect a minimum of 3 dscm per run; for M30A or M30B, collect a minimum sample as specified in the method; for ASTM D6784 [b]collect a minimum of 2 dscm.
	d. Filterable PM (or TSM)	6.7E-03 lb per MMBtu of heat input or (2.1E-04 lb per MMBtu of heat input)	1.2E-02 lb per MMBtu of steam output or 7.0E-02 lb per MWh; or (3.5E-04 lb per MMBtu of steam output or 2.2E-03 lb per MWh)	Collect a minimum of 3 dscm per run.

[a] If you are conducting stack tests to demonstrate compliance and your performance tests for this pollutant for at least 2 consecutive years show that your emissions are at or below this limit, you can skip testing according to § 63.7515 if all of the other provisions of § 63.7515 are met. For all other pollutants that do not contain a footnote a, your performance tests for this pollutant for at least 2 consecutive years must show that your emissions are at or below 75 percent of this limit in order to qualify for skip testing.

[b] Incorporated by reference, see § 63.14.

[78 FR 7195, Jan. 31, 2013]

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Table 3 to Subpart DDDDD of Part 63—Work Practice Standards

As stated in § 63.7500, you must comply with the following applicable work practice standards:

If your unit is . . .	You must meet the following . . .
1. A new or existing boiler or process heater with a continuous oxygen trim system that maintains an optimum air to fuel ratio, or a heat input capacity of less than or equal to 5 million Btu per hour in any of the following subcategories: unit designed to burn gas 1; unit designed to burn gas 2 (other); or unit designed to burn light liquid, or a limited use boiler or process heater	Conduct a tune-up of the boiler or process heater every 5 years as specified in § 63.7540.
2. A new or existing boiler or process heater without a continuous oxygen trim system and with heat input capacity of less than 10 million Btu per hour in the unit designed to burn heavy liquid or unit designed to burn solid fuel subcategories; or a new or existing boiler or process heater with heat input capacity of less than 10 million Btu per hour, but greater than 5 million Btu per hour, in any of the following subcategories: unit designed to burn gas 1; unit designed to burn gas 2 (other); or unit designed to burn light liquid	Conduct a tune-up of the boiler or process heater biennially as specified in § 63.7540.
3. A new or existing boiler or process heater without a continuous oxygen trim system and with heat input capacity of 10 million Btu per hour or greater	Conduct a tune-up of the boiler or process heater annually as specified in § 63.7540. Units in either the Gas 1 or Metal Process Furnace subcategories will conduct this tune-up as a work practice for all regulated emissions under this subpart. Units in all other subcategories will conduct this tune-up as a work practice for dioxins/furans.
4. An existing boiler or process heater located at a major source facility, not including limited use units	Must have a one-time energy assessment performed by a qualified energy assessor. An energy assessment completed on or after January 1, 2008, that meets or is amended to meet the energy assessment requirements in this table, satisfies the energy assessment requirement. A facility that operates under an energy management program compatible with ISO 50001 that includes the affected units also satisfies the energy assessment requirement. The energy assessment must include the following with extent of the evaluation for items a. to e. appropriate for the on-site technical hours listed in § 63.7575:
	a. A visual inspection of the boiler or process heater system.
	b. An evaluation of operating characteristics of the boiler or process heater systems, specifications of energy using systems, operating and maintenance procedures, and unusual operating constraints.

If your unit is . . .	You must meet the following . . .
	c. An inventory of major energy use systems consuming energy from affected boilers and process heaters and which are under the control of the boiler/process heater owner/operator.
	d. A review of available architectural and engineering plans, facility operation and maintenance procedures and logs, and fuel usage.
	e. A review of the facility's energy management practices and provide recommendations for improvements consistent with the definition of energy management practices, if identified.
	f. A list of cost-effective energy conservation measures that are within the facility's control.
	g. A list of the energy savings potential of the energy conservation measures identified.
	h. A comprehensive report detailing the ways to improve efficiency, the cost of specific improvements, benefits, and the time frame for recouping those investments.
5. An existing or new boiler or process heater subject to emission limits in Table 1 or 2 or 11 through 13 to this subpart during startup	You must operate all CMS during startup. For startup of a boiler or process heater, you must use one or a combination of the following clean fuels: natural gas, synthetic natural gas, propane, distillate oil, syngas, ultra-low sulfur diesel, fuel oil-soaked rags, kerosene, hydrogen, paper, cardboard, refinery gas, and liquefied petroleum gas.
	If you start firing coal/solid fossil fuel, biomass/bio-based solids, heavy liquid fuel, or gas 2 (other) gases, you must vent emissions to the main stack(s) and engage all of the applicable control devices except limestone injection in fluidized bed combustion (FBC) boilers, dry scrubber, fabric filter, selective non-catalytic reduction (SNCR), and selective catalytic reduction (SCR). You must start your limestone injection in FBC boilers, dry scrubber, fabric filter, SNCR, and SCR systems as expeditiously as possible. Startup ends when steam or heat is supplied for any purpose.
	You must comply with all applicable emission limits at all times except for startup or shutdown periods conforming with this work practice. You must collect monitoring data during periods of startup, as specified in § 63.7535(b). You must keep records during periods of startup. You must provide reports concerning activities and periods of startup, as specified in § 63.7555.

If your unit is . . .	**You must meet the following . . .**
6. An existing or new boiler or process heater subject to emission limits in Tables 1 or 2 or 11 through 13 to this subpart during shutdown	You must operate all CMS during shutdown. While firing coal/solid fossil fuel, biomass/bio-based solids, heavy liquid fuel, or gas 2 (other) gases during shutdown, you must vent emissions to the main stack(s) and operate all applicable control devices, except limestone injection in FBC boilers, dry scrubber, fabric filter, SNCR, and SCR.
	You must comply with all applicable emissions limits at all times except for startup or shutdown periods conforming with this work practice. You must collect monitoring data during periods of shutdown, as specified in § 63.7535(b). You must keep records during periods of shutdown. You must provide reports concerning activities and periods of shutdown, as specified in § 63.7555.

[78 FR 7198, Jan. 31, 2013]

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Table 4 to Subpart DDDDD of Part 63—Operating Limits for Boilers and Process Heaters

As stated in § 63.7500, you must comply with the applicable operating limits:

When complying with a Table 1, 2, 11, 12, or 13 numerical emission limit using . . .	**You must meet these operating limits . . .**
1. Wet PM scrubber control on a boiler not using a PM CPMS	Maintain the 30-day rolling average pressure drop and the 30-day rolling average liquid flow rate at or above the lowest one-hour average pressure drop and the lowest one-hour average liquid flow rate, respectively, measured during the most recent performance test demonstrating compliance with the PM emission limitation according to § 63.7530(b) and Table 7 to this subpart.
2. Wet acid gas (HCl) scrubber control on a boiler not using a HCl CEMS	Maintain the 30-day rolling average effluent pH at or above the lowest one-hour average pH and the 30-day rolling average liquid flow rate at or above the lowest one-hour average liquid flow rate measured during the most recent performance test demonstrating compliance with the HCl emission limitation according to § 63.7530(b) and Table 7 to this subpart.
3. Fabric filter control on units not using a PM CPMS	a. Maintain opacity to less than or equal to 10 percent opacity (daily block average); or
	b. Install and operate a bag leak detection system according to § 63.7525 and operate the fabric filter such that the bag leak detection system alert is not activated more than 5 percent of the operating time during each 6-month period.

When complying with a Table 1, 2, 11, 12, or 13 numerical emission limit using . . .	**You must meet these operating limits . . .**
4. Electrostatic precipitator control on units not using a PM CPMS	a. This option is for boilers and process heaters that operate dry control systems (i.e., an ESP without a wet scrubber). Existing and new boilers and process heaters must maintain opacity to less than or equal to 10 percent opacity (daily block average); or
	b. This option is only for boilers and process heaters not subject to PM CPMS or continuous compliance with an opacity limit (i.e., COMS). Maintain the 30-day rolling average total secondary electric power input of the electrostatic precipitator at or above the operating limits established during the performance test according to § 63.7530(b) and Table 7 to this subpart.
5. Dry scrubber or carbon injection control on a boiler not using a mercury CEMS	Maintain the minimum sorbent or carbon injection rate as defined in § 63.7575 of this subpart.
6. Any other add-on air pollution control type on units not using a PM CPMS	This option is for boilers and process heaters that operate dry control systems. Existing and new boilers and process heaters must maintain opacity to less than or equal to 10 percent opacity (daily block average).
7. Fuel analysis	Maintain the fuel type or fuel mixture such that the applicable emission rates calculated according to § 63.7530(c)(1), (2) and/or (3) is less than the applicable emission limits.
8. Performance testing	For boilers and process heaters that demonstrate compliance with a performance test, maintain the operating load of each unit such that it does not exceed 110 percent of the highest hourly average operating load recorded during the most recent performance test.
9. Oxygen analyzer system	For boilers and process heaters subject to a CO emission limit that demonstrate compliance with an O_2analyzer system as specified in § 63.7525(a), maintain the 30-day rolling average oxygen content at or above the lowest hourly average oxygen concentration measured during the most recent CO performance test, as specified in Table 8. This requirement does not apply to units that install an oxygen trim system since these units will set the trim system to the level specified in § 63.7525(a).
10. SO_2CEMS	For boilers or process heaters subject to an HCl emission limit that demonstrate compliance with an SO_2CEMS, maintain the 30-day rolling average SO_2emission rate at or below the highest hourly average SO_2concentration measured during the most recent HCl performance test, as specified in Table 8.

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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 testing for existing, new or reconstructed affected sources:

To conduct a performance test for the following pollutant...	**You must...**	**Using...**
1. Filterable PM	a. Select sampling ports location and the number of traverse points	Method 1 at 40 CFR part 60, appendix A-1 of this chapter.
	b. Determine velocity and volumetric flow-rate of the stack gas	Method 2, 2F, or 2G at 40 CFR part 60, appendix A-1 or A-2 to part 60 of this chapter.
	c. Determine oxygen or carbon dioxide concentration of the stack gas	Method 3A or 3B at 40 CFR part 60, appendix A-2 to part 60 of this chapter, or ANSI/ASME PTC 19.10-1981.[a]
	d. Measure the moisture content of the stack gas	Method 4 at 40 CFR part 60, appendix A-3 of this chapter.
	e. Measure the PM emission concentration	Method 5 or 17 (positive pressure fabric filters must use Method 5D) at 40 CFR part 60, appendix A-3 or A-6 of this chapter.
	f. Convert emissions concentration to lb per MMBtu emission rates	Method 19 F-factor methodology at 40 CFR part 60, appendix A-7 of this chapter.
2. TSM	a. Select sampling ports location and the number of traverse points	Method 1 at 40 CFR part 60, appendix A-1 of this chapter.
	b. Determine velocity and volumetric flow-rate of the stack gas	Method 2, 2F, or 2G at 40 CFR part 60, appendix A-1 or A-2 of this chapter.
	c. Determine oxygen or carbon dioxide concentration of the stack gas	Method 3A or 3B at 40 CFR part 60, appendix A-1 of this chapter, or ANSI/ASME PTC 19.10-1981.[a]
	d. Measure the moisture content of the stack gas	Method 4 at 40 CFR part 60, appendix A-3 of this chapter.
	e. Measure the TSM emission concentration	Method 29 at 40 CFR part 60, appendix A-8 of this chapter
	f. Convert emissions concentration to lb per MMBtu emission rates	Method 19 F-factor methodology at 40 CFR part 60, appendix A-7 of this chapter.

To conduct a performance test for the following pollutant...	**You must...**	**Using...**
3. HCl	a. Select sampling ports location and the number of traverse points	Method 1 at 40 CFR part 60, appendix A-1 of this chapter.
	b. Determine velocity and volumetric flow-rate of the stack gas	Method 2, 2F, or 2G at 40 CFR part 60, appendix A-2 of this chapter.
	c. Determine oxygen or carbon dioxide concentration of the stack gas	Method 3A or 3B at 40 CFR part 60, appendix A-2 of this chapter, or ANSI/ASME PTC 19.10-1981.[a]
	d. Measure the moisture content of the stack gas	Method 4 at 40 CFR part 60, appendix A-3 of this chapter.
	e. Measure the HCl emission concentration	Method 26 or 26A (M26 or M26A) at 40 CFR part 60, appendix A-8 of this chapter.
	f. Convert emissions concentration to lb per MMBtu emission rates	Method 19 F-factor methodology at 40 CFR part 60, appendix A-7 of this chapter.
3. Hydrogen chloride	a. Select sampling ports location and the number of traverse points	Method 1 at 40 CFR part 60, appendix A-1 of this chapter.
	b. Determine velocity and volumetric flow-rate of the stack gas	Method 2, 2F, or 2G at 40 CFR part 60, appendix A-2 of this chapter.
	c. Determine oxygen or carbon dioxide concentration of the stack gas	Method 3A or 3B at 40 CFR part 60, appendix A-2 of this chapter, or ANSI/ASME PTC 19.10-1981.[a]
	d. Measure the moisture content of the stack gas	Method 4 at 40 CFR part 60, appendix A-3 of this chapter.
	e. Measure the hydrogen chloride emission concentration	Method 26 or 26A (M26 or M26A) at 40 CFR part 60, appendix A-8 of this chapter.
	f. Convert emissions concentration to lb per MMBtu emission rates	Method 19 F-factor methodology at 40 CFR part 60, appendix A-7 of this chapter.
4. Mercury	a. Select sampling ports location and the number of traverse points	Method 1 at 40 CFR part 60, appendix A-1 of this chapter.
	b. Determine velocity and volumetric flow-rate of the stack gas	Method 2, 2F, or 2G at 40 CFR part 60, appendix A-1 or A-2 of this chapter.

To conduct a performance test for the following pollutant...	**You must...**	**Using...**
	c. Determine oxygen or carbon dioxide concentration of the stack gas	Method 3A or 3B at 40 CFR part 60, appendix A-1 of this chapter, or ANSI/ASME PTC 19.10-1981.[a]
	d. Measure the moisture content of the stack gas	Method 4 at 40 CFR part 60, appendix A-3 of this chapter.
	e. Measure the mercury emission concentration	Method 29, 30A, or 30B (M29, M30A, or M30B) at 40 CFR part 60, appendix A-8 of this chapter or Method 101A at 40 CFR part 61, appendix B of this chapter, or ASTM Method D6784.[a]
	f. Convert emissions concentration to lb per MMBtu emission rates	Method 19 F-factor methodology at 40 CFR part 60, appendix A-7 of this chapter.
5. CO	a. Select the sampling ports location and the number of traverse points	Method 1 at 40 CFR part 60, appendix A-1 of this chapter.
	b. Determine oxygen concentration of the stack gas	Method 3A or 3B at 40 CFR part 60, appendix A-3 of this chapter, or ASTM D6522-00 (Reapproved 2005), or ANSI/ASME PTC 19.10-1981.[a]
	c. Measure the moisture content of the stack gas	Method 4 at 40 CFR part 60, appendix A-3 of this chapter.
	d. Measure the CO emission concentration	Method 10 at 40 CFR part 60, appendix A-4 of this chapter. Use a measurement span value of 2 times the concentration of the applicable emission limit.

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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 (as defined in § 63.7575) may be used in lieu of the prescribed methods at the discretion of the source owner or operator:

To conduct a fuel analysis for the following pollutant . . .	**You must . . .**	**Using . . .**
1. Mercury	a. Collect fuel samples	Procedure in § 63.7521(c) or ASTM D5192 [a], or ASTM D7430 [a], or ASTM D6883 [a], or ASTM D2234/D2234M [a](for coal) or EPA 1631 or EPA 1631E or ASTM D6323 [a](for solid), or EPA 821-R-01-013 (for liquid or solid), or ASTM D4177 [a](for liquid), or ASTM D4057 [a](for liquid), or equivalent.
	b. Composite fuel samples	Procedure in § 63.7521(d) or equivalent.
	c. Prepare composited fuel samples	EPA SW-846-3050B [a](for solid samples), EPA SW-846-3020A [a](for liquid samples), ASTM D2013/D2013M [a](for coal), ASTM D5198 [a](for biomass), or EPA 3050 [a](for solid fuel), or EPA 821-R-01-013 [a](for liquid or solid), or equivalent.
	d. Determine heat content of the fuel type	ASTM D5865 [a](for coal) or ASTM E711 [a](for biomass), or ASTM D5864 [a]for liquids and other solids, or ASTM D240 [a]or equivalent.
	e. Determine moisture content of the fuel type	ASTM D3173 [a], ASTM E871 [a], or ASTM D5864 [a], or ASTM D240, or ASTM D95 [a](for liquid fuels), or ASTM D4006 [a](for liquid fuels), or ASTM D4177 [a](for liquid fuels) or ASTM D4057 [a](for liquid fuels), or equivalent.
	f. Measure mercury concentration in fuel sample	ASTM D6722 [a](for coal), EPA SW-846-7471B [a](for solid samples), or EPA SW-846-7470A [a](for liquid samples), or equivalent.
	g. Convert concentration into units of pounds of mercury per MMBtu of heat content	Equation 8 in § 63.7530.
	h. Calculate the mercury emission rate from the boiler or process heater in units of pounds per million Btu	Equations 10 and 12 in § 63.7530.
2. HCl	a. Collect fuel samples	Procedure in § 63.7521(c) or ASTM D5192 [a], or ASTM D7430 [a], or ASTM D6883 [a], or ASTM D2234/D2234M [a](for coal) or ASTM D6323 [a](for coal or biomass), ASTM D4177 [a](for liquid fuels) or ASTM D4057 [a](for liquid fuels), or equivalent.
	b. Composite fuel samples	Procedure in § 63.7521(d) or equivalent.

To conduct a fuel analysis for the following pollutant . . .	**You must . . .**	**Using . . .**
	c. Prepare composited fuel samples	EPA SW-846-3050B [a](for solid samples), EPA SW-846-3020A [a](for liquid samples), ASTM D2013/D2013M§[a](for coal), or ASTM D5198§[a](for biomass), or EPA 3050 [a]or equivalent.
	d. Determine heat content of the fuel type	ASTM D5865 [a](for coal) or ASTM E711 [a](for biomass), ASTM D5864, ASTM D240 [a]or equivalent.
	e. Determine moisture content of the fuel type	ASTM D3173 [a]or ASTM E871 [a], or D5864 [a], or ASTM D240 [a], or ASTM D95[a](for liquid fuels), or ASTM D4006 [a](for liquid fuels), or ASTM D4177 [a](for liquid fuels) or ASTM D4057 [a](for liquid fuels) or equivalent.
	f. Measure chlorine concentration in fuel sample	EPA SW-846-9250 [a], ASTM D6721 [a], ASTM D4208 [a](for coal), or EPA SW-846-5050 [a]or ASTM E776 [a](for solid fuel), or EPA SW-846-9056 [a]or SW-846-9076 [a](for solids or liquids) or equivalent.
	g. Convert concentrations into units of pounds of HCl per MMBtu of heat content	Equation 7 in § 63.7530.
	h. Calculate the HCl emission rate from the boiler or process heater in units of pounds per million Btu	Equations 10 and 11 in § 63.7530.
3. Mercury Fuel Specification for other gas 1 fuels	a. Measure mercury concentration in the fuel sample and convert to units of micrograms per cubic meter	Method 30B (M30B) at 40 CFR part 60, appendix A-8 of this chapter or ASTM D5954 [a], ASTM D6350 [a], ISO 6978-1:2003(E) [a], or ISO 6978-2:2003(E) [a], or EPA-1631 [a]or equivalent.
	b. Measure mercury concentration in the exhaust gas when firing only the other gas 1 fuel is fired in the boiler or process heater	Method 29, 30A, or 30B (M29, M30A, or M30B) at 40 CFR part 60, appendix A-8 of this chapter or Method 101A or Method 102 at 40 CFR part 61, appendix B of this chapter, or ASTM Method D6784 [a]or equivalent.
4. TSM for solid fuels	a. Collect fuel samples	Procedure in § 63.7521(c) or ASTM D5192 [a], or ASTM D7430 [a], or ASTM D6883 [a], or ASTM D2234/D2234M [a](for coal) or ASTM D6323 [a](for coal or biomass), or ASTM D4177 [a],(for liquid fuels)or ASTM D4057 [a](for liquid fuels),or equivalent.
	b. Composite fuel samples	Procedure in § 63.7521(d) or equivalent.
	c. Prepare composited fuel samples	EPA SW-846-3050B [a](for solid samples), EPA SW-846-3020A [a](for liquid samples), ASTM D2013/D2013M [a](for coal), ASTM D5198 [a]or TAPPI T266 [a](for biomass), or EPA 3050 [a]or equivalent.

To conduct a fuel analysis for the following pollutant . . .	You must . . .	Using . . .
	d. Determine heat content of the fuel type	ASTM D5865 [a](for coal) or ASTM E711 [a](for biomass), or ASTM D5864 [a]for liquids and other solids, or ASTM D240 [a]or equivalent.
	e. Determine moisture content of the fuel type	ASTM D3173 [a]or ASTM E871 [a], or D5864, or ASTM D240 [a], or ASTM D95 [a](for liquid fuels), or ASTM D4006[a](for liquid fuels), or ASTM D4177 [a](for liquid fuels) or ASTM D4057 [a](for liquid fuels), or equivalent.
	f. Measure TSM concentration in fuel sample	ASTM D3683 [a], or ASTM D4606 [a], or ASTM D6357 [a]or EPA 200.8 [a]or EPA SW-846-6020 [a], or EPA SW-846-6020A [a], or EPA SW-846-6010C [a], EPA 7060 [a]or EPA 7060A [a](for arsenic only), or EPA SW-846-7740 [a](for selenium only).
	g. Convert concentrations into units of pounds of TSM per MMBtu of heat content	Equation 9 in § 63.7530.
	h. Calculate the TSM emission rate from the boiler or process heater in units of pounds per million Btu	Equations 10 and 13 in § 63.7530.

[a] Incorporated by reference, see § 63.14.

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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. PM, TSM, or mercury	a. Wet scrubber operating parameters	i. Establish a site-specific minimum scrubber pressure drop and minimum flow rate operating limit according to § 63.7530(b)	(1) Data from the scrubber pressure drop and liquid flow rate monitors and the PM or mercury performance test	(a) You must collect scrubber pressure drop and liquid flow rate data every 15 minutes during the entire period of the performance tests.
				(b) Determine the lowest hourly average scrubber pressure drop and liquid flow rate by computing the hourly averages using all of the 15-minute readings taken during each performance test.
	b. Electrostatic precipitator operating parameters (option only for units that operate wet scrubbers)	i. Establish a site-specific minimum total secondary electric power input according to § 63.7530(b)	(1) Data from the voltage and secondary amperage monitors during the PM or mercury performance test	(a) You must collect secondary voltage and secondary amperage for each ESP cell and calculate total secondary electric power input data every 15 minutes during the entire period of the performance tests.
				(b) Determine the average total secondary electric power input by computing the hourly averages using all of the 15-minute readings taken during each performance test.
2. HCl	a. Wet scrubber operating parameters	i. Establish site-specific minimum pressure drop, effluent pH, and flow rate operating limits according to § 63.7530(b)	(1) Data from the pressure drop, pH, and liquid flow-rate monitors and the HCl performance test	(a) You must collect pH 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 hourly average pH and liquid flow rate by computing the hourly averages using all of the 15-minute readings taken during each performance test.
	b. Dry scrubber operating parameters	i. Establish a site-specific minimum sorbent injection rate operating limit according to § 63.7530(b). If different acid gas sorbents are used during the HCl performance test, the average value for each sorbent becomes the site-specific operating limit for that sorbent	(1) Data from the sorbent injection rate monitors and HCl or mercury performance test	(a) You must collect sorbent injection rate data every 15 minutes during the entire period of the performance tests.
				(b) Determine the hourly average sorbent injection rate by computing the hourly averages using all of the 15-minute readings taken during each performance test.
				(c) Determine the lowest hourly average of the three test run averages established during the performance test as your operating limit. When your unit operates at lower loads, multiply your sorbent injection rate by the load fraction (e.g., for 50 percent load, multiply the injection rate operating limit by 0.5) to determine the required injection rate.
	c. Alternative Maximum SO_2emission rate	i. Establish a site-specific maximum SO_2emission rate operating limit according to § 63.7530(b)	(1) Data from SO_2CEMS and the HCl performance test	(a) You must collect the SO_2emissions data according to § 63.7525(m) during the most recent HCl 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) The maximum SO_2emission rate is equal to the lowest hourly average SO_2emission rate measured during the most recent HCl performance tests.
3. Mercury	a. Activated carbon injection	i. Establish a site-specific minimum activated carbon injection rate operating limit according to § 63.7530(b)	(1) Data from the activated carbon rate monitors and mercury performance test	(a) You must collect activated carbon injection rate data every 15 minutes during the entire period of the performance tests.
				(b) Determine the hourly average activated carbon injection rate by computing the hourly averages using all of the 15-minute readings taken during each performance test.
				(c) Determine the lowest hourly average established during the performance test as your operating limit. When your unit operates at lower loads, multiply your activated carbon injection rate by the load fraction (e.g., actual heat input divided by heat input during performance test, for 50 percent load, multiply the injection rate operating limit by 0.5) to determine the required injection rate.
4. Carbon monoxide	a. Oxygen	i. Establish a unit-specific limit for minimum oxygen level according to § 63.7520	(1) Data from the oxygen analyzer system specified in § 63.7525(a)	(a) You must collect oxygen data every 15 minutes during the entire period of the performance tests.
				(b) Determine the hourly average oxygen concentration by computing the hourly averages using all of the 15-minute readings taken during each performance test.

If you have an applicable emission limit for . . .	And your operating limits are based on . . .	You must . . .	Using . . .	According to the following requirements
				(c) Determine the lowest hourly average established during the performance test as your minimum operating limit.
5. Any pollutant for which compliance is demonstrated by a performance test	a. Boiler or process heater operating load	i. Establish a unit specific limit for maximum operating load according to § 63.7520(c)	(1) Data from the operating load monitors or from steam generation monitors	(a) You must collect operating load or steam generation data every 15 minutes during the entire period of the performance test.
				(b) Determine the average operating load by computing the hourly averages using all of the 15-minute readings taken during each performance test.
				(c) Determine the average of the three test run averages during the performance test, and multiply this by 1.1 (110 percent) as your operating limit.

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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 each boiler or process heater 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(c) and § 63.7535; and
	b. Reducing the opacity monitoring data to 6-minute averages; and
	c. Maintaining opacity to less than or equal to 10 percent (daily block average).
2. PM CPMS	a. Collecting the PM CPMS output data according to § 63.7525;

If you must meet the following operating limits or work practice standards . . .	**You must demonstrate continuous compliance by . . .**
	b. Reducing the data to 30-day rolling averages; and
	c. Maintaining the 30-day rolling average PM CPMS output data to less than the operating limit established during the performance test according to § 63.7530(b)(4).
3. 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.
4. 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
	b. Reducing the data to 30-day rolling averages; and
	c. Maintaining the 30-day rolling average pressure drop and liquid flow-rate at or above the operating limits established during the performance test according to § 63.7530(b).
5. Wet Scrubber pH	a. Collecting the pH monitoring system data according to §§ 63.7525 and 63.7535; and
	b. Reducing the data to 30-day rolling averages; and
	c. Maintaining the 30-day rolling average pH at or above the operating limit established during the performance test according to § 63.7530(b).
6. Dry Scrubber Sorbent or Carbon Injection Rate	a. Collecting the sorbent or carbon injection rate monitoring system data for the dry scrubber according to §§ 63.7525 and 63.7535; and
	b. Reducing the data to 30-day rolling averages; and
	c. Maintaining the 30-day rolling average sorbent or carbon injection rate at or above the minimum sorbent or carbon injection rate as defined in § 63.7575.
7. Electrostatic Precipitator Total Secondary Electric Power Input	a. Collecting the total secondary electric power input monitoring system data for the electrostatic precipitator according to §§ 63.7525 and 63.7535; and
	b. Reducing the data to 30-day rolling averages; and
	c. Maintaining the 30-day rolling average total secondary electric power input at or above the operating limits established during the performance test according to § 63.7530(b).
8. Emission limits using fuel analysis	a. Conduct monthly fuel analysis for HCl or mercury or TSM according to Table 6 to this subpart; and
	b. Reduce the data to 12-month rolling averages; and
	c. Maintain the 12-month rolling average at or below the applicable emission limit for HCl or mercury or TSM in Tables 1 and 2 or 11 through 13 to this subpart.

If you must meet the following operating limits or work practice standards . . .	**You must demonstrate continuous compliance by . . .**
9. Oxygen content	a. Continuously monitor the oxygen content using an oxygen analyzer system according to § 63.7525(a). This requirement does not apply to units that install an oxygen trim system since these units will set the trim system to the level specified in § 63.7525(a)(2).
	b. Reducing the data to 30-day rolling averages; and
	c. Maintain the 30-day rolling average oxygen content at or above the lowest hourly average oxygen level measured during the most recent CO performance test.
10. Boiler or process heater operating load	a. Collecting operating load data or steam generation data every 15 minutes.
	b. Maintaining the operating load such that it does not exceed 110 percent of the highest hourly average operating load recorded during the most recent performance test according to § 63.7520(c).
11. SO_2emissions using SO_2CEMS	a. Collecting the SO_2CEMS output data according to § 63.7525;
	b. Reducing the data to 30-day rolling averages; and
	c. Maintaining the 30-day rolling average SO_2CEMS emission rate to a level at or below the minimum hourly SO_2rate measured during the most recent HCl performance test according to § 63.7530.

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Table 9 to Subpart DDDDD of Part 63—Reporting Requirements

As stated in § 63.7550, you must comply with the following requirements for reports:

You must submit a(n)	**The report must contain . . .**	**You must submit the report . . .**
1. Compliance report	a. Information required in § 63.7550(c)(1) through (5); and	Semiannually, annually, biennially, or every 5 years according to the requirements in § 63.7550(b).

You must submit a(n)	The report must contain . . .	You must submit the report . . .
	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 3 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) where you are not using a CMS to comply with that emission limit or operating limit, or a deviation from a work practice standard during the reporting period, the report must contain the information in § 63.7550(d); and	
	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), or otherwise not operating, the report must contain the information in § 63.7550(e)	

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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	Applies to subpart DDDDD
§ 63.1	Applicability	Yes.
§ 63.2	Definitions	Yes. Additional terms defined in § 63.7575
§ 63.3	Units and Abbreviations	Yes.
§ 63.4	Prohibited Activities and Circumvention	Yes.
§ 63.5	Preconstruction Review and Notification Requirements	Yes.

Citation	**Subject**	**Applies to subpart DDDDD**
§ 63.6(a), (b)(1)-(b)(5), (b)(7), (c)	Compliance with Standards and Maintenance Requirements	Yes.
§ 63.6(e)(1)(i)	General duty to minimize emissions.	No. See § 63.7500(a)(3) for the general duty requirement.
§ 63.6(e)(1)(ii)	Requirement to correct malfunctions as soon as practicable.	No.
§ 63.6(e)(3)	Startup, shutdown, and malfunction plan requirements.	No.
§ 63.6(f)(1)	Startup, shutdown, and malfunction exemptions for compliance with non-opacity emission standards.	No.
§ 63.6(f)(2) and (3)	Compliance with non-opacity emission standards.	Yes.
§ 63.6(g)	Use of alternative standards	Yes.
§ 63.6(h)(1)	Startup, shutdown, and malfunction exemptions to opacity standards.	No. See § 63.7500(a).
§ 63.6(h)(2) to (h)(9)	Determining compliance with opacity emission standards	Yes.
§ 63.6(i)	Extension of compliance	Yes. Note: Facilities may also request extensions of compliance for the installation of combined heat and power, waste heat recovery, or gas pipeline or fuel feeding infrastructure as a means of complying with this subpart.
§ 63.6(j)	Presidential exemption.	Yes.
§ 63.7(a), (b), (c), and (d)	Performance Testing Requirements	Yes.
§ 63.7(e)(1)	Conditions for conducting performance tests	No. Subpart DDDDD specifies conditions for conducting performance tests at § 63.7520(a) to (c).
§ 63.7(e)(2)-(e)(9), (f), (g), and (h)	Performance Testing Requirements	Yes.
§ 63.8(a) and (b)	Applicability and Conduct of Monitoring	Yes.

Citation	**Subject**	**Applies to subpart DDDDD**
§ 63.8(c)(1)	Operation and maintenance of CMS	Yes.
§ 63.8(c)(1)(i)	General duty to minimize emissions and CMS operation	No. See § 63.7500(a)(3).
§ 63.8(c)(1)(ii)	Operation and maintenance of CMS	Yes.
§ 63.8(c)(1)(iii)	Startup, shutdown, and malfunction plans for CMS	No.
§ 63.8(c)(2) to (c)(9)	Operation and maintenance of CMS	Yes.
§ 63.8(d)(1) and (2)	Monitoring Requirements, Quality Control Program	Yes.
§ 63.8(d)(3)	Written procedures for CMS	Yes, except for the last sentence, which refers to a startup, shutdown, and malfunction plan. Startup, shutdown, and malfunction plans are not required.
§ 63.8(e)	Performance evaluation of a CMS	Yes.
§ 63.8(f)	Use of an alternative monitoring method.	Yes.
§ 63.8(g)	Reduction of monitoring data	Yes.
§ 63.9	Notification Requirements	Yes.
§ 63.10(a), (b)(1)	Recordkeeping and Reporting Requirements	Yes.
§ 63.10(b)(2)(i)	Recordkeeping of occurrence and duration of startups or shutdowns	Yes.
§ 63.10(b)(2)(ii)	Recordkeeping of malfunctions	No. See § 63.7555(d)(7) for recordkeeping of occurrence and duration and § 63.7555(d)(8) for actions taken during malfunctions.
§ 63.10(b)(2)(iii)	Maintenance records	Yes.
§ 63.10(b)(2)(iv) and (v)	Actions taken to minimize emissions during startup, shutdown, or malfunction	No.
§ 63.10(b)(2)(vi)	Recordkeeping for CMS malfunctions	Yes.
§ 63.10(b)(2)(vii) to (xiv)	Other CMS requirements	Yes.

Citation	Subject	Applies to subpart DDDDD
§ 63.10(b)(3)	Recordkeeping requirements for applicability determinations	No.
§ 63.10(c)(1) to (9)	Recordkeeping for sources with CMS	Yes.
§ 63.10(c)(10) and (11)	Recording nature and cause of malfunctions, and corrective actions	No. See § 63.7555(d)(7) for recordkeeping of occurrence and duration and § 63.7555(d)(8) for actions taken during malfunctions.
§ 63.10(c)(12) and (13)	Recordkeeping for sources with CMS	Yes.
§ 63.10(c)(15)	Use of startup, shutdown, and malfunction plan	No.
§ 63.10(d)(1) and (2)	General reporting requirements	Yes.
§ 63.10(d)(3)	Reporting opacity or visible emission observation results	No.
§ 63.10(d)(4)	Progress reports under an extension of compliance	Yes.
§ 63.10(d)(5)	Startup, shutdown, and malfunction reports	No. See § 63.7550(c)(11) for malfunction reporting requirements.
§ 63.10(e)	Additional reporting requirements for sources with CMS	Yes.
§ 63.10(f)	Waiver of recordkeeping or reporting requirements	Yes.
§ 63.11	Control Device Requirements	No.
§ 63.12	State Authority and Delegation	Yes.
§ 63.13-63.16	Addresses, Incorporation by Reference, Availability of Information, Performance Track Provisions	Yes.
§ 63.1(a)(5),(a)(7)-(a)(9), (b)(2), (c)(3)-(4), (d), 63.6(b)(6), (c)(3), (c)(4), (d), (e)(2), (e)(3)(ii), (h)(3), (h)(5)(iv), 63.8(a)(3), 63.9(b)(3), (h)(4), 63.10(c)(2)-(4), (c)(9).	Reserved	No.

[76 FR 15664, Mar. 21, 2011, as amended at 78 FR 7205, Jan. 31, 2013]

Table 11 to Subpart DDDDD of Part 63—Toxic Equivalency Factors for Dioxins/Furans

Dioxin/furan congener	Toxic equivalency factor
2,3,7,8-tetrachlorinated dibenzo-p-dioxin	1
1,2,3,7,8-pentachlorinated dibenzo-p-dioxin	1
1,2,3,4,7,8-hexachlorinated dibenzo-p-dioxin	0.1
1,2,3,7,8,9-hexachlorinated dibenzo-p-dioxin	0.1
1,2,3,6,7,8-hexachlorinated dibenzo-p-dioxin	0.1
1,2,3,4,6,7,8-heptachlorinated dibenzo-p-dioxin	0.01
octachlorinated dibenzo-p-dioxin	0.0003
2,3,7,8-tetrachlorinated dibenzofuran	0.1
2,3,4,7,8-pentachlorinated dibenzofuran	0.3
1,2,3,7,8-pentachlorinated dibenzofuran	0.03
1,2,3,4,7,8-hexachlorinated dibenzofuran	0.1
1,2,3,6,7,8-hexachlorinated dibenzofuran	0.1
1,2,3,7,8,9-hexachlorinated dibenzofuran	0.1
2,3,4,6,7,8-hexachlorinated dibenzofuran	0.1
1,2,3,4,6,7,8-heptachlorinated dibenzofuran	0.01
1,2,3,4,7,8,9-heptachlorinated dibenzofuran	0.01
octachlorinated dibenzofuran	0.0003

Table 12 to Subpart DDDDD of Part 63—Alternative Emission Limits for New or Reconstructed Boilers and Process Heaters That Commenced Construction or Reconstruction After June 4, 2010, and Before May 20, 2011

If your boiler or process heater is in this subcategory	For the following pollutants	The emissions must not exceed the following emission limits, except during periods of startup and shutdown	Using this specified sampling volume or test run duration
1. Units in all subcategories designed to burn solid fuel	a. Mercury	3.5E-06 lb per MMBtu of heat input	For M29, collect a minimum of 2 dscm per run; for M30A or M30B, collect a minimum sample as specified in the method; for ASTM D6784 [a]collect a minimum of 2 dscm.

If your boiler or process heater is in this subcategory	**For the following pollutants**	**The emissions must not exceed the following emission limits, except during periods of startup and shutdown**	**Using this specified sampling volume or test run duration**
2. Units in all subcategories designed to burn solid fuel that combust at least 10 percent biomass/bio-based solids on an annual heat input basis and less than 10 percent coal/solid fossil fuels on an annual heat input basis	a. Particulate Matter	0.008 lb per MMBtu of heat input (30-day rolling average for units 250 MMBtu/hr or greater, 3-run average for units less than 250 MMBtu/hr)	Collect a minimum of 1 dscm per run.
	b. Hydrogen Chloride	0.004 lb per MMBtu of heat input	For M26A, collect a minimum of 1 dscm per run; for M26, collect a minimum of 60 liters per run.
3. Units in all subcategories designed to burn solid fuel that combust at least 10 percent coal/solid fossil fuels on an annual heat input basis and less than 10 percent biomass/bio-based solids on an annual heat input basis	a. Particulate Matter	0.0011 lb per MMBtu of heat input (30-day rolling average for units 250 MMBtu/hr or greater, 3-run average for units less than 250 MMBtu/hr)	Collect a minimum of 3 dscm per run.
	b. Hydrogen Chloride	0.0022 lb per MMBtu of heat input	For M26A, collect a minimum of 1 dscm per run; for M26, collect a minimum of 60 liters per run.
4. Units designed to burn pulverized coal/solid fossil fuel	a. CO	90 ppm by volume on a dry basis corrected to 3 percent oxygen	1 hr minimum sampling time.
	b. Dioxins/Furans	0.003 ng/dscm (TEQ) corrected to 7 percent oxygen	Collect a minimum of 4 dscm per run.
5. Stokers designed to burn coal/solid fossil fuel	a. CO	7 ppm by volume on a dry basis corrected to 3 percent oxygen	1 hr minimum sampling time.
	b. Dioxins/Furans	0.003 ng/dscm (TEQ) corrected to 7 percent oxygen	Collect a minimum of 4 dscm per run.
6. Fluidized bed units designed to burn coal/solid fossil fuel	a. CO	30 ppm by volume on a dry basis corrected to 3 percent oxygen	1 hr minimum sampling time.
	b. Dioxins/Furans	0.002 ng/dscm (TEQ) corrected to 7 percent oxygen	Collect a minimum of 4 dscm per run.

If your boiler or process heater is in this subcategory	**For the following pollutants**	**The emissions must not exceed the following emission limits, except during periods of startup and shutdown**	**Using this specified sampling volume or test run duration**
7. Stokers designed to burn biomass/bio-based solids	a. CO	560 ppm by volume on a dry basis corrected to 3 percent oxygen	1 hr minimum sampling time.
	b. Dioxins/Furans	0.005 ng/dscm (TEQ) corrected to 7 percent oxygen	Collect a minimum of 4 dscm per run.
8. Fluidized bed units designed to burn biomass/bio-based solids	a. CO	260 ppm by volume on a dry basis corrected to 3 percent oxygen	1 hr minimum sampling time.
	b. Dioxins/Furans	0.02 ng/dscm (TEQ) corrected to 7 percent oxygen	Collect a minimum of 4 dscm per run.
9. Suspension burners/Dutch Ovens designed to burn biomass/bio-based solids	a. CO	1,010 ppm by volume on a dry basis corrected to 3 percent oxygen	1 hr minimum sampling time.
	b. Dioxins/Furans	0.2 ng/dscm (TEQ) corrected to 7 percent oxygen	Collect a minimum of 4 dscm per run.
10. Fuel cells designed to burn biomass/bio-based solids	a. CO	470 ppm by volume on a dry basis corrected to 3 percent oxygen	1 hr minimum sampling time.
	b. Dioxins/Furans	0.003 ng/dscm (TEQ) corrected to 7 percent oxygen	Collect a minimum of 4 dscm per run.
11. Hybrid suspension/grate units designed to burn biomass/bio-based solids	a. CO	1,500 ppm by volume on a dry basis corrected to 3 percent oxygen	1 hr minimum sampling time.
	b. Dioxins/Furans	0.2 ng/dscm (TEQ) corrected to 7 percent oxygen	Collect a minimum of 4 dscm per run.
12. Units designed to burn liquid fuel	a. Particulate Matter	0.002 lb per MMBtu of heat input (30-day rolling average for units 250 MMBtu/hr or greater, 3-run average for units less than 250 MMBtu/hr)	Collect a minimum of 2 dscm per run.

If your boiler or process heater is in this subcategory	For the following pollutants	The emissions must not exceed the following emission limits, except during periods of startup and shutdown	Using this specified sampling volume or test run duration
	b. Hydrogen Chloride	0.0032 lb per MMBtu of heat input	For M26A, collect a minimum of 1 dscm per run; for M26, collect a minimum of 60 liters per run.
	c. Mercury	3.0E-07 lb per MMBtu of heat input	For M29, collect a minimum of 2 dscm per run; for M30A or M30B, collect a minimum sample as specified in the method; for ASTM D6784 [a]collect a minimum of 2 dscm.
	d. CO	3 ppm by volume on a dry basis corrected to 3 percent oxygen	1 hr minimum sampling time.
	e. Dioxins/Furans	0.002 ng/dscm (TEQ) corrected to 7 percent oxygen	Collect a minimum of 4 dscm per run.
13. Units designed to burn liquid fuel located in non-continental States and territories	a. Particulate Matter	0.002 lb per MMBtu of heat input (30-day rolling average for units 250 MMBtu/hr or greater, 3-run average for units less than 250 MMBtu/hr)	Collect a minimum of 2 dscm per run.
	b. Hydrogen Chloride	0.0032 lb per MMBtu of heat input	For M26A, collect a minimum of 1 dscm per run; for M26, collect a minimum of 60 liters per run.
	c. Mercury	7.8E-07 lb per MMBtu of heat input	For M29, collect a minimum of 1 dscm per run; for M30A or M30B, collect a minimum sample as specified in the method; for ASTM D6784 [a]collect a minimum of 2 dscm.
	d. CO	51 ppm by volume on a dry basis corrected to 3 percent oxygen	1 hr minimum sampling time.
	e. Dioxins/Furans	0.002 ng/dscm (TEQ) corrected to 7 percent oxygen	Collect a minimum of 4 dscm per run.

If your boiler or process heater is in this subcategory	For the following pollutants	The emissions must not exceed the following emission limits, except during periods of startup and shutdown	Using this specified sampling volume or test run duration
14. Units designed to burn gas 2 (other) gases	a. Particulate Matter	0.0067 lb per MMBtu of heat input (30-day rolling average for units 250 MMBtu/hr or greater, 3-run average for units less than 250 MMBtu/hr)	Collect a minimum of 1 dscm per run.
	b. Hydrogen Chloride	0.0017 lb per MMBtu of heat input	For M26A, collect a minimum of 1 dscm per run; for M26, collect a minimum of 60 liters per run.
	c. Mercury	7.9E-06 lb per MMBtu of heat input	For M29, collect a minimum of 1 dscm per run; for M30A or M30B, collect a minimum sample as specified in the method; for ASTM D6784 [a]collect a minimum of 2 dscm.
	d. CO	3 ppm by volume on a dry basis corrected to 3 percent oxygen	1 hr minimum sampling time.
	e. Dioxins/Furans	0.08 ng/dscm (TEQ) corrected to 7 percent oxygen	Collect a minimum of 4 dscm per run.

[a] Incorporated by reference, see § 63.14.

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Table 11 to Subpart DDDDD of Part 63—Alternative Emission Limits for New or Reconstructed Boilers and Process Heaters That Commenced Construction or Reconstruction After June 4, 2010, and Before May 20, 2011

If your boiler or process heater is in this subcategory . . .	For the following pollutants . . .	The emissions must not exceed the following emission limits, except during periods of startup and shutdown . . .	Using this specified sampling volume or test run duration . . .
1. Units in all subcategories designed to burn solid fuel	a. HCl	0.022 lb per MMBtu of heat input	For M26A, collect a minimum of 1 dscm per run; for M26 collect a minimum of 120 liters per run.

If your boiler or process heater is in this subcategory . . .	**For the following pollutants . . .**	**The emissions must not exceed the following emission limits, except during periods of startup and shutdown . . .**	**Using this specified sampling volume or test run duration . . .**
2. Units in all subcategories designed to burn solid fuel that combust at least 10 percent biomass/bio-based solids on an annual heat input basis and less than 10 percent coal/solid fossil fuels on an annual heat input basis	a. Mercury	8.0E-07 [a]lb per MMBtu of heat input	For M29, collect a minimum of 4 dscm per run; for M30A or M30B, collect a minimum sample as specified in the method; for ASTM D6784 [b]collect a minimum of 4 dscm.
3. Units in all subcategories designed to burn solid fuel that combust at least 10 percent coal/solid fossil fuels on an annual heat input basis and less than 10 percent biomass/bio-based solids on an annual heat input basis	a. Mercury	2.0E-06 lb per MMBtu of heat input	For M29, collect a minimum of 4 dscm per run; for M30A or M30B, collect a minimum sample as specified in the method; for ASTM D6784 [b]collect a minimum of 4 dscm.
4. Units designed to burn coal/solid fossil fuel	a. Filterable PM (or TSM)	1.1E-03 lb per MMBtu of heat input; or (2.3E-05 lb per MMBtu of heat input)	Collect a minimum of 3 dscm per run.
5. Pulverized coal boilers designed to burn coal/solid fossil fuel	a. Carbon monoxide (CO) (or CEMS)	130 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (320 ppm by volume on a dry basis corrected to 3 percent oxygen, 30-day rolling average)	1 hr minimum sampling time.
6. Stokers designed to burn coal/solid fossil fuel	a. CO (or CEMS)	130 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (340 ppm by volume on a dry basis corrected to 3 percent oxygen, 10-day rolling average)	1 hr minimum sampling time.
7. Fluidized bed units designed to burn coal/solid fossil fuel	a. CO (or CEMS)	130 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (230 ppm by volume on a dry basis corrected to 3 percent oxygen, 30-day rolling average)	1 hr minimum sampling time.

If your boiler or process heater is in this subcategory . . .	**For the following pollutants . . .**	**The emissions must not exceed the following emission limits, except during periods of startup and shutdown . . .**	**Using this specified sampling volume or test run duration . . .**
8. Fluidized bed units with an integrated heat exchanger designed to burn coal/solid fossil fuel	a. CO (or CEMS)	140 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (150 ppm by volume on a dry basis corrected to 3 percent oxygen, 30-day rolling average)	1 hr minimum sampling time.
9. Stokers/sloped grate/others designed to burn wet biomass fuel	a. CO (or CEMS)	620 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (390 ppm by volume on a dry basis corrected to 3 percent oxygen, 30-day rolling average)	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	3.0E-02 lb per MMBtu of heat input; or (2.6E-05 lb per MMBtu of heat input)	Collect a minimum of 2 dscm per run.
10. Stokers/sloped grate/others designed to burn kiln-dried biomass fuel	a. CO	560 ppm by volume on a dry basis corrected to 3 percent oxygen	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	3.0E-02 lb per MMBtu of heat input; or (4.0E-03 lb per MMBtu of heat input)	Collect a minimum of 2 dscm per run.
11. Fluidized bed units designed to burn biomass/bio-based solids	a. CO (or CEMS)	230 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (310 ppm by volume on a dry basis corrected to 3 percent oxygen, 30-day rolling average)	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	9.8E-03 lb per MMBtu of heat input; or (8.3E-05 [a]lb per MMBtu of heat input)	Collect a minimum of 3 dscm per run
12. Suspension burners designed to burn biomass/bio-based solids	a. CO (or CEMS)	2,400 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (2,000 ppm by volume on a dry basis corrected to 3 percent oxygen, 10-day rolling average)	1 hr minimum sampling time.

If your boiler or process heater is in this subcategory . . .	**For the following pollutants . . .**	**The emissions must not exceed the following emission limits, except during periods of startup and shutdown . . .**	**Using this specified sampling volume or test run duration . . .**
	b. Filterable PM (or TSM)	3.0E-02 lb per MMBtu of heat input; or (6.5E-03 lb per MMBtu of heat input)	Collect a minimum of 2 dscm per run.
13. Dutch Ovens/Pile burners designed to burn biomass/bio-based solids	a. CO (or CEMS)	1,010 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (520 ppm by volume on a dry basis corrected to 3 percent oxygen, 10-day rolling average)	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	8.0E-03 lb per MMBtu of heat input; or (3.9E-05 lb per MMBtu of heat input)	Collect a minimum of 3 dscm per run.
14. Fuel cell units designed to burn biomass/bio-based solids	a. CO	910 ppm by volume on a dry basis corrected to 3 percent oxygen	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	2.0E-02 lb per MMBtu of heat input; or (2.9E-05 lb per MMBtu of heat input)	Collect a minimum of 2 dscm per run.
15. Hybrid suspension grate boiler designed to burn biomass/bio-based solids	a. CO (or CEMS)	1,100 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (900 ppm by volume on a dry basis corrected to 3 percent oxygen, 30-day rolling average)	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	2.6E-02 lb per MMBtu of heat input; or (4.4E-04 lb per MMBtu of heat input)	Collect a minimum of 3 dscm per run.
16. Units designed to burn liquid fuel	a. HCl	4.4E-04 lb per MMBtu of heat input	For M26A: Collect a minimum of 2 dscm per run; for M26, collect a minimum of 240 liters per run.
	b. Mercury	4.8E-07 [a]lb per MMBtu of heat input	For M29, collect a minimum of 4 dscm per run; for M30A or M30B, collect a minimum sample as specified in the method; for ASTM D6784 [b]collect a minimum of 4 dscm.

If your boiler or process heater is in this subcategory . . .	For the following pollutants . . .	The emissions must not exceed the following emission limits, except during periods of startup and shutdown . . .	Using this specified sampling volume or test run duration . . .
17. Units designed to burn heavy liquid fuel	a. CO	130 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	1.3E-02 lb per MMBtu of heat input; or (7.5E-05 lb per MMBtu of heat input)	Collect a minimum of 3 dscm per run.
18. Units designed to burn light liquid fuel	a. CO	130 ppm by volume on a dry basis corrected to 3 percent oxygen	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	2.0E-03 [a]lb per MMBtu of heat input; or (2.9E-05 lb per MMBtu of heat input)	Collect a minimum of 3 dscm per run
19. Units designed to burn liquid fuel that are non-continental units	a. CO	130 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average based on stack test	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	2.3E-02 lb per MMBtu of heat input; or (8.6E-04 lb per MMBtu of heat input)	Collect a minimum of 4 dscm per run
20. Units designed to burn gas 2 (other) gases	a. CO	130 ppm by volume on a dry basis corrected to 3 percent oxygen	1 hr minimum sampling time.
	b. HCl	1.7E-03 lb per MMBtu of heat input	For M26A, collect a minimum of 2 dscm per run; for M26, collect a minimum of 240 liters per run.
	c. Mercury	7.9E-06 lb per MMBtu of heat input	For M29, collect a minimum of 3 dscm per run; for M30A or M30B, collect a minimum sample as specified in the method; for ASTM D6784 [b]collect a minimum of 3 dscm.
	d. Filterable PM (or TSM)	6.7E-03 lb per MMBtu of heat input; or (2.1E-04 lb per MMBtu of heat input)	Collect a minimum of 3 dscm per run

[a] If you are conducting stack tests to demonstrate compliance and your performance tests for this pollutant for at least 2 consecutive years show that your emissions are at or below this limit, you can skip testing according to § 63.7515 if all of the other provisions of § 63.7515 are met. For all other pollutants

that do not contain a footnote “a”, your performance tests for this pollutant for at least 2 consecutive years must show that your emissions are at or below 75 percent of this limit in order to qualify for skip testing.

[b] Incorporated by reference, see § 63.14.

[78 FR 7206, Jan. 31, 2013]

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Table 12 to Subpart DDDDD of Part 63—Alternative Emission Limits for New or Reconstructed Boilers and Process Heaters that Commenced Construction or Reconstruction after May 20, 2011, and Before December 23, 2011

If your boiler or process heater is in this subcategory . . .	**For the following pollutants . . .**	**The emissions must not exceed the following emission limits, except during periods of startup and shutdown . . .**	**Using this specified sampling volume or test run duration . . .**
1. Units in all subcategories designed to burn solid fuel	a. HCl	0.022 lb per MMBtu of heat input	For M26A, collect a minimum of 1 dscm per run; for M26 collect a minimum of 120 liters per run.
	b. Mercury	3.5E-06 [a]lb per MMBtu of heat input	For M29, collect a minimum of 3 dscm per run; for M30A or M30B, collect a minimum sample as specified in the method; for ASTM D6784 [b]collect a minimum of 3 dscm.
2. Units design to burn coal/solid fossil fuel	a. Filterable PM (or TSM)	1.1E-03 lb per MMBtu of heat input; or (2.3E-05 lb per MMBtu of heat input)	Collect a minimum of 3 dscm per run.
3. Pulverized coal boilers designed to burn coal/solid fossil fuel	a. Carbon monoxide (CO) (or CEMS)	130 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (320 ppm by volume on a dry basis corrected to 3 percent oxygen, 30-day rolling average)	1 hr minimum sampling time.
4. Stokers designed to burn coal/solid fossil fuel	a. CO (or CEMS)	130 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (340 ppm by volume on a dry basis corrected to 3 percent oxygen, 10-day rolling average)	1 hr minimum sampling time.
5. Fluidized bed units designed to burn coal/solid fossil fuel	a. CO (or CEMS)	130 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (230 ppm by volume on a dry basis corrected to 3 percent oxygen, 30-day rolling average)	1 hr minimum sampling time.

If your boiler or process heater is in this subcategory . . .	For the following pollutants . . .	The emissions must not exceed the following emission limits, except during periods of startup and shutdown . . .	Using this specified sampling volume or test run duration . . .
6. Fluidized bed units with an integrated heat exchanger designed to burn coal/solid fossil fuel	a. CO (or CEMS)	140 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (150 ppm by volume on a dry basis corrected to 3 percent oxygen, 30-day rolling average)	1 hr minimum sampling time.
7. Stokers/sloped grate/others designed to burn wet biomass fuel	a. CO (or CEMS)	620 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (390 ppm by volume on a dry basis corrected to 3 percent oxygen, 30-day rolling average)	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	3.0E-02 lb per MMBtu of heat input; or (2.6E-05 lb per MMBtu of heat input)	Collect a minimum of 2 dscm per run.
8. Stokers/sloped grate/others designed to burn kiln-dried biomass fuel	a. CO	460 ppm by volume on a dry basis corrected to 3 percent oxygen	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	3.0E-02 lb per MMBtu of heat input; or (4.0E-03 lb per MMBtu of heat input)	Collect a minimum of 2 dscm per run.
9. Fluidized bed units designed to burn biomass/bio-based solids	a. CO (or CEMS)	260 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (310 ppm by volume on a dry basis corrected to 3 percent oxygen, 30-day rolling average)	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	9.8E-03 lb per MMBtu of heat input; or (8.3E-05 [a]lb per MMBtu of heat input)	Collect a minimum of 3 dscm per run.
10. Suspension burners designed to burn biomass/bio-based solids	a. CO (or CEMS)	2,400 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (2,000 ppm by volume on a dry basis corrected to 3 percent oxygen, 10-day rolling average)	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	3.0E-02 lb per MMBtu of heat input; or (6.5E-03 lb per MMBtu of heat input)	Collect a minimum of 2 dscm per run.

If your boiler or process heater is in this subcategory . . .	**For the following pollutants . . .**	**The emissions must not exceed the following emission limits, except during periods of startup and shutdown . . .**	**Using this specified sampling volume or test run duration . . .**
11. Dutch Ovens/Pile burners designed to burn biomass/bio-based solids	a. CO (or CEMS)	470 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (520 ppm by volume on a dry basis corrected to 3 percent oxygen, 10-day rolling average)	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	3.2E-03 lb per MMBtu of heat input; or (3.9E-05 lb per MMBtu of heat input)	Collect a minimum of 3 dscm per run.
12. Fuel cell units designed to burn biomass/bio-based solids	a. CO	910 ppm by volume on a dry basis corrected to 3 percent oxygen	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	2.0E-02 lb per MMBtu of heat input; or (2.9E-05 lb per MMBtu of heat input)	Collect a minimum of 2 dscm per run.
13. Hybrid suspension grate boiler designed to burn biomass/bio-based solids	a. CO (or CEMS)	1,500 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (900 ppm by volume on a dry basis corrected to 3 percent oxygen, 30-day rolling average)	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	2.6E-02 lb per MMBtu of heat input; or (4.4E-04 lb per MMBtu of heat input)	Collect a minimum of 3 dscm per run.
14. Units designed to burn liquid fuel	a. HCl	4.4E-04 lb per MMBtu of heat input	For M26A: Collect a minimum of 2 dscm per run; for M26, collect a minimum of 240 liters per run.
	b. Mercury	4.8E-07 [a]lb per MMBtu of heat input	For M29, collect a minimum of 4 dscm per run; for M30A or M30B, collect a minimum sample as specified in the method; for ASTM D6784 [b]collect a minimum of 4 dscm.
15. Units designed to burn heavy liquid fuel	a. CO	130 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	1.3E-02 lb per MMBtu of heat input; or (7.5E-05 lb per MMBtu of heat input)	Collect a minimum of 2 dscm per run.
16. Units designed to burn light liquid fuel	a. CO	130 ppm by volume on a dry basis corrected to 3 percent oxygen	1 hr minimum sampling time.

If your boiler or process heater is in this subcategory . . .	**For the following pollutants . . .**	**The emissions must not exceed the following emission limits, except during periods of startup and shutdown . . .**	**Using this specified sampling volume or test run duration . . .**
	b. Filterable PM (or TSM)	1.3E-03 [a]lb per MMBtu of heat input; or (2.9E-05 lb per MMBtu of heat input)	Collect a minimum of 3 dscm per run.
17. Units designed to burn liquid fuel that are non-continental units	a. CO	130 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average based on stack test	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	2.3E-02 lb per MMBtu of heat input; or (8.6E-04 lb per MMBtu of heat input)	Collect a minimum of 4 dscm per run.
18. Units designed to burn gas 2 (other) gases	a. CO	130 ppm by volume on a dry basis corrected to 3 percent oxygen	1 hr minimum sampling time.
	b. HCl	1.7E-03 lb per MMBtu of heat input	For M26A, Collect a minimum of 2 dscm per run; for M26, collect a minimum of 240 liters per run.
	c. Mercury	7.9E-06 lb per MMBtu of heat input	For M29, collect a minimum of 3 dscm per run; for M30A or M30B, collect a minimum sample as specified in the method; for ASTM D6784 [b]collect a minimum of 3 dscm.
	d. Filterable PM (or TSM)	6.7E-03 lb per MMBtu of heat input; or (2.1E-04 lb per MMBtu of heat input)	Collect a minimum of 3 dscm per run.

[a] If you are conducting stack tests to demonstrate compliance and your performance tests for this pollutant for at least 2 consecutive years show that your emissions are at or below this limit, you can skip testing according to § 63.7515 if all of the other provision of § 63.7515 are met. For all other pollutants that do not contain a footnote “a”, your performance tests for this pollutant for at least 2 consecutive years must show that your emissions are at or below 75 percent of this limit in order to qualify for skip testing.

[b] Incorporated by reference, see § 63.14.

[78 FR 7208, Jan. 31, 2013]

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Table 13 to Subpart DDDDD of Part 63—Alternative Emission Limits for New or Reconstructed Boilers and Process Heaters That Commenced Construction or Reconstruction After December 23, 2011, and Before January 31, 2013

If your boiler or process heater is in this subcategory . . .	For the following pollutants . . .	The emissions must not exceed the following emission limits, except during periods of startup and shutdown . . .	Using this specified sampling volume or test run duration . . .
1. Units in all subcategories designed to burn solid fuel	a. HCl	0.022 lb per MMBtu of heat input	For M26A, collect a minimum of 1 dscm per run; for M26 collect a minimum of 120 liters per run.
	b. Mercury	8.6E-07 [a]lb per MMBtu of heat input	For M29, collect a minimum of 4 dscm per run; for M30A or M30B, collect a minimum sample as specified in the method; for ASTM D6784 [b]collect a minimum of 4 dscm.
2. Pulverized coal boilers designed to burn coal/solid fossil fuel	a. Carbon monoxide (CO) (or CEMS)	130 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (320 ppm by volume on a dry basis corrected to 3 percent oxygen, 30-day rolling average)	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	1.1E-03 lb per MMBtu of heat input; or (2.8E-05 lb per MMBtu of heat input)	Collect a minimum of 3 dscm per run.
3. Stokers designed to burn coal/solid fossil fuel	a. CO (or CEMS)	130 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (340 ppm by volume on a dry basis corrected to 3 percent oxygen, 10-day rolling average)	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	2.8E-02 lb per MMBtu of heat input; or (2.3E-05 lb per MMBtu of heat input)	Collect a minimum of 2 dscm per run.
4. Fluidized bed units designed to burn coal/solid fossil fuel	a. CO (or CEMS)	130 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (230 ppm by volume on a dry basis corrected to 3 percent oxygen, 30-day rolling average)	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	1.1E-03 lb per MMBtu of heat input; or (2.3E-05 lb per MMBtu of heat input)	Collect a minimum of 3 dscm per run.
5. Fluidized bed units with an integrated heat exchanger designed to burn coal/solid fossil fuel	a. CO (or CEMS)	140 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (150 ppm by volume on a dry basis corrected to 3 percent oxygen, 30-day rolling average)	1 hr minimum sampling time.

If your boiler or process heater is in this subcategory . . .	For the following pollutants . . .	The emissions must not exceed the following emission limits, except during periods of startup and shutdown . . .	Using this specified sampling volume or test run duration . . .
	b. Filterable PM (or TSM)	1.1E-03 lb per MMBtu of heat input; or (2.3E-05 lb per MMBtu of heat input)	Collect a minimum of 3 dscm per run.
6. Stokers/sloped grate/others designed to burn wet biomass fuel	a. CO (or CEMS)	620 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (410 ppm by volume on a dry basis corrected to 3 percent oxygen, 10-day rolling average)	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	3.0E-02 lb per MMBtu of heat input; or (2.6E-05 lb per MMBtu of heat input)	Collect a minimum of 2 dscm per run.
7. Stokers/sloped grate/others designed to burn kiln-dried biomass fuel	a. CO	460 ppm by volume on a dry basis corrected to 3 percent oxygen	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	3.2E-01 lb per MMBtu of heat input; or (4.0E-03 lb per MMBtu of heat input)	Collect a minimum of 2 dscm per run.
8. Fluidized bed units designed to burn biomass/bio-based solids	a. CO (or CEMS)	230 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (310 ppm by volume on a dry basis corrected to 3 percent oxygen, 30-day rolling average)	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	9.8E-03 lb per MMBtu of heat input; or (8.3E-05 [a]lb per MMBtu of heat input)	Collect a minimum of 3 dscm per run.
9. Suspension burners designed to burn biomass/bio-based solids	a. CO (or CEMS)	2,400 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (2,000 ppm by volume on a dry basis corrected to 3 percent oxygen, 10-day rolling average)	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	5.1E-02 lb per MMBtu of heat input; or (6.5E-03 lb per MMBtu of heat input)	Collect a minimum of 2 dscm per run.
10. Dutch Ovens/Pile burners designed to burn biomass/bio-based solids	a. CO (or CEMS)	810 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (520 ppm by volume on a dry basis corrected to 3 percent oxygen, 10-day rolling average)	1 hr minimum sampling time.

If your boiler or process heater is in this subcategory . . .	**For the following pollutants . . .**	**The emissions must not exceed the following emission limits, except during periods of startup and shutdown . . .**	**Using this specified sampling volume or test run duration . . .**
	b. Filterable PM (or TSM)	3.6E-02 lb per MMBtu of heat input; or (3.9E-05 lb per MMBtu of heat input)	Collect a minimum of 2 dscm per run.
11. Fuel cell units designed to burn biomass/bio-based solids	a. CO	910 ppm by volume on a dry basis corrected to 3 percent oxygen	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	2.0E-02 lb per MMBtu of heat input; or (2.9E-05 lb per MMBtu of heat input)	Collect a minimum of 2 dscm per run.
12. Hybrid suspension grate boiler designed to burn biomass/bio-based solids	a. CO (or CEMS)	1,500 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (900 ppm by volume on a dry basis corrected to 3 percent oxygen, 30-day rolling average)	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	2.6E-02 lb per MMBtu of heat input; or (4.4E-04 lb per MMBtu of heat input)	Collect a minimum of 3 dscm per run.
13. Units designed to burn liquid fuel	a. HCl	1.2E-03 lb per MMBtu of heat input	For M26A: Collect a minimum of 2 dscm per run; for M26, collect a minimum of 240 liters per run.
	b. Mercury	4.9E-07 [a]lb per MMBtu of heat input	For M29, collect a minimum of 4 dscm per run; for M30A or M30B, collect a minimum sample as specified in the method; for ASTM D6784 [b]collect a minimum of 4 dscm.
14. Units designed to burn heavy liquid fuel	a. CO (or CEMS)	130 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (18 ppm by volume on a dry basis corrected to 3 percent oxygen, 10-day rolling average)	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	1.3E-03 lb per MMBtu of heat input; or (7.5E-05 lb per MMBtu of heat input)	Collect a minimum of 3 dscm per run.
15. Units designed to burn light liquid fuel	a. CO (or CEMS)	130 [a]ppm by volume on a dry basis corrected to 3 percent oxygen; or (60 ppm by volume on a dry basis corrected to 3 percent oxygen, 1-day block average).	1 hr minimum sampling time.

If your boiler or process heater is in this subcategory . . .	**For the following pollutants . . .**	**The emissions must not exceed the following emission limits, except during periods of startup and shutdown . . .**	**Using this specified sampling volume or test run duration . . .**
	b. Filterable PM (or TSM)	1.1E-03 [a]lb per MMBtu of heat input; or (2.9E-05 lb per MMBtu of heat input)	Collect a minimum of 3 dscm per run.
16. Units designed to burn liquid fuel that are non-continental units	a. CO	130 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average based on stack test; or (91 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-hour rolling average)	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	2.3E-02 lb per MMBtu of heat input; or (8.6E-04 lb per MMBtu of heat input)	Collect a minimum of 2 dscm per run.
17. Units designed to burn gas 2 (other) gases	a. CO	130 ppm by volume on a dry basis corrected to 3 percent oxygen	1 hr minimum sampling time.
	b. HCl	1.7E-03 lb per MMBtu of heat input	For M26A, Collect a minimum of 2 dscm per run; for M26, collect a minimum of 240 liters per run.
	c. Mercury	7.9E-06 lb per MMBtu of heat input	For M29, collect a minimum of 3 dscm per run; for M30A or M30B, collect a minimum sample as specified in the method; for ASTM D6784 [b]collect a minimum of 3 dscm.
	d. Filterable PM (or TSM)	6.7E-03 lb per MMBtu of heat input; or (2.1E-04 lb per MMBtu of heat input)	Collect a minimum of 3 dscm per run.

[a] If you are conducting stack tests to demonstrate compliance and your performance tests for this pollutant for at least 2 consecutive years show that your emissions are at or below this limit and you are not required to conduct testing for CEMS or CPMS monitor certification, you can skip testing according to § 63.7515 if all of the other provision of § 63.7515 are met. For all other pollutants that do not contain a footnote “a”, your performance tests for this pollutant for at least 2 consecutive years must show that your emissions are at or below 75 percent of this limit in order to qualify for skip testing.

[b] Incorporated by reference, see § 63.14.

[78 FR 7210, Jan. 31, 2013]

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Indiana Department of Environmental Management
Office of Air Quality

Addendum to the Technical Support Document (ATSD)
for a New Source Construction and Part 70 Operating Permit

Source Description and Location

Source Name:	Ohio Valley Resources, LLC
Source Location:	300-400 East CR 350 North, Rockport, Indiana 47635
County:	Spencer, Ohio Township
SIC Code:	2873
Operation Permit No.:	T 147-32322-00062
Permit Reviewer:	David Matousek

Public Notice Information

On February 28, 2013 and March 28, 2013, the Office of Air Quality (OAQ) had a notice published in the Journal Democrat in Rockport, Indiana stating that Ohio Valley Resources, LLC applied for a PSD/New Source Construction and Part 70 Operating Permit. This PSD/New Source Construction and Part 70 Operating Permit would allow Ohio Valley Resources, LLC to construct and operate a new nitrogenous fertilizer production plant.

Both notices stated that the OAQ proposed to issue a Part 70 Operating Permit for this operation and provided information on how the public could review the proposed permit and other documentation. Finally, the notice informed interested parties that there was a period of thirty days to provide comments on the issuance of this permit.

IDEM, OAQ received several public comments on the draft permit documents, including multiple requests for a public hearing. On April 4, 2013, the Office of Air Quality had a third notice published in the Journal Democrat in Rockport, Indiana. This notice extended the public comment period until May 20, 2013 and provided information on a public hearing and public meeting in the Rockport, Indiana area.

On May 15, 2013, IDEM, OAQ conducted a public meeting and a public hearing at the South Spencer County High School in Rockport, Indiana. IDEM, OAQ staff was available to accept formal comments and answer questions from the public on the proposed permit.

Comments and IDEM's Responses

IDEM, OAQ received written comments during the public comment period from the following individuals:

Sarah Winner P.O. Box 305 Santa Claus, IN 47579	Rex L. Winchell 715 W. Old State Road 45 Rockport, IN 47635	John Blair (Multiple Comments) Valley Watch, Inc. 800 Adams Ave. Evansville, Indiana 47713
Sunil Bector Sierra Club 85 Second Street, 2nd Floor San Francisco, CA 94105	Johnny R. Bretz 3202 N. Old State Road Rockport, Indiana 47635	Roger & Rachel Hurm Hurm Farms, Inc. 3610 N. Silverdale Rd. Rockport, Indiana 47635

Chuck and Janet Botsko 12540 N. Base Road Gentryville, Indiana 47537 (Multiple Comments)	Cheryl Y. Hurst 114 E. Medcalf, P.O. Box 104 Dale, Indiana 47523	Doug Matthews Rockport, Indiana
Carolyn Altstadt Santa Claus, Indiana	Rollie Kelly 630 East CR 400 North Rockport, Indiana 47635	Drs. Jim and Lee Olson 209 South 2nd Street Rockport, Indiana 47635-1371
Elaine Sorenson 10001 N. Stones Ln Evanston, Indiana 47531-8110	Sara Dunn 2105 College Avenue Vincennes, Indiana 47591-5632	Kim Schiavone 10401 W. Bnvl New Har Rd Evansville, Indiana 47720-8137
Rhonda Kohl 42 Wildwood Rd Jeffersonville, Indiana 47130-6820	Kelly Morrison 1220 Weed Ln Vincennes, Indiana 47591-5049	Hans Huber 7400 S. Shady Side Dr. Bloomington, Indiana 47401-9551
Jeffery Cottingham 417 4th Street Aurora, Indiana 47001-1207	Rick Honeycutt 8735 N. Spades Rd. Milan, Indiana 47031-9415	Daniel Burnham 6775 N. Hudoff Rd. Bloomington, Indiana 47408-9527
David Motz 1608 Southeast Blvd. Evansville, Indiana 47714-2036	Imogene Burkhart 328 Adams Ave. Evansville, Indiana 47713-1538	Yvonne French 322 E. Kirkwood Ave. Bloomington, Indiana 47408-3586
Wes Milner 7109 E. Chestnut St. Evansville, Indiana 47715-3620	Derek Green 14200 Worthington Ct Evansville, Indiana 47725-8272	Georgia Sumner 2409 E. Rock Creek Dr. Bloomington, Indiana 47401-6821
Rebecca Brookman 1742 N. Old Petersburg Rd. Princeton, Indiana 47670-8509	Shari Caldwell 13101 Caldwell Ln Dillsboro, Indiana 47018-8010	Dorothy Wilson 4500 N. Woodlands Ln. Bloomington, Indiana 47404-9420
Ashley Verkamp 22125 Blue Ridge Rd. Bristow, Indiana 47515-9102	Stephen Arnold 627 W. 7th Street Bloomington, Indiana 47404-3941	Kristen Hackman 521 E. 7th St., Apt #4 Bloomington, Indiana 47408-3899
Philip Lipton 720 S. College Mall Rd., Apt H6 Bloomington, Indiana 47401-5464	Karisha Kirk 3231 S. Bradshire Ct Bloomington, Indiana 47401-8725	Stephen Simonds 1305 Timberlake Rd. Evansville, Indiana 47710-4125
George Oglesby 9607 Darmstadt Rd. Evansville, Indiana 47710-5042	Tracy Fox 11900 N. County Rd 50 W. Batesville, Indiana 47006-9787	Jan Reynolds 1412 W. 12th Street Bloomington, Indiana 47404-3145

Elizabeth Izzo 815 S. Rogers St. Bloomington, Indiana 47403-2337 (Multiple Comments)	Darrel Joy 4 Arbor Pl. New Albany, Indiana 47150-7292	Bruce L. Pearson 1025 S. Graywell Dr. Bloomington, Indiana 47401-9718
Jean Webb 2105 E. Columbia St. Evansville, Indiana 47711-5908	Patrick Coppage 612 Mulberry St. Madison, Indiana 47250-3442	James Ashcraft 200 E. Center St. Lawrenceburg, Indiana 47025-1875
Pamela Schrantz 12281 N. Hogan Rd. Aurora, Indiana 47001-8015	Raymond Minton 1531 E. State Rd. 356 Scottsburg, Indiana 47170-6645	Patricia Canary 1015 W. Van Trees St. Washington, Indiana 47501-2427
Tad Legler 4630 N. Chatham Dr. Bloomington, Indiana 47404-1319	Steve Harrison 871 Chandler Dr. Ellettsville, Indiana 47429-1611	Ellen Stauffer 2631 E. Poplar Dr. Bloomington, Indiana 47401-4329
June Tomastick 215 E. 2nd Street Bloomington, Indiana 47401-4778	Kara Horstman 3957 Terra Trace St. Evansville, Indiana 47715-2045	Leandro Lopes 612 N. Kerry Dr. Bloomington, Indiana 47408-2730
Anthony Schmitt 4308 Aj Dr. N. Wadesville, Indiana 47638-8601	Thomas Lehr 8948 W. County Road 57 N. Richland, Indiana 47634-9108	Anne Fraker 2606 E. Windermere Woods Dr. Bloomington, Indiana 47401-5450
Michael Caldie 618 S. Lincoln St. Bloomington, Indiana 47401-4708	Annita Mason 1511 Beechwood Ave. New Albany, Indiana 47150-3804	W. Jake Lindauer 2532 S. Lindauer Rd. Eckerty, Indiana 47116-9221
Paola Quadrini 327 W. 1st St. Bloomington, Indiana 47403-3477 (Multiple Comments)	Richard Ullrich 403 Main St. Aurora, Indiana 47001-1250	Jessica Cresseveur 2834 Charlestown Rd., Apt 6 New Albany, Indiana 47150-2593
Bronwyn Shroyer 3169 E. Braeside Dr. Bloomington, Indiana 47408-4387	Paul Schneller 1500 E. Richland Dr. Bloomington, Indiana 47408-9755	Donald Rhoads 1000 W. Williams Rd. Bloomington, Indiana 47404-9491
Tonya Dale 2461 S. Old US 41 Vincennes, Indiana 47591-6103	Diane Seltz 3199 N. Thompson Rd. Madison, Indiana 47250-8081	Matt Baucco 2500 S. Ford Ave. Bloomington, Indiana 47403-3622
Steven Wilson 4026 E. SR 258 Seymour, Indiana 47274-7920	Shannon Wenger P.O. Box 3512 Bloomington, Indiana 47402-3512	Mark Roeder 225 E. 20th St, Apt 4 Bloomington, Indiana 47408-1573

Ray Crittenden 8587 W. Rice Rd. Bloomington, Indiana 47403-7302	Barbara Russell 914 Pfeiffer Rd. Evansville, Indiana 47711-6249	Ellie Macfarlane 1008 S. Meadowbrook Dr. Bloomington, Indiana 47401-4234
Deborah Schade 8100 Upper Mount Vernon Rd. Evansville, Indiana 47712-7317	Lawrence Moss 1228 E. Maxwell Ln. Bloomington, Indiana 47401-5065	Linda Greene 7487 N. John Young Rd. Unionville, Indiana 47468-9722
Sherry Kraus 6161 Abbott Rd. Tell City, Indiana 47586-9005	Paul Hill 3800 W. H. and H. Rustic Ln Madison, Indiana 47250-7920	Rene Rezvan 9687 W. SR 48 Bloomington, Indiana 47404-9381
Whitney Arvin 5048c Amstel Dr. Evansville, Indiana 47715-6744	Martha Murphy 2536 N. Main St. Evansville, Indiana 47711-3242	Kaleb Jeffries 2308 Scheips Ln. Evansville, Indiana 47720-5463
Joe Weisman 5156 N. Brummetts Creek Rd. Bloomington, Indiana 47408-9616	Linda Dean 955 S. Basswood Circle Bloomington, Indiana 47403-2818	Suzanne Merriman 125 S. Jaclyn Dr. Bloomington, Indiana 47401-9460
Vincent Desjardins 505 E. Dixie St. Bloomington, Indiana 47401-5907	Robert Stoll 1405 E. Prairie Drive Bloomington, Indiana 47408-9250	Nancy Brooks 1207 W. Green Tree Ln. Bloomington, Indiana 47403-2182
Kurt Singleton 2117 E. Virginia St. Evansville, Indiana 47711-5953 (Multiple Comments)	Kent Pellerite 2224 S. Sussex Dr. Bloomington, Indiana 47401-6860	Jennifer Knable Thompson (Multiple Comments) 13585 Opera Rd. Leopold, Indiana 47551-9023
Antonia Matthew 1307 S. Grant St. Bloomington, Indiana 47401-5867	Laura and Jerry Hunter 8550 E. Doe Run Rd. Madison, Indiana 47250-8541	Steven Black 3511 S. Roxbury Circle Bloomington, Indiana 47401-8819
Marlene Beachy 925 W. Oakwood Ln. Paoli, Indiana 47454-9120	Terri Greene 9510 S. Snow Rd. Bloomington, Indiana 47403-9556	Mary and Phil Mininger 1171 S. Paoli Unionville Rd. Paoli, Indiana 47454-9376
Joan Keeler 3927 S. Cramer Circle Bloomington, Indiana 47403-8932	Paul Lukey 3600 E. Morningside Dr. Bloomington, Indiana 47408-4334	Jeanne Melchior 880 Church Ave. Jasper, Indiana 47546-3713
Robert Bieder 2010 S. Grovesnor Pl. Bloomington, Indiana 47401-6743	Mary Connors 3722 W. Parkview Dr. Bloomington, Indiana 47404-1734	Nelvin Gaba 1750 N. Range Rd., Apt K104 Bloomington, Indiana 47408-9593

Linda Richardson 7756 S. Locust Grove Rd. Hardinsburg, Indiana 47125-8804	Emily Frazier 3974 S. Bushmill Dr. Bloomington, Indiana 47403-8945	Henry Brenner 1101 S. Fess Avenue Bloomington, Indiana 47401-5980
Helen Templeton 208 S. Taft Ave. Evansville, Indiana 47714-1352	Mark Hallett 6430 E. State Road 45 Bloomington, Indiana 47408-9222	Claire Gregory 2949 N. Ramble Rd. E. Bloomington, Indiana 47408-1063
James Hettmer 7455 S. Rockport Rd. Bloomington, Indiana 47403-9158	Scott Sinclair 930 Blum St. Tell City, Indiana 47586-2238	Kathryn Marlett 3636 E. Park Ln. Bloomington, Indiana 47408-6303
Bill Kempf 3764 Woodbridge Dr. Evansville, Indiana 47710-5143	Bethany Martinez 3501 Wellington Dr. Bloomington, Indiana 47401-8824	Michael Schneider 6214 Appleleaf Ln. Sellersburg, Indiana 47172-9432
M. Burton 309 N. Hay St. Bloomington, Indiana 47404-2850	Christian Joyce 1220 Weed Ln. Vincennes, Indiana 47591-5049	Bret Daugherty 111 N. Chestnut St. Seymour, Indiana 47274-2101
Ruth Beeler 151 Winding Way Batesville, Indiana 47006-9190	Claire Gregory 2949 N. Ramble Rd. E. Bloomington, Indiana 47408-1063	Robert McDonald 6458 W. Eureka Rd. Rockport, Indiana 47635-8547
Paul Eisenberg 1005 S. Hawthorne Dr. Bloomington, Indiana 47401-6090	Steve Kreuzburg 386 Brentwood Dr. Madison, Indiana 47250-2902	Erik Hitchcock 4104 W. Daniel Ave. Bloomington, Indiana 47403-1806
Eric Ellis 4345 Country View Dr. Floyds Knobs, Indiana 47119-9313	Kaye Hill 704 N. Park Ridge Rd. Bloomington, Indiana 47408-3072	Sam Rich 1250 Uniontown Rd. Uniontown, Kentucky 42461-5240
Linda Hamilton 3823 S. Hampton Rd. Philpot, Kentucky 42366-9027	Ralph Hirsbrunner P.O. Box 143 Madison, Indiana 47250-0143	Elizabeth & Ronald Butler 1110 S. Alves St. Henderson, Kentucky 42420-4018
Gail West 359 Brey Ln. Hartford, Kentucky 42347-9525	David Lindsey 313 Valley View Dr. Beaver Dam, Kentucky 42320-1635	Rev. Ron Mayhew 2504 State Route 1554 Owensboro, Kentucky 42301-9557
Paul Morsey 2437 Pleasant Valley Rd. Owensboro, Kentucky 42303-9301	Tina Beier 1544 W. 23rd St. Ferdinand, Indiana 47532-9499	Rhonda Moers 5401 Wesbriar Ln. Evansville, Indiana 47720-7875

Sarah Tull 1108 E. Elm St. New Albany, Indiana 47150-3058	Victoria Bedford 1701 E. Circle Dr. Bloomington, Indiana 47401-6027	Robert Mayton 4345 Autumn Ridge Bnd. Owensboro, Kentucky 42303-2635
Rick Fowler 222 E. 21st Street Owensboro, Kentucky 42303-5103	Jennifer Schultz 2978 State Route 140 E. Utica, Kentucky 42376-9006	Tammi Payne 2940 Salem Rd. Olaton, Kentucky 42361-9731
Eva Atkinson 717 Frederica St. Owensboro, Kentucky 42301-3019	Betsy Cockrum 610 N. Burkhardt Rd. Evansville, Indiana 47715-2738	Gary McCoy 2800 Liberty Rd. Providence, Kentucky 42450-2163
Peggy White 431 Booth Ave. Owensboro, Kentucky 42301-5032	Stella Payne 9978 State Road 456 Owensboro, Kentucky 42301-9531	James Russell 737 Cumberland St. Owensboro, Kentucky 42303-4706
Lee Anderson 4325 Brookhill Dr. Owensboro, Kentucky 42303-2192	Barbara Montgomery 1933 Lydia Dr. Owensboro, Kentucky 42301-4907	Sharon Tiahrt 2229 Yewells Lndg. S Owensboro, Kentucky 42303-1969
Mary Cupp 1309 Allen St. Owensboro, Kentucky 42303-3034	Hon. E. Woodford Sigler, Ky Colonel 192 Melwood Pl. Henderson, Kentucky 42420-3870	Ed Cupp 1309 Allen St. Owensboro, Kentucky 42303-3034
Patrick Niese 5109 E. Morris Mill St. Batesville, Indiana 47006-8207	James Mattingly 11881 State Road 144 Philpot, Kentucky 42366-9627	Jeff Poling 144 N. Park Ridge Rd. Bloomington, Indiana 47408-3113
Marcia Droege 205 Krietenstein Rd. S Wadesville, Indiana 47638-8708	Janet Altman 3209 E. 10th Street, APT# D37 Bloomington, Indiana 47408-2484	Sherry Kraus 6161 Abbott Rd. Tell City, Indiana 47586-9005
Jo Ann Gauthier 2102 N 5th Street Evansville, Indiana 47710-2804	Jean Smith 610 S 7th Street Petersburg, Indiana 47567-1811	Robert Mayton 4345 Autumn Ridge Bnd Owensboro, Kentucky 42303-2635
Margee Stone 5633 Kenwood Dr. Newburgh, Indiana 47630-3206	Derek Green 14200 Worthington Ct Evansville, Indiana 47725-8272	Charles Kozak 1153 N Valleyview Rd. West Baden Springs, Indiana 47469-9784
Elaine Sorensen 10001 N Stones Ln Evanston, Indiana 47531-8110	Melissa Szudy 372 N Barclay Dr. Vincennes, Indiana 47591-6542	Richard Ullrich 403 Main Street Aurora, Indiana 47001-1250

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6430 E State Road 45
Bloomington, Indiana 47408-9222

Steve Amos
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Newburgh, Indiana 47630-1118

William Estes
623 E Emerson St
Princeton, Indiana 47670-1901

Hans Huber
7400 S Shady Side Dr
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Gail West
359 Brey Ln
Hartford, Kentucky 42347-9525

Abbi Surles
2755 W Popcorn Rd
Springville, Indiana 47462-9438

Willard & Nan Hardin
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The following individuals provided testimony at the public hearing held on May 15, 2013, at the South Spencer County High School, located in Rockport, Indiana:

Thomas Utter	Marvin Byer	Harold Goffinet
Michael Falkenstein	Jack Kroeger	Doug Wilson
Rex Winchell	Thomas Pearce	John Blair
Jean Webb	Rick Fowler	Rock Blanchard
James Kamuf	Ronald Barnes	Bill Spaetti
Jeff Vogel	Gene Steinkamp	James Mattingly
Chuck Botsko	Greg James	Rachael Anderson
Kenneth Keshard	Rick McKee	Jim Gardner

IDEM, OAQ has summarized and consolidated comments received during the public notice period. IDEM combined comments dealing with similar issues and provided a response on the issue in question. If a change was required to the permit because of a comment, IDEM's response shows the revision immediately following the question, with new text shown in bold and deleted text shown in ~~strikeout~~. IDEM, OAQ did not revise the Technical Support Document (TSD) because; the TSD serves a historical purpose. IDEM, OAQ documents changes due to comments received during the public comment period with this Addendum to the Technical Support Document (ATSD).

U.S. EPA COMMENTS

On May 17, 2013, Genevieve Damico, Chief, Air Permits Section, U.S. EPA, Region V submitted comments on the draft permit. Comments from U.S. EPA are discussed in detail below:

EPA Comment No. 1: **BACT Limit Averaging Periods**

Best available control technology emission limits for carbon dioxide (CO_2), particulate matter (PM), PM_{10}, $PM_{2.5}$, carbon monoxide, and volatile organic compounds (VOCs) are included within the draft permit based on a 3-hour averaging time. Since compliance with these emission rate limits is generally determined by a one-time stack test and monthly record keeping, how is the three-hour average determined?

IDEM RESPONSE

The intent of the three-hour average was to match the BACT limit with the emission testing protocol used by IDEM, OAQ. Compliance with the three hour average limit will be determined by averaging the results of three stack test runs, where each test run consists of a one hour sample. Where control devices are not used or significant variation in emission rates are not anticipated, it is not necessary for the Permittee to demonstrate compliance with this limit every three hours. The stack test and record keeping requirement will be adequate to ensure a large margin of compliance with emission limits over the life of these emission units. This is especially true in emission units without factors that would introduce significant variability into the emission rate of a unit, such as a control device or a fuel supply with highly variable physical properties.

No changes to the draft permit are required as a result of this comment.

EPA Comment No. 2: **CO_2 BACT Limit – Primary Reformer**

The CO_2 limit for the primary reformer in permit Condition D.2.4(b)(5) is 1.28 tons CO_2 per ton of ammonia produced. The ammonia production limit in permit Condition D.2.4(b)(1) is 1,022,000 tons per twelve consecutive month period. This calculates to potential emissions of 1,308,160 tons per twelve consecutive month period, which is higher than the 1,304,033 tons per year limit listed in the technical support document. Please clarify the correct potential emissions for this unit.

IDEM RESPONSE

The limit U.S. EPA is referring to is for the CO_2 purification vent and not the primary reformer. The CO_2 limit contained in Condition D.2.4(b)(5) was rounded up from 1.27596184 lb/ton. IDEM, OAQ will revise the proposed limit by adding one additional significant figure, 1.275 lb/ton. With this change, the Scenario 2 emission rate of CO_2 is 1,303,050, exactly. Total GHG emissions remain at 1,304,033 as CO_2e. The revised permit condition follows:

D.2.4 PSD Best Available Control Technology Limits [326 IAC 2-2-3] and VOC Best Available Control Technology (BACT) Limits [326 IAC 8-1-6]

****

(b) **CO_2 Purification Process (EU-004):**

****

GHG:

(5) Good Operational Practices to achieve a CO_2 emission rate of ~~1.28~~**1.275** tons CO_2 per ton of ammonia, based on a three-hour average.

****

SIERRA CLUB COMMENTS

Sierra Club Comment No. 1 **The NAAQS and Increment Analysis Use Unlawful Procedures**

IDEM conducted an ambient air quality impact analysis to determine whether the OVR facility would cause or contribute to any violation of a National Ambient Air Quality Standard (NAAQS) or any increment. In the first step of that analysis, IDEM modeled the impacts from only the OVR emissions and compared them to "significant impact levels." See TSD Appendix C at 4. Where the OVR's impacts exceeded the "significant impact level" identified by IDEM, IDEM conducted a further analysis of whether the facility's impacts when combined with the impacts from other sources (including both nearby sources included in the model and general background concentrations from other, further away facilities) would cause or contribute to a violation of the NAAQS or the increments. TSD Appendix C at 6. Specifically, IDEM determined that OVR would contribute to a 1-hour NO_x NAAQS concentration of 597.8 ug/m^3, which far exceeds the 188.6 ug/m^3 standard, and the 24-hour $PM_{2.5}$ concentrations of 49.3 ug/m^3, which far exceeds the 35 ug/m^3 standard. However, IDEM nevertheless concluded that the permit could be issued because, IDEM concluded, the highest contribution by OVR to a 1-hour NO_x NAAQS violation was 4.46 ug/m^3 and the highest contribution from OVR to a 24-hour $PM_{2.5}$ NAAQS violation was 0.99 ug/m^3. TSD Appendix C at 6-7. IDEM apparently concluded that these contributions do not constitute OVR causing or contributing to a NAAQS violation. But there is no legal authority for ignoring these contributions for at least two reasons.

First, the Clean Air Act and implementing regulations are rigid. They prohibit the OVR from causing or contributing to any NAAQS violation. 42 U.S.C. § 7475(a)(3)(B); 326 IAC 2-2-5(a)(1). There are no exceptions in the law and IDEM has no authority to waive the plain language of the Act or regulations.

Second, even if the U.S. EPA and IDEM had the authority to waive requirements under the limited, *de minimis*, concept recognized by some federal case law, that concept is limited to instances where granting an exemption actually serves to "implement[] the legislative design." *Alabama Power Co. v. Costle*, 636 F.2d 323, 360 (D.C. Cir. 1979); *accord Public Citizen v. Young*, 831 F.2d 1108, 1116 (D.C. Cir. 1987). That is not the case here. Moreover, the facts in the record for the OVR facility do not support the elements of a *de minimis* exception.

The *de minimis* doctrine is narrow and is "[p]redicated on the notion that 'the Congress is always presumed to intend that pointless expenditures of effort be avoided,'" and that authority to avoid statutory coverage in such instances "'is inherent in most statutory schemes, by implication.'" *Shays v. FEC*, 414 F.3d 76, 113-114 (D.C. Cir. 2005) (quoting *Ass'n of Admin. Law Judges v. FLRA*, 397 F.3d 957, 962 (D.C. Cir. 2005)). Thus, only where regulation would be pointless can the doctrine apply to avoid "futile application" of a statute, *New York v. EPA*, 443 F.3d 880, 888 (D.C. Cir. 2006), where the burdens of regulation yield a gain of trivial or no value." *Shays*, 414 F.3d at 114 (quoting *Envtl. Def. Fund v. EPA* ("*EDF III*"), 82 F.3d 451, 466, *amended by* 92 F.3d 1209 (D.C. Cir. 1996)). To apply the *de minimis* exception, IDEM would have to analyze the "particular circumstances" of the OVR's impact here and bears the burden of showing that "matters are truly *de minimis*." *Alabama Power*, 636 F.2d at 360; *see also Shays*, 414 F.3d at 115. IDEM has not demonstrated that its theory of exempting OVR's contributions to violations of the NAAQS by less than a "significant impact level" implements Congress' legislative design in the Clean Air Act, nor that it covers only situations that provide a gain of only trivial value.

Therefore, because the OVR will cause or contribute to violations of the 1-hour NO_x NAAQS and the 24-hour $PM_{2.5}$ NAAQS and because IDEM does not have the authority to exempt these violations, the permit must be denied. Moreover, even if IDEM did have the authority to exempt these violations based on the de minimis impact concept, IDEM has not and cannot show that prohibiting the impacts by OVR to the NAAQS violations here would be "trivial" and "futile," and would not further the regulatory objectives of the Clean Air Act.

IDEM RESPONSE

IDEM properly conducted its air quality analysis and correctly applied its authority to determine that the Ohio Valley Resources ("OVR") facility will not cause or contribute to a violation of the National Ambient Air Quality Standards ("NAAQS") or increment for any evaluated pollutant.

IDEM does not agree that its use of significant impact levels ("SILs") in this analysis is not allowed under the Clean Air Act ("CAA") or Indiana law. To the contrary, the *de minimis* doctrine has long been interpreted by IDEM and the US Environmental Protection Agency ("EPA") to support the use of SILs in determinations that the requirements for air quality and increment analyses have been met and that the proposed source will satisfy a "culpability analysis" by demonstrating that any impact from the proposed source will not cause or contribute to a violation of the NAAQS. As EPA recently explained:

> For purposes of clarity, EPA reaffirms its interpretation that, with appropriate record support, use of a SIL, as CDPHE did for this Permit, is permissible under the Clean Air Act to determine whether a proposed source or modification contributes to predicted violations of a NAAQS. See, e.g., *Mississippi Lime* at 35-36; *Prairie State*, 13 EAD at 104-1 09; NO_2 NAAQS Guidance at 11.1. The application of a SIL in a culpability analysis of this nature is consistent with the *de minimis* doctrine. As explained in recent guidance on this issue:
>
>> The primary purpose of the SIL is to serve as a screening tool to identify a level of ambient impact that is sufficiently low relative to the NAAQS or PSD ["Prevention of Significant Deterioration"] increments such that the impact can be considered trivial or *de minimis*. Hence, the EPA considers a source whose individual impact falls below a SIL to have a *de minimis* impact on air quality concentrations that already exist. Accordingly, a source that demonstrates that the projected ambient impact of its proposed emissions increase does not exceed the SIL for that pollutant at a location where a NAAQS or increment violation occurs is not considered to cause or contribute to that violation.

NO_2 NAAQS Guidance at 11. EPA further explained, "[t]he concept of a SIL is grounded on the *de minimis* principles described by the court in *Alabama Power Co. v. Costle*, 636 F.2d 323, 360 (D.C. Cir. 1980)." *Id*. (also citing *Sur Contra La Contaminacion* v. EPA, 202 F.3d 443,448-49 (1st Cir. 2000), which upheld EPA's use of a SIL to allow a permit applicant to avoid a full impact analysis, and *Prairie State*, at 105).

Courts have long recognized that EPA has discretion under the Act to exempt from review some emission increases on *de minimis* grounds. In *Alabama Power*, the D.C. Circuit recognized that EPA has the inherent authority under the CAA to exempt emissions increases from new or modified sources from some or all of the PSD requirements where such emissions would be *de minimis* and thus their regulation would yield only trivial or no value. *Ala. Power Co*., 636 F.2d at 360-61. Consistent with this, EPA has long interpreted the phrase "cause, or contribute to" in section 165(a)(3) of the Act to refer to significant, or non-*de minimis*, emission contributions. *Prairie State*, 13 EAD at 104-105, 107-08 (affirming use of SIL in such a culpability analysis); *Mississippi Lime* at 35-36 (stating that "the use of a SIL in the culpability analysis for the one-hour $SO[_2]$ NAAQS is not improper and [the State] did not clearly err by using a SIL").

The Petitioner's argument that the Act forecloses the use of SILs is based on a misunderstanding of the Act and of how SILs operate. First, section 165(a)(3) of the Act, 42 U.S.C. § 7475(a)(3), does not specify how the required demonstration of whether a source will "cause or contribute to" a NAAQS violation is to be made, and EPA's long-standing interpretation of that provision to allow the use of SILs as means to demonstrate compliance is reasonable. Second, the use of SILs does not waive the mandatory requirement in section 165(a)(3) that a source "demonstrate" that it "will not cause, or contribute to," a violation of the NAAQS. Rather, as used by CDPHE for this Permit, the interim SIL was a means of demonstrating through modeling that the source's impact at the time and place of a predicted NAAQS violation will be sufficiently low that such impact will not contribute to that violation. EPA applied this rationale to support the interim 1-hour $NO[_2]$ SIL in the $NO[_2]$ NAAQS guidance.

Order Partially Granting And Partially Denying The Petition For Objection To Permit, *In The Matter Of CF&I Steel, L.P. dba EVRAZ Rocky Mountain Steel*, Petition Number: VIII-2011-01, May 31, 2012 (page 17).

The Air Dispersion Modeling Report (Revised: December 5, 2012) submitted by the permittee states on page 2-2 that the following modeling guidelines were used in the study:

- Guideline on Air Quality Models [Title 40 Code of Federal Regulations ("40 CFR") Chapter 58, Appendix W] (EPA 2001)

- Indiana Department of Environmental Management Air Quality Modeling Policies (IDEM June 2012)

- New Source Review Manual: PSD and Nonattainment Area Permitting (EPA 1990)

Each of these documents discusses the use of SILs in the air quality analysis. The IDEM June 2012 Modeling Policies sets out, in Table 2 on page 6, all of the SILs used by IDEM in its air quality analysis as well as information on the basis for each. This Response to Sierra Club Comment 1 and IDEM's Responses to Sierra Club Comments 2 and 3 provide further explanation of IDEM's use of SILs in its air quality analysis.

IDEM's use of the 1-hour NO_x SIL of 7.55 $\mu g/m^3$ in its determination that the proposed source would not cause or contribute to a violation of the 1-hour NO_x NAAQS is supported by the record. Specifically, IDEM set out the SIL in TSD Appendix C, Table 2 and cited to the EPA guidance memorandum addressing the implementation of the SIL in the air quality analysis, titled "Additional Clarification Regarding Application of Appendix W modeling Guidance for the 1-hour NO_2 National Ambient Air Quality Standard," Tyler Fox, March 21, 2011 ("March 1, 2011 Memorandum"), which supplements and clarifies the memorandum titled "Guidance Concerning the Implementation of the 1-hour NO_2 NAAQS for the Prevention of Significant Deterioration Program," Stephen D. Page, Director, Office of Air Quality Planning and Standards, June 29, 2010 ("June 29, 2010 Memorandum"). In the June 29, 2010 Memorandum, EPA stated on page 12: "Using the interim 1-hour NO_2 SIL, the permit applicant and permitting authority can determine: (1) whether, based on the proposed increase in NO_x emissions, a cumulative air quality analysis is required; (2) the area of impact within which a cumulative air quality analysis should focus; and (3) whether, as part of a cumulative air quality analysis, the proposed source's NO_x emissions will cause or contribute to a modeled violation of the 1-hour NO_2 NAAQS."

The 1-hour NO_x SIL of 7.55 $\mu g/m^3$ (or its mathematical equivalent of 4 parts per billion, "ppb") is reasonable, as explained in detail in EPA's June 29, 2010 Memorandum:

> In this guidance, EPA recommends an interim 1-hour NO_2 SIL value of 4 ppb. To determine initially whether a proposed project's emissions increase will have a significant impact (resulting in the need for a cumulative air quality analysis), this interim SIL should be compared to either of the following:
>
> - The highest of the 5-year averages of the maximum modeled 1-hour NO_2 concentrations predicted each year at each receptor, based on 5 years of National Weather Service data; or

> - The highest modeled 1-hour NO_2 concentration predicted across all receptors based on 1 year of site-specific meteorological data, or the highest of the multi-year averages of the maximum modeled 1-hour NO_2 concentrations predicted each year at each receptor, based on 2 or more, up to 5 complete years of available site-specific meteorological data.
>
> * * *
>
> We derived this interim 1-hour NO_2 SIL by using an impact equal to 4% of the 1-hour NO_2 NAAQS (which is 100 ppb). We have chosen this approach because we believe it is reasonable to base the interim 1-hour NO_2 SIL directly on consideration of impacts relative to the 1-hour NO_2 NAAQS. In 1980, we defined SER for each pollutant subject to PSD. 45 FR 52676, August 7, 1980 at 52705-52710. For PM and SO_2, we defined the SER as the emissions rate that resulted in an ambient impact equal to 4% of the applicable short-term NAAQS. The 1980 analysis focused on levels no higher than 5% of the primary standard because of concerns that higher levels were found to result in unreasonably large amounts of increment being consumed by a single source. Within the range of impacts analyzed, we considered two factors that had an important influence on the choice of *de minimis* emissions levels: (1) cumulative effect on increment consumption of multiple sources in an area, each making the maximum *de minimis* emissions increase; and (2) the projected consequence of a given *de minimis* level on administrative burden. As explained in the preamble to the 1980 rulemaking and the supporting documentation, EPA decided to use 4% of the 24-hour primary NAAQS for PM and SO_2 to define the significant emissions rates (SERs) for those pollutants. It was noted that, at the time, only an annual NO_2 NAAQS existed. Thus, for reasons explained in the 1980 preamble, to define the SER for NO_x emissions we used a design value of 2% of the annual NO_2 NAAQS. See 45 FR 52708. Looking now at a short-term NAAQS for NO_2, we believe that it is reasonable as an interim approach to use a SIL value that represents 4% of the 1-hour NO_2 NAAQS.

June 29, 2010 Memorandum, page 12. IDEM agrees with EPA's basis for this SIL value of 7.55 $\mu g/m^3$ and therefore incorporates and adopts it for purposes of the OVR air quality analysis.

IDEM followed the EPA guidance in implementing the air quality analysis using the SIL. The evaluation IDEM performed is described precisely in the EPA Guidance Memo titled "Additional Clarification Regarding Application of Appendix W modeling Guidance for the 1-hour NO_2 National Ambient Air Quality Standard" by Tyler Fox, dated March 1, 2011:

> *If modeled violations of the NAAQS are found based on the cumulative impact assessment, then the project's contribution to all modeled violations should be compared to the interim SIL to determine whether the project causes or contributes to any of the modeled violations.*
>
> *In past guidance (EPA, 1988), EPA has indicated that the significant contribution analysis should be based on a source's contribution to the modeled violation paired in time and space…*

> *…The recent update to the AERMOD model (dated 11059) includes an option (the MAXDCONT keyword) to automatically perform this contribution analysis (EPA, 2010b), examining the contribution from project emissions to the cumulative impacts at each receptor across a user-specified range of ranked values, paired in time and space, as an internal post-processor within the model.*

March 1, 2011 Memorandum, pp. 3-4. The internal EPA reference citations are set out in full at the end of the memorandum at pp. 21-22.

IDEM's analysis determined two key facts relevant to whether the OVR facility could be expected to cause or contribute to a 1-hour NO_x NAAQS violation. First, for any receptor and time period when OVR's impact was greater than the SIL of 7.55 $\mu g/m^3$, the highest concentration modeled was 119.4 $\mu g/m^3$ (against the NAAQS of 188.6 $\mu g/m^3$). With background concentrations included (which is a conservative approach because the background concentrations are understood to take into account at least some of the modeled emissions from nearby sources), the result is in compliance with the NAAQS at 185.9 $\mu g/m^3$. Second, for any receptor and time period at which a modeled concentration would indicate a NAAQS violation, OVR's highest predicted concentration was 4.46 $\mu g/m^3$, well below the SIL. See, TSD Appendix C, Table 5a.

The commenter points to further support for the determination that OVR's impact on NAAQS violations is *de minimis*. The statement in the comment that "IDEM determined that OVR would contribute to a 1-hour NO_x NAAQS concentration of 597.8 $\mu g/m^3$" is illuminating when read alongside the figure in Table 5a that the comment did not include, which showed that at the receptor and time period at which that highest concentration was predicted, OVR's impact was predicted to be just 0.0006 $\mu g/m^3$. As such, it is clear that OVR's contribution to the result highlighted by the commenter is *de minimis.*

As clearly demonstrated by these results and the remainder of our air quality analysis, IDEM properly determined that OVR does not cause or contribute to a violation of the 1-hour NO_x NAAQS.

Similarly, IDEM's use of the 24-hour $PM_{2.5}$ SIL of 1.2 $\mu g/m^3$ in its determination that the proposed source would not cause or contribute to a violation of the 24-hour $PM_{2.5}$ NAAQS is supported by the record. Specifically, IDEM set out the SIL in TSD Appendix C, Table 2 and cited to the EPA guidance memorandum that describes the implementation of the SIL in the air quality analysis, titled "Modeling Procedures for Demonstrating Compliance with $PM_{2.5}$ NAAQS," Stephen D. Page, Director, Office of Air Quality Planning and Standards, March 23, 2010 ("March 23, 2010 Memorandum").

The 24-hour $PM_{2.5}$ SIL of 1.2 $\mu g/m^3$ is reasonable, and represents the value that is the most stringent of the three options EPA proposed as it promulgated the addition of the $PM_{2.5}$ significance levels to the table in 40 CFR 51.165(b)(2) (along with corresponding PSD-specific provisions, now remanded as noted below). As EPA explained: "The SILs derived under this option are very stringent for Class II and III areas compared to options 1 and 2. Nevertheless, we believe that the NAAQS ratio approach is an appropriate alternative to determine SILs, since it reflects the stringency in the NAAQS for $PM_{2.5}$ relative to that of PM_{10}. We believe that these SIL values would serve as appropriate *de minimis* values." 72 Fed. Reg. 54112 (Sept. 21, 2007). Although the specific implementation provisions for the SILs in 40 CFR 52.21(k)(2) have been vacated and remanded by the Court, as EPA requested because of an inadvertent restriction on the discretion of permitting authorities, the significance levels in 40 CFR 51.165(b)(2) were not vacated. The SIL value is also consistent with significance levels set for other NAAQS as a percentage of the respective NAAQS, as described above (quoting the June

29, 2010 Memorandum at page 12). An impact of 1.2 μg/m^3 is just under 3.5% of the NAAQS. IDEM agreed with EPA's basis for this SIL value of 1.2 μg/m^3 and therefore adopted it for purposes of the OVR air quality analysis.

Shortly after the Court's ruling addressing EPA's SIL rule, EPA provided clarifying guidance on use of $PM_{2.5}$ SIL values in permitting. EPA stated:

> The EPA does not interpret the Court's decision to preclude the use of SILs for $PM_{2.5}$ entirely but additional care should be taken by permitting authorities in how they apply those SILs so that the permitting record supports a conclusion that the source will not cause or contribute to a violation of the $PM_{2.5}$ NAAQS.
>
> * * *
>
> If the preconstruction monitoring data shows that the difference between the $PM_{2.5}$ NAAQS and the monitored $PM_{2.5}$ background concentrations in the area is greater than the EPA's $PM_{2.5}$ SIL value, then the EPA believes it would be sufficient in most cases for permitting authorities to conclude that a proposed source with a $PM_{2.5}$ impact below the $PM_{2.5}$ SIL value will not cause or contribute to a violation of the $PM_{2.5}$ NAAQS and to forego a more comprehensive cumulative modeling analysis for $PM_{2.5}$.
>
> As part of a cumulative analysis, the applicant may continue to show that the proposed source does not contribute to an existing violation of the $PM_{2.5}$ NAAQS by demonstrating that the proposed source's $PM_{2.5}$ impact does not significantly contribute to an existing violation of the $PM_{2.5}$ NAAQS.

Circuit Court Decision on $PM_{2.5}$ Significant Impact Levels and Significant Monitoring Concentration, Questions and Answers, U.S. Environmental Protection Agency, Office of Air Quality Planning and Standards (March 4, 2013). Also subsequent to the Court remand, EPA provided its "Draft Guidance for $PM_{2.5}$ Permit Modeling," Stephen D. Page, Director, Office of Air Quality Planning and Standards, March 4, 2013 ("March 4, 2013 Memorandum"). EPA stated:

> The court decision does not preclude the use of SILs for $PM_{2.5}$, but requires that EPA correct the error in the SIL regulations for $PM_{2.5}$ at 51.166(k)(2) and 52.21(k)(2). In the interim, the EPA believes permitting authorities may continue to apply SILs for $PM_{2.5}$ to support a PSD permitting decision, but permitting authorities should take care to ensure that SILs are not used in a manner that is inconsistent with the requirements of Section 165(a)(3) of the CAA. This document provides some preliminary guidance on how to use SILs for $PM_{2.5}$ in a manner consistent with the CAA.

Id., p. 11. EPA then addressed use of the SIL values included in the remanded provisions and in 40 CFR 51.165(k)(2), which was upheld by the Court:

> To the extent a permitting authority wishes to use any of the SILs values in the vacated Sections 51.166(k)(2) or 52.21(k)(2) as a screening tool to determine whether it is necessary to conduct a cumulative analysis, the permitting authority must first examine background air quality concentrations to determine whether a substantial portion of the NAAQS has been consumed. For this purpose, the EPA recommends using the preconstruction monitoring data compiled to meet the requirements of Section 51.166(m) or 52.21(m) of the EPA's regulations. If the preconstruction monitoring data shows that the difference between the $PM_{2.5}$ NAAQS and the measured $PM_{2.5}$ background concentrations in the area is

> greater than the applicable SIL value from the vacated Sections 51.166(k)(2) and 52.21(k)(2), then the EPA believes it would be sufficient in most cases for permitting authorities to conclude that a source with an impact below that SIL value will not cause or contribute to a violation of the NAAQS and to forego a cumulative modeling analysis for $PM_{2.5}$.

Id., pp. 16-17.

Where the cumulative impact assessment results in modeled violations of the $PM_{2.5}$ NAAQS, use of SILs in the consideration of the contribution of the source to the cumulative impacts at the receptors showing violations is contemplated to be performed in a manner consistent with the air quality analysis for other pollutants. IDEM agrees with and followed EPA's reasoning and procedures in the use of SILs in the air quality analysis to satisfy the requirement to determine that OVR will not cause or contribute to a violation of a NAAQS, and believes it to be an appropriate use of IDEM's authority under the *de minimis* doctrine.

In TSD Appendix C, Table 5, IDEM provided the background concentration relevant to the 24-hour $PM_{2.5}$ NAAQS, showing a level of 27.0 $\mu g/m^3$. Adding this concentration to the SIL of 1.2 $\mu g/m^3$ and comparing against the NAAQS of 35 $\mu g/m^3$ demonstrates that there is no particular circumstance that would make the use of the SIL inconsistent with the requirement to determine whether a source impact will cause or contribute to a NAAQS violation. Of course, such an exercise is contemplated by EPA for the purpose of making a determination that a full cumulative impact analysis is not required to determine whether a source impact will cause or contribute to a NAAQS violation. In this case, a full impact analysis was performed.

As with the 1-hour NO_x analysis, IDEM's analysis determined two key facts relevant to whether the OVR facility could be expected to cause or contribute to a 24-hour $PM_{2.5}$ NAAQS violation. First, for any receptor and time period when OVR's impact was greater than the SIL of 1.2 $\mu g/m^3$, the highest concentration modeled was 5.20 $\mu g/m^3$ (against the NAAQS of 35 $\mu g/m^3$). With background concentrations included (which is a conservative approach because the background concentrations are understood to take into account at least some of the modeled emissions from nearby sources), the result is in compliance with the NAAQS at 32.2 $\mu g/m^3$. Second, for any receptor and time period at which a modeled concentration would indicate a NAAQS violation, OVR's highest predicted contribution was 0.99 $\mu g/m^3$, well below the SIL. See, TSD Appendix C, Table 5b.

Similar to its comment on the 1-hour NO_x analysis, the commenter highlights the highest modeled 24-hour $PM_{2.5}$ NAAQS concentration from IDEM's analysis, 49.3 $\mu g/m^3$. Again, the comment fails to include the very next figure in Table 5b, which shows that, at the receptor and time period at which that highest concentration was predicted, OVR's impact was predicted to be just 0.055 $\mu g/m^3$. Here also, the result that represents a tiny fraction of the modeled concentration, the NAAQS, or even the SIL shows that OVR's contribution to the result highlighted by the commenter is *de minimis.*

As clearly demonstrated by these results and the remainder of our air quality analysis, IDEM properly determined that OVR does not cause or contribute to a violation of the 24-hour $PM_{2.5}$ NAAQS.

Sierra Club Comment No. 2 **Illegally Conducted Increment Analysis**

Similar to the NAAQS analysis discussed above, IDEM's increment analysis looked only at 24-hour $PM_{2.5}$ and annual NO_x because IDEM unlawfully exempted OVR from an analysis for the other increments based on an unlawful "significant impact level" exemption. Moreover, for 24-hour $PM_{2.5}$ and annual NO_x increment analysis, IDEM only looked at receptors where the OVR had an impact greater than the "significant impact level." TSD Appendix C at 8. There is no basis for limiting the analysis to only those receptors. Rather, the Clean Air Act and implementing regulations prohibit *any contribution to any violation* of a PSD increment. IDEM must revise its increment analysis:

- To consider OVR's contribution to all increment standards and not limited to those pollutants exceeding the "significant impact level"
- To consider the OVR's contribution to all increment concentrations, not limited to those receptors where the OVR's contribution is higher than the "significant impact level."

IDEM RESPONSE

IDEM properly conducted its air quality analysis and correctly applied its authority to determine that the OVR facility will not cause or contribute to a violation of the PSD increment for any evaluated pollutant. Consistent with the discussion in IDEM's Response to Sierra Club Comment 1 on the legal basis for the use of SILs in IDEM's air quality analysis, IDEM has authority to determine that further analysis is not required.

IDEM appropriately determined that OVR would not cause or contribute to a violation of the 24-hour and annual PM_{10} increment and annual $PM_{2.5}$ increment. As explained in TSD Appendix C, Section C, IDEM compared the results of the significant impact analysis against the SILs for those pollutants and averaging period. IDEM's reasons for the use of the specific SILs for annual $PM_{2.5}$, 24-hour PM_{10}, and annual PM_{10} are explained in IDEM's Responses to Sierra Club Comments 1 and 3.

IDEM's legal authority for limiting the increment analysis to receptors at which OVR had a significant impact is founded on the principles discussed in IDEM's Response to Sierra Club Comment 1 addressing the *de minimis* doctrine. IDEM's reasons for limiting the analysis to the specific receptors are discussed in the EPA's 1990 NSR Workshop Manual:

> *The proposed project's impact area is the geographical area for which the required air quality analyses for the NAAQS and PSD increments are carried out. This area includes all locations where the significant increase in the potential emissions of a pollutant from a new source, or significant net emissions increase from a modification, will cause a significant ambient impact (i.e., equal or exceed the applicable significant ambient impact level…).*

The following EPA statement supporting the use of SILs generally in the increment analysis is also persuasive:

> *In looking at the amount of increment that could be consumed by a source that is ultimately exempted from having to complete a comprehensive modeling analysis, it should be pointed out that the maximum modeled concentration typically occurs in a relatively limited area, as compared to the entire modeling domain. In particular, for the short-term averaging periods, such as the 24-hour*

> *averaging period, modeled concentrations across the modeled area generally show that ground level impacts are reduced significantly from the peak value as the pollutant travels a relatively short distance from the source, so that the peak modeled concentrations represent the source's impact at only a relatively few receptors within the modeled area. In addition, it is important to note that the temporal and spatial conditions which lead to a maximum impact by one source are seldom the same for other sources, such that maximum impacts of individual sources do not typically occur at the same location or at the same time. Thus, in an area where several sources can demonstrate that their modeled impacts are de minimis, it generally should not be assumed that their individual maximum (albeit de minimis) impacts on the increment are additive. For example, four sources with de minimis* $PM_{2.5}$ *impacts, each consuming 12 percent of the 24-hour* $PM_{2.5}$ *increment, would not necessarily consume 48% of the 24-hour increment. Increment consumption is determined by the cumulative impact of source emissions on each individual receptor or modeling point in the area of impact within the baseline area defined for the affected PSD sources.*
>
> *The preamble for the 1980 final rule for PSD included a description of a modeling analysis that EPA conducted to illustrate that a number of major sources each making a de minimis emissions increase for* SO_2 *could locate in an area (in that case, the Dayton area) and not cause a violation of either the applicable* SO_2 *increment or NAAQS. In that particular case, the modeling indicated that the maximum aggregate increment consumption for 37 sources emitting 40 tpy of* SO_2 *(the de minimis emissions rate for* SO_2*) would have a cumulative impact at any location of less than 1.5 ug/m*^{3} *on a 24-hour basis—well below the NAAQS and increments for* SO_2*. 45 FR 52708.*

75 Fed. Reg. 64864, 64893-4 (October 20, 2010). As such, IDEM agrees with and followed EPA's reasoning and procedures in the use of SILs in the increment analysis to satisfy the requirement to determine that OVR will not cause or contribute to a violation of a PSD increment, and believes it to be an appropriate use of IDEM's authority under the *de minimis* doctrine. As explained in TSD Appendix C, Table 6, modeled impacts for 24-hour $PM_{2.5}$ and annual NO_2 were predicted to be below the increment. Therefore, IDEM's evaluation was properly performed.

Sierra Club Comment No. 3 **SIL Analysis and Annual $PM_{2.5}$ Impacts**

IDEM also excluded the OVR's facility from a refined analysis of the facility's impacts on the annual $PM_{2.5}$ concentrations because IDEM modeled the facility's impacts at 0.26 ug/m^3, compare to the threshold "significant impact level" of 0.3 ug/m^3. TSD Appendix C at 4. IDEM does not provide a basis for using 0.3 ug/m^3 as the threshold for determining that the OVR facility's emissions cannot cause or contribute to a violation of the annual $PM_{2.5}$ NAAQS. Note that there are no such exemptions in the applicable statute or Indiana State Implementation Plan. To the extent that such an exemption existed in federal regulations, those regulations were vacated by the D.C. Circuit. See Sierra Club v. EPA, Case No. 10-1413, Opinion at 22 (D.C. Cir. Jan. 22, 2013).

We also note that EPA's $PM_{2.5}$ SIL were based on a value representing no greater than 2% of the applicable NAAQS. The now-vacated annual $PM_{2.5}$ SIL conceived by EPA was based on a 15 ug/m^3 annual NAAQS. However, the NAAQS is now 12 ug/m^3. Two percent of the 12 ug/m^3 standard is 0.24 ug/m^3, not 0.3 ug/m^3. Therefore, even if a significant impact level concept is lawful, IDEM's use of the 0.3 ug/m^3 value is still inconsistent with EPA's 2% concept because the annual $PM_{2.5}$ NAAQS is now 12 ug/m^3 and 2% is 0.24 ug/m^3. Because the predicted impact from OVR is 0.26 ug/m^3, a comprehensive analysis of the facility's impacts on the annual PM$_{2.5}$ air quality is required under U.S. EPA's theory of significant impact levels.

Furthermore, IDEM conducted only a cursory screening model for the annual NO$_x$ standard, the PM$_{10}$ standards, and the annual PM$_{2.5}$ standard to determine that, because the modeled impacts from these pollutants was below a "significant impact level," no further modeling was required. See TSD Appendix C at p. 4. In addition to the use of a "significant impact level" being illegal, as noted above, many of the impacts predicted by IDEM were based on assumed emission rates that are not representative of the actual worst case emissions from the OVR as noted below. Because the facility's worst-case emission rates are higher than IDEM assumed, the impacts predicted by IDEM are too low. IDEM must revise its analysis based on the higher emission rates, as noted below, and rerun the model.

IDEM RESPONSE

In its Response to Sierra Club Comment 1, IDEM explained the basis for the use of a SIL in its air quality analysis. The annual PM$_{2.5}$ SIL of 0.3 ug/m^3 is reasonable and appropriate for this permit. Its basis is described in IDEM's Response to Sierra Club Comment 1 addressing the SIL for the 24-hour PM$_{2.5}$ standard, as they were developed through the same process. For annual PM$_{2.5}$, an impact of 0.3 ug/m^3 is 2% of the NAAQS of 15 ug/m^3 and, as such, is consistent in this respect with significance levels set for other NAAQS as a percentage of the respective NAAQS, as described in the Response to Sierra Club Comment 1 (quoting the June 29, 2010 Memorandum at page 12). Further, when the SIL of 0.3 ug/m^3 is added to the background concentration of 12.4 ug/m^3 (determined from monitoring data gathered by the Dale, Indiana monitor, the appropriateness of which was discussed in the Response to Sierra Club Comment 5), the sum falls below the NAAQS of 15 ug/m^3, providing another indication that the SIL is a reasonable value.

The suggestion in the comment that IDEM used the wrong SIL is premised on the applicability of the revised PM$_{2.5}$ annual NAAQS. However, public notice was published for the draft permit on February 28, 2013, prior to the effective date of the revised NAAQS. Therefore, the applicable standard for the purposes of this air quality analysis is 15 ug/m^3. See, 78 Fed. Reg. 3086, 3281 (January 15, 2013). The comment ignores this fact and provides no other basis for otherwise considering the use of a different SIL.

The commenter is incorrect in stating that IDEM conducted only a screening model for the annual NO$_x$ standard. A full NAAQS analysis using refined modeling was performed for the annual NO$_2$ standard and no NAAQS violation was identified. See, TSD Appendix C, Table 6.

IDEM's use of the annual 24-hour PM$_{10}$ SIL of 5 ug/m^3 and annual PM$_{10}$ SIL of 1 ug/m^3 in the air quality analysis is reasonable. EPA promulgated the PM$_{10}$ significance levels in 1987 when they were added to the table of significance levels at 40 CFR 51.165(b)(2). See, 52 Fed. Reg. 24672 (July 1, 1987). The SIL values are consistent in this respect with significance levels set for other NAAQS as a percentage of the respective NAAQS, as described in the Response to Sierra Club Comment 1 (quoting the June 29, 2010 Memorandum at page 12). For 24-hour PM$_{10}$, an impact of 5 ug/m^3 is approximately 3.3% of the NAAQS. When added to the background concentration of, for example, 42 ug/m^3 based on 2009 to 2011 data from the Evansville – Buena Vista site monitor, the sum is about a third of the NAAQS of 150 ug/m^3, providing further indication that use of a SIL is reasonable. A summary of the Evansville – Buena Vista data and other PM$_{10}$ ambient monitoring data were submitted by the permittee and can be found in the record on pages

16-5 and 16-6 of the Modeling Report. As noted on page 5-1 of the Modeling Report, those data were taken from IDEM's website (http://www.in.gov/idem/4652.htm). For annual PM_{10}, although there is no longer an applicable NAAQS, an impact of 1 ug/m^3 is 2% of the former NAAQS of 50 ug/m^3. Based on recent data showing background concentrations below 30 ug/m^3, this impact and background would have summed to less than 60% of the former NAAQS when added to background. IDEM agreed with EPA's basis for these SIL values and therefore adopted them for purposes of the OVR air quality analysis. For these reasons, IDEM determined that the SILs are reasonable and appropriate for use as *de minimis* thresholds in the air quality analysis for the OVR facility.

As presented in TSD Appendix C, Table 2, the maximum modeled impacts predicted for OVR for both PM_{10} standards were well under the SILs and were therefore appropriately determined by IDEM to be *de minimis*.

It is unclear what emission rates are addressed in the statement: "…many of the impacts predicted by IDEM were based on assumed emission rates that are not representative of the actual worst case emissions from the OVR as noted below." IDEM has addressed all specific public comments on emission rates and the commenter is referred to those responses. The impacts predicted by IDEM were based on appropriate emission rates from the OVR facility, as described in the Technical Support Document and elsewhere in IDEM's responses to public comments. For example, IDEM specifically addresses the use of worst-case operating scenarios emission rates on pages 4 and 6 in TSD Appendix C.

Sierra Club Comment No. 4 **Preconstruction Monitoring**

The Clean Air Act and implementing regulations require that any facility receiving a preconstruction Prevention of Significant Deterioration (PSD) permit (including OVR here) must conduct a pre-application analysis of the air quality in the area to be impacted by the applicant's new or increased emissions. There are specific exceptions to this requirement provided by Congress, but anyone not meeting those specific exceptions must conduct sufficient preconstruction monitoring. The Clean Air Act is rigid and neither U.S. EPA nor IDEM has the authority to waive monitoring requirements. See Sierra Club v. EPA, supra.

However, for the draft permit for OVR, IDEM exempted the facility from the obligation to monitor preconstruction air quality for annual NO_2, 24-hour PM_{10}, 24-hour $PM_{2.5}$, and carbon monoxide based on IDEM's determination that the OVR's impacts would be below a "de minimis level" for those pollutants. TSD Appendix C at 5. There is no such de minimis level in the Clean Air Act. In fact, the D.C. Circuit recently rejected an attempt by U.S. EPA to graft such a de minimis level onto the Act through administrative fiat. The Court correctly found that there are no exceptions to the requirement to conduct preconstruction monitoring except those provided by Congress. IDEM must require the facility to conduct full preconstruction monitoring, including for those pollutants in Table 3 on page 5 of TSD Appendix C. The permit must then be re-noticed and a new public comment period provided.

IDEM RESPONSE

IDEM disagrees with the commenter's statement that IDEM unlawfully exempted the facility from PSD preconstruction monitoring requirements, specifically for 8-hour CO, annual NO_2, 24-hour PM_{10}, and 24-hour $PM_{2.5}$. The commenter bases its argument that IDEM unlawfully exempted the facility from preconstruction monitoring on a recent D.C. Circuit Court of Appeals ruling, Sierra Club v. EPA, Case No. 10-1413 (D.C. Cir. Jan. 22, 2013). In that ruling, the Court vacated the preconstruction monitoring exemption (also known as the significant monitoring concentration or "SMC") for 24-hour $PM_{2.5}$. Although the Court stated its belief that Congress did not authorize EPA to create exemptions from preconstruction monitoring, the Court did not make any ruling or issue any statement regarding the validity of any SMCs that existed prior to the 2010 SMC for 24-hour $PM_{2.5}$.

The Court was very clear it limited the scope of its ruling to the $PM_{2.5}$ SMC. In the Court's conclusion, it explicitly stated:

> *We grant the Sierra Club's petition as to the parts of the EPA's rule establishing a $PM_{2.5}$ SMC, and vacate them because these parts of the rule exceed the EPA's statutory authority.*

Furthermore, in response to an argument EPA offered that Sierra Club was time-barred from challenging the $PM_{2.5}$ SMC because SMCs were originally established in PSD regulations long ago, the Court clarified it was taking a narrow view of the challenge to SMCs, limited simply to the $PM_{2.5}$ SMC:

> *By establishing a new monitoring exemption for a new pollutant, the EPA exposes its $PM_{2.5}$ regulations, including whether it has authority to adopt the SMC exemption for $PM_{2.5}$ and whether it used an appropriate method to determine the level of the SMC, to challenge by a timely filed petition.*

Consequently, all SMCs other than 24-hour $PM_{2.5}$ remain in effect, including those found in 326 IAC 2-2-4(b)(2)(A), as approved by EPA in various SIP revisions since 2003. The exemptions from preconstruction monitoring for 8-hour CO, annual NO_2, and 24-hour PM_{10} remain in effect, and IDEM did not exceed its legal authority to exempt OVR from preconstruction monitoring for those pollutants and averaging periods.

IDEM legally exempted OVR from preconstruction monitoring for 24-hour $PM_{2.5}$. Although the D.C. Circuit vacated the SMC for $PM_{2.5}$, the January 22, 2013 ruling occurred after OVR had submitted its PSD permit application (September 17, 2012) and its final air quality analysis report (December 6, 2012). The preconstruction monitoring provisions in the PSD rules require a source to conduct the preconstruction monitoring before it submits a PSD application. At the time OVR submitted its PSD application and final air quality analysis report, the $PM_{2.5}$ SMC was in effect. OVR met all the PSD application requirements at the time its application was submitted. In order for the commenter's view that IDEM illegally granted OVR a preconstruction monitoring exemption for $PM_{2.5}$ to be correct, IDEM would have needed to take the view that OVR's permit application was invalid on the basis of the D.C. Circuit Court ruling. OVR's application met all PSD application requirements at the time the application was submitted and was therefore valid.

Furthermore, preconstruction monitoring was not waived by IDEM, instead it was substituted with 3 years of data from pre-existing ambient monitors deemed representative of the proposed site's area by IDEM as prescribed in EPA guidance. Allowing the substitution of pre-existing monitoring data for a preconstruction monitor is an acceptable practice pursuant to Section 2.4 in EPA's 1987 Ambient Monitoring Guidelines for PSD (Ambient Monitoring Guidelines for Prevention of Significant Deterioration (PSD), EPA-450/4-87-007, U.S. Environmental Protection Agency, 1987) and in Section III.A of EPA's 1990 New Source Review Workshop Manual (Draft, October 1990). As noted on pages 5 and 6 of the Technical Support Document – Appendix C, IDEM used representative ambient monitoring data to satisfy the requirement for preconstruction monitoring data for annual NO_2 and 24-hour $PM_{2.5}$. For annual NO_2 a monitor located in Owensboro, KY was selected as representative. For 24-hour $PM_{2.5}$, a monitor in Dale, IN was selected as representative.

Sierra Club Comment No. 5 **Modeling Background Concentrations**

Before IDEM can issue any PSD permit, including the permit for OVR at issue here, the applicant facility must demonstrate to IDEM that the facility will comply with the applicable NAAQS "based upon the total estimated air quality, which is the sum of the ambient estimates resulting from existing sources of air pollution (modeled source impacts plus measured background concentrations) and the modeled ambient impact caused by the applicant's proposed emissions increase… and associated growth." NSR Manual at C.3. Pursuant to the Clean Air Act, an applicant must "agree[] to conduct such monitoring as may be necessary to determine the effect which emissions from any such facility may have, or is having, on air quality in any area which may be affected by emissions from such source." 42 U.S.C. § 7475(a)(7). More specifically, at a minimum, the preconstruction PSD review must "be preceded by an analysis... by the State… or by the major emitting facility applying for such permit, of the ambient air quality at the proposed site and in areas which may be affected..." 42 U.S.C. § 7475(e)(1). This analysis "shall include continuous air quality monitoring data gathered for purposes of determining whether emissions from such facility will exceed the [NAAQS or TSD increment]." 42 U.S.C. § 7475(e)(2) (emphasis added). The Act specifies that this data "shall be gathered over a period of one calendar year preceding the date of application for a permit under this part unless the State... determines that a complete and adequate analysis for such purposes may be accomplished in a shorter period." Id. The implementing regulations require the same. 40 C.F.R. § 52.21(m)(f); 326 IAC 2-2-4(c)(3). Thus, an applicant must either conduct site-specific monitoring for a year (or at least 4 months with prior approval).

The NSR Manual further provides that:

> It is generally preferable to use data collected within the area of concern; however, the possibility of using measured concentrations from representative "regional" sites may be discussed with the permitting agency. The PSD Monitoring Guideline provides additional guidance on the use of such regional sites.

> Once a determination is made by the permitting agency that ambient monitoring data must be submitted as part of the PSD application, the requirement can be satisfied in one of two ways. First, under certain conditions, the applicant may use existing ambient data. To be acceptable, such data must be judged by the permitting agency to be representative of the air quality for the area in which the proposed project would construct and operate. Although a State or local agency may have monitored air quality for several years, the data collected by such efforts may not necessarily be adequate for the preconstruction analysis required under PSD. In determining the representativeness of any existing data, the applicant and the permitting agency must consider the following critical items (described further in the PSD Monitoring Guideline):
>
> 1) monitor location;
>
> 2) quality of the data; and
>
> 3) currentness of the data.
>
> If existing data are not available, or they are judged not to be representative, then the applicant must proceed to establish a site-specific monitoring network.
>
> U.S. EPA, New Source Review Workshop Manual (October 1990) at C.18-.19 (“NSR Manual”).

The Administrator has previously held that “EPA allows substitution of existing representative data in lieu of having the source generate its own preconstruction monitoring data, provided these data meet the criteria in the ‘Ambient Monitoring Guidelines for the Prevention of Significant Deterioration’…” In re Hibbing Taconite Co., 2 E.A.D. 838, 850 (Adm’r 1989) (emphasis added); see also In re Northern Michigan University Ripley Heating Plant, 14 E.A.D. __, PSD 08-02, Slip Op. at 62-63 (EAB Feb. 18, 2009) (remanding for a determination of whether the preconstruction monitoring complied with regulations and EPA guidance). Indiana code also requires that all monitoring used for PSD purposes comply with the Guidelines. 326 IAC 22-4(c)(7).

The PSD Monitoring Guidelines, referenced in the NSR Manual, in EAB decisions, and in 326 IAC 2-2-4(c)(7) provide that monitoring data from off-site monitors to be used if those data represent the locations of:

(a) maximum concentration increase from the proposed facility;

(b) maximum air pollutant concentration from existing sources; and

(c) maximum combined impact area (existing sources plus proposed facility).

Ambient Monitoring Guidelines § 2.4.1, at 6-8; Hibbing Taconite, 2 E.A.D. at 850-51. Where the monitors are not located within the area modeled for the permit decision, regional monitoring data can only be used in certain limited situations. Id. The Monitoring Guidelines provide three types of situations and the respective limitations on use of regional monitors in each such situation. Id. These are generally as follows:

Situation	Conditions and Limits on use of Regional Monitoring Data
Case I: proposed source will be constructed "in an area that is generally free from the impact of other point sources and area sources associated with human activity"	Regional monitoring data may be used but the site of the monitor must be "similar in nature to the impact area… [and] characteristic of air quality across a broad region." Additionally, the use of these regional monitors are intended to be limited to "relatively remote areas" and not in "areas of multisource emission or areas of complex terrain."
Case II: proposed source will be constructed in a multisource area and "basically flat terrain"	Regional monitoring data may be used only if either of the following is met: 1) "The existing monitor is within 10 km of the proposed emissions; or 2) The existing monitor is within or not farther than 1 km away from either the area(s) of the maximum air pollutant concentration from existing sources or the area(s) of the combined maximum impact from existing and proposed sources."
Case III: if the proposed construction will be in an area of multisource emissions and in areas of complex terrain, aerodynamic downwash complications, or land/water interface situations	Regional (existing) data can only be used if collected: 1) "at the modeled location(s) of the maximum air pollution concentration from existing sources; 2) At the location(s) of the maximum concentration increase from the proposed construction, and 3) At the location(s) of the maximum impact area.

Additionally, the data used from regional monitors must be of sufficient quality. The Monitoring Guidelines provide some minimum requirements in section 2.4.2. Additional quality requirements are set forth in 40 C.F.R. part 58, Appendix A (formerly Appendix B). Among the minimum data requirements are minimum data recovery, continuous monitoring, and minimum quality control practices and documentation. Monitoring Guidelines § 2.4.2; 40 C.F.R. part 58, App. A.

Lastly, the data used for PSD permitting must be current, which generally means that it must have been collected in a 3-year period preceding the application, provided that they are still representative of current conditions. Monitoring Guidelines § 2.4.3.

In IDEM's TSD, the agency purports to take background air quality data "from representative monitoring stations." TSD Appendix C at 5. There is no discussion, nor any record evidence, demonstrating that the monitors and data that IDEM uses as background comply with the minimum requirements of the Guidelines. Specifically, because the location of the OVR facility will be a multi-source area, and complex terrain, the existing monitor locations would have to be located at the location of the highest modeled concentration from existing sources, the location of the maximum modeled impacts from the OVR facility and the location of the maximum combined impact from OVR and existing sources. Even if the area around the facility was not complex terrain, the existing monitors must be located within 10 km of the site and no more than 1 km from the highest modeled concentration from existing sources or from the location of the highest modeled concentration from existing sources plus the impacts from OVR.

While IDEM did not make a record showing that the existing monitors it used for background concentrations, TSD Appendix C p. 6, Table 4, met these criteria—it is clear that they do not. Dale, Indiana, the location of the $PM_{2.5}$ monitor IDEM used is 29 km from the proposed OVR site. The location of the 1-hour and annual NO_x monitor—Owensboro, Kentucky—is over 25 km. It is not possible for these locations to meet the minimum location criteria of the Guidelines.

Moreover, in addition to the location criteria, the monitors must meet the data quality standards for site specific monitors. Those standards are different from regional monitoring data quality standards, so simply maintaining an EPA certification for regional monitoring meeting the regional monitoring standards does not ensure site-specific monitoring data quality standards are met. Additionally, the data must be from the most recent five years.

IDEM must require the facility to conduct site-specific monitoring for at least one year prior to permitting and to use that background monitoring to conduct the air quality analysis for the facility. And, because the public is entitled to public notice and comment on the correct air quality analysis—including the correct background concentrations based on monitors that meet the Guidelines' requirements—IDEM must re-notice the permit for public comment after this monitoring is collected.

IDEM RESPONSE

The practice of using existing ambient monitoring data collected by state and local air quality agencies in lieu of preconstruction monitoring has long been accepted and encouraged by EPA and state permitting authorities. EPA guidance documents, particularly the Ambient Monitoring Guidelines for Prevention of Significant Deterioration (EPA-450/4-87-007, EPA, 1987) and the 1990 NSR Workshop Manual provide state permitting authorities with significant discretion regarding representative monitor selection. This discretion is based on three general criteria: monitor location; quality of the data; and currentness of the data. IDEM selected the Dale, Indiana and Owensboro, Kentucky monitors as representative monitoring data in accordance with these general principles.

For monitor location, while there is a preference for using existing monitors in the immediate area of the proposed source, EPA recognizes that such monitoring data will often be unavailable. As cited by the commenter, EPA provides three examples of monitor locations it would deem acceptable. The commenter, however, overstates the purpose of the examples – claiming the examples represent the only circumstances where an existing monitor satisfies the location criteria in the Ambient Monitoring Guidelines. It is important to note that the Ambient Monitoring Guidelines state that the examples are only examples and ultimately, the permitting authority must make a decision about monitor location on a case-by-case basis.

> *In situations where there is no existing monitor in the modeled areas, monitors located outside these three types of areas may or may not be used. Each determination must be made on a case-by-case basis. In order to clarify EPA's intent regarding the use of existing monitoring data, some examples are included to demonstrate the overall intent.*

Because no monitors exist in the immediate vicinity to the proposed plant site, IDEM appropriately selected nearby monitors that would provide representative air quality data. The Owensboro NO_2 monitor is approximately 12 miles from the proposed OVR plant, and in all likelihood presents higher NO_2 monitoring values because it is located in an area with greater population density and with more point and area sources of NO_2 emissions. The Dale $PM_{2.5}$ monitor is approximately 17 miles away, at a location with similar terrain features as the proposed site. The Dale monitor may also present higher $PM_{2.5}$ values because it is located in a more populated area and is downwind of a broader swath of large $PM_{2.5}$ and $PM_{2.5}$ precursor emission sources. These monitors are well within the 50 kilometer range that EPA requires as the distance for which modeling must be conducted, further evidence that the monitors are located in a representative area. Moreover, because these monitors are within the 50 kilometer range, use of the monitoring data from these sites as background concentrations will cause a conservative double-counting of influence from other nearby sources that are included in the comprehensive air quality modeling analysis.

IDEM disagrees with Sierra Club's comment that the data quality from a regional monitor cannot meet the representativeness criteria for data quality simply because the data quality requirements for regional monitors operated by state and local agencies are slightly different from the data quality requirements for PSD monitors. To the contrary, as Sierra Club correctly notes, 326 IAC 2-2-4(c)(7) requires that monitoring used for PSD purposes follow the Ambient Monitoring Guidelines. The Ambient Monitoring Guidelines in Section 2.4.2 on page 8 state that data gathered from state and local agency monitors operated in conformance with 40 CFR Part 58 Appendix A (state and local monitoring quality assurance requirements) or B (PSD monitoring quality assurance requirements) satisfy the data quality criteria. (Note: EPA has subsequently merged Appendices A and B into Appendix A as a single document addressing both state/local monitoring and PSD monitoring.) Therefore, the PSD ambient monitoring requirements in the Indiana rules specifically contemplate and authorize the use of data from regional monitors based on data quality assurance.

Furthermore, there is significant overlap between the State and Local Air Monitoring Stations (SLAMS) data quality requirements and the PSD monitoring requirements – as indicated earlier EPA merged the 40 CFR Part 58 Appendices A and B into a single set of regulations under Appendix A. A quick review of Appendix A reveals how similar the quality assurance requirements are. In Appendix A, Section 1.1 EPA clearly states the quality assurance requirements for state monitoring and PSD monitoring are essentially the same:

> *1.1 Similarities and Differences Between SLAMS and PSD Monitoring. In most cases, the quality assurance requirements for SLAMS, SPMs [Special Purpose Monitoring Stations] if applicable, and PSD are the same. Affected SPMs are subject to all the SLAMS requirements, even where not specifically stated in each section. Table A–1 of this appendix summarizes the major similarities and differences of the requirements for SLAMS and PSD. Both programs require:*
>
> *(a) The development, documentation, and implementation of an approved quality system;*
> *(b) The assessment of data quality;*
> *(c) The use of reference, equivalent, or approved methods. The requirements of this appendix do not*

> *apply to a SPM that does not use a FRM, FEM, or ARM;*
> *(d) The use of calibration standards traceable to NIST or other primary standard;*
> *(e) Performance evaluations and systems.*

Appendix A consists of 17 pages in the Code of Federal Regulations. It contains hundreds of quality assurance requirements. Table A-1 in Appendix A, which describes the major similarities and differences between state quality assurance requirements and PSD quality assurance requirements, lists fewer than ten minor differences in quality assurance requirements, and these differences essentially reflect the fact that monitoring and quality assurance responsibilities for PSD are with the owner/operator seeking the permit, whereas for SLAMS they are with the State or local agency. With the rigorous quality assurance requirements imposed on both state and PSD monitors, there is no material difference in data quality between a state monitor and a PSD monitor, and the commenter has failed to demonstrate any meaningful differences in data quality.

The commenter identifies three differences between the requirements for state and local monitoring networks and PSD monitoring, and but does not describe how those differences would lead to material differences in data quality. Instead, the commenter suggests that, because the requirements are different and appear more stringent, the monitors used in OVR's air quality analysis are substantially inadequate and should not be allowed as representative. IDEM disagrees with this implication and believes that despite the differences in regulatory requirements the data quality from the two monitoring sites provide the same degree of quality as one operated under the PSD monitoring requirements.

IDEM disagrees with the commenter's suggestion that the differences between the PSD monitoring rule requirement for independent personnel to conduct monitor quality control checks and the state monitoring rule requirement that prefers independent personnel leads to lower quality data from state operated monitors. The purpose of the independent personnel requirement for PSD monitoring exists because PSD monitor networks are usually operated by a regulated source or its agent, and thus having an independent person conduct quality checks could be viewed as a way of ensuring the regulated source is not operating the PSD monitor in a way to compromise the data to its benefit. This motivation does not exist with a state agency that is operating a monitoring network. Employees of the state agency have no inherent bias or benefit resulting from the outcome of the monitoring. Arguably, any underlying bias a state employee might have to influence data could bend in either direction. Moreover, as a matter of practice, IDEM and the State of Kentucky both use separate staff to conduct quality control and assurance audits of the monitoring network. Therefore, as a matter of principle, and a matter of fact, there is no basis to the statement that the difference in regulatory requirements leads to lower quality data from IDEM or Kentucky operated air quality monitoring.

IDEM also disagrees that the difference between the regulatory requirements for the frequency of certain quality control checks for PSD monitoring (each monitor must undergo a multi-point accuracy test each quarter) and state monitoring (25% of the monitors must undergo the multi-point accuracy test each quarter) automatically leads to a conclusion the data quality for a state monitor would lead to data that is not representative. The commenter isolates one aspect of the quality assurance program – the frequency of a multi-point accuracy audit – and suggests that state monitoring is inadequate. This comment ignores the fact that EPA's regulations require each monitor to undergo various auditing procedures daily, and others as frequently as every two weeks. This ensures the data collected by IDEM and other states can be trusted and is valid for air quality management purposes, including substitution as representative monitoring data for PSD applications. The comment also ignores the fact that IDEM and Kentucky both implement quality assurance plans which require them to conduct comprehensive accuracy audits on every monitor every quarter – the same as required under the PSD monitoring rules. The commenter has provided no factual information that demonstrates state operated monitoring networks have lower data quality than PSD monitoring sites.

Likewise, IDEM disagrees with the commenter's suggestion that the regulatory differences between PSD monitoring and state monitoring with regard to sampling frequency lead to an automatic conclusion that the state's monitoring data does not meet the data quality requirements envisioned in the Ambient Monitoring Guidelines. Although the rules allow state monitors to sample less frequently, this has no practical application for the monitors in question. The NO_2 monitor in Owensboro is a continuous monitoring system that collects and analyzes air samples several times each minute. The $PM_{2.5}$ monitor in Dale collects particulate matter samples every three days, which exceeds the PSD monitoring requirements of once every 6 days. There is no question these monitors sample air quality at a sufficient frequency to provide a high quality assessment of pollutant concentrations, and a frequency that would satisfy the PSD monitoring requirements.

IDEM also disagrees with the comment that in order to meet the Ambient Monitoring Guidelines representativeness criteria the data must be from the most recent five years. The Guidelines state in Section 2.4.3 on page 9:

> *Generally, this would mean for the preconstruction phase that the data must have been collected in the 3-year period preceding the permit application, provided the data are still representative of the current conditions.*

The data from Owensboro and Dale cover the period 2009-2011, the three calendar years preceding the application submittal, as prescribed by EPA guidance.

Finally, IDEM disagrees with the comment that the record does not contain a discussion or evidence to support its decision to use the Dale and Owensboro monitors as representative monitoring data in lieu of preconstruction monitoring data. Page 5 of the Technical Support Document, Appendix C cites to EPA's Ambient Monitoring Guidelines as the basis for approving the Dale and Owensboro monitors as representative sites for the area. Furthermore, in the December 6, 2013 Air Dispersion Modeling Report submitted by OVR, the applicant states it followed IDEM's Modeling Policies and selected *the nearest* monitoring stations to the proposed site. The nearest monitoring station is most likely to be the most representative monitoring station due to geography, topography, and meteorological conditions being similar to the proposed site and all the other location criteria discussed in EPA's PSD Ambient Monitoring Guidelines. Because the monitoring sites used as representative sites in this application were both operated by state agencies using modern technology in compliance with current regulatory requirements for data quality, a factor IDEM is familiar with, the basis for approval of the relative data quality from these monitoring sites could have been reasonably presumed by IDEM and the public. Finally, OVR's modeling report stated it was using monitoring data from the most recent three year period. All of these documents that substantiate the decision to accept the Owensboro and Dale monitoring sites as representative, including the monitoring data itself, are either in the record for this permit or continuously available to the public on IDEM and EPA internet sites identified in OVR's application. IDEM's statement in the TSD and the applicant's statements in the modeling report both demonstrate that IDEM considered the various criteria for determining whether the data from the monitoring sites was representative in accordance with EPA guidance.

Sierra Club Comment No. 6 **Compliance Monitoring**

Throughout the draft permit IDEM appears to rely on one-time emission testing to determine compliance with ongoing requirements. For example, in section D.1.11, the permit requires only a one-time test to ensure compliance with the CO, CO_2 and efficiency requirements. There are no monitoring requirements to ensure that the facility is complying with the emission limits (and minimum efficiency requirement) during at any time after the initial test. This is insufficient. Both PSD and Title V permits must ensure continuous compliance with the permit limits. CO and CO_2 CEMS should be used and regular heat rate testing should be utilized. Similarly, the permit requires only one-time testing for CO and CO_2 emissions from the reformer (sections D.2.10.(a) and (b)), of CO, CO_2 and VOCs from the CO_2 vent (sections D.2.10.(c)-(e)).

Section D.4.12(a) contains parametric monitoring of the demisters at the ammonium nitrate plant, but there is no basis in the permit record for the implicit conclusion that if the facility maintains a pressure drop between 1.5 and 11 inches that the emission limits are met. The only rationale that could justify this monitoring is a conclusion that: (1) pressure drop across the demisters is the only variable that affects emission rates—otherwise monitoring the pressure drop alone would be insufficient to determine compliance; and (2) that pressure drop cannot change within a 24-hour period—otherwise recording the pressure drop once per day is insufficient to determine whether compliance was continuous between readings. Yet these assumptions, and the basis for them, are not in the record. IDEM must create and allow the public to comment on the full basis for its monitoring provisions.

Additionally, section D.4.12(a) provides that an excursion from the required pressure drop range “is not a deviation from this permit.” But this causes unnecessary confusion. An excursion from the pressure drop range may not, in the literal sense, be a violation—it is conclusive evidence of a violation of the underlying emission rate that the pressure drop range is intended to serve as the monitoring requirement for. That is, the pressure drop reading is intended as a parametric monitoring substitute for directing monitoring the pollutant emission rates. To be sufficient, the parametric monitoring must provide data sufficient to determine the source’s continuous compliance with the emission rate. If the pressure drop range is correct, then a deviation from it demonstrates that the facility did not comply with its limit. If the pressure drop range is not sufficient or not correctly set—so that it, alone, does not indicate compliance or non-compliance with the underlying limit—then the monitoring in the permit is insufficient.

Moreover, the permit lacks any monitoring at all for some emissions. There is no compliance testing or other monitoring required to ensure compliance with the following:

- Particulate matter or VOC emissions from the boilers in section D.1. of the permit;
- Particulate matter or VOC emissions from the reformer in section D.2.4(a);
- Particulate matter from the flares in section D.2.4(c).

The IDEM must require the facility to conduct adequate monitoring sufficient to provide representative data demonstrating the facility's compliance during all periods. The draft permit fails to do so. This must be corrected before a final permit can be issued.

IDEM RESPONSE

Permits issued under 326 IAC 2-7 are required by 326 IAC 2-7-5(3) to include monitoring and related record keeping and reporting requirements, which assure that all reasonable information is provided to evaluate continuous compliance with the applicable requirements. Where an applicable requirement does not include sufficient terms, 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. If necessary to assure that all reasonable information is provided to evaluate continuous compliance, they will be supplemented with compliance monitoring requirements, also in Section D of the permit. Compliance monitoring requirements are usually required by IDEM, OAQ for emission units with an emission limitation or permit condition requiring the use of a control device. Monitoring parameters are measured properties and may include indicators such as pressure drop, pH, temperature, liquid flow rates, visible emission notations and emission unit throughputs.

IDEM evaluates several criteria when determining the sufficient compliance determination and monitoring requirements for a permit. Those criteria include, but are not limited to the following:

- The magnitude of emissions;
- The expected variability of the emissions based on the nature and design of the emission unit and actions of the operator;
- Whether emission control systems are used to reduce emissions (which inherently increases the potential variability of the emissions) or whether emissions are uncontrolled;
- The difference between the expected emission rates and the emission limit or the degree of emission reduction claimed;
- The basis for determining emission values during the permitting process;
- The value of parametric monitoring data to demonstrate performance of emission controls or operation within design variables;
- The value of recordkeeping to satisfy, in whole or in part, the compliance monitoring requirements based on the applicable requirement, particularly for units where emissions are uncontrolled;

- The representativeness of the data obtained by testing or monitoring;
- The cost of various testing and monitoring schemes in relation to environmental impacts and compliance risk.

The determination of sufficient monitoring is accomplished on a case-by-case basis considering the factors listed above. The Technical Support Document gave substantial information about the monitoring requirements, fully satisfying the public notice requirements.

For the Ammonium Nitrate Units, daily reading of the demister pressure drop was selected to monitor the performance of the demisters. The demister is a form of a filter unit designed to remove entrained liquids from exhaust gases. For this particular application, the demister is the critical operation to assure compliance with the emission limits. The pressure drop across the demister is the only parametric indication of the performance of this control device because the demister operates passively with no mechanical or electronic actions required to control emissions. The pressure drop will remain consistent and reflect normal operating conditions. Pressure drop values would rise if the demister filter were clogged, a problem which would generally occur over a long period of time, not instantaneously. A daily reading of the pressure drop provides an adequate time frame to alert facility personnel to any clogging issues that may be developing. For these reasons, IDEM, OAQ proposed daily reading of pressure drop from the demister as the parameter most reflective of the performance of the control device used for ammonium nitrate units.

Continuous emissions monitors are not an appropriate technology for the ammonium nitrate units. The high moisture content of this exhaust stream would create interference with particulate matter CEMS systems and thus provide false high readings. In order to reduce the high moisture from the exhaust, the exhaust would have to be heated. Heating the exhaust would cause ammonium nitrate dissolved in the water droplets to form into a fine particle that would not have otherwise been considered particulate matter. Therefore, heating the exhaust to remove the moisture would also provide false high readings.

The commenter correctly understands that an out of range pressure drop reading is not a deviation from the permit. However, if the information indicates that the process and/or controls are operating in the same fashion as during the last compliance determination, it can be reasonably assumed that the emissions unit is in compliance with the applicable requirements. With all parametric monitoring, the correlation between the parametric range and compliance with the underlying emission limits is not perfectly aligned. Therefore, IDEM utilizes the parametric range that reflects normal, compliant operations, not operations that are on the edge of compliance with the underlying limits. Requiring the source to respond to readings that are out-of-range of parametric values that represent normal operations is intended to allow time for the source to take corrective actions before emissions limits are exceeded. This approach is more likely to ensure continuous compliance than a system that aims to define the acceptable parametric monitoring range at the edges of the compliance spectrum.

If a reading is observed outside the range, the Permittee is required to take reasonable response steps to return the control device to within the approved pressure drop range. Failure to take such response steps would be a violation of the permit condition.

For some emission units and emission limits, IDEM may determine that stack testing is the appropriate means of determining compliance. IDEM has imposed numerous stack testing provisions for OVR in this proposed permit. Some of the stack testing must be repeated every five years. For other operations, IDEM may require a single stack test to confirm the emission unit is capable of meeting its design criteria, including emission limits. These decisions are based on evaluating the various criteria described at the beginning of this response.

It should be noted that IDEM, OAQ may require additional testing at any time to ensure compliance with permit limits, terms and conditions. Section C – Compliance Requirements [326 IAC 2-1.1-11] states, "The commissioner may require stack testing, monitoring, or reporting at any time to assure compliance with 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."

In the case of the one-time stack testing identified by the commenter for the natural gas boilers and the natural gas-fired reformer, IDEM determined that one-time testing for CO, CO_2, and energy efficiency is appropriate for the boilers and one-time testing of CO and energy efficiency is appropriate for the reformer. This testing is appropriate based on several factors:

- These units do not use emission control systems to reduce emissions, so testing determines that the system operates as designed.

- The permit requires recordkeeping and reporting of fuel usage which ensures that only clean-burning natural gas or process off-gases are burned.

- Natural gas-fired equipment is relatively simple to operate and requires a low degree of maintenance to assure long term achievement of good combustion and energy efficiency. Emissions and energy efficiency from the units are expected to be stable over the short term and the performance is not expected to worsen significantly over time.

- The boilers and the reformer are subject to NESHAP Subpart DDDDD, which requires periodic tune-ups and energy efficiency evaluations, and those requirements are included in the permit. These activities will ensure the systems operate effectively over the long term.

- CO emission levels are based on design guarantees by the equipment vendor.

- Because there is little expected variability or deterioration of performance, the value of data provided by CO or CO_2 continuous emission monitoring systems (CEMS) is greatly exceeded by the cost of installing and operating the CEMS.

For the CO_2 Purification Vent, IDEM determined that periodic testing for CO_2 is appropriate because CO_2 is a relatively new regulated pollutant and the quantity of CO_2 emissions from the vent is high. IDEM determined, however, that one-time testing for CO, and VOCs is appropriate. This testing is appropriate based on the following factors:

- These units do not use emission control systems to reduce emissions.

- Because there is little expected variability or deterioration of performance of the process, the value of data provided by CO or CO_2 continuous emission monitoring systems (CEMS) is greatly exceeded by the cost of installing and operating the CEMS.

However, upon further review, IDEM has determined that an additional recordkeeping requirement is appropriate to document compliance with the requirement in Condition D.2.4(b)(4) for the use of a low VOC catalyst, as follows:

D.2.14 Record Keeping Requirements

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(h) **To document the compliance status with Condition D.2.4(b)(4), the Permittee shall maintain a record of the use of a low VOC catalyst for the CO_2 Purification Process.**

(i) Section C – General Record Keeping Requirements contains the Permittee's obligations with regard to the record keeping required by this condition. **********

IDEM may determine, as it did in the case of particulate matter and VOC emissions from the boilers and reformer, and particulate matter from the flares, that no testing or monitoring is necessary. For these emission sources, IDEM determined no testing was necessary. This is appropriate based on the following reasons:

- These emission units burn natural gas or clean process off-gases, which create very low levels of these pollutants.

- Emissions were calculated and limits were established from conservative AP-42 values. Because the AP-42 emission rates are conservative and no lower emission rates have been claimed, there is no basis to require stack testing to validate emission levels.

- The permit requires recordkeeping and reporting of fuel usage which ensures that only clean-burning natural gas or process off-gases are burned.

- These emission units do not operate with add-on emission controls to reduce particulate matter or VOC emissions.

- A natural gas-fired combustion unit operating under normal conditions will not likely experience variability in particulate matter or VOC emissions.

- The boilers and reformer must comply with NESHAP Subpart DDDDD tune-up and energy efficiency requirements, and those requirements are included in the permit. Proper operation of the units over the long term is assured.

- For the boilers and reformer, there is a high correlation between CO emission levels, particulate matter, and VOC emissions for a natural gas-fired combustion unit. CO emission levels are often used as an indicator of performance for particulate matter and VOC emission levels. If a facility is able to comply with its CO emission limits, as demonstrated by a stack test, there is a very high probability it is in compliance with particulate matter and VOC emission limits.

- For the flare, particulate emissions were calculated from the use of natural gas for the pilot and purge. None of the process streams that will be vented to the flare will generate particulate matter emissions.

Sierra Club Comment No. 7 **Compliance Monitoring Periods**

In the draft permit, IDEM's air quality analysis assumed that the emission sources at the OVR facility would never exceed certain hourly emission rates. The air quality modeling conclusions—that the facility will not cause violations of the NAAQS or increments at permitted emission rates—assumed that the emission sources at the plant would never exceed the modeling one-hour emission rates. However, the permit does not limit the facility's emissions based on one-hour averaging times. This allows emissions during any particular hour to exceed the emission rates assumed in IDEM's dispersion modeling. According to U.S. EPA guidance, the Guidelines on air quality modeling, and good air quality permitting practices, the permit limits should match the inputs assumed in the dispersion model—including not only the emission rate but also the averaging period.

Emission rates can fluctuate and, therefore, averages over time do not necessarily represent the maximum emission rate during a shorter period of time. This is especially problematic when emission limits are averaged over periods longer than the short-term air quality standards that those limits are supposed to protect. Therefore, the Modeling Guidelines require that the maximum allowable emission rate be used to model for PSD permitting. 40 C.F.R. pt. 51, Appx. W Table 8-2. The Guidelines further require that emission limits be set at the maximum emission rate that was modeled for the most stringent air quality standard. 40 C.F.R. pt. 51, Appx. W § 10.2.3.1.a ("Emission limits should be based on concentration estimates for the averaging time that results in the most stringent control requirements."). EPA's *NSR Manual* similarly requires that NAAQS compliance demonstration modeling be conducted at the maximum allowable operating conditions over the averaging period represented in the NAAQS. *NSR Manual* at C.45; *see also e.g., In re Northern Michigan University*, 14 E.A.D. __, PSD Appeal No. 08-02, Slip Op. at 50-51, 54-55 (EAB Feb 18, 2009). EPA guidance related to the new 1-hour NAAQS again confirms this requirement and specifically directs permitting authorities implementing the federal program to establish limits over a 1-hour period:

> Because compliance with the new SO_2 NAAQS must be demonstrated on the basis of a 1-hour averaging period, the reviewing authority should ensure that the source's PSD permit defines a maximum allowable hourly emission limitation for SO_2… Hourly limits are important because they are the foundation of the air quality based emissions demonstration relative to the 1-hour SO_2 NAAQS.
>
> Memorandum from Anna Marie Wood, USEPA AQPS, Re: General Guidance for Implementing the 1-hour SO_2 National Ambient Air Quality Standard in Prevention of Significant Deterioration Permits, at p. 7 (August 23, 2012), available at: http://www.epa.gov/region7/air/nsr/nsrmemos/appwso2.pdf (emphasis added).

Here, IDEM has not limited NO_x emissions on a one-hour average—providing, instead, for the averaging of emissions over several hours or more. At the same time, the modeling analysis in support of the permit assumed that these limits were actually maximum one-hour limits. For example, permit section D.1.4(f) limits NO_x emissions from the four boilers to 20.40 lb/MMCF on a 24-hour average. However, IDEM's air quality analysis assumed that the boilers would not exceed a rate of 20.40 lb/MMCF during any single hour. By failing to ensure that the NO_x emission limit matches the modeling assumptions—especially for assuring compliance with the one-hour NO_x NAAQS—IDEM cannot ensure that the NAAQS are protected because during some hours the boilers' emissions can greatly exceed 20.40 lb/MMCF due to the facility's ability to average 24 hours' emissions to determine compliance with the permit limit. Similarly, the emission limit for the reformer in section D.2.4(a)(5) is based on a 30-day average; sections D.2.4.(c)(7) and (8) are based on a three hour average; sections D.3.4(a)(5), (b)(7) and (8), and (c)(7) and (8) are based on a 3-hour average; section D.4.4(a)(2) on a 30-day average; section D.4.4.(d)(7) and (8) on a 3-hour basis; section D.4.4.(i)(2) and (3) on an annual average of monthly data; and section D.5.4(b)(4) on a 3-hour basis.

IDEM cannot issue the permit in its current form. IDEM must either make all NO_x emission limits hourly mass emission limits (or input-based limits with an additional cap on hourly input) or it must re-run the air quality dispersion models based on the highest peak hour emission rate that the facility can emit due to multiple-hour averaging.

IDEM RESPONSE

IDEM disagrees that the averaging period for a PSD permit limit cannot be longer than the averaging period for the affected NAAQS. The form of the NAAQS, i.e., the way in which compliance with the NAAQS is determined, is an important characteristic that can provide flexibility for how emission limits may be structured instead of an absolute approach.

The 1-hour NO_2 NAAQS is not a straight, deterministic 1-hour standard under which any one hour concentration above 100 ppb in a year would mean non-compliance with the standard. Instead, it is a probabilistic standard where compliance is defined as achieving a 3 year average of the 98th percentile of the distribution of the maximum daily one-hour values. In other words, compliance is determined by isolating out the highest one-hour value for each day of the year, then picking the 8th highest of those 365 daily maximums for each year, and finally determining the average of those 8th highs over a three year period. Under this type of standard, there could be anywhere from 7 to 168 one-hour values that could be above 100 ppb and compliance with the NO_2 NAAQS would be assured.

This type of statistical approach allows variability in the averaging period for emission limits. The possibility of the source emitting at values above the emission limit for some duration less than the averaging period of the emission limit and still maintaining compliance with the emission limit, all at the same time the meteorological conditions needed to cause a concentration above the NAAQS on as many as 8 days per year is extremely remote.

EPA recognized that the statistical form of the 1-hour NO_2 NAAQS provides flexibility for modeling demonstrations in PSD permitting and has provided guidance to state permitting agencies about assumed emission rates used in dispersion modeling in support of PSD permits involving the 1-hour NO_2 NAAQS. In the March 21, 2011 memorandum from Tyler Fox, Leader of EPA's Air Quality Modeling Group, EPA stated:

> *In fact, the probabilistic form of the standard is explicitly intended to provide a more stable metric for characterizing ambient air quality levels by mitigating the impact that outliers in the distribution might have on the design value.*

"Additional Clarification Regarding Application of Appendix W Modeling Guidance for the 1-hour NO_2 National Ambient Air Quality Standard", EPA, March 1, 2011, at 8.

Based on this recognition of the statistical variability that the form of the 1-hour NO_2 NAAQS can tolerate, EPA stated:

> *EPA believes the most appropriate data to use for compliance demonstrations for the 1-hour NO_2 NAAQS are those based on emissions scenarios that are continuous enough or frequent enough to contribute significantly to the annual distribution of daily maximum 1-hour concentrations.*

March 1, 2011 memorandum at 9.

As explained below for each NO_x emission limit, IDEM followed the EPA guidance by modeling the emission scenarios that are continuous enough or frequent enough to contribute significantly to the annual distribution of daily maximum 1-hour concentrations. In each case, IDEM modeled either the permitted emissions limit or a value slightly higher than the permitted emission limit on an hourly basis because those are the emission scenarios IDEM expects to be continuous enough or frequent enough to contribute significantly to the annual distribution of daily maximum 1-hour concentrations. In addition, in the NO_2 modeling scenario, IDEM conservatively included intermittent emissions, such as emergency generators and flares during venting period, even though EPA guidance states such emissions do not need to be included in the modeling.

The commenter argues that, because NO_2 NAAQS is a 1-hr standard, then all NOx limits in the PSD permit must be expressed as 1-hour emission limits, or the NO_2 modeling must be re-run based on the highest hourly emission rate the facility could emit and still maintain compliance with the emission limits. In support, the commenter cites EPA guidance developed in 2010, shortly after the 1-hour NO_2 and SO_2 standards were issued by EPA. However, EPA later clarified the 2010 NO_2 and SO_2 guidance with a memorandum that explicitly states it applies to both NO_2 and SO_2. Additional Clarification Regarding Application of Appendix W Modeling Guidance for the 1-hour NO_2 National Ambient Air Quality Standard, March 1, 2011 (hereinafter referred to as the Tyler Fox memo). In the Tyler Fox memo, EPA notes that Appendix W, which is cited by the commenter as an absolute authority for requiring 1-hour emission limits, is not a strict modeling cookbook. Instead, EPA states that Appendix W provides permitting agencies with broad discretion to use the most appropriate data in modeling analyses. EPA does not demand that modeling take into account the highest possible hourly emissions that could occur during an averaging period. Instead, EPA expects PSD modeling based only on continuous or frequent emission scenarios. Tyler Fox memo at 9.

Under this approach, EPA explicitly allows states to ignore intermittent emissions sources such as emergency generators or startup/shutdown emissions in PSD modeling on the basis that even though under the worst case meteorological conditions such emissions might result in hourly NO_2 concentrations above the 100 ppb level of the NAAQS, the infrequency of such emissions, the variability of weather conditions, and the statistical nature of the NAAQS permit ignoring these emissions in the model.

Based on the Tyler Fox memorandum, modeling the emissions at an hourly rate that matches the allowable emissions, even if the compliance averaging period is longer than one hour, represents a continuous or frequent emissions scenario for demonstrating compliance with the statistical form of the 1-hour NO_2 standard, particularly when, as is the case with OVR's permit, the permit does not allow frequent occurrences where emissions are higher than the modeled scenario.

For the uncontrolled combustion sources, such as the boilers, ammonia startup heater, flares, and diesel engines in this application, the emission limits are based on operating at maximum capacity without add-on emission controls. Except for the possibility of higher emissions during very infrequent startups and shutdowns, there are no realistic operating scenarios where the hourly emissions would be continuously or frequently greater than the emission limits. Furthermore, all of these combustion units are subject to restrictions on fuel usage or operating hours, which greatly reduces the possibility of them operating at permitted capacity for significant time periods.

Considering these factors, IDEM believes modeling 1-hour NO_x emission rates at the 3-hour and 24-hour emission limits reflects the emission scenarios that will occur continuously and frequently and thus provide an accurate assessment of the impact on the annual distribution of daily 1-hour maximum concentrations. During normal (ie., continuous and frequent) operations, the emission units with 3-hour and 24-hour compliance averaging periods characteristics (the natural gas-fired boilers, the four flares, the ammonia catalyst startup heater, the nitric acid storage tank, the diesel fired emergency generator, and the diesel fired firewater pump) will operate at steady states, with consistent emission rates. Emission levels during normal operations do not vary appreciably over time. For example, the four boilers, which have NO_x limits with 24-hour averaging periods are expected to emit less than its emission limit for every hour in operation, including startup and shutdown. The only time when the boilers might emit at levels above the emission limit for as long as an hour would be in the event of an unforeseen malfunction that was not indicated by the NO_x continuous emissions monitoring system on those units. This is an extremely unlikely event – far beyond the scope of the continuous or frequent emission scenario contemplated by EPA guidance. The 3-hour and 24-hour averaging periods for these units protect the statistical form of the 1-hour NO_2 standard.

The use of 30 day averaging periods for the steam methane reformer and the nitric acid plants are consistent with the modeling demonstration. In both instances, modeling emissions at a 1-hour level based on the emission limit represents the emissions scenario that is continuous and frequent as contemplated by the EPA guidance. No other emission scenarios from these units will occur either continuously or frequently or the source risks noncompliance with the emission limits. Both of these operations are subject to stringent emission limits which require the use of add-on emission controls to operate at a high level of control on a continuous basis in order to maintain compliance. During normal operations, these units will likely emit at levels near the emission limit. This means the one-hour emission rate will be above the level of the emission limit infrequently or intermittently, or otherwise OVR risks noncompliance with the emission limit.

EPA data employed to establish the 30-day averaging period under the New Source Performance Standard for Nitric Acid plants (40 CFR 60 Subpart Ga) in 2012 substantiates the continuous nature of the emission levels attained by nitric acid facilities utilizing selective catalytic reduction for NO_x control (the same arrangement proposed by OVR). EPA evaluated CEMS data from newer nitric acid plants equipped with SCR to ascertain the appropriate compliance averaging period. The CEMS data shows 97 to 98% of the 1-hour emission rates from the SCR-controlled facilities were lower than the emission limit of 0.5 lb NO_x/ton of acid produced. This is clear evidence that modeling at the emission limit for an SCR-controlled nitric acid plant represents the most continuous and frequent modeling scenario and provides adequate protection of the 1-hour NO_2 NAAQS. This data includes periods of startup, shutdown, and malfunction – the periods when emissions would be expected to be above the emission limit during any one hour. See "Statistical Evaluation of CEMS Data to Determine the NO_x Emission Standard, Nitric Acid NSPS Review", EPA Docket EPA-HQ-OAR-2010-0750, Document # EPA-HQ-OAR-2010-0750-0082, http://www.regulations.gov/#!documentDetail;D=EPA-HQ-OAR-2010-0750-0082, July 18, 2011. As indicated in the March 1, 2011 Tyler Fox memorandum, emissions from startup and shutdown can be excluded from the modeling demonstration. The actual startup periods for OVR's nitric acid units will not be a long-running or frequent occurrence with high emissions. Only one unit will be started at a time, and the startup time before the operations and NOx controls stabilize to normal levels will be approximately one hour. Projected emissions from the nitric acid units during startup will be only slightly above the 0.5 lb/ton emission rate.

Although a similar data analysis is not readily available for a steam methane reformer, IDEM expects the statistical variation for an SCR controlled reformer to be similar to the nitric acid plants data. An SCR unit on a reformer will provide comparable levels of consistency. A reformer is an extremely large operation that inherently operates at a steady state. Under such conditions, the emissions from the reformer are not expected to vary significantly. Similarly, the SCR unit that controls NO_x emissions on a reformer will operate at a steady state level that also reduces variability in emissions. The primary difference between the emissions profile from a reformer and the emissions profile of a nitric acid plant is that the startup period for a reformer will be longer, but not so long or frequent to be considered for modeling. The reformer is expected to startup once and remaining in operation for as long as three years before shutting it down for maintenance. The SCR will achieve its full emission control capabilities within 10 to 20 hours.

Furthermore, the modeling demonstration was based on conservative 1-hour emission scenarios from the reformer and the nitric acid units. They were modeled at an hourly emission rate higher than the emission limits. Although modeling one-hour emission rates at the emission limit would have represented the most continuous and frequently occurring emissions scenario, OVR and IDEM built in 10 to 15% conservatism into the model. The emissions from the reformer were modeled at an emission rate equivalent to 10 ppm, more than 10% higher than the 9 ppm limit. Similarly, emissions from the nitric acid plants were modeled at 0.578 lb NO_x/ton of nitric acid, more than 15% higher than the 0.5 lb/ton limit. This conservatism provided an extra measure of assurance that the 1-hour NO_2 NAAQS would be protected.

Finally, the permit contains implicit limitations on the amount of startup periods for the plant. The permit contains limits on the extent of startup that can occur. The ammonia catalyst startup heater will be operating during startups of the ammonia plant. It is limited to the equivalent of 200 hours per year of operation, so in effect the permit limits the amount of startup time to no more than 200 hours per year. These startup conditions for the reformer and the nitric acid plants are clearly within the same context as the infrequent and intermittent emissions that EPA has indicated can be excluded from PSD modeling.

IDEM disagrees with the comment that all emission rates for NO_x must be expressed as one-hour averaging periods in order to protect the one-hour NO_2 NAAQS. The statistical form of the NO_2 NAAQS does not prohibit any one hour in a year from being over the level of the NAAQS, and the standard can tolerate variability in emission rates without jeopardizing attainment of the standard. Recent EPA guidance authorizes permitting agencies to demonstrate compliance with the one-hour NO_2 NAAQS by modeling the emissions scenarios that occur continuously or frequently – not the maximum rate that could occur. As a conservative measure, emissions from the reformer and nitric acid units were modeled at emission levels above the expected emissions rate. The proposed permit for OVR includes several provisions that limit the quantity or occurrence of above-normal emissions scenarios. All of these factors and requirements in the permit assure the one-hour NO_2 standard is protected even with emissions limits that contain compliance averaging periods greater than one hour.

Sierra Club Comment No. 8 **Flaring Limits and Short Term NAAQS**

In its TSD, the IDEM asserts that the OVR requested annual limits on the number of hours that the flares can be used "to ensure emissions from this source do not cause an increment violation or a violation of the [NAAQS] for PM, PM_{10} and $PM_{2.5}$." TSD Appendix B at 10. It is not clear how limiting annual operation protect short term (24-hour) standards. Because compliance with 24-hour standards is determined based on the worst case emissions during the highest-emission hour, a limit on the total number of hours a flare operates does not affect the analysis.

Additionally, even for annual standards, modeling assumes an emission rate for each hour but determines compliance based on the average of individual hourly values for each receptor point. Because the impact at each receptor differs based on meteorological data in addition to emission rates, the hourly air quality concentration at each receptor is not proportionate to the emission rate alone. High emission rates paired with meteorological conditions that produce higher ground-level concentrations of air pollution have a disproportionate impact on the annual average. In short, simply averaging emissions over fewer hours does not have a proportionate effect on the average air quality over those hours.

IDEM has not explained how it used the annual limit on hours of flaring to ensure that air quality is protected.

IDEM RESPONSE

As noted in the application and discussed in the Response to Sierra Club's Comment 9, the process streams vented to the flares do not generate particulate emissions when combusted in the flares. In contrast, combustion of natural gas used in the pilot and as purge gas to sweep the lines going to the flare will generate a small amount of particulate. As a conservative measure, the emissions estimates and air quality analyses assumed that the pilot and purge emissions would occur continuously for both short-term and annual standards, and no credit was taken in those evaluations for the annual limits on the hours of operation for the flares. Therefore, the worst-case PM emissions for the flares were used for both short-term and annual modeling.

While the pilot will run throughout the year, this is a very conservative estimate for the purge gas. The sweeping of the lines with natural gas as purge gas is planned prior to each flaring episode. Therefore, the annual limit on number of hours of flaring employed as BACT for other pollutants has the effect of also limiting the amount of natural gas combusted as purge gas and the amount of particulate emitted at the flares. As such, the permit and the technical support document (TSD) acknowledge that effect as an additional measure to ensure actual operations are protective of air quality, even though the air quality analysis was conservatively performed assuming 8,760 hours of operation of the purge function annually. Detailed descriptions of the emissions calculations and air quality modeling assumptions, including citations to the permitting record, are included in the Response to Sierra Club Comment 9.

For the annual standards, modeling utilized flare emission rates that incorporated the annual hourly limit for emissions generated by flaring process gases. For emissions generated from the combustion of pilot and purge natural gas no limit on hours was applied. Therefore the emissions from process gas flaring were averaged over 8,760 hours and added to the natural gas combustion emissions. This ensured the maximum potential emissions were evaluated for the annual standards as well. This methodology follows the guidance in Section IV.D.4 of EPA's 1990 New Source Review Workshop Manual (Draft, October 1990).

In establishing the annual limit for flare hours, OVR originally proposed a limit of 168 hours for the three ammonia flares and 100 hours for the UAN Flare. OVR revised this request to 336 hours for the front end and backend ammonia flares and the UAN flare. The ammonia storage flare remained at 168 hours. Revised application materials, including modeling, were submitted to IDEM in December 2012. These revised application materials were also made available at the Spencer County Public Library.

Sierra Club Comment No. 9 **Air Quality Analysis and Flares**

It is unclear from the IDEM's Technical Support Document (TSD) whether the ambient air quality analysis conducted by IDEM included the emission rates from all flares at the rates that the flares emit while flaring is occurring. Notably, only some permit conditions in the permit set limits on the flares when flaring, as opposed to limits for the pilot flame for non-flaring conditions. It is not clear, whether the IDEM's air quality modeling from the flare emission points assumed emissions representative of flaring events or only of the pilot light.

Additionally, for those emission points that do have different emission limits for periods of flaring and for other periods (i.e., the pilot light), it is unclear whether IDEM's modeling assumed the worse-case flaring emission rates. For example, did IDEM's NO_x NAAQS and increment analysis assume an emission rate from the flares based on the limits in section D.2.4(c)(7) (non-flaring events) or the higher limits in section D.2.4(c)(8) (flaring events)? Since flaring emissions are much higher, the air quality analysis must be based on the higher emission rate.

It is also unclear whether the PM/PM_{10}/$PM_{2.5}$ emission rate that IDEM included in section D.2.4(c)(5) and (6) apply during periods of flaring, or how compliance with these limits (during flaring or non-flaring periods) will be determined. Since these emission limits appear to represent the emission factors in Table AP-42 1.4-2 for natural gas burning only, it appears that IDEM either assumes that the gases vented to the flare have an emission factor equal to natural gas, or that IDEM seeks to prohibit flaring since the gases vented to the flare would have an emission rate higher than for the burning of natural gas and therefore the facility would violate the limits. If the former (equal emission factors) IDEM must make a record for how it reached that determination. If the latter, and IDEM actually intends to effectively prohibit flaring through particulate emission limits applicable to the flare, IDEM should make that prohibition explicit. Obviously, if emissions will exceed the pilot-flame-only rates during flaring periods (including both the emission factor in lb/MMBtu and the fact that the capacity while flaring is higher than the 0.126 MMBtu/hour capacity of the pilot flame), IDEM must revise and re-run its air quality analysis with the higher emissions representing flaring periods. Sufficient emission monitoring must also be conducted to assure that PM, PM_{10} and $PM_{2.5}$ emissions never exceed the emission rates included in the permit (and upon which the air quality analysis was based).

IDEM RESPONSE

As explained below, the draft permit and the ambient air quality analysis conducted by IDEM fully account for the combined emissions from natural gas combustion as pilot and purge gas and the combustion of flared process streams.

Along with other BACT requirements, the permit includes short term emission limits for each of the flares in addition to an annual limit on the total number of hours that each flare operates, as well as corresponding compliance determination provisions. The following is a list of permit conditions with the short term limits, the permit condition that details how to calculate each flare's emissions to show compliance with its respective limit, and the recordkeeping to document compliance for each.

- Front End Process Flare – D.2.4(c) (5)-(14) has short-term flare emission limits. D.2.11 has the calculation to determine compliance with those limits. D.2.14 includes recordkeeping requirements related to hours of venting and emissions.

- Back End Ammonia Process Flare – D.3.4(b) (5)-(14) has short-term flare emission limits. D.3.8 has the calculation to determine compliance with those limits. D.3.9 includes recordkeeping requirements related to hours of venting and emissions.

- Ammonia Storage Flare – D.3.4(c) (5)-(11) has short-term flare emission. D.3.8 has the calculation to determine compliance with those limits. D.3.9 includes recordkeeping requirements related to hours of venting and emissions.

- UAN Plant Vent Flare – D.4.4(d) (5)-(12) has short-term flare emission limits. D.4.11 has the calculation to determine compliance with those limits. D.4.13 includes recordkeeping requirements related to hours of venting and emissions.

As an initial matter, there are no components in the process streams associated with a venting event for any flare that could result in particulate emissions, and there are no components in the process streams associated with a venting event for the UAN Flare or the Ammonia Storage Flare that could result in carbon monoxide emissions.

Emissions from combustion in the pilot and of the purge gas used to sweep the lines going to the flare were estimated based on emission factors for combustion of natural gas, which will include a small amount of particulate.

Therefore, for those pollutants generated by both combustion of natural gas and venting of process streams at a given flare, separate emission limits are included for that flare for non-venting and venting operations (e.g., for NO_x from the Front End Process Flare, see Conditions D.2.4(c)(7) and (8)).

For those pollutants generated from combustion of natural gas for pilot and purge operations, but not generated by venting of process streams at a given flare, a single emission limit is included that applies during both non-venting and venting periods (e.g., for PM_{10} and $PM_{2.5}$ from the Front End Process Flare, see Condition D.2.4(c)(6)).

Simply put, if a flare does not have a limit for a specific pollutant for venting events, it is because the pollutant is not generated by venting of process streams at a given flare.

The ambient air quality analysis conducted by IDEM included emission rates from all the flares at the rates that incorporate the combustion of flared streams in addition to pilot and purge gas streams. IDEM's ambient air quality analysis used the emission rates from the applicant's analysis as set forth in the permit application and the applicant's Air Dispersion Modeling Report. The treatment of flare emissions, including how venting emissions were used in modeling, is described in Section 6.4 of the Modeling Report. The flare stack parameters, including the modeled emission rates, were provided in Table 6-2 of the Modeling Report, and Tables 13-11 through 13-14 show the modeled emission rates for each emission source by pollutant and averaging period. Table B-1 in Attachment B of the Modeling Report includes all of the modeled emission rates for each analysis, pollutant, and averaging period. The applicant's permit application and Modeling Report were available for the public to review in the documents at the Spencer County Public Library during the entire comment period from February 28, 2013 through May 20, 2013.

To address the specific comment on IDEM's NO_x NAAQS and increment analysis, modeling against the short-term NO_2 standard assumes a worst-case emission rate based on the hours each flare is allowed to operate. As explained in Section 6.4 of the modeling report, and reflected in the emission rates used as noted in Tables 6-2, 13-11 and 13-12, the total emissions from these intermittent sources were averaged out over the full 8,760 hours. This methodology follows EPA Guidance Memo titled "Additional Clarification Regarding Application of Appendix W modeling Guidance for the 1-hour NO_2 National Ambient Air Quality Standard" by Tyler Fox, dated March 1, 2011. Specifically on page 11 it states:

> *"Another approach that may be considered in cases where there is more uncertainty regarding the applicability of this guidance would be to model impacts from intermittent emissions based on an average hourly rate, rather than the maximum hourly emission. For example, if a proposed permit includes a limit of 500 hours/year or less for an emergency generator, a modeling analysis could be based on assuming continuous operation at the average rate, i.e., the maximum hourly rate times 500/8760. This approach would account for potential worst-case meteorological conditions associated with emergency generator emissions by assuming continuous operation, while use of the average hourly emission represents a simple approach to account for the probability of the emergency generator actually operating for a given hour. Also note that the contribution of intermittent emissions to annual impacts should continue to be addressed as in the past to demonstrate compliance with the annual NO_2 standard."*

The Tyler Fox memo of March 1, 2011 from EPA also states:

> *"…we are concerned that assuming continuous operations for intermittent emissions would effectively impose an additional level of stringency beyond that intended by the level of the standard itself. As a result, we feel that it would be inappropriate to implement the 1-hour NO_2 standard in such a manner…. EPA believes that existing modeling guidelines provide sufficient discretion for reviewing authorities to exclude certain types of intermittent emissions from compliance demonstrations for the 1-hour NO_2 standard under these circumstances."*

Therefore, although the guidance acknowledges that IDEM had discretion to exclude the intermittent emission, the analysis conservatively accounted for them in the NAAQS modeling evaluation.

Further, flaring emissions were modeled in combination with the worst-case emissions from all other sources at the OVR plant. This is a conservative approach because, if the flares are in operation, then many units in the remainder of the plant are likely offline and it is unlikely all flares would be used at the same time. For example, with the Ammonia Plant venting emissions to the front end or back end flares and no ammonia and CO_2 going to the UAN Plants, those emission points would be offline.

IDEM's ambient air quality analysis was appropriately conducted to account for higher emissions from flaring periods. Therefore, no revision to this analysis is needed.

The permit conditions listed above provide the permit conditions for compliance determination and related recordkeeping to document compliance with the limits that account for venting emissions. For those limits that address the pilot and purge emissions from combustion of natural gas, the permit requires the use of natural gas only (e.g., Condition D.2.4(c)(1)) and requires recordkeeping to document compliance (e.g., Condition D.2.14(c)). Direct emissions monitoring from a flare is not feasible.

Footnotes to Sierra Club Comment 9 include a number of statements and questions related to the use of flare emissions in IDEM's air quality analysis, emissions calculations for the flares and IDEM's basis for them, and the operation of permit terms related to flare emissions. Many of those statements and questions are addressed by the information provided above related to permit limits and other terms, modeling, and the nature of the flaring emissions. In addition, IDEM provides the detailed information below.

In response to Footnote 7: IDEM's responses above address emissions used in modeling. As noted above, IDEM determined that no additional PM/PM_{10}/$PM_{2.5}$ or SO_2 would be generated from combustion of the vented streams. The components of the various streams vented to the flares are described in the permit application in Section 3-5, including Table 3-3, and the accompanying emissions calculations provided in Attachments 3-5, 3-6, 3-7, and 3-17 to the application. Collectively, these provide the basis for IDEM's emissions estimates. The commenter has provided IDEM with no information, and it received none during the permitting process, indicating that the streams to be vented to any flare will contain components that would generate particulate or sulfur dioxide emissions.

In response to Footnote 8: Conditions D.2.4.(c)(9) and (10) of the permit impose limitations of 0.37 lb/MMBtu during non-venting and 3,240.16 lb/hr during venting periods, respectively, on the Front End Process Flare (EU-007). Table 6-2 of the applicant's Modeling Report identifies the modeled CO emission rate for the Front End Process Flare as 3,254.12 lb/hr, which includes the venting emissions plus the non-venting emissions. The calculation of the non-venting emissions utilized an emission factor of 0.37 lb/MMBtu as represented by page 17 of Appendix A of the TSD. A higher emission rate was evaluated than defined by the permit for the Front End Process Flare; therefore, IDEM considers the CO NAAQS evaluation conservative. The ozone and $PM_{2.5}$ secondary formation analysis included the higher NO_x and VOC emissions during flaring as documented in Appendix C and Appendix A of the TSD. For the secondary ozone formation analysis, page 10 of Appendix C states "OVR's proposed emissions would be 512.43 tons per year of NO_x and 93.81 tons per year of VOCs for a total of 606.24 tons per year of NO_x and VOCs from OVR." The same NO_x emissions are stated for the secondary $PM_{2.5}$ formation analysis on p. 13 of Appendix C. These figures are slightly higher (i.e., more conservative) than the total NO_x and VOC for the source, which can be seen in the table entitled "Limited PTE of the Entire Source (TPY)" included in the corrected emissions calculations set forth in the IDEM, OAQ Revisions section of this ATSD at IDEM Modification # 1. That table provides a breakdown of NO_x and VOC emissions by source and includes total SSM emissions occurring at the flares (individual flare emission calculations estimating venting emissions were included at TSD Appendix A pp. 21-22 of 30).

In response to Footnote 9: The commenter is correct that the flare emissions calculations overall reflect PM/PM_{10}/$PM_{2.5}$ from natural gas only. This is because no additional particulate will be generated from combustion of vented streams, as explained above. The permit requires the use of natural gas for pilot and purge gas at the flares; therefore emission limits based on AP-42 1.4-2 for natural gas combustion are appropriate for the emissions related to the combustion of pilot and purge gas. The commenter is also correct that the emissions estimates for each flare for natural gas combustion with purge gas reflected only the pilot flame capacity. This does not indicate that flaring emissions were ignored in the emissions estimates or the air quality analysis. As noted above, flaring emissions estimates were included in TSD Appendix A, pp. 21-22 of 30 and were fully addressed in the air quality analysis. However, the emissions estimates for “Natural Gas Combustion with Purge Gas” for each flare, set out at TSD Appendix A pp. 15-18, included only pilot heat input yet were intended to include the additional heat input for the combustion of natural gas as purge gas, which is used to sweep the lines prior to flaring. Corrected emissions estimates are included in the IDEM, OAQ Revisions section of this ATSD at IDEM Modification No. 1. Although combustion of purge gas happens infrequently because it is associated with the limited flaring allowed by the permit, the corrected emissions estimates, permit terms, and air quality analysis all conservatively presumed combustion of purge gas at 8,760 hours annually. Hourly emission rates for pilot and purge combustion that correspond to the corrected emissions calculations are also reflected in the compliance determination calculations in Permit Conditions D.2.11(a); D.3.8(a) and (b); and D.4.11(a). Also corresponding to the corrected emissions estimates are emissions calculations and associated explanations included in the permit application (Attachments 3-5, 3-6, 3-7, and 3-17) and following Table 3-3 on Page 3-30 of the application text. Finally, the corrected emissions estimates correspond to the total emissions levels noted in TSD Appendix C and to the specific flare emissions used in modeling as set out in the Modeling Report, as described above.

Sierra Club Comment No. 10 Particulate Emissions Control for Haul Roads

For clarity IDEM, OAQ has divided Sierra Club Comment No. 10 into subparts 10.a to 10.f

Comment 10.a: The permit and the TSD appear to conclude that as long as the facility paves all roads, conducts daily sweeping with “wet suppression as needed,” and promptly cleans up spilled materials, it will achieve a 90% reduction of potential particulate emissions. However, there is no basis in the record for that conclusion. First, there is no determination of what effects daily sweeping and wet suppression will have on these values, from which to calculate a 90% reduction. We are not aware of any basis outside the permit record here that would support a 90% reduction for paved roads. Moreover, the AP-42 emission factors that do reference a 90% control efficient do so for only ideal conditions (near continuous chemical dust suppression and application of high volumes of water with no drying between water applications).

IDEM RESPONSE TO COMMENT 10.a

As set forth in Appendix B to the Technical Support Document (TSD) BACT Analysis (Technical Support Document, Appendix B, p. 35 of 169, et seq.), the requirement for 90% control and the specific requirements for roadway dust controls derive from the Best Available Control Technology review, including recent permits for which IDEM determined that the roadway dust control requirements would provide for 90% control.

The draft permit for OVR imposes specific requirements for employing wet suppression. Condition D.5.10 requires wet suppression for roadway dust control except under limited circumstances (which are discussed in more detail in the Response 10.d). Condition D.5.10 also sets out the frequency for roadway dust control treatments and provides that compliance shall be demonstrated using records of haul road usage and control measures. In addition, necessary ambient temperature monitoring is required by Condition D.5.12 in order to determine when safety considerations allow the use of a vacuum sweeper in lieu of the wet suppression treatment. Condition D.5.13 requires that records be maintained to document the reason for any instance where treatment of a haul road is not required and performed in accordance with Condition D.5.10. As is typical for this type of condition, deviations are reportable under the quarterly deviation reporting and annual compliance certification requirements.

In addition, upon further consideration, IDEM has determined that several revisions to the permit conditions are appropriate to add clarity to the determination and compliance assurance terms for implementation of the roadway dust control measures. The revisions add additional compliance determination and associated record keeping requirements essentially the same as those that IDEM included in the most recent of the permits identified in Appendix B upon which the BACT determination was made – that permit was issued to Indiana Gasification LLC, Permit No. T147-30464-00060 ("Indiana Gasification Permit," issued June 27, 2012). In Condition D.12.5 of the Indiana Gasification Permit, IDEM provided that compliance with the BACT requirement would be demonstrated using records showing a frequency of required roadway dust control treatments for haul roads sufficient to ensure that the required 90% control efficiency is maintained for the recorded volume of truck traffic daily. The term is supported by EPA-450/2-92-004, Fugitive Dust Background Document and Technical Information Document for Best Available Control Measures, Sept. 1992 – Table 3-1, available at the following US EPA link: http://www.epa.gov/oaqps001/lead/pdfs/1992_09_fugitive_dust.pdf. IDEM has determined that this additional compliance determination requirement is appropriate for the OVR permit as well. Therefore, Conditions D.5.10(b) and D.5.13(d) have been revised in the permit accordingly:

Compliance Determination Requirements

D.5.10 Compliance Determination Requirements

To demonstrate compliance with Condition D.5.4(d), PM, PM_{10} and $PM_{2.5}$ PSD BACT:

(a) **********

(b) Compliance shall be demonstrated for each active haul road using records of haul road usage and control measures. The frequency of required roadway dust control treatments for haul roads shall be **at least** daily**, unless a treatment is not required for one of the reasons under (a) above, and the frequency shall be sufficient to achieve 90% control based on the following formula or an equivalent:**

Control Efficiency = 96 – (0.263 * (T/C))

Where: Control Efficiency = percent control efficiency
T = Daily truck trips on roadway (truck trips/calendar day)
C = Number of roadway dust control treatments per calendar day.

For the purposes of this formula, if~~. If~~ at the time of a scheduled roadway dust control treatment, the treatment is not required for one of the reasons under (a) above, such an event shall be counted as a roadway dust control treatment. **********

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

D.5.13 Record Keeping Requirements

(a) **************

(d) **To document the compliance status with Conditions D.5.4(d) and D.5.10, the Permittee shall maintain the following daily records for haul roads:**

(1) **The number of trucks on the haul road each calendar day.**

(2) **The date, approximate time, and type of each roadway dust control treatment.**

(3) If a treatment of the haul roads is not required and not performed in accordance with D.5.10, records shall be maintained documenting the reason for the lack of a treatment (i.e. ambient temperature, precipitation**, etc.**).

(e) **************

Thus, the permit addresses with specificity the frequency of applications necessary to achieve the required 90% control efficiency on a short and long term basis, the atmospheric and operational conditions under which wet suppression should be applied, and appropriate monitoring and recordkeeping to implement the requirements and assure compliance.

Further support for IDEM's approach may be found in AP-42 Section 13.2.1.4 Controls, which notes that mitigative measures may be expected to be more successful where factors are present to extend the time before the paved road returns to equilibrium, stating: "[B]ecause of the more limited scope of roads at an industrial site, mitigative measures may be used quite successfully…" For the OVR facility, which does not include the solid materials handling and hauling involved in so many of the industrial sites considered in the development of the AP-42 emissions rate estimates, this likelihood of success is even more pronounced.

Comment 10.b: From page 32 of Appendix A to the TSD, it appears that IDEM used AP-42 Table 13.2.1-1 for the emission factor, and assumed the following values for the variables as the baseline: silt loading of 2.35 g/m^2 and 119 days of rain per year. IDEM's calculation merely assumes a 90% control and applies that reduction to calculate the emissions. But, to achieve a 90% control from these baseline assumptions, the facility would have to achieve a silt loading of 0.171 g/m^2 or less— which is greater than 93% removal of silt from a low baseline-- a virtually impossible feat through street sweeping. In fact, even if the facility applied sufficient water every day to achieve the equivalent of 365 days of rain per year (P= 365 in the AP-42 emission factor used by IDEM) and removed sufficient silt loading every day to achieve a 1.0 g/m^2 maximum silt loading, the reduction would only be a little greater than 50% from the baseline IDEM assumes.

IDEM RESPONSE TO COMMENT 10.b

The offered hypothetical addresses the precipitation correction factor in the emissions calculations. As noted in the Response 10.f below, the short term emission rates used in the air quality analysis did not include a precipitation adjustment factor. Therefore, the comment applies to the calculation of annual emissions, which did. In In re Cash Creek Generation, Petition No. IV-2010-4, Order at 26-27 (EPA Adm'r, June 22, 2012) ("Cash Creek Order"), the Administrator stated "the equation for estimating particulate matter emissions from roadways that considers precipitation (i.e., natural mitigation) is appropriate for annual or other long-term applications." The comment compares results of the AP-42 emission rate calculations, using various assumptions for silt loading and precipitation, with results of the IDEM calculations applying the 90% control required by the BACT permit conditions. In each case, the comment appears to suggest a mathematical equivalency between silt removal and control from control measures that is not there. While silt removal is an important part of the various control measures, such as vacuum sweeping, prompt cleanup of spilled materials, and the washing effect realized by the use of wet suppression, control from wet suppression is also achieved by wetting of surface of dust particles to limit their mobility. As such, it is inappropriate to draw conclusions from the hypotheticals offered. Elsewhere in the permit record and these responses, IDEM has addressed the 90% control requirement and IDEM's determination that the permit terms will assure compliance.

Comment 10.c: Second, "wet suppression as needed" is an inherently vague phrase that requires additional definition (as well as monitoring and reporting) to be enforceable. That is, it begs the questions: when is wet suppression "needed"; how will that need be determined; how often; and by whom?

IDEM RESPONSE TO COMMENT 10.c

As noted in the Response 10.a, specific requirements for employing wet suppression are already included in the permit, and have been further supplemented by the additional terms IDEM has added in the revised permit. Therefore, the draft permit provisions already address the questions raised by the commenter. However, in light of the specificity in Condition D.5.10, D.5.12, D.5.13, and the quarterly deviation reporting, IDEM agrees that the phrase "as needed" may be removed. Therefore, Condition D.5.4(d)(2) has been revised in the permit accordingly:

D.5.4 PSD Best Available Control Technology Limits [326 IAC 2-2-3]

****

(d) **Paved Roadways and Parking Lots with Public Access:**

PM, PM_{10}, $PM_{2.5}$:

The PM, PM_{10}, and $PM_{2.5}$ emissions from paved haul roads shall be controlled to an overall control efficiency of 90% by employing the following work practices:

(1) Paving all plant haul roads;

(2) Daily sweeping with wet suppression ~~as needed~~; and

(3) Prompt cleanup of any spilled materials.

****

Comment 10.d: Third, IDEM's analysis makes no mention of the fact that for at least four months per year, according to the national weather service, the average temperature in Spencer County is freezing—meaning application of water would not only be difficult, but it would create an extremely unsafe ice covering on the roadways.

IDEM RESPONSE TO COMMENT 10.d

It is not correct that the average temperature in Spencer County, one of the southernmost counties in Indiana, remains at or below freezing for one third of the year. To the contrary, IDEM noted in its response to similar comments on the recent air permitting decision for the Indiana Gasification LLC facility, which is in the immediate vicinity of OVR: "A review of past temperature data for the area (Evansville Met data for 2006-2009) shows that temperatures consistently below 32°F are infrequent in this area. In fact, less than 1% of the time the temperature gets that low without either precipitation (which would provide natural mitigation) or warmer temperatures within the past 48 hours (which would allow the use of wet suppression). Accordingly, the exemption from watering at temperatures below 32°F would not result in significant periods of no wet suppression." Further, IDEM addressed the appropriateness of paved haul road wet suppression when the actual temperature is below 32°F and found that it is not deemed appropriate or necessary. See, Permit No. T147-30464-00060 (issued June 27, 2012), Addendum to the Technical Support Document, Response to Sierra Club Comment 67, pp. 102-103 of 122.

Comment 10.e: In fact, not only is water application impossible for those months, but it is almost certain that to maintain safe road conditions during the winter the facility will apply salt, sand, or both when the roads are frozen. Each such application adds at least 2 g/m^2 of silt in addition to the baseline concentration according to the AP-42 emission factor that IDEM used.

IDEM RESPONSE TO COMMENT 10.e

Wet suppression is not only possible during the winter months, but the limited permit exemption for freezing temperatures is expected to have little impact on dust control efficiency during the winter months. The temperature-based exemption from wet suppression is determined on a case-by-case basis each time the roadway dust control treatment is due (and even when the exemption applies, the draft permit still requires sweeping when temperature is the only reason for the exemption). As noted in Response 10.d, because sustained periods with freezing temperatures and no precipitation are infrequent in this area, the exemption from watering at temperatures below 32°F would not result in significant periods of no wet suppression.

Treatment for frozen roadway conditions is also expected to have little impact on roadway emissions. As IDEM noted in response to a similar comment in the Indiana Gasification permitting decision (referenced above), while AP-42 does mention that higher silt loadings can occur "in areas that experience frozen precipitation with periodic application of anti-skid material", AP-42's reference to adjustments for these factors is an analysis done using studies in Denver, Colorado and Duluth, Minnesota associated with the application of sand as a wintertime antiskid material. (http://www.epa.gov/ttnchie1/conference/ei11/dust/cowherd.pdf). In southern Indiana, which has much milder winters than Colorado or Minnesota, salt is the common wintertime road treatment. AP-42, (page 13.2.1-8) specifically states that "Ordinary rock salt and other chemical deicers add little to the silt loading, because most of the chemical dissolves during the snow/ice melting process." Nevertheless, even with sand, the increase to baseline silt content is not necessarily significant compared to OVR's assumed silt level. Below is the Denver silt loading study from the above referenced EPA report. Note that even winter silt loadings on the tested roads, treated with sand for antiskid in winter, are well below the assumed 2.35 g/m^2.

The baseline silt loading results from the Denver field study are summarized as follows:

Denver Road Site	Baseline Silt Loading (g/m^2)	
	Prewinter	Winter
Kipling	0.05 (November 6, 1996)	0.30 (March 15, 1997)
Jewel (East of Sheridan)	0.10 (November 15, 1996)	0.70 (December 23, 1996)
Speer (South of Colfax)	0.30 (November 14, 1996)	0.50 (December 22, 1996)

Comment 10.f: Lastly, if IDEM used the AP-42 emission factors (with or without the 90% control assumed but not demonstrated in the record as noted above) to determine the hourly emission rate for purposes of the air quality analysis, IDEM must revise that analysis. The emission factor IDEM used in the TSD is for calculating long term emissions—specifically as used by IDEM to calculate annual emissions. That emission factor does not account for the worst-case short terms emission rates that must be used to determine air quality impacts. Instead, the worst case short term conditions (i.e., the highest possible silt content and no rain) must be used to determine the short term emission rates to be used for air quality impact analysis. See e.g., In re Cash Creek Generation, Petition No. IV-2010-4, Order at 26-27 (EPA Adm'r, June 22, 2012).

IDEM RESPONSE TO COMMENT 10.f

In the Cash Creek Order, the Administrator addressed the use of the AP-42 equations for determining 24-hour average fugitive PM emissions, stating:

> As indicated in AP-42, the equation for estimating particulate matter emissions from roadways that considers precipitation (i.e., natural mitigation) is appropriate for annual or other long-term applications. To assess compliance with short-term ambient standards, the potential maximum short-term emission factor associated with the project's industrial road conditions should be used. Because of the possibility of having no rain during many days in an annual period, the maximum short-term particulate emission factor would not include natural mitigation. In response to this petition, KDAQ needs to ensure that Cash Creek does not include a rainfall correction factor in its 24-hour average fugitive PM emissions calculation."

Cash Creek Order, at 27. Here, Permittee and IDEM followed the approach in the Cash Creek Order. For purposes of the air quality analysis, the hourly emission rate for paved roads was determined without any adjustment for precipitation (and no alternative, higher silt-content has been identified). The September 12, 2012 permit application, which was available at the Spencer County library at all times during the public notice period, states in section 3.4.6 Haul Roads (F-100): "Emissions from the onsite haul roads are estimated using the equations provided in AP-42, Section 13.2.1 for paved roads. Annual emissions take into account the precipitation in the area, while the hourly emissions do not." See also, the underlying emissions calculations included in the permit application, Attachment 3-101 "Haul Road Fugitives (F-100) Uncontrolled Emissions".

Therefore, IDEM's calculation of short-term fugitive PM emissions was performed in a manner consistent with the Cash Creek Order.

Sierra Club Comment No. 11 **Ammonium Nitrate Unit BACT**

IDEM concludes that in-stack condensing should not be the basis for particulate matter BACT limits. See TSD Appendix B at pp. 22. This is purportedly because condensing requires "significant energy to reduce the exhaust from the reaction temperature to the final exhaust temperature." Id. But this, alone, is not a sufficient BACT collateral impacts analysis. IDEM must quantify the energy necessary for OVR to use in-stack condensers compared to other facilities that use that control option and determine that use at OVR would pose disproportionate impacts. Additionally, additional energy costs is typically and more appropriately determined through an economic cost-effectiveness analysis. In such an analysis, IDEM would have to determine and document that the energy costs of in-stack condensing at OVR would be disproportionate to other facilities using that control option. For example, since the Pryor Plant Chemical Company in Oklahoma achieves significantly lower emissions than proposed as BACT for OVR through in-stack condensing, IDEM can only reject in-stack condensing as the basis for BACT at OVR if the costs at OVR would be disproportionate to those at the Pryor plant.

When determining if a pollution control option has sufficiently adverse energy or economic impacts to justify rejection of that option and establishment of BACT on a less effective option, a permitting agency must determine that the cost-per-ton of emissions reduced is beyond "the cost borne by other sources of the same type in applying that control alternative." NSR Manual at B.44; see also Steel Dynamics, 9 E.A.D. at 202; Inter-Power, 5 E.A.D. at 135 ("In essence, if the cost of reducing emissions with the top control alternative, expressed in dollars per ton, is on the same order as the cost previously borne by other sources of the same type in applying that control alternative, the alternative should initially be considered economically achievable, and, therefore, acceptable as BACT." (quoting NSR Manual at B.44) (emphasis original)). That is, in a collateral impacts determination in a top-down BACT analysis, the impacts of the permittee's source must be compared to the cost of controlling pollution with the same control option at other facilities in the same source category. This is because the collateral impacts provision for BACT determinations "operates primarily as a safety valve whenever unusual circumstances specific to the facility make it appropriate to use less than the most effective technology." In re Columbia Gulf Transmission Co., 2 E.A.D. 824, 827 (Adm'r 1989) (emphasis added).

In short, cost-effectiveness or energy costs measure the cost differences—if any-- between facilities applying the same technology. A cost analysis that strays too far from this rule by creating and applying a default cost-per-ton threshold that applies across facilities, control technologies, and time, undermines the premise of the collateral impacts analysis. Here, IDEM's analysis of in-stack condensing failed to make any comparison between the cost of that control option at the Pryor plant and the cost at the OVR facility. Only if the cost at the OVR facility is disproportionate to the cost at the Pryor plant can the technology (and the resulting emission rate that is one half of the proposed limit for OVR) be rejected as BACT.

IDEM RESPONSE

Upon further investigation IDEM has determined the Sierra Club comment is based on incorrect data in the USEPA RACT/BACT/LAER clearinghouse which was carried over into Appendix B of IDEM's Technical Support Document. The wet scrubber/demister combination achieving 95% particulate matter control and a 0.0128 lb $PM/PM_{10}/PM_{2.5}$ per ton of ammonium nitrate produced is top level BACT for this type of operation and no energy impacts or cost analysis is necessary to support a control technology that is less effective than the top level.

A close review of three PSD permits issued to Pryor Chemical's fertilizer plant in Oklahoma shows that the Oklahoma Department of Environmental Quality [OK DEQ] rejected the use of high efficiency wet scrubber/demister systems for the Pryor plant on the grounds that installing such controls at the Pryor plant would not be cost-effective. Pryor Chemical was obtaining a PSD permit because it was restarting an older fertilizer plant that had been idle for several years, and OK DEQ determined BACT was a series of 40 year old in-stack steam condensers, which had the effect of reducing the amount of steam that escaped the system (not emissions) by 80%, with an unquantifiable reduction in particulate matter as a result.

Moreover, the Pryor Chemical PSD permits established particulate matter emission limits that are higher than the limits proposed for OVR's ammonium nitrate operations. The limits in the Pryor Chemical permit are 1.2 lb/hr for PM and PM_{10}, and 0.9 lb/hr for $PM_{2.5}$. Based on a permit limit of 23.8 ton/hr of ammonium nitrate production, these limits equate to 0.05 lb/ton of ammonium nitrate for PM and PM_{10}, and 0.038 lb/ton for $PM_{2.5}$. The proposed permit for OVR establishes an emission limit of 0.0128 lb of $PM/PM_{10}/PM_{2.5}$ per ton of ammonium nitrate produced – limits that are one third the limits on the Pryor Chemical plant.

The Pryor Chemical PSD permits can be reviewed from the OK DEQ web site at the following URLs:

- Original PSD permit to restart the idle plant issued February 19, 2009 - http://www.deq.state.ok.us/aqdnew/permitting/permissue/2008100-cp.pdf
- Modified PSD permit issued April 30, 2012 - http://www.deq.state.ok.us/aqdnew/permitting/permissue/2008100-cp2.pdf
- Modified PSD permit issued July 16, 2012 – http://www.deq.state.ok.us/aqdnew/permitting/permissue/2008100-cp1.pdf

Because the proposed emission control technology and emission limits for OVR represent the top level BACT for an ammonium nitrate plant, no further analysis of other technologies is required. Therefore the top level BACT proposed by OVR was appropriately selected as BACT.

Sierra Club Comment No. 12 Ultra-Low NO_x Burners in the Primary Reformer

In its TSD, IDEM notes that the Garyville Refinery achieves a lower emission rate than the proposed NO_x BACT limit for OVR's Primary Reformer with ultra-low NO_x burners (ULNB). See TSD Appendix B at 42. While IDEM concludes that the production process at Garyville results in cleaner fuel stream. However, even if this is true and OVR cannot achieve the same emissions through only ULNB, the performance of the ULNB should have been considered in addition to the SCR. That is, IDEM should have determined whether ULNB and an SCR at OVR would achieve a lower emission rate than the SCR alone. SCRs generally are capable of 90% or better control of NO_x at various inlet concentrations. Absent a demonstration to the contrary, the SCR should be able to control to 90% reduction from the lower inlet concentration achievable through ULNB and thereby achieve a lower emission rate.

Moreover, it appears that the Iowa Fertilizer Company (IA-0105) achieves 9 ppm_{vd} while IDEM proposes 10 ppm_{vd} (or the equivalent) for the OVR BACT limit. At a minimum, IDEM should require no less stringent a limit than 9 ppm_{vd}.

IDEM RESPONSE

IDEM disagrees that the Iowa Fertilizer Company NO_x BACT limit for the reformer is more stringent than the proposed NO_x BACT limit on OVR's reformer. The comment incorrectly states the NO_x emission limit for the reformer at the Iowa Fertilizer Company is more stringent than the NO_x emission limit proposed for the reformer at OVR. Condition D.2.4(a)(5) proposes a NO_x emission limit of 9 ppm_{vd} for OVR's reformer, based on a thirty-day rolling average, which is equivalent to the numerical limit and averaging period established in the Iowa Fertilizer Company BACT requirements for its reformer.

Although the commenter appears to have been based solely on this factual error, the correction of which fully addresses the comment, IDEM also notes that it disagrees that it should have considered a combination of ultra-low NO_x burners (ULNB) and selective catalytic reduction (SCR) as NO_x BACT for the reformer on the grounds the Garyville refinery achieves a lower emission rate for its reformer. First, the 9 ppm limit proposed for OVR represents the lowest NO_x emission limit for a steam methane reformer at an ammonia fertilizer plant. The permit requires OVR to use SCR to control NO_x emissions to 9 ppm, which is the same determination recently made by the state of Iowa in a BACT determination for the reformer at the proposed Iowa Fertilizer Company. SCR achieving greater than 90% NO_x control efficiency is considered top BACT for NO_x controls on an ammonia plant steam methane reformer. The commenter has not identified a methane reformer at an ammonia plant that utilizes both ULNB and SCR as BACT. IDEM is not aware of any other steam methane reformers that utilize both ULNB and SCR.

IDEM based its decision to require OVR to achieve its 9 ppm NO_x limit on the use of SCR because requiring the use of ULNB in a steam methane reformer would have required a reconfiguration of the burners to a design that is not typically used in ammonia plant reformers or utilization of a ULNB that does not achieve the same emission rate as the Garyville refinery. Steam methane reformers at ammonia plants utilize downward facing burners to achieve the desired heat flows in the reformer. The reformer at the Garyville refinery uses naphtha as the feedstock, which requires a different type of burner – one that is located at the bottom of the reformer with an upward direction. The most highly effective ULNB that achieve emission rates such as Garyville's hydrogen reformer are upward facing burners that are not used in applications like an ammonia plant reformer because of the heat flow and transfer differences. OVR was unable to identify a ULNB burner vendor who would guarantee the 0.0125 lb/MMBtu emission rate achieved by Garyville.

The emission limitations for OVR and the Garyville refinery are barely distinguishable. The 9 ppm limit for the OVR steam reformer is equivalent to an emission rate of 0.0126 lb/MMBtu. This is nearly identical to the 0.0125 lb/MMBtu limit for the Garyville refinery. If OVR were able to achieve the same emission rate per MMBtu as the Garyville refinery, the difference in NO_x emissions would be less than one-half ton per year.

http://www.deq.louisiana.gov/apps/pubNotice/pdf/Permit%20PSD-LA-719,%20PER20060013.pdf

Sierra Club Comment No. 13 **LDAR for Greenhouse Gases (GHGs)**

In its TSD, IDEM concludes that an LDAR program for GHG controls is not cost effective. TSD Appendix B at p. 162. There is no discussion of, nor a record to support, this conclusion in the TSD. In fact, since numerous other facilities use LDAR for GHG control (see TSD Appendix B p. 162, Table), it can only be rejected for OVR if the cost would be disproportionate at OVR compared to the facilities that implement LDAR due to site-specific reasons at OVR.

IDEM RESPONSE

OVR submitted a cost analysis to IDEM for conducting a GHG LDAR program at its facility. The analysis included an estimate of the cost-effectiveness of performing LDAR on the potentially leaking components containing methane, carbon dioxide, and nitrous oxide. This information was provided to IDEM before the draft permit went out for public comment on February 28, and was available for the public to review in the documents at the Spencer County Public Library during the entire comment period from February 28, 2013 through May 20, 2013.

IDEM determined that an LDAR program for GHGs was not cost-effective based on the OVR information. OVR estimated the cost of implementing an LDAR program for GHGs based only on the labor cost of implementing a program and did not include the capital cost of purchasing and maintaining the LDAR instruments. Traditional LDAR monitoring equipment cannot be used for an LDAR program for GHGs because the traditional LDAR system monitors only organic hydrocarbons and does not detect GHGs such as CO_2 or N_2O. The exclusion of the cost of the additional monitoring system leads to a lower cost estimate and thus would be a conservative assumption because it increases the likelihood an LDAR program would be considered cost effective for GHGs.

Depending on the greenhouse gas and the type of components that would be monitored at OVR, the cost-effectiveness for GHG pollutants ranged from \$203/ton of CO_2e to as high as \$433,000/ton of CO_2e. Overall, a GHG LDAR program would cost \$57,755 per year to implement, while reducing total pollutant emissions by 31 ton/yr and reducing CO_2e by 116 ton/yr. This results in an overall cost-effectiveness value of \$1,862/ton of pollutant emitted and \$498/ton of CO_2e.

IDEM determined that the cost of implementing a GHG LDAR program at OVR greatly exceeds the cost effectiveness values that should be expected for GHG emissions reductions. IDEM has determined other potential GHG controls are not cost effective at values less than the \$498/ton it would cost OVR to implement GHG LDAR.

For example, in the PSD permit for the Indiana Gasification, LLC plant (permit # 147-30464-00060), IDEM determined an LDAR program for CO_2 process streams was not cost-effective at as low as $298 ton/year (Indiana Gasification Technical Support Document, Appendix B, Page 175). In the Indiana Gasification permit, IDEM did conclude an LDAR program for methane in natural gas and SNG piping components was cost-effective at $5 per ton of CO_2e. For Ohio Valley Resources, however, an LDAR program for methane would involve nearly 100 times as many components to monitor and less than 1/3 of the emissions – an overall cost effectiveness of $203 per ton of CO_2e.

Because the 116 tons of CO_2e reduced each year by a GHG LDAR program is less than 1/10,000 of the total GHG emissions from the facility, there would be minimal environmental benefit to requiring the LDAR program for GHGs emitted by leaking components. 116 ton/yr of CO_2e is significantly lower than the margin of calculation error for GHG emissions from the entire site. Based on this information, which was available as part of the public record from the beginning of the public comment period, IDEM concluded an LDAR program for GHG emissions from OVR was not cost-effective.

Cost of implementing a GHG LDAR program at Ohio Valley Resources, LLC

Process Streams	**Pollutant**	**Number of Components**	**Uncontrolled emissions (Ton/yr)**	**Uncontrolled Emissions (Tons/yr CO_2e)**	**Cost to monitor**	**LDAR Cost-Effectiveness ($/ton)**	**LDAR Cost-Effectiveness ($/ton CO_2e)**
Reformer/ ammonia plant	CO_2	848	23	23	$17,655	$768	$768
Reformer/ ammonia plant	CH_4	848	4	87	$17,655	$4,306	$203
UAN Plant Area 1	CO_2	662	4	4	$13,783	$3,446	$3,446
UAN Plant Area 2	CO_2	208	0.01	0.01	$4,331	$433,056	$433,056
UAN Plant Area 2	N_2O	208	0.006	2	$4,331	$721,760	$2,165
Total	**All GHGs**	**1718**	**31.016**	**116.01**	**$57,755**	**$1,862**	**$498**

Sierra Club Comment No. 14 **Cost Effectiveness of Carbon Capture and Sequester (CCS)**

In the TSD, IDEM contends that carbon capture and sequestration is not cost effective and not available to OVR because of the distance from a suitable sequestration site and the cost of building a pipeline. TSD Appendix B at 134-37, 158. However, this appears to be based on the conclusion that a cost of $76.16/ton of CO_2 sequestered is not cost effective. IDEM provides no analysis and no basis for a finding that this is disproportionate to other facilities proposing to sequester their GHG emissions. The U.S. EPA has proposed a New Source Performance Standard for electric generating units based on findings that CCS will be available and cost effective in the near future. IDEM has not shown why the cost of sequestering GHGs from the OVR facility would be disproportionate to the cost to electric generating units.

> Furthermore, IDEM provides the cost of a pipeline to a sequestration site, but then divides the cost by only the reduction achievable by sequestering the GHGs from the CO_2 purification process. See TSD Appendix B at 135. But because the same pipeline would allow sequestration from the other GHG sources, including the boilers and reformer, the cost per ton is actually lower than IDEM figured.

IDEM RESPONSE

The commenter is incorrect in its statement that "IDEM contends that carbon capture and sequestration is not cost effective and not available…" In Appendix B of the Technical Support Document, IDEM identified carbon capture and sequestration (CCS) as an available emission control technology for CO_2 in Step 1 of the 5 step BACT analysis process. CCS, however, was eliminated from consideration as BACT solely on the basis that IDEM determined CCS was technically infeasible for OVR using Step 2 of the BACT review process -- cost effectiveness for CCS was not addressed at all. The economic analysis to which the commenter appears to be referring was provided in the Step 2 analysis of Sale of Captured CO_2, as addressed below.

In EPA's 1990 NSR Workshop Manual, Step 2 is described as determining the technical feasibility of the control options identified in Step 1 with respect to the source-specific (or unit-specific) factors. A determination that a control option is technically infeasible must be based on physical, chemical, and engineering principles that demonstrate the technical difficulties of using the control option. NSR Workshop Manual at B.7.

In addition, EPA discusses GHG control technical feasibility under the five step BACT review process in its PSD and Title V Permitting Guidance for Greenhouse Gases, EPA-457/B-11-001, March 2011. This guidance directs states to "consider all characteristics of a technology option, including its development stage, commercial applications, scope of installations, and performance data." Id at 34.

Moreover, in the GHG permitting guidance EPA states:

> Furthermore, CCS may be eliminated from a BACT analysis in Step 2 if the three components working together are deemed technically infeasible for the proposed source, taking into account the integration of the CCS components with the base facility and site-specific considerations (e.g., space for CO_2 capture equipment at an existing facility, right-of-ways to build a pipeline or access to an existing pipeline, access to suitable geologic reservoirs for sequestration, or other storage options).
>
> While CCS is a promising technology, EPA does not believe that at this time CCS will be a technically feasible BACT option in certain cases. As noted above, to establish that an option is technically infeasible, the permitting record should show that an available control option has neither been demonstrated in practice or is available and applicable to the source type under review. EPA recognizes the significant logistical hurdles that the installation and operation of a CCS system presents and that sets it apart from other add-on controls that are typically used to reduce emissions of other regulated pollutants and already have an existing reasonably accessible infrastructure in place to address waste disposal and other offsite needs. Logistical hurdles for CCS may include obtaining contracts for offsite land acquisition (including the availability of land), the need for funding (including, for example, government subsidies), timing of available transportation infrastructure, and developing a site for secure long term storage. Not every source has the resources to overcome the offsite logistical barriers necessary to apply CCS technology to its operations, and smaller

> sources will likely be more constrained in this regard. Based on these considerations, a permitting authority may conclude that CCS is not applicable to a particular source, and consequently not technically feasible, even if the type of equipment needed to accomplish the compression, capture, and storage of GHGs are determined to be generally available from commercial vendors.

GHG Permitting Guidance at 36.

In Step 2 of the BACT review process for OVR, IDEM determined CCS was technically infeasible for the CO_2 Purification Vent, the steam methane reformer, the boilers, and the other CO_2 emission sources at the proposed site based on the following factors, which are all expressed in great detail in Appendix B of the TSD:

- The unavailability of nearby long-term storage reservoirs for sequestering the CO_2;
- The lack of an available means of transporting CO_2 to a distant enhanced oil recovery operation or sequestration site.
- The unavailability of carbon capture techniques for smaller volume and dilute CO_2 exhausts for industrial applications (eg. other than power plants). See, EPA GHG Permitting Guidance, p. 32, footnote 87, and p. 36.
- The lack of federal funding to support an experimental and high cost program; and

TSD Appendix B at 138-169. Pages 138-139, 141, and 162 discuss detail the basis for rejecting CCS as technically infeasible. CCS as technically infeasible for dilute industrial CO_2 streams is discussed on pages 141, 144, 147, 149, 152, 157, and 159.

The element of a technology's availability for a source-specific application falls within the analytical approach in Step 2 of the BACT analysis. Since IDEM determined CCS was not practically available to OVR, IDEM rightfully concluded it was not technically feasible for OVR. IDEM's rejection was based on the very factors EPA cites in its guidance: lack of nearby sites for sequestration, difficulty in capturing and concentrating dilute CO_2 streams, logistical hurdles in obtaining land for a 400 mile pipeline, and lack of federal funding support,

In the Step 2 analysis of Sale of Captured CO_2, IDEM also determined that the lack of availability of transportation infrastructure rendered the sale of CO_2 infeasible. IDEM did include in the permit documentation the applicant’s economic analysis for constructing and operating a 400 mile pipeline as further evidence of the lack of availability of a technically feasible solution and to demonstrate the logistical issues associated with requiring sale of CO_2 as BACT for the OVR plant. This exercise was not used in the manner where cost effectiveness is used in Step 4 of the BACT analysis to distinguish a technology (or no emission controls) from an available and technically feasible control that ranks higher under Step 3 of the BACT analysis. The cost-effective analysis provided additional context for the infeasibility of the technology for OVR's facility.

Because IDEM rejected CCS and the sale of CO_2 as a control option in Step 2 of the BACT analysis, not in Step 4 of the analysis, IDEM was not required to demonstrate that CCS or the sale of CO_2 was not cost-effective or the cost to OVR was disproportionate to other facilities proposing to sequester GHG emissions. The commenter's claims that IDEM failed to provide an analysis or basis that the cost was disproportionate for OVR is inapplicable because CCS was not rejected on the basis of cost-effectiveness. In addition, the commenter's claim that IDEM incorrectly calculated the cost-effectiveness by omitting additional quantities of CO_2 from OVR that could be sequestered is also incorrect for the same reason: IDEM did not reject CCS on the basis of disproportionate cost-effectiveness. It should be noted that, if a Step 4 cost effectiveness evaluation had been necessary, the additional cost-effectiveness benefits that the commenter suggests could be possible because of the additional CO_2 that could be captured and sequestered is without merit because IDEM (and EPA) found that CO_2 capture technologies for dilute streams from industrial applications other than power plants is not feasible.

Sierra Club Comment No. 15 **Community Safety**

As IDEM is aware, a fertilizer plant very similar to the one being proposed by OVR exploded in West, Texas. Fourteen people were killed and injured as a result. The cause of that explosion is still unknown. What is known, however, is that until the cause is known and all necessary design changes made, IDEM cannot ensure the community that the OVR facility will be safe. The “qualitative” additional impacts analysis by IDEM in the TSD makes no mention of the potential for a catastrophic explosion, or of less catastrophic but also dangerous releases and fires at a fertilizer plant. Especially after the tragedy in Texas, omission of those impacts cannot be justified. IDEM must consider them in the permit record and, until IDEM can guarantee the safety of the community, it should not issue the permit.

IDEM RESPONSE

IDEM, OAQ understands how important safety concerns are to the local community. However, IDEM, OAQ is not authorized to consider fire and explosion safety concerns in issuing PSD/Part 70 Operating Permits. Please contact your local officials for assistance.

In regards to dangerous releases of toxic materials, Permit Condition C.13 – Risk Management Plan is targeted towards the prevention of accidental releases by implementation of 40 CFR 68 (Chemical Accident Prevention Provisions). OVR is subject to the requirements of 40 CFR 68 and must prepare a risk management plan for the storage of anhydrous ammonia. This risk management plan will include the following:

1) The accidental release prevention and emergency response policies at OVR;
2) A list of regulated substances handled;
3) The general accidental release prevention program and chemical-specific prevention steps;
4) A five year accident history;
5) The emergency response program; and
6) Planned changes to improve safety.

Finally, the Office of the State Chemist, Fertilizer Section regulates the storage and distribution of fertilizer. You may contact the State Chemist at (765) 494-1492 for further information. The internet address is http://www.isco.purdue.edu/fertilizer/index_fert.htm.

No revisions to the draft permit are required as a result of this comment.

VALLEY WATCH COMMENTS

Valley Watch Comment No. 1 General Comments

On May 20, 2013, John Blair submitted comments on behalf of Valley Watch, Inc. The comments indicated the future of the Ohio Valley Resource fertilizer plant and the Indiana Gasification facility are tied together. If the Indiana Gasification facility is not constructed, the Ohio Valley Resource facility will also not be constructed. Mr. Blair went on to call Rockport, Indiana one of the worst toxic polluted communities in the world and raised environmental justice concerns due to the amount of emissions from the AEP Rockport plant and AK Steel. Mr. Blair claimed that the occurrence of cancer, heart attack, stroke, asthma, multiple sclerosis and other neurological conditions are rampant in the Spencer County, Indiana region. Mr. Blair stated that there are only two other fertilizer plants in the United States of this size and they have problems with fugitive ammonia leaks. He indicated this plant will also have fugitive ammonia leaks. Mr. Blair expressed his concern over the threat of explosion and other safety issues with a fertilizer plant located so closely to other facilities with storing explosive materials. Mr. Blair expressed concerns over the financial ability of the applicant to construct and operate the facility.

Finally, Mr. Blair called for a moratorium on issuing fertilizer plant permits and authorizing their construction until such time as specific safety assessments can be done by either an independent party qualified to do such an assignment or the State Fire Marshal.

IDEM RESPONSE

The Indiana Gasification project and the Ohio Valley Resources project are separate projects operating under different business plans. Neither project requires the other to be constructed to be economically viable. IDEM, OAQ has evaluated them as separate sources.

In regards to Rockport, Indiana being one of the worst toxic polluted communities in the world, IDEM, OAQ performed air dispersion modeling and a screening analysis for air toxics in Spencer County, Indiana. IDEM, OAQ performed these analyses to ensure the proposed facility did not pose a threat to public health or the environment. The analysis revealed the proposed facility will not significantly affect the ambient air quality in Spencer County, Indiana and a significant increase in asthma or cancer is not expected. In fact, Spencer County is one of the best in the state for low chronic illnesses and the National Air Toxics Assessment (NATA) showed air toxics emissions in Spencer County are below state and national averages. See IDEM RESPONSE to Public Comment No. 2 below for a more detailed description.

In regards to environmental justice, IDEM, OAQ strives to ensure all members of the public have equal access to public information pertinent to agency policies and procedures, have adequate notice regarding all agency program information and decision making processes, and have the opportunity to provide public comments and pertinent information to agency program staff. IDEM’s Environmental Justice Policy can be viewed at http:/www.in.gov/idem/files/A-008-OEA-08-P-R2.pdf. IDEM’s policy requires IDEM to ensure all members of the public have: (1) equal access to public information pertinent to Agency policies and procedures; (2) adequate notice regarding all Agency program information and decision-making processes; and (3) the opportunity to provide public comments and pertinent information to Agency program staff.

Environmental justice is the fair treatment and meaningful involvement of all people regardless of race, color, national origin, geographic location or income with respect to the development, implementation, and enforcement of environmental laws. Regulations, and policies. In 1994, President Clinton issued Executive Order (EO) 12898, “Federal Action to Address Environmental Justice in Minority Populations and Low-Income Populations.” EO 12898 directed all federal agencies to participate in a government-wide effort to address environmental justice issues. The U.S. EPA under Administrator Jackson made environmental justice an agency priority in January 2010 and with input from the White House and other federal agencies, federally recognized tribes, community leaders, local residents, and local officials formulated Plan EJ 2014. Plan EJ 2014 identifies the environmental justice priorities and objectives of the U.S. EPA and includes three major sections: cross-agency focus areas, tools development areas and program initiatives. Plan EJ 2014 is not a rule or regulation. It is a strategy to help integrate environmental justice into every day EPA activities. Further information on Plan EJ 2014 is available from the U.S. EPA at: http://www.epa.gov/environmentaljustice/plan/ej/

Based on Plan EJ2014, U.S. EPA Region 5 established a regional implementation plan to promote meaningful engagement of overburdened communities in permitting activities. U.S. EPA Region 5 encourages enhanced outreach activities for new permits, or the renewal of existing permits that raise environmental concerns. This outreach includes:

1) Sharing a plain-language description of the proposed project with community members.

2) Applying EPA guidance on environmental justice, such as “Promising Practices for Permit Applications Seeking EPA-Issued Permits: Ways to Engage Communities at the Fence-Line.”

3) Holding information meetings.

4) Ensuring public notices reach the impacted community and are written in plain language.

5) Ensuring public documents are accessible to the community.

6) Using communication techniques the community values.

7) Extending the public comment period, when appropriate.

8) Responding to community questions and concerns, especially those of a technical nature.

IDEM, OAQ followed its environmental justice policy and U.S. EPA recommendations throughout the permitting process. IDEM, OAQ published a notice of this permitting action in the local newspaper. IDEM, OAQ posted a copy of the draft permit on its website and provided a copy to the local library. IDEM, OAQ held a public meeting and public hearing in the Town of Rockport, Indiana in an attempt to provide access to permitting information to all residents of the local area. The meeting was well attended and the public provided input on the project.

Finally, the proposed facility is not located in an “area of concern” for environmental justice issues. Using 2000 U.S. census data, IDEM, OAQ created a map to identify potential areas of concern based on racial composition and income. Rockport, Indiana and the downwind areas are not among them. This project will not have a disproportionately high and adverse environmental effect on minority and/or low income populations.

IDEM, OAQ may not require that a similar plant be constructed in another state before issuing a construction and operation permit. IDEM, OAQ measures the ability of the facility to be constructed and operated in accordance with state and federal regulations. If the applicant meets all state and federal regulations, IDEM, OAQ is legally required to issue the permit. Odors related to ammonia are not regulated by IDEM, OAQ. Odors are covered under local nuisance ordinances. Please contact your local officials.

Please see IDEM RESPONSE to Sierra Club Comment No. 15 for a full discussion of safety issues. The application submitted to IDEM, OAQ, Permits Branch for review indicates a 75% to 83% ammonium nitrate solution is created as a chemical intermediate in the production of urea ammonium nitrate. The ammonium nitrate intermediate product is in liquid form and does not present an explosion risk. Granular ammonium nitrate, the form of ammonium nitrate with explosive characteristics, is not produced at this facility. As with noise, odor and safety, IDEM, OAQ is not authorized to assess the ability of the applicant to succeed as a viable business in making permitting decisions. If an applicant submits a complete application illustrating their ability to construct and operate in accordance with state and federal regulations, IDEM, OAQ is legally required to issue the permit.

APPLICANT COMMENTS

Applicant Comment No. 1 Changes, Clarifications and Corrections
Please change CEM to CEMS in Conditions A.2(c)(1) and D.4(c)(1).

IDEM RESPONSE
IDEM, OAQ has revised original Conditions A.2(c)(1) and D.4(c)(1) as requested. Revisions to the permit conditions is shown below:

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

****

(c) **********

(1) Two (2) nitric acid units, identified as EU-001A and EU-001B, with a maximum throughput capacity of 630 ton/day of 100% nitric acid each, approved for construction in 2013, equipped with selective catalytic reduction for NO_x control, catalytic decomposition for N_2O control, and a NO_x CEM**S**, and exhausting to the ambient atmosphere through tailgas stacks EP-001A and EP-001B. [40 CFR 60, Subpart Ga] **********

SECTION D.4 EMISSIONS UNIT OPERATION CONDITIONS

Emissions Unit Description:

(c) **********

(1) Two (2) nitric acid units, identified as EU-001A and EU-001B, with a maximum throughput capacity of 630 ton/day of 100% nitric acid each, approved for construction in 2013, equipped with selective catalytic reduction for NO_x control, catalytic decomposition for N_2O control, and a NO_x CEM**S**, and exhausting to the ambient atmosphere through tailgas stacks EP-001A and EP-001B. [40 CFR 60, Subpart Ga]

****

Applicant Comment No. 2 **Parametric Monitoring for Scrubber**

There is a typographical error in original Condition D.4(c)(1). The condition should reference the particulate demister pressure drop and not the scrubbing liquid flow rate.

IDEM RESPONSE

IDEM, OAQ has revised Condition D.4(c)(1) to indicate a pressure drop reading is required and not a liquid flow rate. Revisions to Condition D.4(c)(1) are shown below:

D.4.12 Parametric Monitoring

****

The instruments used for determining the **particulate demister pressure drop**~~scrubbing liquid flow rate~~ shall comply with Section C – Instrument Specifications, of this permit, shall be subject to approval by IDEM, OAQ, and shall be calibrated or replaced at least once every six (6) months.

Applicant Comment No. 3 **Changes, Clarifications and Corrections**

Please revise the description of the firewater pump to match the condition title. The firewater pump in Conditions D.5.4(b)(5) and (6) should read “diesel-fired emergency firewater pump” and not diesel-fired fire pump.

IDEM RESPONSE

IDEM, OAQ does not object to the emission unit description in these conditions. Revisions are shown below:

D.5.4 PSD Best Available Control Technology Limits [326 IAC 2-2-3]

****

(b) **Diesel-Fired Emergency Firewater Pump (EU-016):**

****

CO:

(5) CO emissions from the diesel-fired **emergency** fire**water** pump**********.

VOC:

(6) VOC emissions from the diesel-fired **emergency** fire**water** pump**********

Applicant Comment No. 4 **Urea Ammonium Nitrate Plants or Units**

The OVR facility includes two urea ammonium nitrate (UAN) plants and each UAN Plant consists of urea, nitric acid, and an ammonium nitrate unit. Throughout the permit, the ammonium nitrate unit is often referred to as an ammonium nitrate “plant.” OVR is concerned that using the term “plant” may confuse the reader and lead them to believe the facility will manufacture ammonium nitrate as a final product. Ammonium nitrate is generated at the site as an intermediate step in the production of UAN. Please change the following references to an “ammonium nitrate plant” to say “ammonium nitrate unit” instead: Section A.2(c)(3), the facility description box in Section D.4, Conditions D.4.4, D.4.4(b) and (b)(1) to (b)(4), D.4.5(b), D.4.7, D.4.8, D.4.12(a), D.4.13(b) and the quarterly report on page 92 of the permit. In addition, Conditions D.4.7 and D.4.8 should be corrected to state “ammonium” and not ammonia.

IDEM RESPONSE

The ammonium nitrate units produce a 75% to 83% ammonium nitrate solution used as a chemical intermediate. This solution will not be used to produce granular ammonium nitrate. IDEM does not object to these changes in emission unit descriptions. Revisions are shown below:

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

(c) **********

(3) Two (2) ammonium nitrate (AN) **units**~~plants~~, identified **********

SECTION D.4 EMISSIONS UNIT OPERATION CONDITIONS

Emissions Unit Description:

(c) **********

(3) Two (2) ammonium nitrate (AN) **units**~~plants~~, identified as EU-002A and EU-002B, approved for construction in 2013, with a maximum throughput capacity of 798 ton/day of ammonium nitrate each, utilizing a scrubber with particulate demister for particulate matter control, and exhausting to the ambient atmosphere through stacks EP-002A and EP-002B. [40 CFR 60, Subpart VVa]

****

D.4.4 PSD Best Available Control Technology Limits [326 IAC 2-2-3]

Pursuant to PSD/Operating Permit T 147-32322-00062 and 326 IAC 2-2 (Prevention of Significant Deterioration (PSD)), the best available control technology (BACT) for the Nitric Acid Units (EU-001A and EU-001B), the Ammonium Nitrate **Units**~~Plants~~ **********

(a) **Nitric Acid Units (EU-001A and EU-001B):**

Common NO_x and GHG Conditions:

(1) The combined nitric acid production from Nitric Acid **Units**~~Plants~~ (EU-001A and EU-001B) shall not exceed 459,900 tons of 100% nitric acid per twelve consecutive month period with compliance determined at the end of each month.

NO_x:

(2) NO_x emissions from the Nitric Acid **Units**~~Plants~~ (EU-001A and EU-001B) shall not exceed 0.5 lb NO_x per ton acid, based on a thirty day average, each, using Selective Catalytic Reduction (SCR). **********

(b) **Ammonium Nitrate Units~~Plants~~ (EU-002A and EU-002B):**

Common PM, PM_{10}, $PM_{2.5}$ and GHG Conditions

(1) The maximum combined production of urea ammonium nitrate (UAN) for the Ammonium Nitrate **Units**~~Plants~~ **********

PM, PM$_{10}$, PM$_{2.5}$:

(2) The PM, PM$_{10}$ and PM$_{2.5}$ emissions from the operation of each Ammonium Nitrate **Units**~~Plants~~ **********

GHG:

(3) CO_2 emissions from the Ammonium Nitrate **Units**~~Plants~~ **********

(4) CO_2 emissions from each of the Ammonium Nitrate **Units**~~Plants~~ **********

D.4.5 General Provisions Relating to New Source Performance Standards (NSPS) [40 CFR 60, Subpart A] [326 IAC 12]

(a) **********

(b) The provisions of 40 CFR 60, Subpart A – General Provisions, which are incorporated by reference in 326 IAC 12-1-1, apply to the ammonia nitrate **units**~~plants~~, **********

D.4.7 New Source Performance Standards (NSPS) [40 CFR 60, Subpart VVa] [326 IAC 12]

The Permittee shall comply with the following provisions of 40 CFR 60, Subpart VVa (Standards of Performance for Equipment Leaks of VOC in the Synthetic Organic Chemicals Manufacturing Industry for Which Construction, Reconstruction, or Modification Commenced After November 7, 2006 (included as Attachment C of this permit) which are incorporated by reference as 326 IAC 12, for the ammoni**um**~~a~~ nitrate **units**~~plants~~, **********

D.4.8 Preventive Maintenance Plan [326 IAC 2-7-5(12)]

A Preventive Maintenance Plan is required for the nitric acid units, identified as EU-001A and EU-001B, the ammoni**um**~~a~~ nitrate **units**~~plants~~, **********

D.4.12 Parametric Monitoring

(a) The Permittee shall record the pressure drop across the particulate demisters following the scrubbers used in conjunction with the ammonium nitrate (AN) **units**~~plants~~, **********

D.4.13 Record Keeping Requirements

(a) In order to document the compliance status with Condition D.4.4(a)(1), the Permittee shall maintain monthly records of the combined 100% nitric acid production from Nitric Acid **Units**~~Plants~~ (EU-001A and EU-001B).

(b) In order to document the compliance status with Condition D.4.4(b)(1), the Permittee shall maintain monthly records of the combined urea ammonium nitrate (UAN) production from Ammonium Nitrate **Units**~~Plant~~, **********

Page 92 – Reporting Form

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

Part 70 Quarterly Report – UAN Production (EU-002A and B)

Source Name:	Ohio Valley Resources, LLC
Source Address:	300-400 East CR 350 North, Rockport, Indiana 47635
Part 70 Permit No.:	T 147-32322-00062
Facility:	Ammonium Nitrate **Units**~~Plants~~ (EU-002A and EU-002B)
Parameter:	Combined UAN Production
Limit:	1,314,000 tons of UAN per twelve consecutive month period.

****

Applicant Comment No. 5 **Changes, Clarifications and Corrections**

Please change the stack heights of the UAN day tank (EP-020C) to 20 feet and the Nitric Acid Tank (EP-022A) to 30 feet.

IDEM RESPONSE

IDEM, OAQ uses the technical support document (TSD) for historical purposes. Any revisions to the permit documents are documented in this addendum to the technical support document (ATSD). This maintains the TSD in its original condition reflecting the document on public display and allows revisions to be documented. No revisions to the TSD will be made as a result of this comment. No changes to the draft permit are required as a result of this comment.

Applicant Comment No. 6 **Changes, Clarifications and Corrections**

The summary of monitoring requirements table on page 40 of the technical support document (TSD) shows the cooling towers twice, with different total dissolved solids (TDS) sampling frequencies. In addition, the requirements for paved roads and parking lots is unclear. As shown, it looks like the ambient temperature must be monitored whenever the temperature is below 32 degrees Fahrenheit. However, it is impossible to know if the temperature is below this threshold unless the temperature is already being monitored.

IDEM RESPONSE

The intent of the table was to indicate the TDS content of the cooling water is to be monitored on a monthly basis. Permit Condition D.5.11 correctly indicates monthly monitoring is required. Condition D.5.12 requires temperature monitoring to show compliance with Condition D.5.12 and Condition D.5.13(e) requires a record of the reason for the lack of a suppression treatment. No changes to the draft permit are required as a result of this comment. IDEM, OAQ uses the technical support document (TSD) for historical purposes. Any revisions to the permit documents are documented in this addendum to the technical support document (ATSD). This maintains the TSD in its original condition reflecting the document on public display and allows revisions to be documented. No revisions to the TSD will be made as a result of this comment.

Applicant Comment No. 7 **Changes, Clarifications and Corrections**

On page 136 of the BACT in the RBLC review, it should clearly state that the emergency firewater engine's VOC emissions are 0.04 tons/year when it operates 500 hr/yr. If it operates for the 200 hours allowed in the permit, then the VOC emissions will be 0.01 ton/yr.

IDEM RESPONSE

IDEM, OAQ does not object to the clarification. The RBLC Review section on page 136 of the BACT analysis (TSD – Appendix B) has been updated as shown below:

RBLC Review
The potential to emit VOC of the diesel-fired emergency fire pump is 0.04 TPY**, when operating at 500 hours per year**. This unit will be limited by permit to operate no more than 200 hours per year, with a PTE of 0.01 TPY. **********

Applicant Comment No. 8 **Changes, Clarifications and Corrections**
The values in the Cancer Risk Column of Table 12 of the AQIA do not equal 1.14E-06 as the table indicates. Either the benzene value should be changed to 6.6e-07 or the total should be changed to 1.8E-06. If the total of the incorrect value, 1.14 needs to be changed to 1.8 in two places in the paragraph following Table 12.

IDEM RESPONSE
IDEM, OAQ concurs with the commenter's analysis. Table 12 of the Air Quality Impact Analysis has been updated as shown below:

TABLE 12
Hazardous Air Pollutant Modeling Results

Compound	CAS Number	Emission Rate (tons/ year)	Annual Concentration (μg/m3)	Cancer URF, (μg/m3)-1	Cancer Risk	Non-Cancer Chronic RfC, μg/m3	Hazard Quotient
**********	**********	**********	**********	**********	**********	**********	**********
Benzene	71432	2.63E-02	8.56E-02	7.80E-06	~~1.33E-06~~ **6.68E-07**	30	5.70E-03
**********	**********	**********	**********	**********	**********	**********	**********

PUBLIC COMMENTS

Public Comment No. 1: **Request to Extend the Public Comment Period**
IDEM, OAQ received several requests to extend the public comment period by an additional 30 to 45 days. These same parties requested a public hearing in the Rockport, Indiana area.

IDEM RESPONSE
IDEM, OAQ conducted a public meeting and public hearing on Wednesday, May 15, 2013 at 5:30 PM, Central Standard Time at the South Spencer County High School located at 1142 North CR 275 West, Rockport, Indiana 47635. Additionally, IDEM, OAQ extended the public notice period by 52 days. Initially, the public comment period was to end on March 29, 2013. IDEM, OAQ extended the public comment period to May 20, 2013. No revisions to the draft permit are required because of this comment.

Public Comment No. 2: **Health Concerns**
IDEM, OAQ received several comments regarding the health impact of this facility on the ambient air pollution levels in Spencer County, Indiana. Public comments addressed a wide range of health effects attributable to an increase in air pollution including asthma and cancer. Examples of typical comments received follow:

(a) I live here; I know how much asthma, cancer, and other environmentally influenced illnesses we already have in this county. My children are growing up here and both have asthma-related health problems. They are good students and I would like them to settle here when they are out of school, but as it stands now with the air quality we already have, I cannot do that in good conscience.

(b) Our area is already very badly polluted from the effluent produced by coal-fired power plants and a steel mill. As a member and board member of a local group, Spencer County Citizens for Quality of Life, I would like to express my reasons for objecting to the construction and operation of another plant which brings additional toxic pollutants with it.

(c) I personally don't believe our area can take any further pollutants without increasing health risks.

(d) Please consider the residents of Spencer County in this plea and the validity of our concerns; especially those of us who already suffer breathing and health issues that are concerned for the unnecessary, further pollution of our air quality conditions. I suffer from asthma, allergies and COPD through no consequence of my own actions. I have never smoked a day in my life and can provide my doctor's findings as witness that this is the case. I have been diagnosed by two tri-state pulmonologists. I know I am not alone, as I see my friends and neighbors fighting similar conditions in every trip I make to the doctor's office. Please open this case for public comments. It is vitally important to the health of area residents is Spencer County, Indiana and surrounding communities.

(e) A public hearing needs to be held regarding the impact this facility will have on the environment of southern Indiana and its residents as well as an unusually high cancer rate.

IDEM RESPONSE

IDEM, OAQ performed air dispersion modeling and a screening analysis for air toxics in Spencer County, Indiana. IDEM, OAQ performed these analyses to ensure the proposed facility did not pose a threat to public health or the environment. The analysis revealed the proposed facility will not significantly affect the ambient air quality in Spencer County, Indiana and a significant increase in asthma or cancer is not expected. In fact, Spencer County is one of the best in the state for low chronic illnesses and the National Air Toxics Assessment (NATA) showed air toxics emissions in Spencer County are below state and national averages.

Current Health Information – Asthma and Cancer rates

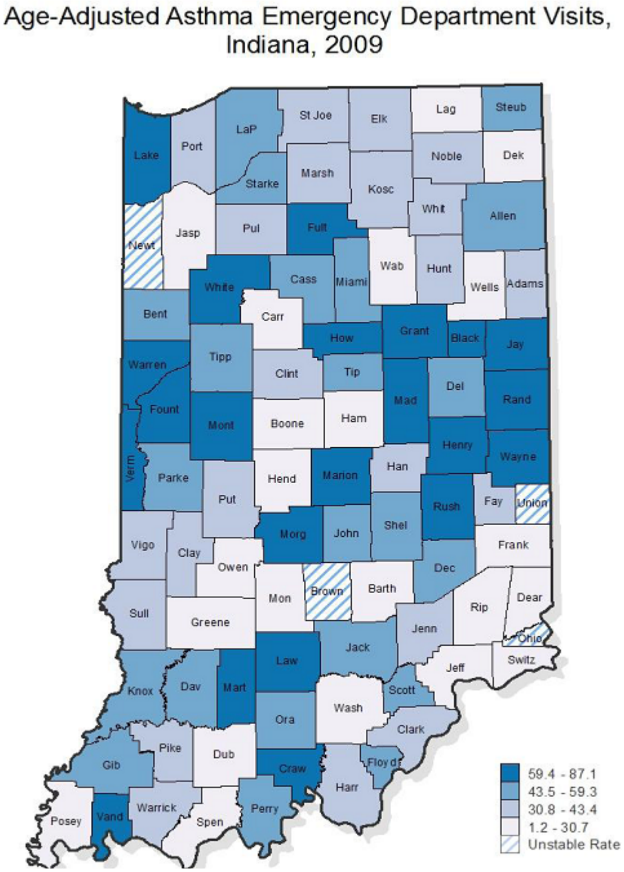
Review of the current data available to the Indiana State Department of Health and IDEM demonstrated that residents in Spencer County have not been at increased risk for exacerbation of asthma (measured by emergency department and hospitalization encounters). Table 1 shows the age adjusted rate for asthma and the state ranking for that rate. Figure 1 shows the ranking of each county in Indiana for age-adjusted emergency department visits for asthma in 2009.

Table 1 - Age-adjusted Emergency Department and Inpatient Asthma-related Encounter Rates and Ranks, Spencer County, 2006–2010

	Age-adjusted Rate~	Rank in State (Out of 92; lower is better)
SPENCER CO ASTHMA-RELATED EMERGENCY DEPARTMENT VISITS*	46.2	15
SPENCER CO ASTHMA-RELATED INPATIENT ADMITS*	17.0	7

**Based on ICD-9 code of 493 (asthma) within first three diagnoses codes*
~Age-adjusted rate per 10,000 population
Source: Indiana Hospital Association's Hospital Discharge Database Figure 1 is a map generated for the 2011 Burden of Asthma in Indiana Report (http://www.in.gov/isdh/files/BR_Asthma_5-11-11gw.pdf). This map depicts asthma-related emergency department rates based on patients having a primary diagnosis of asthma. Spencer County is in the "white" zone, showing that it had a rate during 2009 that was in the lowest (best) quartile in the state.

Figure 1 – Age-Adjusted Asthma Emergency Department Visits in Indiana 2009



Source: Indiana Hospital Association's Hospital Discharge Database

Table 2 below shows the cancer rate compared to the rest of Indiana for overall and receptor specific cancers. Spencer County is not at an increased risk for cancer incidents. In fact, Spencer County's overall age-adjusted cancer incidence rate (425.3 cases per 100,000 people) during 2004–2008 was statistically lower than the Indiana rate (475.6 cases per 100,000 people). There were no increased statistical differences between Spencer County's rates and the state's rates for the leading cancer types (Table 2).

Table 2. Cancer Incidence Rates, Indiana and Spencer County, 2004–2008*

	All Cancers		Prostate (Male-only disease)		Female Breast		Lung		Colon and Rectum	
County	Count	Rate*	Count	Rate*	Count	Rate*	Count	Rate*	Count	Rate*
Spencer	493	425.3 ↓	59	104.1	62	104	84	71.2	69	60.2
Indiana	154,990	475.6	19,770	136	20,511	116	25,914	80	16,739	51.4


↑↓ DENOTE IF COUNTY RATE IS SIGNIFICANTLY DIFFERENT THAN STATE RATE†
↑ = higher ↓ = lower "blank" = no difference

**Rates are per 100,000 people and age-adjusted to the 2000 U.S. Standard Population*
†"↑↓" symbols denote whether the county's rate is significantly different than the Indiana rate based on the 95% confidence interval overlap method (see Page 4 for description). Because of limitations of this method, some of the counties without ↑↓ symbols could still have significantly different rates than the state.

"x" Rate and comparison to state rate is suppressed if fewer than 20 cases occurred because rate is considered unstable.

Source: Indiana State Cancer Registry (http://www.in.gov/isdh/24360.htm)

National Air Toxics Assessment

The United States Environmental Protection Agency (U.S. EPA) conducted the most recent National Air Toxics Assessment (NATA) in 2005. The 2005 NATA was made available to the public in early 2011. The NATA is a large scale evaluation of air toxics that examines many sources of air toxics. The evaluation looks at not only major sources of air toxics, such as factories, but also emissions from vehicles, small sources, and background air toxics. The NATA estimates what level of pollution people will be exposed to and the potential risk of developing health effects over a life time (70 years) when breathing those toxics. The NATA reports risk estimates based on the average concentrations over a census tract. There are five census tracts in Spencer County and 1,412 census tracts in the State of Indiana. The NATA looks at both cancer and non-cancer health effects.

For cancer risk, the highest tract in Spencer County was ranked 979th in the state of Indiana. The highest cancer risk for that census tract from major sources in the NATA was 0.67 excess cancer cases in a million people. That means that if one million people inhaled the same air for 24 hours a day, 7 days a week, 52 weeks a year for 70 years, there would be at most 0.67 extra cancer cases per million people. The average for Spencer County from point sources is 0.48. This is well below the average calculated for Indiana of 2.2 and the national average of 1.6. When considering the risk from all sources, including background, Spencer County's risk is estimated at 2.9 excess cancer cases per million people. This is also less than the Indiana average of 3.6 and the national average of 5.0 excess cancer cases per million people.

For non-cancer hazard, NATA calculated respiratory and neurological hazards. This screening analysis combined the two different health endpoints to get one non-cancer hazard quotient which is an extremely health protective approach. For all census tracts in Spencer County the non-cancer hazard was less than 1. The highest tract was 0.76. For non-cancer hazards any result of less than 1 indicates that adverse health effects from the pollutant are extremely unlikely to occur. http://www.epa.gov/ttn/atw/nata2005/tables.html

Air Toxics Emissions

Emissions estimates used in the air toxics analyses were based on potential emission rates after controls. For the screening analysis, the air toxics emissions were estimated at 29.69 tons.

Air Toxics Dispersion Modeling Evaluation

An AERMOD modeling analysis was conducted using modeling parameters for the new proposed Ohio Valley Resources facility. Ohio Valley Resources, LLC parameters were based on available technological information and permit application data. The AERMOD run used meteorological data from the Evansville, Indiana surface station and mixing heights from the Peoria, IL upper air station. The data was preprocessed minute by minute for 2006-2010. Terrain data was factored in for all sources and receptors. Building data was available for Ohio Valley Resources, LLC and the downwash for those buildings were used in the analysis. The screening analysis contained 5260 receptors in a 50 km by 50 km grid around the OVR facility. Boundary data for Ohio Valley Resources, LLC was available and no receptors were placed on that source's property.

The annual estimated concentration for 2006 to 2010 was averaged into a single concentration for each receptor. The concentration was then used to calculate cancer risk and non-cancer hazards for each source. The cancer Unit Risk Factor (URF) and non-cancer Reference Concentration (RfC) were taken from the most recent version of U.S. EPA's Chronic dose-response Table 1 (http://www.epa.gov/ttn/atw/toxsource/table1.pdf).

The highest modeled cancer risk based on the receptor grid was 1.1 excess cancer cases in a million. This was the only receptor over one in a million. Impacts dropped sharply with distance from the fenceline. The pollutants driving the risk was benzene followed by chromium and ethylbenzene. Generally, U.S. EPA considers risk estimates over one hundred in a million to be at levels where action or more investigation is required. Risks that fall between one in a million and 100 in a million levels generate decisions and actions taking into account the assumptions used to determine the estimate. Risk estimates below one in a million are usually considered as not requiring further action.

For non-cancer hazard quotient, the highest receptor in the study area is 0.0098. Non-cancer drivers were benzene, acrolein and cadmium. Impacts dropped sharply with distance from the fenceline. A non-cancer hazard quotient under 1.0 is commonly recognized to be health-protective. Hazard quotients over 1.0 indicate that further investigation may be necessary but does not necessarily mean that health effects are expected. These are health protective scenarios and are very likely to be greater than the actual non-cancer hazard quotient.

Even if one assumes all of Spencer County was exposed to this one receptor level of chemicals for 70 years, one would not expect a cancer case attributable to OVR. With a 2010 population of just under 21,000, the expected number of cancer cases would be 21,000 X 1.14 in a million, or 0.024. No revisions to the draft permit are required because of this comment.

Public Comment No. 3: **Property Values**

IDEM, OAQ received a comment on the negative effect this project would have on the property values of nearby residents. The comment received stated as follows:

(a) This plant and its air pollutants will devalue our property and make it less desirable for any other development that could occur along Highway 231 in the future.

IDEM RESPONSE

IDEM has no authority to regulate the location of the source. Local government officials determine zoning. IDEM understands that all of these matters are of genuine concern to the commenters. However, IDEM does not have any authority to consider impairment of property values, noise, road traffic, road damage, road safety, fire safety, the reputation or tourism potential of the community, or odor in issuing air permits. No revisions to the draft permit are required because of this comment.

Public Comment No. 4: Negative Effects on Drinking Water

IDEM, OAQ received a comment on the negative effect this project would have on the aquifer used for the drinking water supply in the area. The comment received follows:

(a) The amount of water that this plant plans to take from our aquifer could also affect our water table.

IDEM RESPONSE

IDEM, Office of Air Quality (OAQ) does not regulate drinking water aquifers and as such, it cannot consider the rate of water withdrawal from the aquifer in its permitting decision. No revisions to the draft permit are required because of this comment.

Public Comment No. 5: General Opposition Letter

IDEM, OAQ received a large number of similar letters to express their general opposition to the construction of the Ohio Valley Resources, LLC project. The text of the letter follows:

I am writing this letter to express my opposition to the proposed anhydrous ammonia plant that Ohio Valley Resources, LLC is planning to build in Rockport, Indiana.

I do not believe that the plant will be safe, and I do not think the plant is necessary. Recently, lawmakers dealt a setback to the proposed Leucadia Utility rate hike that would have funded the coal to synthetic gas plant in Rockport. The fertilizer plant in question would need vast amounts of natural gas and neither project has proven that it makes sense from an environmental or customer standpoint.

We agree with the residents of Rockport who have spoken up loudly to say no to any more dangerous and risky proposals for their community. The fertilizer plant adds insult to injury, given the pre-existing amounts of hazardous emissions that residents already deal with every day.

We are asking that you deny this proposed fertilizer plant because it is not conductive to a healthy community. Please tell Ohio Valley Resources and Leucadia that Rockport residents have had enough. Please deny the Ohio Valley Resources permit and protect our citizens.

A small percentage of commenters deviated from this format in the following ways:

(1) Some commenters deleted sections about the plant being unnecessary or a safety risk

(2) Some commenters removed references to the pre-existing amounts of hazardous emissions.

(3) One commenter added the following: There are far too many toxic plants on the Ohio that spew not only on the local community, but to all of us northward. We want energy…but we want it clean.

(4) One commenter added the following: Personally, I support the Call of Valley Watch demanding a moratorium on permits of new fertilizer plants until a thorough safety assessment is conducted regarding proposed sites, especially as they apply to Rockport and Mt. Vernon since each proposal is located immediately adjacent to large manufacturers of other highly explosive materials.

(5) One commenter recommended the Indiana Department of Environmental Management change its name to the Indiana Department of Environmental Protection Agency.

(6) Several commenters noted their close proximity to the proposed facility and the health risks presented by their location.

(7) One commenter referenced the recent explosion of another fertilizer plant in West, Texas and how this plant will not be welcome in the area.

IDEM RESPONSE

The commenters are mostly concerned about the location of the facility and the safety and health impact of the fertilizer plant on the local community. Health concerns were discussed in IDEM RESPONSE to Public Comment No. 2 and will not be readdressed in this response.

In regards to safety, local responses to a fire, explosion or similar emergency situation and the adequacy of emergency procedures and equipment are outside the air permit process. IDEM does not have the authority to consider fire safety, explosions, or other extraordinary conditions in issuing air pollution permit.

In regards to the location of the plant, IDEM has no authority to regulate the location of the source. Zoning is determined by local government officials and these questions should be addressed to them. As long as an applicant for a Part 70 Operating Permit meets all of the state and federal air pollution permitting requirements, IDEM, OAQ is legally required to issue the permit.

No revisions to the draft permit are required as a result of this comment.

Public Comment No. 6: **General Support for the Project**

IDEM, OAQ received written comment on the positive aspects of this project. The text follows:

I am writing this to express my enthusiastic support of the proposed fertilizer plant that Ohio Valley Resources is planning to build in Rockport, Indiana. I believe that the plant in question would be an important consumer of natural gas, and it clearly makes sense from an environmental and consumer standpoint.

I agree with the residents of Rockport that this project would be of great economic benefit to the community. This modern, clean fertilizer plant is a step in the right direction for reducing imports, and providing products for reducing diesel emissions and promoting productive farming.

We are asking that you endorse this proposed fertilizer plant because it is very conducive to a prosperous, healthy community. Please tell Thomas Pearce that Rockport residents and Ohio Valley Resources have had enough pointless opposition and persecution by the Sierra Club! Please do whatever you can to facilitate the issuance of the permit for Ohio Valley Resources.

IDEM RESPONSE

No changes to the draft permit are required as a result of this comment.

PUBLIC HEARING COMMENTS

Hearing Commment No. 1 **General Support for the Project**

Several commenters voiced general support for the project for the following reasons:

(a) IDEM, OAQ reviewed the application from OVR and drafted a complete permit that was protective of health and the environment.

(b) IDEM, OAQ has a professional inspection and monitoring program.

(c) The permit addresses all applicable laws.

(d) While no industry can guarantee completely safe operations, OVR is a world class company and is capable of operating the facility in compliance with all safety regulations.

(e) The air quality in the region would not be adversely affected by the additional pollution produced by OVR.

(f) Local farmers use and need the products produced by OVR.

(g) Construction and operation of the plant will provide desperately needed jobs in an economically challenged part of the state.

(h) Modern pollution control equipment will make emissions from OVR safe for the local community.

(i) The facility is a clean burning plant that should not be compared to the fertilizer plant that exploded in West, Texas. It's like comparing apples and oranges. This plant does not produce granular ammonium nitrate and it is not an explosive hazard.

(j) OVR coordinated the plant design with local fire, police, EMT's, EMS and the local AEP Director to ensure the plant will be safe.

(k) The OVR facility will increase the assessed value of the county and will lower tax rates for everyone in the county.

(l) The plant will secure the food supply in the local area because the products produced will be used by farmers within a 150 mile radius of Rockport, Indiana.

(m) The engineering firm computer modeled each emission process and its effect on the local environment. This plant will be safe and will not harm the community.

(n) I standby this plant because we need nitrogen based agriculture to feed seven billion people in the world. OVR will help feed the world.

(o) This project will be safe. Sierra Club speaks out against everything that comes down the pike in this community. This plant will put people to work in a safe way.

(p) We need this plant because all of the products are used in this county and we have problems during the growing season to get fertilizer on-time. We need this plant to end fertilizer shortages.

IDEM RESPONSE

No changes to the draft permit are required as a result of these comments.

Hearing Commment No. 2 General Concern for the Project

Several commenters voiced concerns for the project for the following reasons:

(a) Pollution adds up. This plant may not be a problem but when added to other sources its unhealthy.

(b) There are always accidents at these facilities. It is not safe to build anywhere near people. If the fertilizer is stored in the wrong way it will explode.

(c) We want the jobs not the pollution.

(d) Emissions will cause health problems.

(e) I am amazed by how much NO_x, CO_2 and SO_2 pollution there is in the Tri-State Area. Breathing here is like smoking a pack of cigarettes every day. This plant will be a problem.

(f) President Lincoln would be disappointed by how Spencer County is going. It should be renamed to Spencer County for More Pollution. We have too much pollution and don't need this plant.

(g) There is a lot of mercury in coal that is being reintroduced into our environment.

IDEM RESPONSE

IDEM, OAQ addressed safety concerns in IDEM's reply to Sierra Club Comment No. 15 above. Please see this comment for a detailed reply on safety concerns. Health concerns were addressed on IDEM's response to Public Comment No. 2 above. Please see this comment for a detailed reply on health concerns. The emission calculations in Appendix A to the Technical Support Document detail all the anticipated emissions of regulated air pollutants from OVR. OVR will not be using coal. OVR will have no mercury emissions.

No changes to the draft permit are required as a result of this comment.

Hearing Commment No. 3 Sierra Club Comments

A representative of the Sierra Club indicated the plant should not be built because:

(a) It is a safety hazard and IDEM does not care about safety.

(b) IDEM, OAQ does not enforce environmental laws properly or there would not be so many sources of pollution in the Rockport area.

(c) Economic development is not a good thing if it destroys our future.

(d) There is too much pollution in Spencer County already. We don't want any more.

IDEM RESPONSE

IDEM, OAQ addressed safety concerns in IDEM's reply to Sierra Club Comment No. 15 above. Please see this comment for a detailed reply on safety concerns. Health concerns were addressed on IDEM's response to Public Comment No. 2 above. Please see this comment for a detailed reply on health concerns.

IDEM's mission is to implement federal and state regulations to protect human health and the environment while allowing the environmentally sound operations of industrial, agricultural, commercial, and government activities vital to a prosperous economy. This permit includes all applicable rules and regulations related to air pollution control.

No changes to the draft permit are required as a result of this comment.

Hearing Commment No. 4 Valley Watch Comments

A representative of Valley Watch indicated the plant should not be built because:

(a) IDEM, OAQ could not care less about safety and doesn't deal with toxic releases.

(b) IDEM, OAQ does not do anything about fine particulate. They say everything is fine in Rockport but EPA is saying Rockport will be in nonattainment for fine particles on an annual basis.

(c) There are two industries in the local area that emit more than 25 million pounds of toxic chemicals into the environment. There is too much pollution.

(d) This is the largest facility of its type in the country. It is an experiment and no one can tell how harmful the pollutants will be for a plant of this scale.

(e) A smaller fertilizer plant in Donaldson, Louisiana emits over 7.9 million pounds of toxic chemicals. We don't want that pollution here in Rockport. In addition, the pollution will not stay here it will spread all over the county.

(f) Rockport, Indiana is one of the most toxic communities in the United States if not the world. We must stop the plant to protect our future.

(g) IDEM, OAQ will not enforce anything. They will rubber stamp the permit and not follow up with monitoring or inspections.

(h) The engineering firm says the plant will not produce ammonium nitrate but the permit mentions two ammonium nitrate plants. This stuff is not safe.

IDEM RESPONSE

IDEM, OAQ addressed safety concerns in IDEM's reply to Sierra Club Comment No. 15 above. Please see this comment for a detailed reply on safety concerns. Health concerns were addressed on IDEM's response to Public Comment No. 2 above. Please see this comment for a detailed reply on health concerns.

IDEM, OAQ is required to issue permits that include all applicable requirements at the time of permit issuance. When this permit is issued, Spencer County, Indiana will be in attainment for the National Ambient Air Quality Standard for fine particulate matter ($PM_{2.5}$).

IDEM, OAQ does not rubber stamp permit applications. A full staff of air quality professionals at IDEM, OAQ has reviewed the application submitted by OVR and believes it is protective of human health and the environment and in compliance with all state and federal laws. As such, IDEM, OAQ is required to issue the permit.

Ohio Valley Resources will not manufacture granular ammonium nitrate. This substance is highly explosive when dry and subjected to heat in a confined area. Ohio Valley Resources will manufacture a liquid ammonium nitrate solution which has a different safety profile. The liquid ammonium nitrate is not a final product. It is created as an intermediate in the manufacture of the final product, urea ammonium nitrate. The application for this permit is correct in stating that ammonium nitrate will not be produced in a granular form. A liquid solution of ammonium nitrate will be produced as a chemical intermediate.

IDEM will be inspecting OVR once it begins operation. IDEM's air compliance inspectors conduct inspections of permitted sources and also respond to complaints. The air inspector for OVR is Tammy Haug. Ms. Haug works out of IDEM's Southwest Regional Office, 1120 Vincennes Ave., Petersburg, Indiana 47567, telephone (812) 380-2309, toll free (888) 672-8323, FAX (812) 380-2304. Environmental complaints may also be filed on-line at www.idem.IN.gov/5274.htm or by calling IDEM's Complaint Coordinator at (800) 451-6027, ext. 2-4464.

No changes to the draft permit are required as a result of this comment.

Hearing Commment No. 5 General Health Effects and Criteria Pollutants

One commenter objected to the issuance of the draft permit because of health effects. The commenter stated that Evansville and Rockport do not meet the criteria that EPA set in December of 2012 for annual $PM_{2.5}$, the criteria of 12 micrograms per cubic meter. High annual $PM_{2.5}$ is linked to increased rates of infant death, slow lung function in children, asthma, lung cancer and cardiovascular disease. The jobs are not worth the health effects. The guidelines the federal government has set does not guarantee you will be safe, not all toxic chemicals have been studied. People should look at the health data for this area before building this plant. This permit should be denied until this area of southern Indiana meets both the annual $PM_{2.5}$ criteria of 12.0 micrograms per cubic meter and the health metrics are more reflective of the rest of the United States.

IDEM RESPONSE

Health concerns were addressed on IDEM's response to Public Comment No. 2 above. Please see this comment for a detailed reply on health concerns.

The remainder of the comment relates to the National Ambient Air Quality Standards for Particulate Matter; Final Rule, published in the Federal Register on January 15, 2013, with an effective date of March 18, 2013. This rule lowered the annual NAAQS for $PM_{2.5}$ from 15 micrograms per cubic meter to 12 micrograms per cubic meter. Pursuant to U.S. EPA guidance, the 15 microgram per cubic meter standard for annual $PM_{2.5}$ is applicable to projects placed on public notice prior to the effective date of the new rule. The draft permit for Ohio Valley Resources was placed on public notice on February 28, 2013; therefore, the 15 microgram per cubic meter standard is correct.

No changes to the draft permit are required as a result of this comment.

Hearing Commment No. 6 Protect All Living Things

One commenter wanted to remind IDEM, OAQ that all living things are related and the permit must protect the planet. We must protect the planet because we do not inherit it from our ancestors, we borrow it from our children.

IDEM RESPONSE

IDEM, OAQ shares the commenter's concern for the environment. No changes to the draft permit are required as a result of this comment.

Hearing Commment No. 7 General Information Questions

A commenter wanted to know what kind of pollutants the stack is going to emit. How will the stack be monitored? Will they use chlorine? They are making anhydrous ammonia and it is not safe to breath. We have too many dangerous sources of pollution in this area. We don't need any more.

IDEM RESPONSE

The emission calculations attached as Appendix A to the Technical Support Document detail all anticipated emissions of regulated air pollutants emitted by this facility. The commenter is directed to Appendix A for the types of regulated pollutants emitted by the source. The commenter is correct in stating that the source will produce anhydrous ammonia as a final product. Ammonia is not a pollutant regulated by IDEM, OAQ. Chlorine is classified as a hazardous air pollutant (HAP) and is regulated by IDEM, OAQ. Chlorine will be produced in small amounts as a combustion product. Ohio Valley Resources will not produce chlorine gas as a product. IDEM, OAQ addressed safety concerns in IDEM's reply to Sierra Club Comment No. 15 above. Please see this comment for a detailed reply on safety concerns. Health concerns were addressed on IDEM's response to Public Comment No. 2 above. Please see this comment for a detailed reply on health concerns.

No changes to the draft permit are required as a result of this comment.

Hearing Commment No. 8 Ammonia Releases

One commenter indicated the plant should not be built because there may be accidental releases of ammonia.

IDEM RESPONSE

Ammonia is not a pollutant regulated by IDEM, OAQ. The source has installed several flares in the design of the facility which will control emissions during any periods of upset in the manufacturing process. The flares will combust the ammonia and minimize potential releases of anhydrous ammonia.

No changes to the draft permit are required as a result of this comment.

Hearing Commment No. 9 Global Warming

One commenter indicated that government is ignoring global warming and everyone needs to be concerned. 98 out of 100 scientists can't be wrong.

IDEM RESPONSE

IDEM, OAQ and the U.S. EPA are aggressively addressing the problems of global warming by way of the Greenhouse Gas Best Available Control Technology (GHG BACT). The applicant was required to identify all sources of greenhouse gas emissions and propose control measures to minimize their emissions. The GHG BACT analysis can be found in Appendix B to the Technical Support Document. Each D Section of the permit will contain numerical emission limits and operational practices to minimize greenhouse gas emissions which is essential in combating global warming.

No changes to the draft permit are required as a result of this comment.

IDEM, OAQ REVISIONS

Upon further review of the permit documents, IDEM, OAQ is making the following minor revisions to the draft permit documents:

IDEM Modification #1

IDEM, OAQ is fixing a typographical error in the emissions summary sheets for the flares. The heat input capacities shown in the emission calculations for all four flares only included the pilot emissions. All permit conditions, and the modeling performed by IDEM and the Applicant were based on the correct heat input capacities. Revisions as a result of this modification are shown below:

Appendix A to TSD - Page 1 of 30:

Uncontrolled PTE of the Entire Source (TPY)											
Process / Emission Unit	PM	PM10	PM2.5	SO2	VOC	CO	NOx	Non-Biogenic GHGs (as CO_2e)	Biogenic GHGs (as CO_2e)	Total HAP	Highest Single HAP Methanol
**********	*********	*******	*******	*******	*******	*********	*******	**********	**********	*******	**********
Ammonia Storage Flare (EP-005)	~~1.00E-03~~ **4.00E-03**	~~0.004~~ **0.015**	~~0.004~~ **0.015**	~~0.0003~~ **0.0012**	~~0.00~~ **0.01**	~~0.20~~ **0.72**	~~0.04~~ **0.13**	~~64~~ **228**	0.00	~~0.0012~~ **0.0041**	0.00
Ammonia Backend Flare (EP-006)	~~2.11E-03~~ **3.18E-01**	~~0.01~~ **1.26**	~~0.01~~ **1.26**	~~0.0007~~ **0.1006**	~~0.01~~ **0.91**	~~0.41~~ **62.01**	~~0.08~~ **11.40**	~~130~~ **19,610**	0.00	~~0.0021~~ **0.3501**	0.00
Ammonia Frontend Flare (EP-007)	~~2.11E-03~~ **3.14E-01**	~~0.01~~ **1.24**	~~0.01~~ **1.24**	~~0.0007~~ **0.0992**	~~0.01~~ **0.89**	~~0.41~~ **61.16**	~~0.08~~ **11.24**	~~130~~ **19,342**	0.00	~~0.0021~~ **0.3459**	0.00
UAN Flare (EP-017)	~~1.57E-03~~ **5.35E-02**	~~0.01~~ **0.21**	~~0.01~~ **0.21**	~~0.0005~~ **0.0169**	~~0.004~~ **0.152**	~~0.31~~ **10.41**	~~0.06~~ **1.91**	~~97~~ **3,293**	0.00	~~0.0017~~ **0.0589**	0.00
**********	*********	*******	*******	*******	*******	*********	*******	**********	**********	*******	**********
PTE of Entire Source	~~194.59~~ **195.27**	~~236.95~~ **239.64**	~~233.70~~ **236.39**	~~8.41~~ **8.63**	~~90.75~~ **92.69**	~~1038.54~~ **1171.51**	~~2,250~~ **2,274**	~~4,204,343~~ **4,246,395**	0.00	~~34.21~~ **34.96**	18.00
Title V Major Source Thresholds	NA	100	100	100	100	100	100	100,000	NA	25	10

Appendix A to TSD – Page 2 of 30:

Controlled PTE of the Entire Source (TPY)											
Process / Emission Unit	PM	PM10	PM2.5	SO2	VOC	CO	NOx	Non-Biogenic GHGs (as CO_2e)	Biogenic GHGs (as CO_2e)	Total HAP	Highest Single HAP Methanol
**********	*********	*******	*******	*******	*******	*********	*******	**********	**********	*******	**********
Ammonia Storage Flare (EP-005)	~~1.00E-03~~ **4.00E-03**	~~0.004~~ **0.015**	~~0.004~~ **0.015**	~~0.0003~~ **0.0012**	~~0.00~~ **0.01**	~~0.20~~ **0.72**	~~0.04~~ **0.13**	~~64~~ **228**	0.00	~~0.0012~~ **0.0041**	0.00
Ammonia Backend Flare (EP-006)	~~2.11E-03~~ **3.18E-01**	~~0.01~~ **1.26**	~~0.01~~ **1.26**	~~0.0007~~ **0.1006**	~~0.01~~ **0.91**	~~0.41~~ **62.01**	~~0.08~~ **11.40**	~~130~~ **19,610**	0.00	~~0.0021~~ **0.3501**	0.00
Ammonia Frontend Flare (EP-007)	~~2.11E-03~~ **3.14E-01**	~~0.01~~ **1.24**	~~0.01~~ **1.24**	~~0.0007~~ **0.0992**	~~0.01~~ **0.89**	~~0.41~~ **61.16**	~~0.08~~ **11.24**	~~130~~ **19,342**	0.00	~~0.0021~~ **0.3459**	0.00
UAN Flare (EP-017)	~~1.57E-03~~ **5.35E-02**	~~0.01~~ **0.21**	~~0.01~~ **0.21**	~~0.0005~~ **0.0169**	~~0.00~~ **0.15**	~~0.31~~ **10.41**	~~0.06~~ **1.91**	~~97~~ **3,293**	0.00	~~0.0017~~ **0.0589**	0.00
**********	*********	*******	*******	*******	*******	*********	*******	**********	**********	*******	**********
PTE of Entire Source	~~29.57~~ **30.25**	~~76.17~~ **78.86**	~~73.67~~ **76.36**	~~8.41~~ **8.63**	~~90.75~~ **92.69**	~~1038.54~~ **1171.51**	~~621.47~~ **645.90**	~~2,776,799~~ **2,818,851**	0.00	~~34.21~~ **34.96**	18.00
Title V Major Source Thresholds	NA	100	100	100	100	100	100	100,000	NA	25	10

Appendix A to TSD – Page 3 of 30:

Limited PTE of the Entire Source (TPY)											
Process / Emission Unit	PM	PM10	PM2.5	SO2	VOC	CO	NOx	Non-Biogenic GHGs (as CO_2e)	Biogenic GHGs (as CO_2e)	Total HAP	Highest Single HAP Methanol
**********	*********	*******	*******	*******	*******	*********	*******	**********	**********	*******	**********
Ammonia Storage Flare (EP-005)	~~1.00E-03~~ **4.00E-03**	~~0.00413~~ **0.01461**	~~0.00413~~ **0.01461**	~~0.0003~~ **0.0012**	~~0.00297~~ **0.01052**	~~0.20~~ **0.72**	~~0.03741~~ **0.13249**	~~64~~ **228**	0.00	~~0.00115~~ **0.00408**	0.00
Ammonia Backend Flare (EP-006)	~~2.11E-03~~ **3.18E-01**	~~0.01~~ **1.26**	~~0.01~~ **1.26**	~~0.0007~~ **0.1006**	~~0.01~~ **0.91**	~~0.41~~ **62.01**	~~0.08~~ **11.40**	~~130~~ **19,610**	0.00	~~0.00211~~ **0.35011**	0.00
Ammonia Frontend Flare (EP-007)	~~2.11E-03~~ **3.14E-01**	~~0.01~~ **1.24**	~~0.01~~ **1.24**	~~0.0007~~ **0.0992**	~~0.01~~ **0.89**	~~0.41~~ **61.16**	~~0.08~~ **11.24**	~~130~~ **19,342**	0.00	~~0.00211~~ **0.34589**	0.00
UAN Flare (EP-017)	~~1.58E-03~~ **5.35E-02**	~~0.01~~ **0.21**	~~0.01~~ **0.21**	~~0.0005~~ **0.0169**	~~0.00~~ **0.15**	~~0.31~~ **10.41**	~~0.06~~ **1.91**	~~97~~ **3,293**	0.00	~~0.00174~~ **0.05887**	0.00
**********	*********	*******	*******	*******	*******	*********	*******	**********	**********	*******	**********
PTE of Entire Source	~~24.01~~ **24.69**	~~54.74~~ **57.43**	~~52.24~~ **54.93**	~~6.16~~ **6.38**	~~74.90~~ **76.84**	~~930.24~~ **1063.21**	~~484.29~~ **508.73**	~~2,442,987~~ **2,485,039**	0.00	~~28.93~~ **29.69**	18.00
PSD Significant Levels	25	15	10	40	40	100	NA	7,000	NA	NA	NA
PSD Major Source Thresholds	NA	NA	NA	NA	NA	NA	100	NA	NA	NA	NA

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Appendix A to the Technical Support Document (TSD)

Ammonia Storage Flare – EP-005 – Natural Gas Combustion with Purge Gas

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Design Data

Heat Input Capacity	**0.445**~~0.126~~	MMBtu/hr
Higher Heating Value	902	MMBtu/MMCF (Natural Gas Pilot + Purge Process CH_4)
Natural Gas Usage	**4.32**~~1.22~~	MMCF/yr
Limited Natural Gas Usage	**4.32**~~1.22~~	MMCF/yr

Pollutant	Emission Factor		PTE (TPY)	Limited PTE (TPY)	Data Source
PM	~~**********~~	~~**********~~	~~0.001~~ **0.004**	~~0.001~~ **0.004**	~~**********~~
PM10 (filterable + condensible)	~~**********~~	~~**********~~	~~0.004~~ **0.015**	~~0.004~~ **0.015**	~~**********~~
PM2.5 (filterable + condensible)	~~**********~~	~~**********~~	~~0.004~~ **0.015**	~~0.004~~ **0.015**	~~**********~~
SO2	~~**********~~	~~**********~~	~~0.0003~~ **0.0012**	~~0.0003~~ **0.0012**	~~**********~~
NOx	~~**********~~	~~**********~~	~~0.038~~ **0.133**	~~0.038~~ **0.132**	~~**********~~
VOC	~~**********~~	~~**********~~	~~0.003~~ **0.011**	~~0.003~~ **0.011**	~~**********~~
CO	~~**********~~	~~**********~~	~~0.20~~ **0.72**	~~0.20~~ **0.72**	~~**********~~
Benzene	~~**********~~	~~**********~~	~~1.28E-06~~ **4.54E-06**	~~1.28E-06~~ **4.54E-06**	~~**********~~
Dichlorobenzene	~~**********~~	~~**********~~	~~7.32E-07~~ **2.59E-06**	~~7.32E-07~~ **2.59E-06**	~~**********~~
Formaldehyde	~~**********~~	~~**********~~	~~4.58E-05~~ **1.62E-04**	~~4.58E-05~~ **1.62E-04**	~~**********~~
Hexane	~~**********~~	~~**********~~	~~1.10E-03~~ **3.89E-03**	~~1.10E-03~~ **3.89E-03**	~~**********~~
Toluene	~~**********~~	~~**********~~	~~2.07E-06~~ **7.34E-06**	~~2.07E-06~~ **7.34E-06**	~~**********~~
Lead	~~**********~~	~~**********~~	~~2.99E-10~~ **1.06E-09**	~~2.99E-10~~ **1.06E-09**	~~**********~~
Cadmium	~~**********~~	~~**********~~	~~6.71E-07~~ **2.38E-06**	~~6.71E-07~~ **2.38E-06**	~~**********~~
Chromium	~~**********~~	~~**********~~	~~8.54E-07~~ **3.02E-06**	~~8.54E-07~~ **3.02E-06**	~~**********~~
Manganese	~~**********~~	~~**********~~	~~2.32E-07~~ **8.21E-07**	~~2.32E-07~~ **8.21E-07**	~~**********~~
Nickel	~~**********~~	~~**********~~	~~1.28E-06~~ **4.54E-06**	~~1.28E-06~~ **4.54E-06**	~~**********~~
Total HAP	~~**********~~	~~**********~~	~~1.15E-03~~ **4.08E-03**	~~1.15E-03~~ **4.08E-03**	~~**********~~
CO_2	~~**********~~	~~**********~~	~~64.31~~ **227.74**	~~64.31~~ **227.74**	~~**********~~

Pollutant	Emission Factor		PTE (TPY)	Limited PTE (TPY)	Data Source
CH_4	~~**********~~	~~**********~~	~~1.21E-03~~ **4.30E-03**	~~1.21E-03~~ **4.30E-03**	~~**********~~
N_2O	~~**********~~	~~**********~~	~~1.20E-04~~ **4.30E-04**	~~1.20E-04~~ **4.30E-04**	~~**********~~
CO_2e	~~**********~~	~~**********~~	~~64~~ **228**	~~64~~ **228**	~~**********~~

~~**********~~

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Appendix A to the Technical Support Document (TSD)

Ammonia Process Backend Flare – EP-006 – Natural Gas Combustion with Purge Gas

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Design Data

Heat Input Capacity	**38.264**~~0.253~~	MMBtu/hr
Higher Heating Value	902	MMBtu/MMCF (Natural Gas Pilot + Purge Process CH_4)
Natural Gas Usage	**371.61**~~2.46~~	MMCF/yr
Limited Natural Gas Usage	**371.61**~~2.46~~	MMCF/yr

Pollutant	Emission Factor		PTE (TPY)	Limited PTE (TPY)	Data Source
PM	~~**********~~	~~**********~~	~~2.11E-03~~ **3.18E-01**	~~2.11E-03~~ **3.18E-01**	~~**********~~
PM10 (filterable + condensible)	~~**********~~	~~**********~~	~~0.01~~ **1.26**	~~0.01~~ **1.26**	~~**********~~
PM2.5 (filterable + condensible)	~~**********~~	~~**********~~	~~0.01~~ **1.26**	~~0.01~~ **1.26**	~~**********~~
SO2	~~**********~~	~~**********~~	~~0.0007~~ **0.1006**	~~0.0007~~ **0.1006**	~~**********~~
NOx	~~**********~~	~~**********~~	~~0.08~~ **11.40**	~~0.08~~ **11.40**	~~**********~~
VOC	~~**********~~	~~**********~~	~~0.01~~ **0.91**	~~0.01~~ **0.91**	~~**********~~
CO	~~**********~~	~~**********~~	~~0.41~~ **62.01**	~~0.41~~ **62.01**	~~**********~~
Benzene	~~**********~~	~~**********~~	~~2.58E-06~~ **3.9E-04**	~~2.58E-06~~ **3.9E-04**	~~**********~~

Pollutant	Emission Factor		PTE (TPY)	Limited PTE (TPY)	Data Source
Dichlorobenzene	~~**********~~	~~**********~~	~~1.48E-06~~ **2.23E-04**	~~1.48E-06~~ **2.23E-04**	~~**********~~
Formaldehyde	~~**********~~	~~**********~~	~~9.23E-05~~ **1.39E-02**	~~9.23E-05~~ **1.39E-02**	~~**********~~
Hexane	~~**********~~	~~**********~~	~~0.002~~ **0.334**	~~0.002~~ **0.334**	~~**********~~
Toluene	~~**********~~	~~**********~~	~~4.18E-06~~ **6.32E-04**	~~4.18E-06~~ **6.32E-04**	~~**********~~
Lead	~~**********~~	~~**********~~	~~1.00E-09~~ **9.10E-08**	~~1.00E-09~~ **9.10E-08**	~~**********~~
Cadmium	~~**********~~	~~**********~~	~~1.35E-06~~ **2.04E-04**	~~1.35E-06~~ **2.04E-04**	~~**********~~
Chromium	~~**********~~	~~**********~~	~~1.72E-06~~ **2.60E-04**	~~1.72E-06~~ **2.60E-04**	~~**********~~
Manganese	~~**********~~	~~**********~~	~~4.67E-07~~ **7.06E-05**	~~4.67E-07~~ **7.06E-05**	~~**********~~
Nickel	~~**********~~	~~**********~~	~~2.58E-06~~ **3.90E-04**	~~2.58E-06~~ **3.90E-04**	~~**********~~
Total HAP	~~**********~~	~~**********~~	~~2.11E-03~~ **3.50E-01**	~~2.11E-03~~ **3.50E-01**	~~**********~~
CO_2	~~**********~~	~~**********~~	~~129.68~~ **19,589.96**	~~129.68~~ **19,589.96**	~~**********~~
CH_4	~~**********~~	~~**********~~	~~0.00~~ **0.37**	~~0.00~~ **0.37**	~~**********~~
N_2O	~~**********~~	~~**********~~	~~0.00~~ **0.04**	~~0.00~~ **0.04**	~~**********~~
CO_2e	~~**********~~	~~**********~~	~~130~~ **19,610**	~~130~~ **19,610**	~~**********~~

~~**********~~

Appendix A to TSD – Page 17 of 30:

Appendix A to the Technical Support Document (TSD)

Ammonia Process Frontend Flare – EP-007 – Natural Gas Combustion with Purge Gas

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Design Data

Heat Input Capacity	**37.741**~~0.253~~	MMBtu/hr
Higher Heating Value	902	MMBtu/MMCF (Natural Gas Pilot + Purge Process CH_4)
Natural Gas Usage	**366.53**~~2.46~~	MMCF/yr
Limited Natural Gas Usage	**366.53**~~2.46~~	MMCF/yr

Pollutant	Emission Factor		PTE (TPY)	Limited PTE (TPY)	Data Source
PM	**********	**********	~~2.11E-03~~ **3.14E-01**	~~2.11E-03~~ **3.14E-01**	**********
PM10 (filterable + condensible)	**********	**********	~~0.01~~ **1.24**	~~0.01~~ **1.24**	**********
PM2.5 (filterable + condensible)	**********	**********	~~0.01~~ **1.24**	~~0.01~~ **1.24**	**********
SO2	**********	**********	~~0.0007~~ **0.0992**	~~0.0007~~ **0.0992**	**********
NOx	**********	**********	~~0.08~~ **11.24**	~~0.08~~ **11.24**	**********
VOC	**********	**********	~~0.01~~ **0.89**	~~0.01~~ **0.89**	**********
CO	**********	**********	~~0.41~~ **61.16**	~~0.41~~ **61.16**	**********
Benzene	**********	**********	~~2.58E-06~~ **3.85E-04**	~~2.58E-06~~ **3.85E-04**	**********
Dichlorobenzene	**********	**********	~~1.48E-06~~ **2.20E-04**	~~1.48E-06~~ **2.20E-04**	**********
Formaldehyde	**********	**********	~~9.225E-05~~ **1.374E-02**	~~9.225E-05~~ **1.374E-02**	**********
Hexane	**********	**********	~~0.002~~ **0.330**	~~0.002~~ **0.330**	**********
Toluene	**********	**********	~~4.18E-06~~ **6.23E-04**	~~4.18E-06~~ **6.23E-04**	**********
Lead	**********	**********	~~1.00E-09~~ **9.00E-08**	~~1.00E-09~~ **9.00E-08**	**********
Cadmium	**********	**********	~~1.35E-06~~ **2.02E-04**	~~1.35E-06~~ **2.02E-04**	**********
Chromium	**********	**********	~~1.72E-06~~ **2.57E-04**	~~1.72E-06~~ **2.57E-04**	**********
Manganese	**********	**********	~~4.67E-07~~ **6.96E-05**	~~4.67E-07~~ **6.96E-05**	**********
Nickel	**********	**********	~~2.58E-06~~ **3.85E-04**	~~2.58E-06~~ **3.85E-04**	**********
Total HAP	**********	**********	~~2.11E-03~~ **3.46E-01**	~~2.11E-03~~ **3.46E-01**	**********
CO_2	**********	**********	~~129.68~~ **19,322.16**	~~129.68~~ **19,322.16**	**********

Pollutant	Emission Factor		PTE (TPY)	Limited PTE (TPY)	Data Source
CH_4	**********	**********	~~0.00~~ **0.36**	~~0.00~~ **0.36**	**********
N_2O	**********	**********	~~0.00~~ **0.04**	~~0.00~~ **0.04**	**********
CO_2e	**********	**********	~~130~~ **19,342**	~~130~~ **19,342**	**********

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Appendix A to TSD – Page 18 of 30:

Appendix A to the Technical Support Document (TSD)

UAN Flare – EP-017 – Natural Gas Combustion with Purge Gas

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Design Data

Heat Input Capacity	**6.426**~~0.189~~	MMBtu/hr
Higher Heating Value	902	MMBtu/MMCF (Natural Gas Pilot + Purge Process CH_4)
Natural Gas Usage	**62.41**~~1.84~~	MMCF/yr
Limited Natural Gas Usage	**62.41**~~1.84~~	MMCF/yr

Pollutant	Emission Factor		PTE (TPY)	Limited PTE (TPY)	Data Source
PM	**********	**********	~~1.57E-03~~ **5.35E-02**	~~1.57E-03~~ **5.35E-02**	**********
PM10 (filterable + condensible)	**********	**********	~~0.01~~ **0.21**	~~0.01~~ **0.21**	**********
PM2.5 (filterable + condensible)	**********	**********	~~0.01~~ **0.21**	~~0.01~~ **0.21**	**********
SO2	**********	**********	~~0.0005~~ **0.0169**	~~0.0005~~ **0.0169**	**********
NOx	**********	**********	~~0.06~~ **1.91**	~~0.06~~ **1.91**	**********
VOC	**********	**********	~~0.0045~~ **0.1520**	~~0.0045~~ **0.1520**	**********
CO	**********	**********	~~0.31~~ **10.41**	~~0.31~~ **10.41**	**********
Benzene	**********	**********	~~1.93E-06~~ **6.55E-05**	~~1.93E-06~~ **6.55E-05**	**********
Dichlorobenzene	**********	**********	~~1.10E-06~~ **3.74E-05**	~~1.10E-06~~ **3.74E-05**	**********

Pollutant	Emission Factor		PTE (TPY)	Limited PTE (TPY)	Data Source
Formaldehyde	**********	**********	~~6.90E-05~~ **2.34E-03**	~~6.90E-05~~ **2.34E-03**	**********
Hexane	**********	**********	~~1.66E-03~~ **5.62E-02**	~~1.66E-03~~ **5.62E-02**	**********
Toluene	**********	**********	~~3.13E-06~~ **1.06E-04**	~~3.13E-06~~ **1.06E-04**	**********
Lead	**********	**********	~~0.00E+00~~ **1.50E-08**	~~0.00E+00~~ **1.50E-08**	**********
Cadmium	**********	**********	~~1.01E-06~~ **3.43E-05**	~~1.01E-06~~ **3.43E-05**	**********
Chromium	**********	**********	~~1.29E-06~~ **4.37E-05**	~~1.29E-06~~ **4.37E-05**	**********
Manganese	**********	**********	~~3.50E-07~~ **1.19E-05**	~~3.50E-07~~ **1.19E-05**	**********
Nickel	**********	**********	~~1.93E-06~~ **6.55E-05**	~~1.93E-06~~ **6.55E-05**	**********
Total HAP	**********	**********	~~0.0017~~ **0.0589**	~~0.0017~~ **0.0589**	**********
CO_2	**********	**********	~~97~~ **3,290**	~~97~~ **3,290**	**********
CH_4	**********	**********	~~1.83E-03~~ **6.21E-02**	~~1.83E-03~~ **6.21E-02**	**********
N_2O	**********	**********	~~1.80E-04~~ **6.21E-03**	~~1.80E-04~~ **6.21E-03**	**********
CO_2e	**********	**********	~~97~~ **3,293**	~~97~~ **3,293**	**********

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IDEM Modification #1

IDEM, OAQ is revising the emission unit description in Condition D.5.11(b) to indicate the fire pump is for emergency purposes. Revisions are shown below:

D.5.11 Parametric Monitoring

(a) **********

(b) In order to demonstrate the compliance status with Condition D.5.4(b)(1), the Permittee shall record the hours of operation of the diesel-fired **emergency** firewater pump (EU-016) at least once per month.

IDEM Contact

Questions regarding this proposed permit can be directed to:

David J. Matousek
Indiana Department Environmental Management
Office of Air Quality
100 North Senate Avenue
MC 61-53, Room 1003
Indianapolis, Indiana 46204-2251
Toll free (within Indiana): 1-800-451-6027 extension (2-8253)
Or dial directly: (317) 232-8253
Fax: (317) 232-6749 attn: David Matousek
E-mail: dmatouse@idem.in.gov

Please reference permit number T 147-32322-00062 in all correspondence.

Appendix A to the Addendum to the Technical Support Document (ATSD)

Company Name: Ohio Valley Resources, LLC
Address: 300-400 East CR 350 North, Rockport, Indiana 47635
Permit Number: T 147-32322-00062
Reviewer: David Matousek
Date: August 1, 2013

Uncontrolled PTE of the Entire Source (TPY)

Process / Emission Unit	PM	PM10	PM2.5	SO2	VOC	CO	NOx	Non-Biogenic GHGs (as CO2e)	Biogenic GHGs (as CO2e)	Total HAP	Highest Single HAP Methanol
Boiler (EP-011A)	1.78	7.11	7.11	0.16	5.15	34.85	28.65	111,719	0.00	1.77	0.00
Boiler (EP-011B)	1.78	7.11	7.11	0.16	5.15	34.85	28.65	111,719	0.00	1.77	0.00
Boiler (EP-011C)	1.78	7.11	7.11	0.16	5.15	34.85	28.65	111,719	0.00	1.77	0.00
Boiler (EP-11D)	1.78	7.11	7.11	0.16	5.15	34.85	28.65	111,719	0.00	1.77	0.00
Startup Heater (EP-010)	0.87	3.47	3.47	0.27	2.51	16.99	83.85	54,475	0.00	0.86	0.00
Steam Methane Reformer (EP-003)	8.21	32.84	32.84	4.85	23.77	187.78	617.12	515,751	0.00	8.15	0.00
CO2 Vent (EP-004)	0.00	0.00	0.00	0.00	28.51	5.98	0.00	1,304,033	0.00	17.99	17.99
Emergency Generator (EP-009)	0.39	0.39	0.39	2.40	0.8	6.75	11.53	1,366	0.00	0.012	0.00
Fire Water Pump (EP-016)	0.04	0.04	0.04	0.25	0.04	0.69	0.76	140	0.00	0.003	0.00
Cooling Tower A (EP-008)	2.83	1.75	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Cooling Tower B (EP-019)	1.10	0.68	0.002	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Ammonia Storage Flare (EP-005)	4.00E-03	0.015	0.015	0.0012	0.01	0.72	0.13	228	0.00	0.0041	0.00
Ammonia Backend Flare (EP-006)	3.18E-01	1.26	1.26	0.1006	0.91	62.01	11.40	19,610	0.00	0.3501	0.00
Ammonia Frontend Flare (EP-007)	3.14E-01	1.24	1.24	0.0992	0.89	61.16	11.24	19,342	0.00	0.3459	0.00
UAN Flare (EP-017)	5.35E-02	0.21	0.21	0.0169	0.152	10.41	1.91	3,293	0.00	0.0589	0.00
Nitric Acid Tail Gas Stack A (EP-001A)	0.00	0.00	0.00	0.00	0.00	0.00	574.88	788,186	0.00	0.00	0.00
Nitric Acid Tail Gas Stack B (EP-001B)	0.00	0.00	0.00	0.00	0.00	0.00	574.88	788,186	0.00	0.00	0.00
UAN Scrubber Vent A (EP-002A)	84.10	84.10	84.10	0.00	0.00	0.00	0.00	43,464	0.00	0.00	0.00
UAN Scrubber Vent B (EP-002B)	84.10	84.10	84.10	0.00	0.00	0.00	0.00	43,464	0.00	0.00	0.00
Product Loadout (EP-024/025)	0.00	0.00	0.00	0.00	1.95	0.00	0.00	0.00	0.00	0.00	0.00
Startup, Shutdown and Malfunctions	0.00	0.00	0.00	0.00	9.91	679.55	271.32	216,766	0.00	0.00	0.00
Miscellaneous Insignificant Activities	0.00	0.00	0.00	0.00	2.63	0.00	0.62	0.00	0.00	0.10	0.00
Process Fugitives	0.00	0.00	0.00	0.00	0.01	0.07	0.01	1,215	0.00	0.01	0.01
Haul Road Fugitives	5.82	1.11	0.28	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
PTE of Entire Source	195.27	239.64	236.39	8.63	92.69	1171.51	2,274	4,246,395	0.00	34.96	18.00
Title V Major Source Thresholds	NA	100	100	100	100	100	100	100,000	NA	25	10

Appendix A to the Addendum to the Technical Support Document (ATSD)
Controlled Potential to Emit Summary (Continued)

Controlled PTE of the Entire Source (TPY)											
Process / Emission Unit	**PM**	**PM10**	**PM2.5**	**SO2**	**VOC**	**CO**	**NOx**	**Non-Biogenic GHGs (as CO2e)**	**Biogenic GHGs (as CO2e)**	**Total HAP**	**Highest Single HAP Methanol**
Boiler (EP-011A)	1.78	7.11	7.11	0.16	5.15	34.85	19.11	111,719	0.00	1.77	0.00
Boiler (EP-011B)	1.78	7.11	7.11	0.16	5.15	34.85	19.11	111,719	0.00	1.77	0.00
Boiler (EP-011C)	1.78	7.11	7.11	0.16	5.15	34.85	19.11	111,719	0.00	1.77	0.00
Boiler (EP-11D)	1.78	7.11	7.11	0.16	5.15	34.85	19.11	111,719	0.00	1.77	0.00
Startup Heater (EP-010)	0.87	3.47	3.47	0.27	2.51	16.99	83.85	54,475	0.00	0.86	0.00
Steam Methane Reformer (EP-003)	8.21	32.84	32.84	4.85	23.77	187.78	61.71	515,751	0.00	8.15	0.00
CO2 Vent (EP-004)	0.00	0.00	0.00	0.00	28.51	5.98	0.00	1,304,033	0.00	17.99	17.99
Emergency Generator (EP-009)	0.39	0.39	0.39	2.40	0.80	6.75	11.53	1,366	0.00	0.012	0.00
Fire Water Pump (EP-016)	0.04	0.04	0.04	0.25	0.04	0.69	0.76	140	0.00	0.003	0.00
Cooling Tower A (EP-008)	2.83	1.75	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Cooling Tower B (EP-019)	1.10	0.68	0.002	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Ammonia Storage Flare (EP-005)	4.00E-03	0.015	0.015	0.0012	0.01	0.72	0.13	228	0.00	0.0041	0.00
Ammonia Backend Flare (EP-006)	3.18E-01	1.26	1.26	0.1006	0.91	62.01	11.40	19,610	0.00	0.3501	0.00
Ammonia Frontend Flare (EP-007)	3.14E-01	1.24	1.24	0.0992	0.89	61.16	11.24	19,342	0.00	0.3459	0.00
UAN Flare (EP-017)	5.35E-02	0.21	0.21	0.0169	0.15	10.41	1.91	3,293	0.00	0.0589	0.00
Nitric Acid Tail Gas Stack A (EP-001A)	0.00	0.00	0.00	0.00	0.00	0.00	57.49	74,414	0.00	0.00	0.00
Nitric Acid Tail Gas Stack B (EP-001B)	0.00	0.00	0.00	0.00	0.00	0.00	57.49	74,414	0.00	0.00	0.00
UAN Scrubber Vent A (EP-002A)	4.21	4.21	4.21	0.00	0.00	0.00	0.00	43,464	0.00	0.00	0.00
UAN Scrubber Vent B (EP-002B)	4.21	4.21	4.21	0.00	0.00	0.00	0.00	43,464	0.00	0.00	0.00
Product Loadout (EP-024/025)	0.00	0.00	0.00	0.00	1.95	0.00	0.00	0.00	0.00	0.00	0.00
Startup, Shutdown and Malfunctions	0.00	0.00	0.00	0.00	9.91	679.55	271.32	216,766	0.00	0.00	0.00
Miscellaneous Insignificant Activities	0.00	0.00	0.00	0.00	2.63	0.00	0.62	0.00	0.00	0.10	0.00
Process Fugitives	0.00	0.00	0.00	0.00	0.01	0.07	0.01	1,215	0.00	0.01	0.01
Haul Road Fugitives	0.58	0.11	0.03	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
PTE of Entire Source	30.25	78.86	76.36	8.63	92.69	1171.51	645.90	2,818,851	0.00	34.96	18.00

Appendix A to the Addendum to the Technical Support Document (ATSD)
Limited Potential to Emit Summary (Continued)

Limited PTE of the Entire Source (TPY)											
Process / Emission Unit	**PM**	**PM10**	**PM2.5**	**SO2**	**VOC**	**CO**	**NOx**	**Non-Biogenic GHGs (as CO2e)**	**Biogenic GHGs (as CO2e)**	**Total HAP**	**Highest Single HAP Methanol**
Boiler (EP-011A)	2.66	10.65	10.65	0.24	7.71	52.16	28.59	167,200	0.00	2.65	0.00
Boiler (EP-011B)											
Boiler (EP-011C)											
Boiler (EP-11D)											
Startup Heater (EP-010)	0.02	0.08	0.08	0.01	0.06	0.39	1.91	1,243	0.00	0.02	0.00
Steam Methane Reformer (EP-003)	8.21	32.84	32.84	4.85	23.77	187.78	61.71	515,751	0.00	8.15	0.00
CO2 Vent (EP-004)	0.00	0.00	0.00	0.00	28.51	5.98	0.00	1,304,033	0.00	17.99	17.99
Emergency Generator (EP-009)	0.16	0.16	0.16	0.96	0.32	2.70	4.61	546	0.00	0.005	0.00
Fire Water Pump (EP-016)	0.02	0.02	0.02	0.10	0.01	0.28	0.30	56	0.00	0.001	0.00
Cooling Tower A (EP-008)	2.83	1.75	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Cooling Tower B (EP-019)	1.10	0.68	0.002	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Ammonia Storage Flare (EP-005)	4.00E-03	0.01461	0.01461	0.0012	0.01052	0.72	0.13249	228	0.00	0.00408	0.000
Ammonia Backend Flare (EP-006)	3.18E-01	1.26	1.26	0.1006	0.91	62.01	11.40	19,610	0.00	0.35011	0.000
Ammonia Frontend Flare (EP-007)	3.14E-01	1.24	1.24	0.0992	0.89	61.16	11.24	19,342	0.00	0.34589	0.000
UAN Flare (EP-017)	5.35E-02	0.21	0.21	0.0169	0.15	10.41	1.91	3,293	0.00	0.05887	0.000
Nitric Acid Tail Gas Stack A (EP-001A)	0.00	0.00	0.00	0.00	0.00	0.00	57.49	74,414	0.00	0.00	0.00
Nitric Acid Tail Gas Stack B (EP-001B)	0.00	0.00	0.00	0.00	0.00	0.00	57.49	74,414	0.00	0.00	0.00
UAN Scrubber Vent A (EP-002A)	4.21	4.21	4.21	0.00	0.00	0.00	0.00	43,464	0.00	0.00	0.00
UAN Scrubber Vent B (EP-002B)	4.21	4.21	4.21	0.00	0.00	0.00	0.00	43,464	0.00	0.00	0.00
Product Loadout (EP-024/025)	0.00	0.00	0.00	0.00	1.95	0.00	0.00	0.00	0.00	0.00	0.00
Startup, Shutdown and Malfunctions	0.00	0.00	0.00	0.00	9.91	679.55	271.32	216,766	0.00	0.00	0.00
Miscellaneous Insignificant Activities	0.00	0.00	0.00	0.00	2.63	0.00	0.62	0.00	0.00	0.10	0.00
Process Fugitives	0.00	0.00	0.00	0.00	0.01	0.07	0.01	1,215	0.00	0.01	0.01
Haul Road Fugitives	0.58	0.11	0.03	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
PTE of Entire Source	24.69	57.43	54.93	6.38	76.84	1063.21	508.73	2,485,039	0.00	29.69	18.00
PSD Significant Levels	25	15	10	40	40	100	NA	75,000	NA	NA	NA
PSD Major Source Threshold	NA	NA	NA	NA	NA	NA	100	NA	NA	NA	NA

Appendix A to the Addendum to the Technical Support Document (ATSD)
Package Boiler - EP-011A - Natural Gas Combustion

Company Name: Ohio Valley Resources, LLC
Address: 300-400 East CR 350 North, Rockport, Indiana 47635
Permit Number: T 147-32322-00062
Reviewer: David Matousek
Date: August 1, 2013

Boiler Design Data

Heat Input Capacity	218.00	MMBtu/hr
Higher Heating Value	1,020	MMBtu/MMCF
Natural Gas Usage	1,872.24	MMCF/yr
Limited Natural Gas Usage	1,872.24	MMCF/yr

Pollutant	Emission Factor		PTE (TPY)	Control Efficiency (%)	Controlled PTE (TPY)		Data Source
PM (filterable)	1.9	lb/MMCF	1.78	0.00%	1.78		AP-42, Ch 1.4, Table 1.4-2, 7/98
PM10 (filterable + condensible)	7.6	lb/MMCF	7.11	0.00%	7.11		AP-42, Ch 1.4, Table 1.4-2, 7/98
PM2.5 (filterable + condensible)	7.6	lb/MMCF	7.11	0.00%	7.11		AP-42, Ch 1.4, Table 1.4-2, 7/98
SO2	0.17	lb/MMCF	0.16	0.00%	0.16		Design Specification
Nox (Ultra-Low NOx, FGR)	30.6	lb/MMCF	28.65	33.30%	19.11		Design Specification
VOC	5.5	lb/MMCF	5.15	0.00%	5.15		AP-42, Ch 1.4, Table 1.4-2, 7/98
CO	37.23	lb/MMCF	34.85	0.00%	34.85		Design Specification
Benzene	2.10E-03	lb/MMCF	1.97E-03	0.00%	1.97E-03		AP-42, Ch 1.4, Table 1.4-3, 7/98
Dichlorobenzene	1.20E-03	lb/MMCF	1.12E-03	0.00%	1.12E-03		AP-42, Ch 1.4, Table 1.4-3, 7/98
Formaldehyde	7.50E-02	lb/MMCF	0.07	0.00%	0.07		AP-42, Ch 1.4, Table 1.4-3, 7/98
Hexane	1.8	lb/MMCF	1.69	0.00%	1.69		AP-42, Ch 1.4, Table 1.4-3, 7/98
Toluene	3.40E-03	lb/MMCF	3.18E-03	0.00%	3.18E-03		AP-42, Ch 1.4, Table 1.4-3, 7/98
Lead	5.00E-04	lb/MMCF	4.68E-04	0.00%	4.70E-04		AP-42, Ch 1.4, Table 1.4-3, 7/98
Cadmium	1.10E-03	lb/MMCF	1.03E-03	0.00%	1.03E-03		AP-42, Ch 1.4, Table 1.4-3, 7/98
Chromium	1.40E-03	lb/MMCF	1.31E-03	0.00%	1.31E-03		AP-42, Ch 1.4, Table 1.4-3, 7/98
Manganese	3.80E-04	lb/MMCF	3.56E-04	0.00%	3.60E-04		AP-42, Ch 1.4, Table 1.4-3, 7/98
Nickel	2.10E-03	lb/MMCF	1.97E-03	0.00%	1.97E-03		AP-42, Ch 1.4, Table 1.4-3, 7/98
Total HAP			1.77	0.00%	1.77		
CO_2	53.02	kg CO2/MMBtu	111,610	0.00%	111,610		40 CFR 98, Subpart C, Table C-1
CH_4	1.00E-03	kg CO2/MMBtu	2.11	0.00%	2.11		40 CFR 98, Subpart C, Table C-2
N_2O	1.00E-04	kg CO2/MMBtu	0.21	0.00%	0.21		40 CFR 98, Subpart C, Table C-2
CO_2e			111,719	0.00%	111,719		

Methodology:

1)Gas Throughput (MMCF/yr) = Heat Input (MMBtu/hr) * 8,760 hr/yr / Heating Value (MMBtu/MMCF)
2)PTE (TPY) = Gas Throughput (MMCF/yr) * Emission Factor (lb/MMCF) / 2000 lb/ton
3)PTE (TPY) = Emission Factor (kg/MMBtu) * 2.2046 lb/kg x Heating Value (MMBtu/MMCF) * Throughput (MMCF/yr) / 2000 lb/ton
4)PTE CO_2e = PTE CO_2 + (PTE CH_4 * 21) + (PTE N_2O * 310)

Appendix A to the Addendum to the Technical Support Document (ATSD)
Package Boiler - EP-011B - Natural Gas Combustion

Company Name: **Ohio Valley Resources, LLC**
Address: **300-400 East CR 350 North, Rockport, Indiana 47635**
Permit Number: **T 147-32322-00062**
Reviewer: **David Matousek**
Date: **August 1, 2013**

Boiler Design Data

Heat Input Capacity	218.00	MMBtu/hr
Higher Heating Value	1,020	MMBtu/MMCF
Natural Gas Usage	1,872.24	MMCF/yr
Limited Natural Gas Usage	1,872.24	MMCF/yr

Pollutant	Emission Factor		PTE (TPY)	Control Efficiency (%)	Controlled PTE (TPY)		Data Source
PM (filterable)	1.9	lb/MMCF	1.78	0.00%	1.78		AP-42, Ch 1.4, Table 1.4-2, 7/98
PM10 (filterable + condensible)	7.6	lb/MMCF	7.11	0.00%	7.11		AP-42, Ch 1.4, Table 1.4-2, 7/98
PM2.5 (filterable + condensible)	7.6	lb/MMCF	7.11	0.00%	7.11		AP-42, Ch 1.4, Table 1.4-2, 7/98
SO2	0.17	lb/MMCF	0.16	0.00%	0.16		Design Specification
Nox (Ultra-Low NOx, FGR)	30.6	lb/MMCF	28.65	33.30%	19.11		Design Specification
VOC	5.5	lb/MMCF	5.15	0.00%	5.15		AP-42, Ch 1.4, Table 1.4-2, 7/98
CO	37.23	lb/MMCF	34.85	0.00%	34.85		Design Specification
Benzene	2.10E-03	lb/MMCF	1.97E-03	0.00%	1.97E-03		AP-42, Ch 1.4, Table 1.4-3, 7/98
Dichlorobenzene	1.20E-03	lb/MMCF	1.12E-03	0.00%	1.12E-03		AP-42, Ch 1.4, Table 1.4-3, 7/98
Formaldehyde	7.50E-02	lb/MMCF	0.07	0.00%	0.07		AP-42, Ch 1.4, Table 1.4-3, 7/98
Hexane	1.8	lb/MMCF	1.69	0.00%	1.69		AP-42, Ch 1.4, Table 1.4-3, 7/98
Toluene	3.40E-03	lb/MMCF	3.18E-03	0.00%	3.18E-03		AP-42, Ch 1.4, Table 1.4-3, 7/98
Lead	5.00E-04	lb/MMCF	4.68E-04	0.00%	4.70E-04		AP-42, Ch 1.4, Table 1.4-3, 7/98
Cadmium	1.10E-03	lb/MMCF	1.03E-03	0.00%	1.03E-03		AP-42, Ch 1.4, Table 1.4-3, 7/98
Chromium	1.40E-03	lb/MMCF	1.31E-03	0.00%	1.31E-03		AP-42, Ch 1.4, Table 1.4-3, 7/98
Manganese	3.80E-04	lb/MMCF	3.56E-04	0.00%	3.60E-04		AP-42, Ch 1.4, Table 1.4-3, 7/98
Nickel	2.10E-03	lb/MMCF	1.97E-03	0.00%	1.97E-03		AP-42, Ch 1.4, Table 1.4-3, 7/98
Total HAP			1.77	0.00%	1.77		
CO_2	53.02	kg CO2/MMBtu	111,610	0.00%	111,610		40 CFR 98, Subpart C, Table C-1
CH_4	1.00E-03	kg CO2/MMBtu	2.11	0.00%	2.11		40 CFR 98, Subpart C, Table C-2
N_2O	1.00E-04	kg CO2/MMBtu	0.21	0.00%	0.21		40 CFR 98, Subpart C, Table C-2
CO_2e			111,719	0.00%	111,719		

Methodology:

1)Gas Throughput (MMCF/yr) = Heat Input (MMBtu/hr) * 8,760 hr/yr / Heating Value (MMBtu/MMCF)
2)PTE (TPY) = Gas Throughput (MMCF/yr) * Emission Factor (lb/MMCF) / 2000 lb/ton
3)PTE (TPY) = Emission Factor (kg/MMBtu) * 2.2046 lb/kg x Heating Value (MMBtu/MMCF) * Throughput (MMCF/yr) / 2000 lb/ton
4)PTE CO_2e = PTE CO_2 + (PTE CH_4 * 21) + (PTE N_2O * 310)

Appendix A to the Addendum to the Technical Support Document (ATSD)
Package Boiler - EP-011C - Natural Gas Combustion

Company Name: Ohio Valley Resources, LLC
Address: 300-400 East CR 350 North, Rockport, Indiana 47635
Permit Number: T 147-32322-00062
Reviewer: David Matousek
Date: August 1, 2013

Boiler Design Data

Heat Input Capacity	218.00	MMBtu/hr
Higher Heating Value	1,020	MMBtu/MMCF
Natural Gas Usage	1,872.24	MMCF/yr
Limited Natural Gas Usage	1,872.24	MMCF/yr

Pollutant	Emission Factor		PTE (TPY)	Control Efficiency (%)	Controlled PTE (TPY)		Data Source
PM (filterable)	1.9	lb/MMCF	1.78	0.00%	1.78		AP-42, Ch 1.4, Table 1.4-2, 7/98
PM10 (filterable + condensible)	7.6	lb/MMCF	7.11	0.00%	7.11		AP-42, Ch 1.4, Table 1.4-2, 7/98
PM2.5 (filterable + condensible)	7.6	lb/MMCF	7.11	0.00%	7.11		AP-42, Ch 1.4, Table 1.4-2, 7/98
SO2	0.17	lb/MMCF	0.16	0.00%	0.16		Design Specification
Nox (Ultra-Low NOx, FGR)	30.6	lb/MMCF	28.65	33.30%	19.11		Design Specification
VOC	5.5	lb/MMCF	5.15	0.00%	5.15		AP-42, Ch 1.4, Table 1.4-2, 7/98
CO	37.23	lb/MMCF	34.85	0.00%	34.85		Design Specification
Benzene	2.10E-03	lb/MMCF	1.97E-03	0.00%	1.97E-03		AP-42, Ch 1.4, Table 1.4-3, 7/98
Dichlorobenzene	1.20E-03	lb/MMCF	1.12E-03	0.00%	1.12E-03		AP-42, Ch 1.4, Table 1.4-3, 7/98
Formaldehyde	7.50E-02	lb/MMCF	0.07	0.00%	0.07		AP-42, Ch 1.4, Table 1.4-3, 7/98
Hexane	1.8	lb/MMCF	1.69	0.00%	1.69		AP-42, Ch 1.4, Table 1.4-3, 7/98
Toluene	3.40E-03	lb/MMCF	3.18E-03	0.00%	3.18E-03		AP-42, Ch 1.4, Table 1.4-3, 7/98
Lead	5.00E-04	lb/MMCF	4.68E-04	0.00%	4.70E-04		AP-42, Ch 1.4, Table 1.4-3, 7/98
Cadmium	1.10E-03	lb/MMCF	1.03E-03	0.00%	1.03E-03		AP-42, Ch 1.4, Table 1.4-3, 7/98
Chromium	1.40E-03	lb/MMCF	1.31E-03	0.00%	1.31E-03		AP-42, Ch 1.4, Table 1.4-3, 7/98
Manganese	3.80E-04	lb/MMCF	3.56E-04	0.00%	3.60E-04		AP-42, Ch 1.4, Table 1.4-3, 7/98
Nickel	2.10E-03	lb/MMCF	1.97E-03	0.00%	1.97E-03		AP-42, Ch 1.4, Table 1.4-3, 7/98
Total HAP			1.77	0.00%	1.77		
CO_2	53.02	kg CO2/MMBtu	111,610	0.00%	111,610		40 CFR 98, Subpart C, Table C-1
CH_4	1.00E-03	kg CO2/MMBtu	2.11	0.00%	2.11		40 CFR 98, Subpart C, Table C-2
N_2O	1.00E-04	kg CO2/MMBtu	0.21	0.00%	0.21		40 CFR 98, Subpart C, Table C-2
CO_2e			111,719	0.00%	111,719		

Methodology:

1)Gas Throughput (MMCF/yr) = Heat Input (MMBtu/hr) * 8,760 hr/yr / Heating Value (MMBtu/MMCF)
2)PTE (TPY) = Gas Throughput (MMCF/yr) * Emission Factor (lb/MMCF) / 2000 lb/ton
3)PTE (TPY) = Emission Factor (kg/MMBtu) * 2.2046 lb/kg x Heating Value (MMBtu/MMCF) * Throughput (MMCF/yr) / 2000 lb/ton
4)PTE CO_2e = PTE CO_2 + (PTE CH_4 * 21) + (PTE N_2O * 310)

Appendix A to the Addendum to the Technical Support Document (ATSD)
Package Boiler - EP-011D - Natural Gas Combustion

Company Name: Ohio Valley Resources, LLC
Address: 300-400 East CR 350 North, Rockport, Indiana 47635
Permit Number: T 147-32322-00062
Reviewer: David Matousek
Date: August 1, 2013

Boiler Design Data

Heat Input Capacity	218.00	MMBtu/hr
Higher Heating Value	1,020	MMBtu/MMCF
Natural Gas Usage	1,872.24	MMCF/yr
Limited Natural Gas Usage	1,872.24	MMCF/yr

Pollutant	Emission Factor		PTE (TPY)	Control Efficiency (%)	Controlled PTE (TPY)		Data Source
PM (filterable)	1.9	lb/MMCF	1.78	0.00%	1.78		AP-42, Ch 1.4, Table 1.4-2, 7/98
PM10 (filterable + condensible)	7.6	lb/MMCF	7.11	0.00%	7.11		AP-42, Ch 1.4, Table 1.4-2, 7/98
PM2.5 (filterable + condensible)	7.6	lb/MMCF	7.11	0.00%	7.11		AP-42, Ch 1.4, Table 1.4-2, 7/98
SO2	0.17	lb/MMCF	0.16	0.00%	0.16		Design Specification
Nox (Ultra-Low NOx, FGR)	30.6	lb/MMCF	28.65	33.30%	19.11		Design Specification
VOC	5.5	lb/MMCF	5.15	0.00%	5.15		AP-42, Ch 1.4, Table 1.4-2, 7/98
CO	37.23	lb/MMCF	34.85	0.00%	34.85		Design Specification
Benzene	2.10E-03	lb/MMCF	1.97E-03	0.00%	1.97E-03		AP-42, Ch 1.4, Table 1.4-3, 7/98
Dichlorobenzene	1.20E-03	lb/MMCF	1.12E-03	0.00%	1.12E-03		AP-42, Ch 1.4, Table 1.4-3, 7/98
Formaldehyde	7.50E-02	lb/MMCF	0.07	0.00%	0.07		AP-42, Ch 1.4, Table 1.4-3, 7/98
Hexane	1.8	lb/MMCF	1.69	0.00%	1.69		AP-42, Ch 1.4, Table 1.4-3, 7/98
Toluene	3.40E-03	lb/MMCF	3.18E-03	0.00%	3.18E-03		AP-42, Ch 1.4, Table 1.4-3, 7/98
Lead	5.00E-04	lb/MMCF	4.68E-04	0.00%	4.70E-04		AP-42, Ch 1.4, Table 1.4-3, 7/98
Cadmium	1.10E-03	lb/MMCF	1.03E-03	0.00%	1.03E-03		AP-42, Ch 1.4, Table 1.4-3, 7/98
Chromium	1.40E-03	lb/MMCF	1.31E-03	0.00%	1.31E-03		AP-42, Ch 1.4, Table 1.4-3, 7/98
Manganese	3.80E-04	lb/MMCF	3.56E-04	0.00%	3.60E-04		AP-42, Ch 1.4, Table 1.4-3, 7/98
Nickel	2.10E-03	lb/MMCF	1.97E-03	0.00%	1.97E-03		AP-42, Ch 1.4, Table 1.4-3, 7/98
Total HAP			1.77	0.00%	1.77		
CO_2	53.02	kg CO2/MMBtu	111,610	0.00%	111,610		40 CFR 98, Subpart C, Table C-1
CH_4	1.00E-03	kg CO2/MMBtu	2.11	0.00%	2.11		40 CFR 98, Subpart C, Table C-2
N_2O	1.00E-04	kg CO2/MMBtu	0.21	0.00%	0.21		40 CFR 98, Subpart C, Table C-2
CO_2e			111,719	0.00%	111,719		

Methodology:

1)Gas Throughput (MMCF/yr) = Heat Input (MMBtu/hr) * 8,760 hr/yr / Heating Value (MMBtu/MMCF)
2)PTE (TPY) = Gas Throughput (MMCF/yr) * Emission Factor (lb/MMCF) / 2000 lb/ton
3)PTE (TPY) = Emission Factor (kg/MMBtu) * 2.2046 lb/kg x Heating Value (MMBtu/MMCF) * Throughput (MMCF/yr) / 2000 lb/ton
4)PTE CO_2e = PTE CO_2 + (PTE CH_4 * 21) + (PTE N_2O * 310)

Appendix A to the Addendum to the Technical Support Document (ATSD)
Package Boiler Limited Operations - EP-011A to D - Natural Gas Combustion

Company Name: Ohio Valley Resources, LLC
Address: 300-400 East CR 350 North, Rockport, Indiana 47635
Permit Number: T 147-32322-00062
Reviewer: David Matousek
Date: August 1, 2013

Boiler Design Data

Heat Input Capacity	872.00	MMBtu/hr
Higher Heating Value	1,020	MMBtu/MMCF
Natural Gas Usage	7,488.94	MMCF/yr
Limited Natural Gas Usage	2,802	MMCF/yr

Pollutant	Emission Factor		PTE (TPY)	Control Efficiency (%)	Controlled PTE (TPY)	Limited PTE (TPY)	Data Source
PM (filterable)	1.9	lb/MMCF	7.11	0.00%	7.11	2.66	AP-42, Ch 1.4, Table 1.4-2, 7/98
PM10 (filterable + condensible)	7.6	lb/MMCF	28.46	0.00%	28.46	10.65	AP-42, Ch 1.4, Table 1.4-2, 7/98
PM2.5 (filterable + condensible)	7.6	lb/MMCF	28.46	0.00%	28.46	10.65	AP-42, Ch 1.4, Table 1.4-2, 7/98
SO2	0.17	lb/MMCF	0.64	0.00%	0.64	0.24	Design Specification
Nox (Ultra-Low NOx, FGR)	30.6	lb/MMCF	114.58	33.30%	76.42	28.59	Design Specification
VOC	5.5	lb/MMCF	20.59	0.00%	20.59	7.71	AP-42, Ch 1.4, Table 1.4-2, 7/98
CO	37.23	lb/MMCF	139.41	0.00%	139.41	52.16	Design Specification
Benzene	2.10E-03	lb/MMCF	7.86E-03	0.00%	7.86E-03	2.94E-03	AP-42, Ch 1.4, Table 1.4-3, 7/98
Dichlorobenzene	1.20E-03	lb/MMCF	4.49E-03	0.00%	4.49E-03	1.68E-03	AP-42, Ch 1.4, Table 1.4-3, 7/98
Formaldehyde	7.50E-02	lb/MMCF	0.28	0.00%	0.28	0.11	AP-42, Ch 1.4, Table 1.4-3, 7/98
Hexane	1.8	lb/MMCF	6.74	0.00%	6.74	2.52	AP-42, Ch 1.4, Table 1.4-3, 7/98
Toluene	3.40E-03	lb/MMCF	1.27E-02	0.00%	1.27E-02	4.76E-03	AP-42, Ch 1.4, Table 1.4-3, 7/98
Lead	5.00E-04	lb/MMCF	1.87E-03	0.00%	1.87E-03	7.00E-04	AP-42, Ch 1.4, Table 1.4-3, 7/98
Cadmium	1.10E-03	lb/MMCF	4.12E-03	0.00%	4.12E-03	1.54E-03	AP-42, Ch 1.4, Table 1.4-3, 7/98
Chromium	1.40E-03	lb/MMCF	5.24E-03	0.00%	5.24E-03	1.96E-03	AP-42, Ch 1.4, Table 1.4-3, 7/98
Manganese	3.80E-04	lb/MMCF	1.42E-03	0.00%	1.42E-03	5.30E-04	AP-42, Ch 1.4, Table 1.4-3, 7/98
Nickel	2.10E-03	lb/MMCF	7.86E-03	0.00%	7.86E-03	2.94E-03	AP-42, Ch 1.4, Table 1.4-3, 7/98
Total HAP			7.07	0.00%	7.07	2.65	
CO_2	53.02	kg CO2/MMBtu	446,437	0.00%	446,437	167,035	40 CFR 98, Subpart C, Table C-1
CH_4	1.00E-03	kg CO2/MMBtu	8.42	0.00%	8.42	3.15	40 CFR 98, Subpart C, Table C-2
N_2O	1.00E-04	kg CO2/MMBtu	0.84	0.00%	0.84	0.32	40 CFR 98, Subpart C, Table C-2
CO_2e			446,874	0.00%	446,874	167,200	

Methodology:

1)Gas Throughput (MMCF/yr) = Heat Input (MMBtu/hr) * 8,760 hr/yr / Heating Value (MMBtu/MMCF)
2)PTE (TPY) = Gas Throughput (MMCF/yr) * Emission Factor (lb/MMCF) / 2000 lb/ton
3)PTE (TPY) = Emission Factor (kg/MMBtu) * 2.2046 lb/kg x Heating Value (MMBtu/MMCF) * Throughput (MMCF/yr) / 2000 lb/ton
4)PTE CO_2e = PTE CO_2 + (PTE CH_4 * 21) + (PTE N_2O * 310)

Appendix A to the Addendum to the Technical Support Document (ATSD)

Process Heater - EP-010 - Natural Gas Combustion

Company Name: Ohio Valley Resources, LLC
Address: 300-400 East CR 350 North, Rockport, Indiana 47635
Permit Number: T 147-32322-00062
Reviewer: David Matousek
Date: August 1, 2013

Design Data

Heat Input Capacity	106.30	MMBtu/hr
Higher Heating Value	1,020	MMBtu/MMCF
Natural Gas Usage	912.93	MMCF/yr
Limited Natural Gas Usage	20.84	MMCF/yr

Pollutant	Emission Factor		PTE (TPY)	Limited PTE (TPY)	Data Source
PM (filterable)	1.9	lb/MMCF	0.87	0.02	AP-42, Ch 1.4, Table 1.4-2, 7/98
PM10 (filterable + condensible)	7.6	lb/MMCF	3.47	0.08	AP-42, Ch 1.4, Table 1.4-2, 7/98
PM2.5 (filterable + condensible)	7.6	lb/MMCF	3.47	0.08	AP-42, Ch 1.4, Table 1.4-2, 7/98
SO2	0.6	lb/MMCF	0.27	0.01	AP-42, Ch 1.4, Table 1.4-2, 7/98
NOx	183.7	lb/MMCF	83.85	1.91	Design Specification
VOC	5.5	lb/MMCF	2.51	0.06	AP-42, Ch 1.4, Table 1.4-2, 7/98
CO	37.23	lb/MMCF	16.99	0.39	AP-42, Ch 1.4, Table 1.4-1, 7/98
Benzene	2.10E-03	lb/MMCF	9.59E-04	2.19E-05	AP-42, Ch 1.4, Table 1.4-3, 7/98
Dichlorobenzene	1.20E-03	lb/MMCF	5.48E-04	1.25E-05	AP-42, Ch 1.4, Table 1.4-3, 7/98
Formaldehyde	7.50E-02	lb/MMCF	0.03	0	AP-42, Ch 1.4, Table 1.4-3, 7/98
Hexane	1.8	lb/MMCF	0.82	0.02	AP-42, Ch 1.4, Table 1.4-3, 7/98
Toluene	3.40E-03	lb/MMCF	1.55E-03	3.54E-05	AP-42, Ch 1.4, Table 1.4-3, 7/98
Lead	5.00E-04	lb/MMCF	2.28E-04	5.21E-06	AP-42, Ch 1.4, Table 1.4-3, 7/98
Cadmium	1.10E-03	lb/MMCF	5.02E-04	1.15E-05	AP-42, Ch 1.4, Table 1.4-3, 7/98
Chromium	1.40E-03	lb/MMCF	6.39E-04	1.46E-05	AP-42, Ch 1.4, Table 1.4-3, 7/98
Manganese	3.80E-04	lb/MMCF	1.73E-04	3.96E-06	AP-42, Ch 1.4, Table 1.4-3, 7/98
Nickel	2.10E-03	lb/MMCF	9.59E-04	2.19E-05	AP-42, Ch 1.4, Table 1.4-3, 7/98
Total HAP			0.86	0.02	
CO_2	53.02	kg CO2/MMBtu	54,422.34	1,242.33	40 CFR 98, Subpart C, Table C-1
CH_4	1.00E-03	kg CO2/MMBtu	1.03	0.02	40 CFR 98, Subpart C, Table C-2
N_2O	1.00E-04	kg CO2/MMBtu	0.10	2.34E-03	40 CFR 98, Subpart C, Table C-2
CO_2e			54,475	1,243	

Methodology:

1) Gas Throughput (MMCF/yr) = Heat Input (MMBtu/hr) * 8,760 hr/yr / Heating Value (MMBtu/MMCF)
2) PTE (TPY) = Gas Throughput (MMCF/yr) * Emission Factor (lb/MMCF) / 2000 lb/ton
3) PTE (TPY) = Emission Factor (kg/MMBtu) * 2.2046 lb/kg x Heating Value (MMBtu/MMCF) * Throughput (MMCF/yr) / 2000 lb/ton
4) PTE CO_2e = PTE CO_2 + (PTE CH_4 * 21) + (PTE N_2O * 310)

Appendix A to the Addendum to the Technical Support Document (ATSD)
Steam Methane Reformer - EP-003

Company Name: Ohio Valley Resources, LLC
Address: 300-400 East CR 350 North, Rockport, Indiana 47635
Permit Number: T 147-32322-00062
Reviewer: David Matousek
Date: August 1, 2013

Design Data

Heat Input Capacity	1,006.40	MMBtu/hr
Higher Heating Value	1,020	MMBtu/MMCF
Natural Gas Usage	8,643.20	MMCF/yr
Limited Natural Gas Usage	8,643.20	MMCF/yr

Pollutant	Emission Factor		PTE (TPY)	Control Efficiency %	Controlled PTE (TPY)	Limited & Controlled PTE (TPY)	Data Source
PM	1.9	lb/MMCF	8.21	0.00%	8.21	8.21	AP-42, Ch 1.4, Table 1.4-2, 7/98
PM10	7.6	lb/MMCF	32.84	0.00%	32.84	32.84	AP-42, Ch 1.4, Table 1.4-2, 7/98
PM2.5	7.6	lb/MMCF	32.84	0.00%	32.84	32.84	AP-42, Ch 1.4, Table 1.4-2, 7/98
SO2	0.0011	lb/MMBtu	4.85	0.00%	4.85	4.85	Design Specification
NOx	0.14	lb/MMBtu	617.12	90.00%	61.71	61.71	Design Specification
VOC	5.5	lb/MMCF	23.77	0.00%	23.77	23.77	AP-42, Ch 1.4, Table 1.4-2, 7/98
CO	0.0426	lb/MMBtu	187.78	0.00%	187.78	187.78	Design Specification
Benzene	2.10E-03	lb/MMCF	9.08E-03	0.00%	9.08E-03	9.08E-03	AP-42, Ch 1.4, Table 1.4-3, 7/98
Dichlorobenzene	1.20E-03	lb/MMCF	5.19E-03	0.00%	5.19E-03	5.19E-03	AP-42, Ch 1.4, Table 1.4-3, 7/98
Formaldehyde	7.50E-02	lb/MMCF	0.32	0.00%	0.32	0.32	AP-42, Ch 1.4, Table 1.4-3, 7/98
Hexane	1.8	lb/MMCF	7.78	0.00%	7.78	7.78	AP-42, Ch 1.4, Table 1.4-3, 7/98
Toluene	3.40E-03	lb/MMCF	1.47E-02	0.00%	0.015	0.015	AP-42, Ch 1.4, Table 1.4-3, 7/98
Lead	5.00E-04	lb/MMCF	2.16E-03	0.00%	2.16E-03	2.16E-03	AP-42, Ch 1.4, Table 1.4-3, 7/98
Cadmium	1.10E-03	lb/MMCF	4.75E-03	0.00%	4.75E-03	4.75E-03	AP-42, Ch 1.4, Table 1.4-3, 7/98
Chromium	1.40E-03	lb/MMCF	6.05E-03	0.00%	6.05E-03	6.05E-03	AP-42, Ch 1.4, Table 1.4-3, 7/98
Manganese	3.80E-04	lb/MMCF	1.64E-03	0.00%	1.64E-03	1.64E-03	AP-42, Ch 1.4, Table 1.4-3, 7/98
Nickel	2.10E-03	lb/MMCF	9.08E-03	0.00%	9.08E-03	9.08E-03	AP-42, Ch 1.4, Table 1.4-3, 7/98
Total HAP			8.15	0.00%	8.15	8.15	
CO_2	53.02	kg CO2/MMBtu	515,246	0.00%	515,246	515,246	40 CFR 98, Subpart C, Table C-1
CH_4	1.00E-03	kg CO2/MMBtu	9.72	0.00%	9.72	9.72	40 CFR 98, Subpart C, Table C-2
N_2O	1.00E-04	kg CO2/MMBtu	0.97	0.00%	0.97	0.97	40 CFR 98, Subpart C, Table C-2
CO_2e			515,751		515,751	515,751	

Methodology:

1) Gas Throughput (MMCF/yr) = Heat Input (MMBtu/hr) * 8,760 hr/yr / Heating Value (MMBtu/MMCF)
2) PTE (TPY) = Gas Throughput (MMCF/yr) * Emission Factor (lb/MMCF) / 2000 lb/ton
3) PTE (TPY) = Emission Factor (kg/MMBtu) * 2.2046 lb/kg x Heating Value (MMBtu/MMCF) * Throughput (MMCF/yr) / 2000 lb/ton
4) PTE CO_2e = PTE CO_2 + (PTE CH_4 * 21) + (PTE N_2O * 310)

Appendix A to the Addendum to the Technical Support Document (ATSD)
CO_2 Purification Vent - EP-004

Company Name: Ohio Valley Resources, LLC
Address: 300-400 East CR 350 North, Rockport, Indiana 47635
Permit Number: T 147-32322-00062
Reviewer: David Matousek
Date: August 1, 2013

Design Data

Ammonia Production Capacity	116.67	tons ammonia / hr
	1,022,000.00	tons ammonia / year

Scenario 1						
Pollutant	**Emission Factor**		**PTE (TPY)**	**% Vented to Atmosphere**	**Vented Emissisons (TPY)**	**Data Source**
VOC	0.0558	lb/ton ammonia	28.51	100.00%	28.51	Engineering Estimate
CO	0.0117	lb/ton ammonia	5.98	100.00%	5.98	Engineering Estimate
Methanol	0.0352	lb/ton ammonia	17.99	100.00%	17.99	Engineering Estimate
Total HAP			17.99	100.00%	17.99	
CO_2	2,550.00	lb/ton ammonia	1,303,050	77.60%	1,011,167	Engineering Estimate
Methane	0.0916	lb/ton ammonia	46.81	77.60%	36.32	Engineering Estimate
CO_2e			1,304,033		1,011,930	

Scenario 2						
Pollutant	**Emission Factor**		**PTE (TPY)**	**% Vented to Atmosphere**	**Vented Emissisons (TPY)**	**Data Source**
VOC	0.0558	lb/ton ammonia	28.51	100.00%	28.51	Engineering Estimate
CO	0.0117	lb/ton ammonia	5.98	100.00%	5.98	Engineering Estimate
Methanol	0.0352	lb/ton ammonia	17.99	100.00%	17.99	Engineering Estimate
Total HAP			17.99	100.00%	17.99	
CO_2	2,550.00	lb/ton ammonia	1,303,050	100.00%	1,303,050	Engineering Estimate
Methane	0.0916	lb/ton ammonia	46.81	100.00%	46.81	Engineering Estimate
CO_2e			1,304,033		1,304,033	

Methodology:

1) PTE (TPY) = Emission Factor (lb/ton ammonia) * Ammonia Production (tons ammonia/yr) / 2000 lb/ton
2) PTE CO_2e = PTE CO_2 + (PTE CH_4 * 21): No N2O is expected.
3) Vented Emissions (TPY) = PTE (TPY) * % Vented

Appendix A to the Addendum to the Technical Support Document (ATSD)
Potential to Emit - Diesel Fired Emergency Generator EP-009

Company Name: Ohio Valley Resources, LLC
Address: 300-400 East CR 350 North, Rockport, Indiana 47635
Permit Number: T 147-32322-00062
Reviewer: David Matousek
Date: August 1, 2013

Operating Parameters - Diesel Combustion

Engine Output	4,690	Hp			
Brake Specific Fuel Consumption	7,117	Btu/Hp.hr			
Heat Input	33.38	MMBtu/hr			
Diesel Heat Content	140.00	MMBtu/Kgallon			
Hours for Emergency PTE	500	hours/yr	or	119.214	Kgal/yr
Limited Hours	200	hours/yr	or	47.686	Kgal/yr

Pollutant	Emission Factor		PTE (TPY)	Limited PTE (TPY)	Emission Factor Source
PM	0.15	g/hp-hr	0.39	0.16	Design Specification
PM10	0.15	g/hp-hr	0.39	0.16	Design Specification
PM2.5	0.15	g/hp-hr	0.39	0.16	Design Specification
SO2	0.93	g/hp-hr	2.40	0.96	Design Specification
VOC	0.31	g/hp-hr	0.8	0.32	Design Specification
CO	2.61	g/hp-hr	6.75	2.70	Design Specification
NOx	4.46	g/hp-hr	11.53	4.61	Design Specification
Benzene	7.76E-04	lb/MMBtu	6.48E-03	2.59E-03	AP-42, Ch 3.4, Table 3.4-3 and 3.4-4
Toluene	2.81E-04	lb/MMBtu	2.34E-03	9.38E-04	AP-42, Ch 3.4, Table 3.4-3 and 3.4-4
Xylene	1.93E-04	lb/MMBtu	1.61E-03	6.44E-04	AP-42, Ch 3.4, Table 3.4-3 and 3.4-4
Formaldehyde	7.89E-05	lb/MMBtu	6.58E-04	2.63E-04	AP-42, Ch 3.4, Table 3.4-3 and 3.4-4
Acetaldehyde	2.52E-05	lb/MMBtu	2.10E-04	8.41E-05	AP-42, Ch 3.4, Table 3.4-3 and 3.4-4
Acrolein	7.88E-06	lb/MMBtu	6.58E-05	2.63E-05	AP-42, Ch 3.4, Table 3.4-3 and 3.4-4
Naphthalene	1.30E-04	lb/MMBtu	1.08E-03	4.34E-04	AP-42, Ch 3.4, Table 3.4-3 and 3.4-4
Total HAP			1.20E-02	5.00E-03	
CO2	73.96	kg/MMBtu	1,361	544	40 CFR 98, Subpart C, Table C-1
CH4	3.00E-03	kg/MMBtu	0.055	0.022	40 CFR 98, Subpart C, Table C-2
N2O	6.00E-04	kg/MMBtu	0.011	0.004	40 CFR 98, Subpart C, Table C-2
CO2e			1,366	546	

Methodology:
(a) PTE (TPY) = Engine Output (Hp) x Hours Operated (Hr/yr) x Emission Factor (lb/Hp-Hr) x 1 ton / 2,000 lb
(b) PTE (TPY) = Heat Input (MMBtu/hr) x Emission Factor (lb/MMBtu) x Hours Operated (hr/yr) x 1 ton / 2,000 lb
(c) CO2e (ton/yr) = CO2 (ton/yr) + CH4 (ton/yr) x 21 + N2O (ton/yr) x 310
(d) Emission Factor (lb/MMBtu) = Emission Factor (kg/MMBtu) x 2.2046 lb/kg

Appendix A to the Addendum to the Technical Support Document (ATSD)
Potential to Emit - Diesel Fired Emergency Fire Pump EP-016

Company Name: Ohio Valley Resources, LLC
Address: 300-400 East CR 350 North, Rockport, Indiana 47635
Permit Number: T 147-32322-00062
Reviewer: David Matousek
Date: August 1, 2013

Operating Parameters - Diesel Combustion

Engine Output	481	Hp			
Brake Specific Fuel Consumption	7,131	Btu/Hp.hr			
Heat Input	3.43	MMBtu/hr			
Diesel Heat Content	140.00	MMBtu/Kgallon			
Hours for Emergency PTE	500	hours/yr	or	12.250	Kgal/yr
Limited Hours	200	hours/yr	or	4.900	Kgal/yr

Pollutant	Emission Factor		PTE (TPY)	Limited PTE (TPY)	Emission Factor Source
PM	0.15	g/hp-hr	0.04	0.02	Design Specification
PM10	0.15	g/hp-hr	0.04	0.02	Design Specification
PM2.5	0.15	g/hp-hr	0.04	0.02	Design Specification
SO2	0.93	g/hp-hr	0.25	0.10	Design Specification
VOC	0.14	g/hp-hr	0.04	0.01	Design Specification
CO	2.60	g/hp-hr	0.69	0.28	Design Specification
NOx	2.859	g/hp-hr	0.76	0.30	Design Specification
Benzene	9.33E-04	lb/MMBtu	8.00E-04	3.20E-04	AP-42, Ch 3.3, Table 3.3-2
Toluene	4.09E-04	lb/MMBtu	3.51E-04	1.40E-04	AP-42, Ch 3.3, Table 3.3-2
Xylene	2.85E-04	lb/MMBtu	2.44E-04	9.78E-05	AP-42, Ch 3.3, Table 3.3-2
Formaldehyde	1.18E-03	lb/MMBtu	1.01E-03	4.05E-04	AP-42, Ch 3.3, Table 3.3-2
Acetaldehyde	7.67E-04	lb/MMBtu	6.58E-04	2.63E-04	AP-42, Ch 3.3, Table 3.3-2
Naphthalene	8.48E-05	lb/MMBtu	7.27E-05	2.91E-05	AP-42, Ch 3.3, Table 3.3-2
Total HAP			3.00E-03	1.25E-03	
CO2	73.96	kg/MMBtu	140	56	40 CFR 98, Subpart C, Table C-1
CH4	3.00E-03	kg/MMBtu	0.006	0.002	40 CFR 98, Subpart C, Table C-2
N2O	6.00E-04	kg/MMBtu	0.001	4.50E-04	40 CFR 98, Subpart C, Table C-2
CO2e			140	56	

Methodology:
(a) PTE (TPY) = Engine Output (Hp) x Hours Operated (Hr/yr) x Emission Factor (lb/Hp-Hr) x 1 ton / 2,000 lb
(b) PTE (TPY) = Heat Input (MMBtu/hr) x Emission Factor (lb/MMBtu) x Hours Operated (hr/yr) x 1 ton / 2,000 lb
(c) CO2e (ton/yr) = CO2 (ton/yr) + CH4 (ton/yr) x 21 + N2O (ton/yr) x 310
(d) Emission Factor (lb/MMBtu) = Emission Factor (kg/MMBtu) x 2.2046 lb/kg

Appendix A to the Addendum to the Technical Support Document (ATSD)

Cooling Tower A - EP-008
Cooling Tower B - EP-019

Company Name: Ohio Valley Resources, LLC
Address: 300-400 East CR 350 North, Rockport, Indiana 47635
Permit Number: T 147-32322-00062
Reviewer: David Matousek
Date: August 1, 2013

Cooling Tower - Potential to Emit

Emission Unit	Description	Circulation Rate (GPM)	Drift Factor (%)	Solids Content (mg/l)	Pollutant	Mass Fraction (%)	Annual Emissions (TPY)
EP-008	Cooling Tower A	129,320	0.0005	2,000	PM	100.00%	2.83
					PM_{10}	62.00%	1.75
					$PM_{2.5}$	0.22%	0.01
EP-019	Cooling Tower B	50,400	0.0005	2,000	PM	100.00%	1.10
					PM_{10}	62.00%	0.68
					$PM_{2.5}$	0.22%	0.002

Methodology:

1) PM10 and PM2.5 mass fractions were estimated using, "Calculating Realistic PM10 Emissions from Cooling Towers," by Reisman, J. and Frisbie, G.

2) PM Emissions (lb/hr) = Q (GPM) * 60 min/hr * 8.34 lb/gallon x (Solids Con. (mg/l) /1.0E06) * (Drift Factor/100) * 1ton/2,000 lb

3) PM Emissions (TPY) = PM Emissions (lb/hr) * 4.38 ton-hr/lb-yr

Appendix A to the Addendum to the Technical Support Document (ATSD)

Ammonia Storage Flare - EP-005 - Natural Gas Combustion with Purge Gas

Company Name: Ohio Valley Resources, LLC
Address: 300-400 East CR 350 North, Rockport, Indiana 47635
Permit Number: T 147-32322-00062
Reviewer: David Matousek
Date: August 1, 2013

Design Data

Heat Input Capacity	0.445	MMBtu/hr
Higher Heating Value	902	MMBtu/MMCF (Natural Gas Pilot + Purge Process CH_4)
Natural Gas Usage	4.32	MMCF/yr
Limited Natural Gas Usage	4.32	MMCF/yr

Pollutant	Emission Factor		PTE (TPY)	Limited PTE (TPY)	Data Source
PM	0.0019	lb/MMBtu	0.004	0.004	AP-42, Ch 1.4, 1,020 MMBtu/MMCF
PM10 (filterable + condensible)	0.0075	lb/MMBtu	0.015	0.015	AP-42, Ch 1.4, Table 1.4-2
PM2.5 (filterable + condensible)	0.0075	lb/MMBtu	0.015	0.015	AP-42, Ch 1.4, Table 1.4-2
SO2	0.0006	lb/MMBtu	0.0012	0.0012	AP-42, Ch 1.4, Table 1.4-2
NOx	0.068	lb/MMBtu	0.133	0.132	AP-42, Ch 13.5, Table 13.5-1
VOC	0.0054	lb/MMBtu	0.011	0.011	AP-42, Ch 1.4, Table 1.4-2
CO	0.37	lb/MMBtu	0.72	0.72	AP-42, Ch 13.5, Table 13.5-1
Benzene	2.10E-03	lb/MMCF	4.54E-06	4.54E-06	AP-42, Ch 1.4, Table 1.4-3
Dichlorobenzene	1.20E-03	lb/MMCF	2.59E-06	2.59E-06	AP-42, Ch 1.4, Table 1.4-3
Formaldehyde	7.50E-02	lb/MMCF	1.62E-04	1.62E-04	AP-42, Ch 1.4, Table 1.4-3
Hexane	1.8	lb/MMCF	3.89E-03	3.89E-03	AP-42, Ch 1.4, Table 1.4-3
Toluene	3.40E-03	lb/MMCF	7.34E-06	7.34E-06	AP-42, Ch 1.4, Table 1.4-3
Lead	4.90E-07	lb/MMCF	1.06E-09	1.06E-09	AP-42, Ch 1.4, Table 1.4-2
Cadmium	1.10E-03	lb/MMCF	2.38E-06	2.38E-06	AP-42, Ch 1.4, Table 1.4-4
Chromium	1.40E-03	lb/MMCF	3.02E-06	3.02E-06	AP-42, Ch 1.4, Table 1.4-4
Manganese	3.80E-04	lb/MMCF	8.21E-07	8.21E-07	AP-42, Ch 1.4, Table 1.4-4
Nickel	2.10E-03	lb/MMCF	4.54E-06	4.54E-06	AP-42, Ch 1.4, Table 1.4-4
Total HAP			4.08E-03	4.08E-03	
CO_2	53.02	kg CO2/MMBtu	227.74	227.74	40 CFR 98, Subpart C, Table C-1
CH_4	1.00E-03	kg CO2/MMBtu	4.30E-03	4.30E-03	40 CFR 98, Subpart C, Table C-2
N_2O	1.00E-04	kg CO2/MMBtu	4.30E-04	4.30E-04	40 CFR 98, Subpart C, Table C-2
CO_2e			228	228	

Methodology:

1) Gas Throughput (MMCF/yr) = Heat Input (MMBtu/hr) * 8,760 hr/yr / Heating Value (MMBtu/MMCF)
2) PTE (TPY) = Gas Throughput (MMCF/yr) * Emission Factor (lb/MMCF) / 2000 lb/ton
3) PTE (TPY) = Emission Factor (kg/MMBtu) * 2.2046 lb/kg x Heating Value (MMBtu/MMCF) * Throughput (MMCF/yr) / 2000 lb/ton
4) PTE CO_2e = PTE CO_2 + (PTE CH_4 * 21) + (PTE N_2O * 310)

Appendix A to the Addendum to the Technical Support Document (ATSD)

Ammonia Process Backend Flare - EP-006 - Natural Gas Combustion with Purge Gas

Company Name: Ohio Valley Resources, LLC
Address: 300-400 East CR 350 North, Rockport, Indiana 47635
Permit Number: T 147-32322-00062
Reviewer: David Matousek
Date: August 1, 2013

Design Data

Heat Input Capacity	38.264	MMBtu/hr
Higher Heating Value	902	MMBtu/MMCF (Natural Gas Pilot + Purge Process CH_4)
Natural Gas Usage	371.61	MMCF/yr
Limited Natural Gas Usage	371.61	MMCF/yr

Pollutant	Emission Factor		PTE (TPY)	Limited PTE (TPY)	Data Source
PM	0.0019	lb/MMBtu	3.18E-01	3.18E-01	AP-42, Ch 1.4, 1,020 MMBtu/MMCF
PM10 (filterable + condensible)	0.0075	lb/MMBtu	1.26	1.26	AP-42, Ch 1.4, Table 1.4-2
PM2.5 (filterable + condensible)	0.0075	lb/MMBtu	1.26	1.26	AP-42, Ch 1.4, Table 1.4-2
SO2	0.0006	lb/MMBtu	0.1006	0.1006	AP-42, Ch 1.4, Table 1.4-2
NOx	0.068	lb/MMBtu	11.40	11.40	AP-42, Ch 13.5, Table 13.5-1
VOC	0.0054	lb/MMBtu	0.91	0.91	AP-42, Ch 1.4, Table 1.4-2
CO	0.37	lb/MMBtu	62.01	62.01	AP-42, Ch 13.5, Table 13.5-1
Benzene	2.10E-03	lb/MMCF	3.90E-04	3.90E-04	AP-42, Ch 1.4, Table 1.4-3
Dichlorobenzene	1.20E-03	lb/MMCF	2.23E-04	2.23E-04	AP-42, Ch 1.4, Table 1.4-3
Formaldehyde	7.50E-02	lb/MMCF	1.39E-02	1.39E-02	AP-42, Ch 1.4, Table 1.4-3
Hexane	1.8	lb/MMCF	0.334	0.334	AP-42, Ch 1.4, Table 1.4-3
Toluene	3.40E-03	lb/MMCF	6.32E-04	6.32E-04	AP-42, Ch 1.4, Table 1.4-3
Lead	4.90E-07	lb/MMCF	9.10E-08	9.10E-08	AP-42, Ch 1.4, Table 1.4-2
Cadmium	1.10E-03	lb/MMCF	2.04E-04	2.04E-04	AP-42, Ch 1.4, Table 1.4-4
Chromium	1.40E-03	lb/MMCF	2.60E-04	2.60E-04	AP-42, Ch 1.4, Table 1.4-4
Manganese	3.80E-04	lb/MMCF	7.06E-05	7.06E-05	AP-42, Ch 1.4, Table 1.4-4
Nickel	2.10E-03	lb/MMCF	3.90E-04	3.90E-04	AP-42, Ch 1.4, Table 1.4-4
Total HAP			3.50E-01	3.50E-01	
CO_2	53.02	kg CO2/MMBtu	19,589.96	19,589.96	40 CFR 98, Subpart C, Table C-1
CH_4	1.00E-03	kg CO2/MMBtu	0.37	0.37	40 CFR 98, Subpart C, Table C-2
N_2O	1.00E-04	kg CO2/MMBtu	0.04	0.04	40 CFR 98, Subpart C, Table C-2
CO_2e			19,610	19,610	

Methodology:

1) Gas Throughput (MMCF/yr) = Heat Input (MMBtu/hr) * 8,760 hr/yr / Heating Value (MMBtu/MMCF)
2) PTE (TPY) = Gas Throughput (MMCF/yr) * Emission Factor (lb/MMCF) / 2000 lb/ton
3) PTE (TPY) = Emission Factor (kg/MMBtu) * 2.2046 lb/kg x Heating Value (MMBtu/MMCF) * Throughput (MMCF/yr) / 2000 lb/ton
4) PTE CO_2e = PTE CO_2 + (PTE CH_4 * 21) + (PTE N_2O * 310)

Appendix A to the Addendum to the Technical Support Document (ATSD)

Ammonia Process Frontend Flare - EP-007 - Natural Gas Combustion with Purge Gas

Company Name: Ohio Valley Resources, LLC
Address: 300-400 East CR 350 North, Rockport, Indiana 47635
Permit Number: T 147-32322-00062
Reviewer: David Matousek
Date: August 1, 2013

Design Data

Heat Input Capacity	37.741	MMBtu/hr
Higher Heating Value	902	MMBtu/MMCF (Natural Gas Pilot + Purge Process CH_4)
Natural Gas Usage	366.53	MMCF/yr
Limited Natural Gas Usage	366.53	MMCF/yr

Pollutant	Emission Factor		PTE (TPY)	Limited PTE (TPY)	Data Source
PM	0.0019	lb/MMBtu	3.14E-01	3.14E-01	AP-42, Ch 1.4, 1,020 MMBtu/MMCF
PM10 (filterable + condensible)	0.0075	lb/MMBtu	1.24	1.24	AP-42, Ch 1.4, Table 1.4-2
PM2.5 (filterable + condensible)	0.0075	lb/MMBtu	1.24	1.24	AP-42, Ch 1.4, Table 1.4-2
SO2	0.0006	lb/MMBtu	0.0992	0.0992	AP-42, Ch 1.4, Table 1.4-2
NOx	0.068	lb/MMBtu	11.24	11.24	AP-42, Ch 13.5, Table 13.5-1
VOC	0.0054	lb/MMBtu	0.89	0.89	AP-42, Ch 1.4, Table 1.4-2
CO	0.37	lb/MMBtu	61.16	61.16	AP-42, Ch 13.5, Table 13.5-1
Benzene	2.10E-03	lb/MMCF	3.85E-04	3.85E-04	AP-42, Ch 1.4, Table 1.4-3
Dichlorobenzene	1.20E-03	lb/MMCF	2.20E-04	2.20E-04	AP-42, Ch 1.4, Table 1.4-3
Formaldehyde	7.50E-02	lb/MMCF	1.374E-02	1.374E-02	AP-42, Ch 1.4, Table 1.4-3
Hexane	1.8	lb/MMCF	0.330	0.330	AP-42, Ch 1.4, Table 1.4-3
Toluene	3.40E-03	lb/MMCF	6.23E-04	6.23E-04	AP-42, Ch 1.4, Table 1.4-3
Lead	4.90E-07	lb/MMCF	9.00E-08	9.00E-08	AP-42, Ch 1.4, Table 1.4-2
Cadmium	1.10E-03	lb/MMCF	2.02E-04	2.02E-04	AP-42, Ch 1.4, Table 1.4-4
Chromium	1.40E-03	lb/MMCF	2.57E-04	2.57E-04	AP-42, Ch 1.4, Table 1.4-4
Manganese	3.80E-04	lb/MMCF	6.96E-05	6.96E-05	AP-42, Ch 1.4, Table 1.4-4
Nickel	2.10E-03	lb/MMCF	3.85E-04	3.85E-04	AP-42, Ch 1.4, Table 1.4-4
Total HAP			3.46E-01	3.46E-01	
CO_2	53.02	kg CO2/MMBtu	19,322.16	19,322.16	40 CFR 98, Subpart C, Table C-1
CH_4	1.00E-03	kg CO2/MMBtu	0.36	0.36	40 CFR 98, Subpart C, Table C-2
N_2O	1.00E-04	kg CO2/MMBtu	0.04	0.04	40 CFR 98, Subpart C, Table C-2
CO_2e			19,342	19,342	

Methodology:

1) Gas Throughput (MMCF/yr) = Heat Input (MMBtu/hr) * 8,760 hr/yr / Heating Value (MMBtu/MMCF)
2) PTE (TPY) = Gas Throughput (MMCF/yr) * Emission Factor (lb/MMCF) / 2000 lb/ton
3) PTE (TPY) = Emission Factor (kg/MMBtu) * 2.2046 lb/kg x Heating Value (MMBtu/MMCF) * Throughput (MMCF/yr) / 2000 lb/ton
4) PTE CO_2e = PTE CO_2 + (PTE CH_4 * 21) + (PTE N_2O * 310)

Appendix A to the Addendum to the Technical Support Document (ATSD)

UAN Flare - EP-017 - Natural Gas Combustion with Purge Gas

Company Name: Ohio Valley Resources, LLC
Address: 300-400 East CR 350 North, Rockport, Indiana 47635
Permit Number: T 147-32322-00062
Reviewer: David Matousek
Date: August 1, 2013

Design Data

Heat Input Capacity	6.426	MMBtu/hr
Higher Heating Value	902	MMBtu/MMCF (Natural Gas Pilot + Purge Process CH_4)
Natural Gas Usage	62.41	MMCF/yr
Limited Natural Gas Usage	62.41	MMCF/yr

Pollutant	Emission Factor		PTE (TPY)	Limited PTE (TPY)	Data Source
PM	0.0019	lb/MMBtu	5.35E-02	5.35E-02	AP-42, Ch 1.4, 1,020 MMBtu/MMCF
PM10 (filterable + condensible)	0.0075	lb/MMBtu	0.21	0.21	AP-42, Ch 1.4, Table 1.4-2
PM2.5 (filterable + condensible)	0.0075	lb/MMBtu	0.21	0.21	AP-42, Ch 1.4, Table 1.4-2
SO2	0.0006	lb/MMBtu	0.0169	0.0169	AP-42, Ch 1.4, Table 1.4-2
NOx	0.068	lb/MMBtu	1.91	1.91	AP-42, Ch 13.5, Table 13.5-1
VOC	0.0054	lb/MMBtu	0.1520	0.1520	AP-42, Ch 1.4, Table 1.4-2
CO	0.37	lb/MMBtu	10.41	10.41	AP-42, Ch 13.5, Table 13.5-1
Benzene	2.10E-03	lb/MMCF	6.55E-05	6.55E-05	AP-42, Ch 1.4, Table 1.4-3
Dichlorobenzene	1.20E-03	lb/MMCF	3.74E-05	3.74E-05	AP-42, Ch 1.4, Table 1.4-3
Formaldehyde	7.50E-02	lb/MMCF	2.34E-03	2.34E-03	AP-42, Ch 1.4, Table 1.4-3
Hexane	1.8	lb/MMCF	5.62E-02	5.62E-02	AP-42, Ch 1.4, Table 1.4-3
Toluene	3.40E-03	lb/MMCF	1.06E-04	1.06E-04	AP-42, Ch 1.4, Table 1.4-3
Lead	4.90E-07	lb/MMCF	1.50E-08	1.50E-08	AP-42, Ch 1.4, Table 1.4-2
Cadmium	1.10E-03	lb/MMCF	3.43E-05	3.43E-05	AP-42, Ch 1.4, Table 1.4-4
Chromium	1.40E-03	lb/MMCF	4.37E-05	4.37E-05	AP-42, Ch 1.4, Table 1.4-4
Manganese	3.80E-04	lb/MMCF	1.19E-05	1.19E-05	AP-42, Ch 1.4, Table 1.4-4
Nickel	2.10E-03	lb/MMCF	6.55E-05	6.55E-05	AP-42, Ch 1.4, Table 1.4-4
Total HAP			0.0589	0.0589	
CO_2	53.02	kg CO2/MMBtu	3,290	3,290	40 CFR 98, Subpart C, Table C-1
CH_4	1.00E-03	kg CO2/MMBtu	6.21E-02	6.21E-02	40 CFR 98, Subpart C, Table C-2
N_2O	1.00E-04	kg CO2/MMBtu	6.21E-03	6.21E-03	40 CFR 98, Subpart C, Table C-2
CO_2e			3,293	3,293	

Methodology:

1) Gas Throughput (MMCF/yr) = Heat Input (MMBtu/hr) * 8,760 hr/yr / Heating Value (MMBtu/MMCF)
2) PTE (TPY) = Gas Throughput (MMCF/yr) * Emission Factor (lb/MMCF) / 2000 lb/ton
3) PTE (TPY) = Emission Factor (kg/MMBtu) * 2.2046 lb/kg x Heating Value (MMBtu/MMCF) * Throughput (MMCF/yr) / 2000 lb/ton
4) PTE CO_2e = PTE CO_2 + (PTE CH_4 * 21) + (PTE N_2O * 310)

Appendix A to the Addendum to the Technical Support Document (ATSD)
Nitric Acid Tail Gas Units - EP-001A/B
UAN Process Scrubber Vents - EP-002A/B

Company Name: Ohio Valley Resources, LLC
Address: 300-400 East CR 350 North, Rockport, Indiana 47635
Permit Number: T 147-32322-00062
Reviewer: David Matousek
Date: August 1, 2013

Process Description	Emission Point	Product Throughput (TPY)	Pollutant	Emission Factor		PTE (TPY)	Overall Control Efficiency	Controlled PTE (TPY)	Limited PTE (TPY)	Emission Factor Source
Nitric Acid Unit A Tail Gas Stack (Product is Nitric Acid)	EP-001A	229,950	NOx	5.00	lb/ton Nitric Acid	574.88	90.00%	57.49	57.49	Design Specification
			CO_2	320.49		36,848	0.00%	36,848	36,848	
			N_2O	21.08		2,423.67	95.00%	121.18	121.18	
			CO_2e			788,186		74,414	74,414	
Nitric Acid Unit B Tail Gas Stack (Product is Nitric Acid)	EP-001B	229,950	NOx	5.00	lb/ton Nitric Acid	574.88	90.00%	57.49	57.49	
			CO_2	320.49		36,848	0.00%	36,848	36,848	
			N_2O	21.08		2,423.67	95.00%	121.18	121.18	
			CO_2e			788,186		74,414	74,414	
UAN Process Scrubber Vent A (Product is Urea Ammonium Nitrate)	EP-002A	657,000	PM	0.256	lb/ton UAN	84.10	95.00%	4.21	4.21	
			PM_{10}	0.256		84.10	95.00%	4.21	4.21	
			$PM_{2.5}$	0.256		84.10	95.00%	4.21	4.21	
			CO_2 / CO_2e	132.31		43,464	0.00%	43,464	43,464	
UAN Process Scrubber Vent B (Product is Urea Ammonium Nitrate)	EP-002B	657,000	PM	0.256	lb/ton UAN	84.10	95.00%	4.21	4.21	
			PM_{10}	0.256		84.10	95.00%	4.21	4.21	
			$PM_{2.5}$	0.256		84.10	95.00%	4.21	4.21	
			CO_2 / CO_2e	132.31		43,464	0.00%	43,464	43,464	

Methodology:

1) PTE (TPY) = Product Throughput (ton/yr) * Emission Factor (lb/ton product) * 1 ton /2,000 lb
2) Controlled PTE (TPY) = PTE (TPY) * (1 - Control Efficiency)

Appendix A to the Addendum to the Technical Support Document (ATSD)
Product Loadout
UAN Truck and Rail Loading (EP-024)
DEF Truck Loading (EP-025)

Company Name: Ohio Valley Resources, LLC
Address: 300-400 East CR 350 North, Rockport, Indiana 47635
Permit Number: T 147-32322-00062
Reviewer: David Matousek
Date: August 1, 2013

Maximum Annual Pumping

UAN Truck	237,184	kgal/yr
UAN Railcar	237,184	kgal/yr
DEF Truck	11,888	kgal/yr

Molecular Weight of the Vapor 60.06 lb/lb.mole (Assume Pure Urea)

Description	Emission Point	Maximum Hourly Pumping Rate (kgal/hr)	Urea Vapor Pressure (psia)	Bulk Temp of Fluid (Rankine)	Saturation Factor	Emission Factor (lb/kgal)	Annual VOC Emissions (TPY)
UAN Truck Loading	EP-024A	158	0.01	560	0.6	0.0080	0.95
UAN Railcar Loading	EP-024B	158	0.01	560	0.6	0.0080	0.95
DEF Truck Loading	EP-025	7.9	0.01	560	0.6	0.0080	0.05
					Loadout Total		1.95

Appendix A to the Addendum to the Technical Support Document (ATSD)

Startup, Shutdown and Maintenance Emissions

Company Name: Ohio Valley Resources, LLC
Address: 300-400 East CR 350 North, Rockport, Indiana 47635
Permit Number: T 147-32322-00062
Reviewer: David Matousek
Date: August 1, 2013

1) Storage - Ammonia Bullet Tanks and Loadout - Flare EP-005

Loadout

2 Storage Tanks	(EP-013)
4 Ammonia Bullet Tanks	(EP-023)

Flare Heat Input	69.18	MMBtu/hr
Ammonia Feed Rate	9,075	lb ammonia per hour
SSM Allowance	168	hrs of venting per year

Pollutant	Emission Factor		PTE (TPY)	Data Source
NOx - Thermal	0.068	lb/MMBtu	0.40	AP-42, Ch 13.5, Table 13.5-1
NOx - Fuel	0.01325	lb NOx / lb NH_3	10.10	Design Specification
Total NOx Emissions			10.50	
N_2O	1.00E-04	kg CO2/MMBtu	1.28E-03	40 CFR 98, Subpart C, Table C-2
CO_2e			0.40	

2) Ammonia Unit - Ammonia Back End Flare (EP-006)

Refrigeration Compressor

Ammonia Unit Compressor

Flare Heat Input	2,175.07	MMBtu/hr
Ammonia Feed Rate	36,000	lb ammonia per hour
SSM Allowance	336	hrs of venting per year

Pollutant	Emission Factor		PTE (TPY)	Data Source
NOx - Thermal	0.068	lb/MMBtu	24.85	AP-42, Ch 13.5, Table 13.5-1
NOx - Fuel	0.01325	lb NOx / lb NH_3	80.14	Design Specification
NOx - Total			104.99	
VOC	0.0054	lb/MMBtu	1.97	AP-42, Ch 1.4, Table 1.4-2
CO	0.37	lb/MMBtu	135.20	AP-42, Ch 13.5, Table 13.5-1
CO_2	53.02	kg CO2/MMBtu	42,712	40 CFR 98, Subpart C, Table C-1
CH_4	1.00E-03	kg CO2/MMBtu	0.81	40 CFR 98, Subpart C, Table C-2
N_2O	1.00E-04	kg CO2/MMBtu	0.08	40 CFR 98, Subpart C, Table C-2
CO_2e			42,754	

Methodology:

1) PTE (TPY) = Emission Factor (lb/MMBtu) * Heat Input (MMBtu/hr) * hours/yr * (1 ton / 2,000 lb)
2) PTE (TPY) = Emission Factor (kg/MMBtu) * 2.2046 lb/kg * Heat Input (MMBtu/hr) * hours/yr * (1 Ton / 2,000 lb)
3) PTE CO_2e = PTE CO_2 + (PTE CH_4 * 21) + (PTE N_2O * 310)

Appendix A to the Addendum to the Technical Support Document (ATSD)

Startup, Shutdown and Maintenance Emissions (Continued)

3) Steam Methane Reforming Process - Front End Flare EP-007

Reformer	(EP-003)
Shift Reactor	
CO_2 Purification	(EP-004)

Flare Heat Input	8,757.20	MMBtu/hr
SSM Allowance	336	hrs of venting per year

Pollutant	Emission Factor		PTE (TPY)	Data Source
NOx	0.068	lb/MMBtu	100.04	AP-42, Ch 13.5, Table 13.5-1
VOC	0.0054	lb/MMBtu	7.94	AP-42, Ch 1.4, Table 1.4-2
CO	0.37	lb/MMBtu	544.35	AP-42, Ch 13.5, Table 13.5-1
CO_2	53.02	kg CO2/MMBtu	171,967	40 CFR 98, Subpart C, Table C-1
CH_4	1.00E-03	kg CO2/MMBtu	3.24	40 CFR 98, Subpart C, Table C-2
N_2O	1.00E-04	kg CO2/MMBtu	0.32	40 CFR 98, Subpart C, Table C-2
CO_2e			172,134	

4) Urea Units - UAN Flare (EP-017)

NH_3 Scrubber

Decomposer #1

Flare Heat Input	154.73	MMBtu/hr
Ammonia Feed Rate	33,600	lb ammonia per hour
SSM Allowance	336	hrs of venting per year

Pollutant	Emission Factor		PTE (TPY)	Data Source
NOx - Thermal	0.068	lb/MMBtu	1.77	AP-42, Ch 13.5, Table 13.5-1
NOx - Fuel	0.00957	lb NOx / lb NH_3	54.02	Design Specification
Total NOx Emissions			55.79	
CO_2	72.19	lb CO2 / MMBtu	1876.63	Design Specification
N_2O	1.00E-04	kg CO2/MMBtu	5.73E-03	40 CFR 98, Subpart C, Table C-2
CO_2e			1,878	

SSM Summary	
Pollutant	(TPY)
NOx	271.32
VOC	9.91
CO	679.55
CO_2e	216,766

Appendix A to the Addendum to the Technical Support Document (TSD)
Miscellaneous Insignificant Activities

Company Name: Ohio Valley Resources, LLC
Address: 300-400 East CR 350 North, Rockport, Indiana 47635
Permit Number: T 147-32322-00062
Reviewer: David Matousek
Date: August 1, 2013

	Potential to Emit (TPY)									
Emission Unit	**PM**	**PM10**	**PM2.5**	**SO2**	**VOC**	**CO**	**NOx**	**GHG**	**Total HAP**	**Worst Case HAP Methanol**
UAN Storage Tank A (EP-012A)	0.00	0.00	0.00	0.00	0.694	0.00	0.00	0.00	0.00	0.00
UAN Storage Tank A (EP-012B)	0.00	0.00	0.00	0.00	0.694	0.00	0.00	0.00	0.00	0.00
DEF Tank EP-021	0.00	0.00	0.00	0.00	0.01	0.00	0.00	0.00	0.00	0.00
Diesel Storage Tank EP-014	0.00	0.00	0.00	0.00	1.77E-03	0.00	0.00	0.00	3.53E-05	0.00
Gasoline Storage Tank EP-015	0.00	0.00	0.00	0.00	0.45	0.00	0.00	0.00	0.10	0.00
UAN Day Tank A (EP-020A)	0.00	0.00	0.00	0.00	0.26	0.00	0.00	0.00	0.00	0.00
UAN Day Tank B (EP-020B)	0.00	0.00	0.00	0.00	0.26	0.00	0.00	0.00	0.00	0.00
UAN Day Tank C (EP-020C)	0.00	0.00	0.00	0.00	0.26	0.00	0.00	0.00	0.00	0.00
Nitric Acid Surge Tank Plant A (EP-022)	0.00	0.00	0.00	0.00	0.00	0.00	0.31	0.00	0.00	0.00
Nitric Acid Surge Tank Plant B (EP-022)	0.00	0.00	0.00	0.00	0.00	0.00	0.31	0.00	0.00	0.00
Total for Misc. Insignificant	0.00	0.00	0.00	0.00	2.63	0.00	0.62	0.00	0.10	0.00

Appendix A to the Addendum to the Technical Support Document (ATSD)
Fugitive Emissions from Process Units (F-200a/b/c-1/c-2/d)

Company Name: Ohio Valley Resources, LLC
Address: 300-400 East CR 350 North, Rockport, Indiana, 47635
Permit Number: T 147-32322-00062
Reviewer: David Matousek
Date:

1) Reformer and Ammonia Units (F-200a)

Component	Service	# of Components	Uncontrolled Emission Factor (lb/hr-component)	Uncontrolled PTE (lb/hr)	Uncontrolled PTE (TPY)
Valves	Gas/Vapor	169	0.01316	2.2240	9.7411
	Light Liquid	211	0.00888	1.8737	8.2068
	Heavy Liquid	0	0.00051	0.0000	0.0000
Pumps	Light Liquid	8	0.04387	0.3510	1.5374
	Light Liquid Double Seals	0	0.04387	0.0000	0.0000
	Light Liquid Single Seals	0	0.04387	0.0000	0.0000
	Heavy Liquid Single Seals	0	0.019	0.0000	0.0000
Flanges	Gas/Vapor	292	0.00086	0.2511	1.0998
	Light Liquid	35	0.00024	0.0084	0.0368
	Heavy Liquid	0	0.000001	0.0000	0.0000
Compressors	Gas/Vapor	2	0.50265	1.0053	4.4032
Relief Valves	Rupture Disk	18	0.22928	4.1270	18.0763
	Gas/Vapor	2	0.22928	0.4586	2.0087
Open Ended Lines		111	0.00375	0.4163	1.8234
Sampling Points		0	0.03307	0.0000	0.0000
		Total Fugitives (lb/hr and TPY)		**10.7154**	**46.9335**

Emission Summary - Reformer and Ammonia Units			
Component	**Component Description**	**% by Mass of Total Fugitive**	**Potential to Emit (TPY)**
CO	Criteria Pollutant	0.14%	0.07
NOx		0.00%	0.00
Methanol	VOC / Worst Case HAP	0.02%	0.01
Urea	VOC	0.00%	0.00
aMDEA	VOC	0.00%	0.00
Total VOC	VOC		0.01
Total HAP	HAP		0.01
CO_2	Greenhouse Gas	84.51%	39.66
N_2O		0.00%	0.00
CH_4		15.34%	7.2
CO_2e			191

Appendix A to the Addendum to the Technical Support Document (ATSD)
Fugitive Emissions from Process Units (Continued)

2) aMDEA Area (F-200b)

Component	Service	# of Components	Uncontrolled Emission Factor (lb/hr-component)	Uncontrolled PTE (lb/hr)	Uncontrolled PTE (TPY)
Valves	Gas/Vapor	0	0.01316	0.0000	0.0000
	Light Liquid	0	0.00888	0.0000	0.0000
	Heavy Liquid	152	0.00051	0.0775	0.3395
Pumps	Light Liquid Sealless	0	0.04387	0.0000	0.0000
	Light Liquid Double Seals	0	0.04387	0.0000	0.0000
	Light Liquid Single Seals	0	0.04387	0.0000	0.0000
	Heavy Liquid Single Seals	9	0.019	0.1710	0.7490
Flanges	Gas/Vapor	0	0.00086	0.0000	0.0000
	Light Liquid	0	0.00024	0.0000	0.0000
	Heavy Liquid	750	0.000001	0.0008	0.0035
Compressors	Gas/Vapor	0	0.50265	0.0000	0.0000
Relief Valves	Rupture Disk	0	0.22928	0.0000	0.0000
	Gas/Vapor	2	0.22928	0.4586	2.0087
Open Ended Lines		8	0.00375	0.0300	0.1314
Sampling Points		28	0.03307	0.9260	4.0559
		Total Fugitives (lb/hr and TPY)		**1.6639**	**7.2880**

Emission Summary - aMDEA Area

Component	Component Description	% by Mass of Total Fugitive	Potential to Emit (TPY)
CO	Criteria Pollutant	0.00%	0
NOx		0.00%	0
Methanol	VOC / Worst Case HAP	0.00%	0
Urea	VOC	0.00%	0
aMDEA	VOC	100.00%	7.29
Total VOC	VOC		0
Total HAP	HAP		0
CO_2	Greenhouse Gas	0.00%	0
N_2O		0.00%	0
CH_4		0.00%	0
CO_2e			0

Appendix A to the Addendum to the Technical Support Document (ATSD)
Fugitive Emissions from Process Units (Continued)

3) UAN Plant / CO_2 (F-200c-1)

Component	Service	# of Components	Uncontrolled Emission Factor (lb/hr-component)	Uncontrolled PTE (lb/hr)	Uncontrolled PTE (TPY)
Valves	Gas/Vapor	82	0.01316	1.0791	4.7265
	Light Liquid	196	0.00888	1.7405	7.6234
	Heavy Liquid	0	0.00051	0.0000	0.0000
Pumps	Light Liquid Sealless	0	0.04387	0.0000	0.0000
	Light Liquid Double Seals	0	0.04387	0.0000	0.0000
	Light Liquid Single Seals	6	0.04387	0.2632	1.1528
	Heavy Liquid Single Seals	0	0.019	0.0000	0.0000
Flanges	Gas/Vapor	132	0.00086	0.1135	0.4971
	Light Liquid	238	0.00024	0.0571	0.2501
	Heavy Liquid	0	0.000001	0.0000	0.0000
Compressors	Gas/Vapor	0	0.50265	0.0000	0.0000
Relief Valves	Rupture Disk	0	0.22928	0.0000	0.0000
	Gas/Vapor	6	0.22928	1.3757	6.0256
Open Ended Lines		0	0.00375	0.0000	0.0000
Sampling Points		2	0.03307	0.0661	0.2895
			Total Fugitives (lb/hr and TPY)	**4.6952**	**20.5650**

Emission Summary - UAN Plant /CO_2

Component	Component Description	% by Mass of Total Fugitive	Potential to Emit (TPY)
CO	Criteria Pollutant	0.00%	0.00
NOx		0.00%	0.00
Methanol	VOC / Worst Case HAP	0.00%	0.00
Urea	VOC	43.00%	8.84
aMDEA	VOC	0.00%	0.00
Total VOC	VOC		0
Total HAP	HAP		0.00
CO_2	Greenhouse Gas	19.00%	3.91
N_2O		0.00%	0.00
CH_4		0.00%	0.00
CO_2e			4

Appendix A to the Addendum to the Technical Support Document (ATSD)
Fugitive Emissions from Process Units (Continued)

4) UAN Plant NOx/N_2O (F-200c-2)

Component	Service	# of Components	Uncontrolled Emission Factor (lb/hr-component)	Uncontrolled PTE (lb/hr)	Uncontrolled PTE (TPY)
Valves	Gas/Vapor	82	0.01316	1.0791	4.7265
	Light Liquid	196	0.00888	1.7405	7.6234
	Heavy Liquid	0	0.00051	0.0000	0.0000
Pumps	Light Liquid Sealless	0	0.04387	0.0000	0.0000
	Light Liquid Double Seals	0	0.04387	0.0000	0.0000
	Light Liquid Single Seals	6	0.04387	0.2632	1.1528
	Heavy Liquid Single Seals	0	0.019	0.0000	0.0000
Flanges	Gas/Vapor	132	0.00086	0.1135	0.4971
	Light Liquid	238	0.00024	0.0571	0.2501
	Heavy Liquid	0	0.000001	0.0000	0.0000
Compressors	Gas/Vapor	0	0.50265	0.0000	0.0000
Relief Valves	Rupture Disk	0	0.22928	0.0000	0.0000
	Gas/Vapor	6	0.22928	1.3757	6.0256
Open Ended Lines		0	0.00375	0.0000	0.0000
Sampling Points		2	0.03307	0.0661	0.2895
			Total Fugitives (lb/hr and TPY)	**4.6952**	**20.5650**

Emission Summary - UAN Plant /CO_2

Component	Component Description	% by Mass of Total Fugitive	Potential to Emit (TPY)
CO	Criteria Pollutant	0.00%	0.00
NOx		0.04%	0.01
Methanol	VOC / Worst Case HAP	0.00%	0.00
Urea	VOC	0.00%	0
aMDEA	VOC	0.00%	0.00
Total VOC	VOC		0
Total HAP	HAP		0.00
CO_2	Greenhouse Gas	2.39%	0.49
N_2O		16.00%	3.29
CH_4		0.00%	0.00
CO_2e			1,020

Appendix A to the Addendum to the Technical Support Document (ATSD)
Fugitive Emissions from Process Units (Continued)

5) UAN Product Storage Area (F-200d)

Component	Service	# of Components	Uncontrolled Emission Factor (lb/hr-component)	Uncontrolled PTE (lb/hr)	Uncontrolled PTE (TPY)
Valves	Gas/Vapor	0	0.01316	0.0000	0.0000
	Light Liquid	110	0.00888	0.9768	4.2784
	Heavy Liquid	0	0.00051	0.0000	0.0000
Pumps	Light Liquid Sealless	0	0.04387	0.0000	0.0000
	Light Liquid Double Seals	0	0.04387	0.0000	0.0000
	Light Liquid Single Seals	2	0.04387	0.0877	0.3841
	Heavy Liquid Single Seals	0	0.019	0.0000	0.0000
Flanges	Gas/Vapor	0	0.00086	0.0000	0.0000
	Light Liquid	260	0.00024	0.0624	0.2733
	Heavy Liquid	0	0.000001	0.0000	0.0000
Compressors	Gas/Vapor	0	0.50265	0.0000	0.0000
Relief Valves	Rupture Disk	0	0.22928	0.0000	0.0000
	Gas/Vapor	0	0.22928	0.0000	0.0000
Open Ended Lines		22	0.00375	0.0825	0.3614
Sampling Points		0	0.03307	0.0000	0.0000
			Total Fugitives (lb/hr and TPY)	**1.2094**	**5.2972**

Emission Summary - UAN Product Storage Area			
Component	**Component Description**	**% by Mass of Total Fugitive**	**Potential to Emit (TPY)**
CO	Criteria Pollutant	0.00%	0.00
NOx		0.00%	0.00
Methanol	VOC / Worst Case HAP	0.00%	0.00
Urea	VOC	36.00%	1.91
aMDEA	VOC	0.00%	0.00
Total VOC	VOC		0
Total HAP	HAP		0.00
CO_2	Greenhouse Gas	0.00%	0
N_2O		0.00%	0.00
CH_4		0.00%	0.00
CO_2e			0

Appendix A to the Addendum to the Technical Support Document (ATSD)
Fugitive Emissions from Process Units (Continued)

Process Fugitive Emission Summary

Pollutant	F-200a (TPY)	F-200b (TPY)	F-200c-1 (TPY)	F-200c-2 (TPY)	F-200d (TPY)	Total (TPY)
CO	0.07	0	0.00	0.00	0.00	0.07
NOx	0	0	0.00	0.01	0.00	0.01
Methanol	0.01	0	0.00	0.00	0.00	0.01
Urea	0	0	8.84	0.00	1.91	10.75
aMDEA	0	7.29	0.00	0.00	0.00	7.29
Total VOC	0.01	0	0.00	0.00	0.00	0.01
Total HAP	0.01	0	0.00	0.00	0.00	0.01
CO_2	39.66	0	3.91	0.49	0.00	44.06
N_2O	0	0	0.00	3.29	0.00	3.29
CH_4	7.2	0	0.00	0.00	0.00	7.2
CO_2e	191	0	4	1,020	0	1,215

Appendix A to the Addendum to the Technical Support Document (ATSD)
Paved Road Emissions - Haul Roads (F-100)

Company Name: **Ohio Valley Resources, LLC**
Address: **300-400 East CR 350 North, Rockport, Indiana 47635**
Permit Number: **T 147-32322-00062**
Reviewer: **David Matousek**
Date: **August 1, 2013**

Average Vehicle Weight Calculation

Vehicle Type	Trucks/Day	Average Weight (tons)	Total Trips per Year	Miles per Trip	Vehicle Miles Traveled (miles per year)	Traffic Component (%)	Component Weight (tons)
DEF Tanker	6	27.5	2,190	0.4053	888	5.17%	1.42
Ammonia Tanker	110	27.5	40,150	0.4053	16,273	94.83%	26.08
				Total VMT	17,160		
				Average Vehicle Weight (tons) - W			27.50

Site Constants

Value Name	Symbol	Value	Units	Source
Emission Factor	E	---	g/VMT	Calculated
Particle Size Multiplier	k for PM	5.24	g/VMT	AP-42 Table 13.2.1-1, January 2011
Particle Size Multiplier	k for PM10	1.00	g/VMT	AP-42 Table 13.2.1-1, January 2011
Particle Size Multiplier	k for PM2.5	0.25	g/VMT	AP-42 Table 13.2.1-1, January 2011
Silt Loading	sL	2.35	g/m^2	Estimated by IDEM (Higher than AP-42 default)
Days >0.01" of rain	P	119	days	AP-42, Figure 13.2.1-2, January 2011
Mean Vehicle Weight	W	27.50	tons	Calculated above

Emission Factor Calculations

E = [k * (sL)^0.91 * (W)^1.02] * [1 - P/(4 * N)] AP-42, Chapter 13.2.1-5, January 2011, Eq. 2

E for PM =	307.75	g/VMT	0.6785	lb/VMT
E for PM10 =	58.73	g/VMT	0.1295	lb/VMT
E for PM2.5 =	14.68	g/VMT	0.0324	lb/VMT

Potential to Emit

PM Emissions (TPY) = [Annual Average E for PM (lb/VMT) * Total VMT/yr * 1 ton / 2,000 lb]	5.82	TPY
PM10 Emissions (TPY) = [Annual Average E for PM10 (lb/VMT) * Total VMT/yr * 1 ton / 2,000 lb]	1.11	TPY
PM2.5 Emissions (TPY) = [Annual Average E for PM2.5 (lb/VMT) * Total VMT/yr * 1 ton / 2,000 lb]	0.28	TPY

Limited Potential to Emit

Control Efficiency 90.00%

Limited PM Emissions (TPY) = Potential to Emit PM * (1 - Control Efficiency)	0.58	TPY
Limited PM10 Emissions (TPY) = Potential to Emit PM10 * (1 - Control Efficiency)	0.11	TPY
Limited PM2.5 Emissions (TPY) = Potential to Emit PM2.5 * (1 - Control Efficiency)	0.03	TPY

Indiana Department of Environmental Management
Office of Air Quality

Technical Support Document (TSD) for a
New Source Construction and Part 70 Permit

Source Description and Location

Source Name:	Ohio Valley Resources, LLC
Source Location:	300-400 East CR 350 North, Rockport, Indiana 47635
County:	Spencer, Ohio Township
SIC Code:	2873
Operation Permit No.:	T 147-32322-00062
Permit Reviewer:	David Matousek

Existing Approvals

There have been no previous approvals issued to this source.

County Attainment Status

The source is located in Spencer County, Ohio Township.

Pollutant	Designation
SO_2	Better than national standards.
CO	Unclassifiable or attainment effective November 15, 1990.
O_3	Unclassifiable or attainment effective June 15, 2004, for the 8-hour ozone standard.[1]
PM_{10}	Unclassifiable effective November 15, 1990.
NO_2	Cannot be classified or better than national standards.
Pb	Not designated.

[1] Unclassifiable or attainment effective October 18, 2000, for the 1-hour ozone standard which was revoked effective June 15, 2005.
Unclassifiable or attainment effective October 27, 2011, for the Ohio Twp for $PM_{2.5}$.
The remainder of Spencer County is unclassifiable or attainment effective April 5, 2005, for $PM_{2.5}$.

(a) Ozone Standards
Volatile organic compounds (VOC) and Nitrogen Oxides (NO_x) 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_x emissions are considered when evaluating the rule applicability relating to ozone. Spencer County has been designated as attainment or unclassifiable for ozone. Therefore, VOC and NO_x emissions were reviewed pursuant to the requirements for Prevention of Significant Deterioration (PSD), 326 IAC 2-2.

(b) $PM_{2.5}$
Spencer County has been classified as attainment for $PM_{2.5}$. On May 8, 2008, U.S. EPA promulgated the requirements for Prevention of Significant Deterioration (PSD) for $PM_{2.5}$ 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 $PM_{2.5}$ significant level at ten (10) tons per year. This rule became effective, June 28, 2011. Therefore, direct $PM_{2.5}$, SO_2, and NO_x 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
Spencer County has been classified as attainment or unclassifiable in Indiana for SO_2, CO, PM_{10}, NO_x and lead. Therefore, these emissions were reviewed pursuant to the requirements for Prevention of Significant Deterioration (PSD), 326 IAC 2-2.

Fugitive Emissions

Since this source is classified as a chemical process plant, it is considered one of the twenty-eight (28) listed source categories, as specified in 326 IAC 2-2, 326 IAC 2-3, or 326 IAC 2-7. Therefore, fugitive emissions are counted toward the determination of PSD, Emission Offset, and Part 70 Permit applicability.

Description of Proposed New Source Construction

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

(a) A reformer process for production of hydrogen and nitrogen syngas consisting of the following emission units and emission control devices:

  (1) One (1) primary reformer, identified as EU-003, approved for construction in 2013, with a maximum rated heat input capacity of 1,006.4 MMBtu/hr, using selective catalytic reduction for NO_x emissions control, equipped with NO_x CEMS, and exhausting to the ambient atmosphere through stack EP-003. [40 CFR 63, Subpart DDDDD]

  (2) One (1) CO_2 purification process, identified as EU-004, with a maximum rated CO_2 production of 3,570 ton per day, approved for construction in 2013, and exhausting to the ambient atmosphere through stack EP-004.
  [40 CFR 63, Subpart FFFF]

  (3) One (1) front end process flare for combusting intermittent process gas emissions from maintenance, startup, shutdown, and malfunctions, identified as EU-007, with a pilot nominally rated at 0.253 MMBtu/hr, approved for construction in 2013, utilizing proper flare design and operation minimization practices, and exhausting to the ambient atmosphere through the emission point EP-007.

(b) An ammonia unit with a maximum throughput capacity of 2,800 ton/day of ammonia consisting of the following emission units and emission control devices:

  (1) One (1) ammonia catalyst startup heater, identified as EU-010, approved for construction in 2013, with a maximum rated heat input capacity of 106.3 MMBtu/hr, utilizing no control devices, and exhausting to the ambient atmosphere through stack EP-010. [40 CFR 63, Subpart DDDDD]

  (2) One (1) back end ammonia process vent flare for combusting intermittent process gas emissions from maintenance, startup, shutdown, and malfunctions, identified as EU-006, approved for construction in 2013, with pilot capacity of 0.253 MMBtu per hour, utilizing proper flare design and operation minimization practices, and exhausting to the ambient atmosphere through emission point EP-006.

  (3) Four (4) ammonia bullet tanks, identified as EU-023A through EU-023D, with a maximum rated capacity of 90,000 gallons each, approved for construction in 2013, utilizing the flare identified as EU-005 as an emission control device, and exhausting to the ambient atmosphere through emissions point EP-005.

(4) Three (3) ammonia cold storage tanks, identified as EU-013A, EU-013B, and EU-013C, with a maximum rated capacity of 40,000 tons each, approved for construction in 2013, utilizing the flare identified as EU-005 as an emission control device, and exhausting to the ambient atmosphere through emission point EP-005.

(5) One (1) ammonia storage flare, identified as EU-005, approved for construction in 2013, with pilot capacity of 0.126 MMBtu per hour, utilizing proper flare design and operation minimization practices, and exhausting to the ambient atmosphere through emission point EP-005.

(c) Two (2) urea ammonium nitrate (UAN) plants, including the production of urea, nitric acid, ammonium nitrate, and diesel exhaust fluid (DEF), consisting of the following emission units and emission control devices:

(1) Two (2) nitric acid units, identified as EU-001A and EU-001B, with a maximum throughput capacity of 630 ton/day of 100% nitric acid each, approved for construction in 2013, equipped with selective catalytic reduction for NO_x control, catalytic decomposition for N_2O control, and a NO_x CEM, and exhausting to the ambient atmosphere through tailgas stacks EP-001A and EP-001B.
[40 CFR 60, Subpart Ga]

(2) Two (2) nitric acid storage tanks, identified as EU-022A and EU-022B, approved for construction in 2013, with a maximum throughput of 1,105 ton/day of 57% nitric acid each, and exhausting to the ambient atmosphere through the UAN process vent stacks EP-002A and EP-002B.

(3) Two (2) ammonium nitrate (AN) plants, identified as EU-002A and EU-002B, approved for construction in 2013, with a maximum throughput capacity of 798 ton/day of ammonium nitrate each, utilizing a scrubber with particulate demister for particulate matter control, and exhausting to the ambient atmosphere through stacks EP-002A and EP-002B. [40 CFR 60, Subpart VVa]

(4) Two (2) UAN Storage Tanks, identified as EU-012A and EU-012B, approved for construction in 2013, with a maximum rated capacity of 30,000 tons each, and exhausting to the ambient atmosphere through vents EP-012A and EP-012B.
[40 CFR 60, Subpart VVa]

(5) Three (3) UAN Day Tanks, identified as EU-020A, EU-020B, and EU-020C, approved for construction in 2013, with a maximum rated capacity of 750 tons each, and exhausting to the ambient atmosphere through vents EP-020A, EP-020B, and EP-020C. [40 CFR 60, Subpart VVa]

(6) Two (2) UAN loadout facilities (one (1) truck and one (1) for rail), identified as EU-024A and EU-024B, approved for construction in 2013, and exhausting to the ambient atmosphere as fugitive emission sources EP-024A and EP-024B.
[40 CFR 60, Subpart VVa]

(7) One (1) UAN plant vent flare for combusting intermittent process gas emissions from maintenance, startup, shutdown, and malfunctions, identified as EU-017, approved for construction in 2013, with a pilot capacity of 0.189 MMBtu per hour, utilizing proper flare design and operation minimization practices, and exhausting to the ambient atmosphere through emission point EP-017.

(8) One (1) DEF tank, identified as EU-021, approved for construction in 2013, with capacity of 100 tons, and exhausting to the ambient atmosphere through vent EP-021. [40 CFR 60, Subpart VVa]

(9) One (1) DEF truck loadout facility, identified as EU-025, approved for construction in 2013, and exhausting to the ambient atmosphere as fugitive emission source EP-025. [40 CFR 60, Subpart VVa]

(d) Four (4) natural gas-fired boilers, identified as EU-011A, EU-011B, EU-011C, and EU-011D, approved for construction in 2013, with a maximum rated heat input capacity of 218 MMBtu/hr each, using ultra low NO_x burners and flue gas recirculation for NO_x emissions control, equipped with NO_x CEMS, and exhausting to the ambient atmosphere through stacks EP-011A, EP-011B, EP-011C, and EP-011D. [40 CFR 60, Subpart Db] [40 CFR 63, Subpart DDDDD]

(e) One (1) diesel-fired emergency generator, identified as EU-009, approved for construction in 2013, with a maximum rated capacity of 4,690 horsepower, utilizing no control devices, and exhausting to the ambient atmosphere through stack EP-009.
[40 CFR 60, Subpart IIII] [40 CFR 63, Subpart ZZZZ]

Specifically Regulated Insignificant Activities

This stationary source consists of the following specifically regulated insignificant activities:

(a) One (1) diesel-fired emergency firewater pump, identified as EU-016, approved for construction in 2013, with a maximum rated capacity of 481 horsepower, utilizing no control devices, and exhausting to the ambient atmosphere through stack EP-016.
[40 CFR 60, Subpart IIII] [40 CFR 63, Subpart ZZZZ] [326 IAC 2-2]

(b) Two (2) cooling towers, with a total of fourteen (14) cells, identified as EU-008A through EU-008H and EU-019A through EU-019F, approved for construction in 2013, with a combined maximum rated capacity of 179,720 gallons per minute, utilizing high efficiency drift eliminators for particulate matter control, and exhausting to the ambient atmosphere through cells EP-008A through EP-008H and EP-019A through EP-019F. [326 IAC 2-2]

(c) Fuel dispensing activities, including the gasoline fuel transfer dispensing operation, identified as EU-015, approved for construction in 2013, handling less than or equal to one thousand three hundred (1,300) gallons per day and filling storage tanks having a capacity equal to or less than ten thousand five hundred (10,500) gallons. Such storage tanks may be in a fixed location or on mobile equipment. [326 IAC 2-2]

(d) Fuel dispensing activities, including a petroleum fuel other than gasoline dispensing facility, identified as EU-014, approved for construction in 2013, having a storage tank capacity less than or equal to ten thousand five hundred (10,500) gallons, and dispensing three thousand five hundred (3,500) gallons per day or less. [326 IAC 2-2]

(e) Fugitive NO_x, VOC, and GHG Emissions from Equipment Leaks
[326 IAC 2-2] [40 CFR 60, Subpart VVa]

(f) Paved roadways and parking lots with public access. [326 IAC 6-4] [326 IAC 2-2]

Insignificant Activities

This stationary source consists of the following insignificant activities:

(a) The following activities:

  (1) Water based activities, including the following:

    (A) Activities associated with the treatment of wastewater streams with an oil and grease content less than or equal to one percent (1%) by volume.

    (B) Any operation using aqueous solutions containing less than or equal to one percent (1%) by weight of VOCs excluding HAPs.

  (2) Flue gas conditioning systems and associated chemicals, such as ammonia.

  (3) Equipment used to collect any material that might be released during a malfunction, process upset, or spill cleanup, including tanks.

  (4) Blowdown for boilers and cooling towers.

Trivial Activities

This stationary source consists of the following trivial activities:

(a) Any activity or emission unit not regulated by a NESHAP, with potential uncontrolled emissions that are equal to or less than one (1) pound per day on an emission unit basis for any single HAP or combination of HAPs; and for which the potential uncontrolled emissions meet the exemption levels specified in the following:

  (1) For VOC, potential uncontrolled emissions that are equal to or less than one (1) pound per day.

  (2) For nitrogen oxides (NO_x), potential uncontrolled emissions that are equal to or less than one (1) pound per day.

  (3) For particulate matter with an aerodynamic diameter less than or equal to ten (10) micrometers (PM_{10}), potential uncontrolled emissions that are equal to or less than one (1) pound per day.

(b) Water related activities, including the following:

  (1) Production of hot water for on-site personal use not related to any industrial or production process.

  (2) Water treatment activities used to provide potable and process water for the plant, excluding any activities associated with wastewater treatment.

  (3) Steam traps, vents, leaks, and safety relief valves.

  (4) Demineralized water tanks and demineralizer vents.

  (5) Boiler water treatment operations, not including cooling towers.

(c) Activities related to ventilation, venting equipment, and refrigeration, including the following:

  (1) Ventilation exhaust, central chiller water systems, refrigeration, and air conditioning equipment, not related to any industrial or production process, including natural draft hoods or ventilating systems that do not remove air pollutants.

  (2) Stack and vents from plumbing traps used to prevent the discharge of sewer gases, handling domestic sewage only, excluding those at wastewater treatment plants or those handling any industrial waste.

  (3) Vents from continuous emissions monitors and other analyzers.

(d) Housekeeping and janitorial activities and supplies, including the following:

  (1) Vacuum cleaning systems used exclusively for housekeeping or custodial activities, or both.

  (2) Steam cleaning activities.

  (3) Restrooms and associated cleanup operations and supplies.

  (4) Mobile floor sweepers and floor scrubbers.

  (5) Pest control fumigation.

(e) Office related activities, including the following:

  (1) Office supplies and equipment.

  (2) Photocopying equipment and associated supplies.

  (3) Paper shredding.

(f) Storage equipment and activities, including the following:

  (1) Pressurized storage tanks and associated piping for anhydrous ammonia.

  (2) Storage tanks, vessels, and containers holding or storing liquid substances that do not contain any VOC or HAP.

  (3) Storage of drums containing maintenance raw materials.

  (4) Portable containers used for the collection, storage, or disposal of materials provided the container capacity is equal to or less than forty-six hundredths (0.46) cubic meters and the container is closed, except when the material is added or removed.

(g) Emergency and standby equipment, including process safety relief devices installed solely for the purpose of minimizing injury to persons or damage to equipment that could result from abnormal process operating conditions, including rupture discs and safety relief valves.

(h) Sampling and testing equipment and activities, including the following:

  (1) Equipment used for quality control/assurance or inspection purposes, including sampling equipment used to withdraw materials for analysis.

  (2) Instrument air dryers and distribution.

(i) Activities generating limited amounts of fugitive dust, including the following:

  (1) Fugitive emissions related to movement of passenger vehicles, provided the emissions are not counted for applicability purposes under subdivision (22) (B), and any required fugitive dust control plan or its equivalent is submitted.

  (2) Road salting and sanding.

Enforcement Issues

There are no pending enforcement actions.

Stack Summary

Stack ID	Type / Shape	Operation	Height (ft)	Diameter (ft)	Flow Rate (acfm)	Temperature (^{0}F)
EP-001A	Vertical / Circular	Nitric Acid Plant	125.00	3.50	71,523	288
EP-001B	Vertical / Circular	Nitric Acid Plant	125.00	3.50	71,523	288
EP-002A	Vertical / Circular	UAN Scrubber Vent	170.00	1.33	3,203	179
EP-002B	Vertical / Circular	UAN Scrubber Vent	170.00	1.33	3,203	179
EP-003	Vertical / Circular	Primary Reformer	98.43	12.50	355,110	325
EP-004	Vertical / Circular	CO$_2$ Purification	213.25	2.50	24,180	100
EP-005	Vertical / Circular	Ammonia Flare	30.00	1.17	4,232	1,832
EP-006	Vertical / Circular	Backend Flare	70.00	12.08	451,229	1,832
EP-007	Vertical / Circular	Frontend Flare	75.00	10.92	368,717	1,832
EP-008A	Vertical / Circular	Cooling Tower A	75.00	35.43	588,149	106.5
EP-008B	Vertical / Circular	Cooling Tower A	75.00	35.43	588,149	106.5
EP-008C	Vertical / Circular	Cooling Tower A	75.00	35.43	588,149	106.5
EP-008D	Vertical / Circular	Cooling Tower A	75.00	35.43	588,149	106.5
EP-008E	Vertical / Circular	Cooling Tower A	75.00	35.43	588,149	106.5
EP-008F	Vertical / Circular	Cooling Tower A	75.00	35.43	588,149	106.5
EP-008G	Vertical / Circular	Cooling Tower A	75.00	35.43	588,149	106.5
EP-008H	Vertical / Circular	Cooling Tower A	75.00	35.43	588,149	106.5
EP-009	Vertical / Circular	Emergency Generator	20.00	1.17	8,489	750
EP-010	Vertical / Circular	Startup Heater	112.03	6.50	93,389	1,650
EP-011A	Vertical / Circular	Package Boiler	100.00	6.00	76,826	350
EP-011B	Vertical / Circular	Package Boiler	100.00	6.00	76,826	350
EP-011C	Vertical / Circular	Package Boiler	100.00	6.00	76,826	350
EP-011D	Vertical / Circular	Package Boiler	100.00	6.00	76,826	350
EP-012A	Other / TBD	UAN Storage Tank	65	TBD	Breathing	Ambient
EP-012B	Other / TBD	UAN Storage Tank	65	TBD	Breathing	Ambient
EP-014	Other / TBD	Diesel Storage Tank	5	TBD	Breathing	Ambient
EP-015	Other / TBD	Gasoline Storage Tank	5	TBD	Breathing	Ambient
EP-016	Vertical / Circular	Firewater Pump	20.00	0.67	1,519	750
EP-017	Vertical / Circular	UAN Flare	150.00	4.70	19,326	1,832
EP-019A	Vertical / Circular	Cooling Tower B	75.00	35.43	293,104	106.5

Stack ID	Type / Shape	Operation	Height (ft)	Diameter (ft)	Flow Rate (acfm)	Temperature (^{0}F)
EP-019B	Vertical / Circular	Cooling Tower B	75.00	35.43	293,104	106.5
EP-019C	Vertical / Circular	Cooling Tower B	75.00	35.43	293,104	106.5
EP-019D	Vertical / Circular	Cooling Tower B	75.00	35.43	293,104	106.5
EP-019E	Vertical / Circular	Cooling Tower B	75.00	35.43	293,104	106.5
EP-019F	Vertical / Circular	Cooling Tower B	75.00	35.43	293,104	106.5
EP-020A	Other / TBD	UAN Day Tank	20	TBD	Breathing	Ambient
EP-020B	Other / TBD	UAN Day Tank	20	TBD	Breathing	Ambient
EP-020C	Other / TBD	UAN Day Tank	16	TBD	Breathing	Ambient
EP-021	Other / TBD	DEF Tank	16	TBD	Breathing	Ambient
EP-022A	Other / TBD	Nitric Acid Tanks	20	TBD	Exhaust EP-002	
EP-022B	Other / TBD	Nitric Acid Tanks	30	TBD		

Emission Calculations

See Appendix A of this Technical Support Document for detailed emission calculations.

Unrestricted Potential Emissions

This table reflects the unrestricted potential emissions of the source.

Unrestricted Potential Emissions	
Pollutant	**Tons/year**
PM	194.59
PM_{10}	236.95
$PM_{2.5}$	233.70
SO_2	8.41
VOC	90.75
CO	1,038.54
NO_x	2,250
GHGs as CO_2e	4,204,343
Single HAP (Methanol)	18.00
Total HAP	34.21

(a) The potential to emit (as defined in 326 IAC 2-7-1(29)) of PM_{10}, $PM_{2.5}$, CO and NO_x is equal to or greater than 100 tons per year. Therefore, the source is subject to the provisions of 326 IAC 2-7 and will be issued a Part 70 Operating Permit.

(b) The potential to emit (as defined in 326 IAC 2-7-1(29)) of GHGs is equal to or greater than one hundred thousand (100,000) tons of CO_2 equivalent emissions (CO_2e) per year. Therefore, the source is subject to the provisions of 326 IAC 2-7 and will be issued a Part 70 Operating Permit.

Actual Emissions

No previous emission data has been received from the source.

Part 70 Permit Conditions

This source is subject to the requirements of 326 IAC 2-7, because the source met the following:

(a) Emission limitations and standards, including those operational requirements and limitations that assure compliance with all applicable requirements at the time of issuance of Part 70 permits.

(b) Monitoring and related record keeping requirements which assume that all reasonable information is provided to evaluate continuous compliance with the applicable requirements.

Potential to Emit After Issuance

The table below summarizes the potential to emit, reflecting all limits, of the emission units. Any new control equipment is considered federally enforceable only after issuance of this Part 70 permit, 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 of the Entire Source After Issuance (tons/year)									
	PM	PM_{10}*	$PM_{2.5}$**	SO_2	NO_x	VOC	CO	GHGs	Total HAPs	Worst Single HAP Methanol
Boiler (EP-011A)	2.66	10.65	10.65	0.24	28.59	7.71	52.16	167,200	2.65	0.00
Boiler (EP-011B)										
Boiler (EP-011C)										
Boiler (EP-011D)										
Startup Heater (EU-010)	0.02	0.08	0.08	0.01	1.91	0.06	0.39	1,243	0.02	0.00
Reformer (EU-003)	8.21	32.84	32.84	4.85	61.71	23.77	187.78	515,751	8.15	0.00
CO_2 Vent (EU-004)	0.00	0.00	0.00	0.00	0.00	28.51	5.98	1,304,033	17.99	17.99
Emerg. Generator (EU-009)	0.16	0.16	0.16	0.96	4.61	0.32	2.70	546	0.005	0.00
Firewater Pump (EU-016)	0.02	0.02	0.02	0.10	0.30	0.01	0.28	56	0.001	0.00
Cooling Tower A (EU-008)	2.83	1.75	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Cooling Tower B (EU-019)	1.10	0.68	0.002	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Ammonia Storage Flare Pilot (EU-005)	0.001	0.004	0.004	0.001	0.04	0.01	0.2	64	0.001	0.00

Process/ Emission Unit	Potential To Emit of the Entire Source After Issuance (tons/year)									
	PM	PM_{10}*	$PM_{2.5}$**	SO_2	NO_x	VOC	CO	GHGs	Total HAPs	Worst Single HAP Methanol
Backend Flare Pilot (EU-006)	0.002	0.01	0.01	0.001	0.08	0.01	0.41	130	0.002	0.00
Front End Flare Pilot (EU-007)	0.002	0.01	0.01	0.001	0.08	0.01	0.41	130	0.002	0.00
UAN Flare Pilot (EU-017)	0.002	0.01	0.01	0.005	0.06	0.01	0.31	97	0.002	0.00
Nitric Acid Stack (EU-001A)	0.00	0.00	0.00	0.00	57.49	0.00	0.00	74,414	0.00	0.00
Nitric Acid Stack (EU-001B)	0.00	0.00	0.00	0.00	57.49	0.00	0.00	74,414	0.00	0.00
UAN Scrubber (EU-002A)	4.21	4.21	4.21	0.00	0.00	0.00	0.00	43,464	0.00	0.00
UAN Scrubber (EU-002B)	4.21	4.21	4.21	0.00	0.00	0.00	0.00	43,464	0.00	0.00
Product Loadout (EU-024 & 025)	0.00	0.00	0.00	0.00	0.00	1.95	0.00	0.00	0.00	0.00
Startup, Shutdown and Malfunction	0.00	0.00	0.00	0.00	271.32	9.91	679.55	216,766	0.00	0.00
Misc. Insignificant Activities	0.00	0.00	0.00	0.00	0.62	2.63	0.00	0.00	0.10	0.00
Process Fugitives	0.00	0.00	0.00	0.00	0.01	0.01	0.07	1,215	0.01	0.01
Haul Road Fugitives	0.58	0.11	0.03	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Total PTE of Entire Source	**24.01**	**54.74**	**52.24**	**6.16**	**484.29**	**74.90**	**930.24**	**2,442,987**	**28.93**	**18.00**
Title V Major Source Thresholds	NA	100	100	100	100	100	100	100,000 CO_2e	25	10
PSD Major Source Thresholds	100	100	100	100	100	100	100	100,000 CO_2e	NA	NA

*Under the Part 70 Permit program (40 CFR 70), particulate matter with an aerodynamic diameter less than or equal to a nominal 10 micrometers (PM_{10}), not particulate matter (PM), is considered as a "regulated air pollutant".
**$PM_{2.5}$ listed is direct $PM_{2.5}$. negl. = negligible

This proposed stationary source is major for PSD because the emissions of at least one criteria pollutant are greater than one hundred (>100) tons per year, emissions of GHGs are equal to or greater than one hundred thousand (>100,000) tons of CO_2 equivalent emissions (CO_2e) per year, and it is in one of the twenty-eight (28) listed source categories.

Federal Rule Applicability Determination

IDEM has analyzed the applicability of the following federal rules:

NSPS:

(a) **40 CFR 60, Subpart D - Standards of Performance for Fossil-Fuel Fired Steam Generators for which construction is commenced after August 17, 1971:**

(1) This source is not subject to 40 CFR Part 60, Subpart D because each boiler has a heat input capacity less than 250 MMBtu/hr.

(2) This source is not subject to 40 CFR Part 60, Subpart D because the ammonia catalyst preheater has a heat input capacity less than 250 MMBtu/hr.

(3) This source is not subject to 40 CFR Part 60, Subpart D because the reformer is not a steam-generating unit.

(b) **40 CFR 60, Subpart Da - Standards of Performance for Electric Utility Steam Generating Units for which Construction is Commenced after September 18, 1978:** This source is not subject to 40 CFR Part 60, Subpart Da because none of the combustion or steam generating units at the source will generate electricity for utility power distribution.

(c) **40 CFR 60, Subpart Dc Standards of Performance for Small Industrial Commercial Institutional Steam Generating Units:** This source is not subject to 40 CFR Part 60, Subpart Dc because the boilers have a heat input capacity greater 100 MMBtu/hr and the other combustion units at the source are not steam generating units.

(d) **40 CFR 60, Subpart K - Standards of Performance for Volatile Organic Liquid Storage Vessels for Which Construction, Reconstruction, or Modification Commenced after June 11, 1973 and prior to May 19, 1978:** Subpart K does not apply to this source because all tanks at the site will be constructed after May 19, 1978.

(e) **40 CFR 60, Subpart Ka - Standards of Performance for Volatile Organic Liquid Storage Vessels for Which Construction, Reconstruction, or Modification Commenced after May 19, 1978 and prior to July 23, 1984:** Subpart Ka does not apply to this source because all tanks at the site will be constructed after July 23, 1984.

(f) **40 CFR 60, Subpart Kb - Standards of Performance for Volatile Organic Liquid Storage Vessels (including Petroleum Liquid Storage Vessels) for Which Construction, Reconstruction, or Modification Commenced after July 23, 1984:** 40 CFR Part 60, Subpart Kb is not applicable to this source because none of the tanks storing organic materials have capacities greater than 151 cubic meters (m^3) and store organic liquids with maximum true vapor pressure greater than 3.5 kPa. Urea and urea ammonium nitrate (UAN) are organic liquids with vapor pressure less than 3.5 kPa.

(g) **40 CFR 60, Subparts T, U, V, W, and X – Standards of Performance that apply to phosphate fertilizer plants**: These rules are not applicable to this source because this source manufactures ammonia and urea ammonium nitrate (UAN) fertilizers and does not manufacture any phosphate fertilizers.

(h) **40 CFR 60, Subpart GG and KKKK - Standards of Performance for Stationary Gas Turbines:** Subpart GG does not apply to this source because the turbines at this source are steam turbines and not gas-fired turbines.

(i) **40 CFR 60, Subparts III, NNN, RRR and YYY – Standards of Performance that apply to the Synthetic Organic Chemicals Manufacturing Industry**: These Subparts do not apply to this source because it does not produce any of the chemicals listed in 40 CFR 60.489. Methanol is created as an emission by-product at the source, but such emissions are not defined as a product that would render any of these subparts applicable.

(j) **40 CFR 60, Subpart JJJJ - Standards of Performance for Stationary Spark Ignition Internal Combustion Engines:** These rules are not applicable to this source because it applies only to spark ignition engines. The engines at this source will be compression ignition engines that are subject to 40 CFR 60, Subpart IIII.

(k) **40 CFR 60, Subpart Ga – Standards of Performance for Nitric Acid Plants for Which Construction, Reconstruction, or Modification Commenced After October 14, 2011:** The nitric acid production units are subject to the Standards of Performance for Nitric Acid Plants for Which Construction, Reconstruction, or Modification Commenced After October 14, 2011, 40 CFR 60.70a, Subpart Ga, which is incorporated by reference as 326 IAC 12. The units subject to this rule include the following:

(1) Two (2) nitric acid units, identified as EU-001A and EU-001B, with a maximum throughput capacity of 630 ton/day of 100% nitric acid each, approved for construction in 2013, equipped with selective catalytic reduction for NO_x control, catalytic decomposition for N_2O control, and a NO_x CEM, and exhausting to the ambient atmosphere through tailgas stacks EP-001A and EP-001B. [40 CFR 60, Subpart Ga]

The nitric acid units are subject to the following portions of Subpart Ga.

(1) 40 CFR 60.70a;
(2) 40 CFR 60.72a;
(3) 40 CFR 60.73a;
(4) 40 CFR 60.74a;
(5) 40 CFR 60.75a;
(6) 40 CFR 60.76a; and
(7) 40 CFR 60.77a.

(l) **40 CFR 60, Subpart VVa – Standards of Performance for Equipment Leaks of VOC in the Synthetic Organic Chemicals Manufacturing Industry for Which Construction, Reconstruction, or Modification Commenced After November 7, 2006:** The ammonium nitrate plants, UAN storage tanks, UAN day tanks, UAN loadout facilities, DEF storage tanks, and DEF loadout facilities are subject to Standards of Performance for Equipment Leaks of VOC in the Synthetic Organic Chemicals Manufacturing Industry for Which Construction, Reconstruction, or Modification Commenced After November 7, 2006, 40 CFR 60.480a, Subpart VVa, which is incorporated by reference as 326 IAC 12. The facilities subject to this rule include the following:

(1) Two (2) ammonium nitrate (AN) plants, identified as EU-002A and EU-002B, approved for construction in 2013, with a maximum throughput capacity of 798 ton/day of ammonium nitrate each, utilizing a scrubber with particulate demister for particulate matter control, and exhausting to the ambient atmosphere through stacks EP-002A and EP-002B. [40 CFR 60, Subpart VVa]

(2) Two (2) UAN Storage Tanks, identified as EU-012A and EU-012B, approved for construction in 2013, with a maximum rated capacity of 30,000 tons each, and exhausting to the ambient atmosphere through vents EP-012A and EP-012B. [40 CFR 60, Subpart VVa]

(3) Three (3) UAN Day Tanks, identified as EU-020A, EU-020B, and EU-020C, approved for construction in 2013, with a maximum rated capacity of 750 tons each, and exhausting to the ambient atmosphere through vents EP-020A, EP-020B, and EP-020C. [40 CFR 60, Subpart VVa]

(4) Two (2) UAN loadout facilities (one (1) truck and one (1) for rail), identified as EU-024A and EU-024B, approved for construction in 2013, and exhausting to the ambient atmosphere as fugitive emission sources EP-024A and EP-024B.
[40 CFR 60, Subpart VVa]

(5) One (1) UAN plant vent flare for combusting intermittent process gas emissions from maintenance, startup, shutdown, and malfunctions, identified as EU-017, approved for construction in 2013, with a pilot capacity of 0.189 MMBtu per hour, utilizing proper flare design and operation minimization practices, and exhausting to the ambient atmosphere through emission point EP-017.

(6) One (1) DEF tank, identified as EU-021, approved for construction in 2013, with capacity of 100 tons, and exhausting to the ambient atmosphere through vent EP-021.
[40 CFR 60, Subpart VVa]

(7) One (1) DEF truck loadout facility, identified as EU-025, approved for construction in 2013, and exhausting to the ambient atmosphere as fugitive emission source EP-025.
[40 CFR 60, Subpart VVa]

These facilities are subject to the following portions of Subpart VVa.

(1) 40 CFR 60.480a(a) to (c);
(2) 40 CFR 60.480a(d)(1) and (d)(3); and
(3) 40 CFR 60.486a(i).

(m) **40 CFR 60, Subpart Db – Standards of Performance for Industrial-Commercial-Institutional Steam Generating Units:** Boiler EU-011A, Boiler EU-011B, Boiler EU-011C, and Boiler EU-011D are subject to the Standards of Performance for Industrial-Commercial-Institutional Steam Generating Units, 40 CFR 60.40b, Subpart Db, which is incorporated by reference as 326 IAC 12. The facilities subject to this rule include the following:

(1) Four (4) natural gas-fired boilers, identified as EU-011A, EU-011B, EU-011C, and EU-011D, approved for construction in 2013, with a maximum rated heat input capacity of 218 MMBtu/hr each, using ultra low NO_x burners and flue gas recirculation for NO_x emissions control, equipped with NO_x CEMS, and exhausting to the ambient atmosphere through stacks EP-011A, EP-011B, EP-011C, and EP-011D.
[40 CFR 60, Subpart Db]

Boiler EU-011A, Boiler EU-011B, Boiler EU-011C, and Boiler EU-011D are subject to the following portions of Subpart Db.

(1) 40 CFR 60.42b(k)(2);
(2) 40 CFR 60.44b(h) and (i);
(3) 40 CFR 60.44b(l);
(4) 40 CFR 60.46b(a);
(5) 40 CFR 60.46b(c);
(6) 40 CFR 60.46b(e);
(7) 40 CFR 60.48b(b) to (f);
(8) 40 CFR 60.49b(a) and (b);
(9) 40 CFR 60.49b(d);
(10) 40 CFR 60.49b(g);

(11) 40 CFR 60.49b(i); and
(12) 40 CFR 60.49b(o).

(n) **40 CFR 60, Subpart IIII – Standards of Performance for Stationary Compression Ignition Internal Combustion Engines:** The emergency diesel-fired generator and emergency diesel-fired firewater pump are subject to Standards of Performance for Stationary Compression Ignition Internal Combustion Engines, 40 CFR 60.4200, Subpart IIII, which is incorporated by reference as 326 IAC 12. The units subject to this rule include the following:

(1) One (1) diesel-fired emergency generator, identified as EU-009, approved for construction in 2013, with a maximum rated capacity of 4,690 horsepower, utilizing no control devices, and exhausting to the ambient atmosphere through stack EP-009. [40 CFR 60, Subpart IIII][40 CFR 63, Subpart ZZZZ]

(2) One (1) diesel-fired emergency firewater pump, identified as EU-016, approved for construction in 2013, with a maximum rated capacity of 481 horsepower, utilizing no control devices, and exhausting to the ambient atmosphere through stack EP-016. [40 CFR 60, Subpart IIII][40 CFR 63, Subpart ZZZZ][326 IAC 2-2]

The emergency diesel-fired emergency generator (EU-009) is subject to the following portions of Subpart IIII.

(1) 40 CFR 60.4200(a)(2)(i);
(2) 40 CFR 60.4205;
(3) 40 CFR 60.4206:
(4) 40 CFR 60.4207;
(5) 40 CFR 60.4208;
(6) 40 CFR 60.4209(a);
(7) 40 CFR 60.4211(a), (c) and (e)
(8) 40 CFR 60.4212;
(9) 40 CFR 60.4214(b); and
(10) 40 CFR 60.4218.

The emergency diesel-fired firewater pump (EU-016) is subject to the following portions of Subpart IIII.

(1) 40 CFR 60.4200(a)(2)(ii);
(2) 40 CFR 60.4205;
(3) 40 CFR 60.4206;
(4) 40 CFR 60.4207;
(5) 40 CFR 60.4208;
(6) 40 CFR 60.4209(a);
(7) 40 CFR 60.4211(a), (c) and (e);
(8) 40 CFR 60.4212;
(9) 40 CFR 60.4214(b);
(10) 40 CFR 60.4218; and
(11) Table 4

NESHAP:

(a) **40 CFR 63, Subpart B - Requirements For Control Technology Determinations for Major Sources in Accordance with Clean Air Act Sections, Sections 112(g) And 112(j):** These rules are not applicable to the source because other sections in Part 63 are applicable to the source.

(b) **40 CFR 63, Subparts F, G, and H - National Emission Standards for Organic Hazardous Air Pollutants from the Synthetic Organic Chemical Manufacturing Industry**: These rules are not applicable to the source because the source will not manufacture or produce any of the chemicals listed in Table 1 of 40 CFR 63, Subpart F, Table 1.

(c) **40 CFR 63, Subpart Q - National Emission Standards for Hazardous Air Pollutants for Industrial Process Cooling Towers:** These rules are not applicable to this source because the source will not use chromium based materials in its cooling towers.

(d) **40 CFR 63, Subpart BB – National Emission Standards for Hazardous Air Pollutants from Phosphate Fertilizers Production Plants:** These rules are not applicable to this source because it applies to the production of phosphate based fertilizers. This source manufactures ammonia and urea ammonium nitrate (UAN) fertilizers, which do not contain phosphorous.

(e) **40 CFR 63, Subparts OO and PP – National Emission Standards for Tanks and Containers**: These rules apply to storage and containers when another NSPS or NESHAP standard that is applicable to a source refers to these standards. This source is not subject to any NSPS or NESHAP rules that reference these standards.

(f) **40 CFR 63, Subpart EEEE – National Emission Standards for Hazardous Air Pollutants for Organic Liquids Distribution:** These rules are not applicable to this source because it will only distribute ammonia and urea ammonium nitrate (UAN) products. Neither ammonia nor UAN are considered hazardous air pollutants, and therefore, this subpart does not apply.

(g) **40 CFR 63, Subpart YYYY – National Emission Standards for Hazardous Air Pollutants for Stationary Combustion Turbines:** These rules do not apply to this source because the turbines at the site are steam turbines and not combustion turbines.

(h) **40 CFR 63, Subpart CCCCCC – National Emission Standards for Hazardous Air Pollutants for Source Category Gasoline Dispensing Facilities:** This rule does not apply to this source because it is applicable to area sources of hazardous air pollutants, and this source is a major source of hazardous air pollutants.

(i) **40 CFR 63, Subpart JJJJJJ – National Emission Standards for Hazardous Air Pollutants for Industrial, Commercial, and Institutional Boilers Area Sources:** This rule does not apply to this source because it is applicable to area sources of hazardous air pollutants, and this source is a major source of hazardous air pollutants.

(j) **40 CFR 63, Subpart VVVVVV – National Emission Standards for Hazardous Air Pollutants for Chemical Manufacturing Area Sources:** This rule does not apply to this source because it is applicable to area sources of hazardous air pollutants, and this source is a major source of hazardous air pollutants.

(k) **40 CFR 63, Subpart BBBBBBB – National Emission Standards for Hazardous Air Pollutants for Area Sources Chemical Preparations Industry:** This rule does not apply to this source because it is applicable to area sources of hazardous air pollutants, and this source is a major source of hazardous air pollutants.

(l) **40 CFR 63, Subpart FFFF – National Emission Standards for Hazardous Air Pollutants: Miscellaneous Organic Chemical Manufacturing:** This source is subject to the National Emission Standards for Hazardous Air Pollutants: Miscellaneous Organic Chemical Manufacturing, 40 CFR 63.2430, Subpart FFFF, which is incorporated by reference as 326 IAC 20-84. The units subject to this rule include the following:

(1) One (1) CO_2 purification process, identified as EU-004, with maximum rated CO_2 production of 3,570 ton per day, approved for construction in 2013, and exhausting to the ambient atmosphere through stack EP-004. [40 CFR 63, Subpart FFFF]

The CO_2 Purification Process (EU-004) is subject to the following portions of Subpart FFFF:

(1) 40 CFR 63.2435;
(2) 40 CFR 63.2440;
(3) 40 CFR 63.2445(a)(2);
(4) 40 CFR 63.2450;
(5) 40 CFR 63.2455;
(6) 40 CFR 63.2480;
(7) 40 CFR 63.2495;
(8) 40 CFR 63.2500;
(9) 40 CFR 63.2515;
(10) 40 CFR 63.2520;
(11) 40 CFR 63.2525;
(12) 40 CFR 63.2540; and
(13) Table 6

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

(m) **40 CFR 63, Subpart ZZZZ – National Emission Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines:** The diesel-fired emergency generator and firewater pump are subject to the National Emission Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines, 40 CFR 63.6580, Subpart ZZZZ, which is incorporated by reference as 326 IAC 20-82. The units subject to this rule include the following:

(1) One (1) diesel-fired emergency generator, identified as EU-009, approved for construction in 2013, with a maximum rated capacity of 4,690 horsepower, utilizing no control devices, and exhausting to the ambient atmosphere through stack EP-009. [40 CFR 60, Subpart IIII][40 CFR 63, Subpart ZZZZ]

(2) One (1) diesel-fired emergency firewater pump, identified as EU-016, approved for construction in 2013, with a maximum rated capacity of 481 horsepower, utilizing no control devices, and exhausting to the ambient atmosphere through stack EP-016. [40 CFR 60, Subpart IIII][40 CFR 63, Subpart ZZZZ][326 IAC 2-2]

The emergency diesel-fired emergency generator (EU-009) is subject to the following portions of 40 CFR 63, Subpart ZZZZ:

(1) 40 CFR 63.6605;
(2) 40 CFR 63.6640; and
(3) 40 CFR 63.6645(f).

The emergency diesel-fired firewater pump (EU-016) is subject to the following portions of 40 CFR 63, Subpart ZZZZ:

(1) 40 CFR 63.6590(c)(6).

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

(n) **40 CFR 61, Subpart FF – National Emission Standards for Benzene Waste Operations:** This entire source is subject to the National Emission Standards for Benzene Waste Operations, 40 CFR 61.340, Subpart FF. The entire source is subject to the following portions of 40 CFR 61, Subpart FF:

(1) 40 CFR 61.340(a)
(2) 40 CFR 61.341
(3) 40 CFR 61.342(a)
(4) 40 CFR 61.355
(5) 40 CFR 61.356
(6) 40 CFR 61.357(a) and (b)

The provisions of 40 CFR 61 Subpart A – General Provisions, which are incorporated as 326 IAC 14-1-1, apply to the facility described in this section except when otherwise specified in 40 CFR 61, Subpart FF.

(o) **40 CFR 63, Subpart DDDDD – National Emission Standards for Hazardous Air Pollutants for Major Sources: Industrial, Commercial, and Institutional Boilers and Process Heaters:** The Primary Reformer (EU-003), the Ammonia Catalyst Startup Heater (EU-010) and the boilers (EU-011A, EU-011B, EU-011C, and EU-011D) are subject to the National Emission Standards for Hazardous Air Pollutants for Major Sources: Industrial, Commercial, and Institutional Boilers and Process Heaters, 40 CFR 63.7485, Subpart DDDDD. The units subject to this rule include the following:

(1) One (1) primary reformer, identified as EU-003, approved for construction in 2013, with a maximum rated heat input capacity of 1,006.4 MMBtu/hr, using selective catalytic reduction for NO_x emissions control, equipped with NO_x CEMS, and exhausting to the ambient atmosphere through stack EP-003. [40 CFR 63, Subpart DDDDD]

(2) One (1) ammonia catalyst startup heater, identified as EU-010, approved for construction in 2013, with a maximum rated heat input capacity of 106.3 MMBtu/hr, utilizing no control devices, and exhausting to the ambient atmosphere through stack EP-010. [40 CFR 63, Subpart DDDDD]

(3) Four (4) natural gas-fired boilers, identified as EU-011A, EU-011B, EU-011C, and EU-011D, approved for construction in 2013, with a maximum rated heat input capacity of 218 MMBtu/hr each, using ultra low NO_x burners and flue gas recirculation for NO_x emissions control, equipped with NO_x CEMS, and exhausting to the ambient atmosphere through stacks EP-011A, EP-011B, EP-011C, and EP-011D.
[40 CFR 60, Subpart Db] [40 CFR 63, Subpart DDDDD]

These emission units are subject to the following portions of 40 CFR 63, Subpart DDDDD:

(A) 40 CFR 63.7485;
(B) 40 CFR 63.7490 (b);
(C) 40 CFR 63.7495 (a), (b);
(D) 40 CFR 63.7500;
(E) 40 CFR 63.7505;
(F) 40 CFR 63.7510;
(G) 40 CFR 63.7525;
(H) 40 CFR 63.7540(a)(10);
(I) 40 CFR 63.7545;
(J) 40 CFR 63.7550;
(K) 40 CFR 63.7555;
(L) 40 CFR 63.7560;
(M) 40 CFR 63.7565; and
(N) Table 3(2).

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

CAM:

(a) 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.

The following table is used to identify the applicability of each of the criteria, under 40 CFR 64.1, to each new or modified emission unit involved:

CAM Applicability Analysis

Emission Unit	**Control Device Used**	**Emission Limitation** (Y/N)	**Uncontrolled PTE** (ton/yr)	**Controlled PTE** (ton/yr)	**Part 70 Major Source Threshold** (ton/yr)	**CAM Applicable** (Y/N)	**Large Unit** (Y/N)
Primary Reformer (EU-003) NO_x	Y	Y	617.12	61.71	100	N	N
Nitric Acid Plant A (EU-001A) NO_x	Y	Y	574.88	57.49	100	N	N
Nitric Acid Plant B (EU-001B) NO_x	Y	Y	574.88	57.49	100	N	N

The requirements of CAM do not apply to Nitric Acid Plant A (EU-001A), Nitric Acid Plant B (EU-001B) and the Primary Reformer (EU-003) for NO_x because the applicant has installed Continuous Emissions Monitoring System (CEMS) for NO_x.

State Rule Applicability Determination – Entire Source

The following state rules are applicable to the source:

326 IAC 1-5 (Episode Alert Levels)

This rule applies to all persons responsible for the operation of a source that has the potential to emit one hundred (100) tons per year or more of any pollutant. This source has the potential to emit PM, PM_{10}, $PM_{2.5}$, CO and NO_x in excess of 100 tons per year; therefore, this source is subject to 326 IAC 1-5.

326 IAC 1-7 (Stack Height Provisions)
This rule applies to all sources having exhaust gas stacks through which a potential of twenty-five (25) tons per year or more of particulate or sulfur dioxide are emitted. It also applies to all dispersion techniques used in ambient air quality modeling for the purpose of establishing an emission limitation and for calculating the ambient air quality impact of a source. This source has exhaust gas stacks through which a potential of twenty-five tons per year of more of particulate matter is emitted. Therefore, this rule applies to this source.

326 IAC 2-2 (PSD)
This new stationary source is one of the 28 listed source categories and has the potential to emit of at least one regulated pollutant greater than 100 tons per year. Therefore, this is a major source pursuant to 326 IAC 2-2.

326 IAC 2-2-3 (PSD Rule: Control Technology Review Requirements)
A new, major stationary source shall apply best available control technology (BACT) for each regulated NSR pollutant for which the source has the potential to emit in significant amounts, as defined in 326 IAC 2-2-1(ww). Ohio Valley Resources, LLC has the potential to emit of Greenhouse Gases (GHGs) in excess of 100,000 TPY, and the potential to emit of NO_x and CO in excess of 250 TPY. The potential to emit PM, PM_{10}, $PM_{2.5}$ and VOC are greater than the PSD significant level of each pollutant. Therefore, a control technology review is required for PM, PM_{10}, $PM_{2.5}$, VOC, NO_x, CO and greenhouse gases (GHGs). See Appendix B to this Technical Support Document (TSD) for the PSD BACT Analysis.

326 IAC 2-2-4 (Air Quality Analysis Requirements)
326 IAC 2-2-4(a) requires PSD applications to contain an analysis of ambient air quality in the area the major source would affect for pollutants that are emitted at major levels or significant amounts. Ohio Valley Resources, LLC submitted an air quality analysis, which was evaluated by IDEM's Technical Support and Modeling Section. See Appendix C to this Technical Support Document (TSD) for the PSD Air Quality Analysis.

326 IAC 2-2-5 (Air Quality Impact Requirements)
326 IAC 2-2-5(e)(1) requires the air quality impact analysis to be conducted in accordance with the following provisions:

(1) Any estimates of ambient air concentrations used in the demonstration processes shall be based upon the applicable air quality models, data bases, and other requirements specified in 40 CFR Part 51, Appendix W (Requirements for Preparation, Adoption, and Submittal of Implementation Plans, Guideline on Air Quality Models).

(2) Where an air quality impact model specified in the guidelines in subdivision (1) is inappropriate, a model may be modified or another model substituted provided that all applicable guidelines are satisfied.

(3) Modifications or substitution of any model may only be done in accordance with guideline documents and with written approval from U.S. EPA and shall be subject to the public comment procedures set forth in 326 IAC 2-1.1-6.

326 IAC 2-2-6 (Increment Consumption Requirements)
326 IAC 2-2-6(a) requires that any demonstration under 326 IAC 2-2-5 shall demonstrate that increased emissions caused by the proposed major stationary source will not exceed eighty percent (80%) of the available maximum allowable increases (MAI) over the baseline concentrations of PM, PM_{10}, $PM_{2.5}$, VOC, NO_x, CO and greenhouse gases (GHGs), indicated in 326 IAC 2-2-6(b)(1). PM, PM_{10}, $PM_{2.5}$, VOC, NO_x, CO and greenhouse gases (GHGs) are emitted and subject to PSD in this proposed permit, T 147-32322-00062.

326 IAC 2-2-7 (Additional Analysis, Requirements)
323 IAC 2-2-7(a) requires an analysis of the impairment to visibility, soils and vegetation. An analysis of the air quality impact projected for the area as a result of general commercial, residential, industrial and other growth associated with the source. See Appendix C to this Technical Support Document (TSD) for the additional analysis required by 326 IAC 2-2-7.

326 IAC 2-2-8 (Source Obligation)
Pursuant to 326 IAC 2-2-8(1), approval to construct, shall become invalid if construction is not commenced within eighteen (18) months after receipt of the approval, if construction is discontinued for a period of eighteen (18) months or more, or if construction is not completed within a reasonable time. Approval for construction shall not relieve the Permittee of the responsibility to comply fully with applicable provisions of the state implementation plan and any other requirements under local, state or federal law.

326 IAC 2-2-9 (Innovative Control Technology)
326 IAC 2-2-9 allows any owner or operator of a proposed major stationary source or major modification may request the commissioner in writing to approve a system of innovative control technology. Ohio Valley Resources, LLC has not requested the use of any innovative control technologies as part of the PSD application for T 147-32322-00062.

326 IAC 2-2-10 (Source Information)
The applicant has submitted all information necessary to perform analysis or make the determination required by this rule.

326 IAC 2-2-12 (Permit Rescission)
The permit issued under this rule shall remain in effect unless and until it is rescinded, modified, revoked, or it expires in accordance with 326 IAC 2-1.1-9.5 or 326 IAC 2-2-8.

326 IAC 2-6 (Emission Reporting)
Since this source is required to have an operating permit under 326 IAC 2-7, Part 70 Permit Program, this source is subject to 326 IAC 2-6 (Emission Reporting). In accordance with the compliance schedule in 326 IAC 2-6-3, an emission statement must be submitted triennially. The first report is due no later than July 1, 2015, and subsequent reports are due every three (3) years thereafter. The emission statement shall contain, at a minimum, the information specified in 326 IAC 2-6-4.

326 IAC 5-1 (Opacity Limitations)
This rule applies to opacity, not including condensed water vapor, emitted by or from a facility or source. This source has sources of opacity; therefore, this rule applies.

326 IAC 6-4 (Fugitive Dust Emissions)
This rule applies to all sources of fugitive dust emissions. This source has fugitive dust emissions; therefore, 326 IAC 6-4 applies to the source.

State Rule Applicability Determination – Individual Facilities

Boiler Units EU-011A, EU-011B, EU-011C to EU-011D

326 IAC 2-2-3 (PSD Rule: Control Technology Review Requirements)
Pursuant to PSD/Operating Permit T 147-32322-00062 and 326 IAC 2-2-3 (Prevention of Significant Deterioration), the best available control technology (BACT) for Boiler Units EU-011A, EU-011B, EU-011C and EU-011D shall be as follows:

Common PM, PM_{10}, $PM_{2.5}$, NO_x, CO, VOC and GHG Conditions:

(a) PM, PM_{10}, $PM_{2.5}$, NO_x, CO, VOC and GHG from the boilers (EU-011A, EU-011B, EU-011C and EU-011D) shall be controlled through the use of proper boiler design and good combustion practices.

(b) Combined fuel usage in the boilers (EU-011A, EU-011B, EU-011C and EU-011D) shall not exceed 2,802 MMCF per twelve consecutive month period with compliance determined at the end of each month.

(c) The boilers (EU-011A, EU-011B, EU-011C, and EU-011D) shall combust natural gas.

PM, PM_{10} and $PM_{2.5}$:

(d) PM, PM_{10} and $PM_{2.5}$ emissions from each of the boilers (EU-011A, EU-011B, EU-011C and EU-011D) shall not exceed 1.9, 7.6 and 7.6 lb/MMCF, respectively, based on a three-hour average. PM includes filterable particulate matter, while, PM_{10} and $PM_{2.5}$ include both filterable and condensable particulate matter.

NO_x:

(e) NO_x emissions from the boilers (EU-011A, EU-011B, EU-011C, and EU-011D) shall be controlled by the use of Ultra Low NO_x Burners and Flue Gas Recirculation (FGR).

(f) NO_x emissions from each of the boilers (EU-011A, EU-011B, EU-011C, and EU-011D) shall not exceed 20.40 lb/MMCF, based on a twenty-four hour average.

CO:

(g) CO emissions from each of the boilers (EU-011A, EU-011B, EU-011C, and EU-011D) shall not exceed 37.22 lb/MMCF, based on a three-hour average.

VOC:

(h) VOC emissions from each of the boilers (EU-011A, EU-011B, EU-011C, and EU-011D) shall not exceed 5.5 lb/MMCF, based on a three-hour average.

GHG:

(i) CO_2 emissions from each of the boilers (EU-011A, EU-011B, EU-011C, and EU-011D) shall not exceed 59.61 tons/MMCF, based on a three-hour average.

(j) Each of the boilers (EU-011A, EU-011B, EU-011C and EU-011D) shall be equipped with the following energy efficient design features: air inlet controls, heat recovery, condensate recovery, and blowdown heat recovery.

(k) Each of the boilers (EU-011A, EU-011B, EU-011C and EU-011D) shall be designed to achieve a thermal efficiency of 80% (HHV).

326 IAC 2-4.1 (Major Sources of Hazardous Air Pollutants (HAP))
The boilers (EU-011A, EU-011B, EU-011C, and EU-011D) are subject to 40 CFR 63, Subpart DDDDD. Therefore, 326 IAC 2-4.1 does not apply.

326 IAC 3-5 (Continuous Monitoring of Emissions)
This rule applies to fossil fuel-fired steam generators of greater than 100 MMBtu/hr heat input capacity. 326 IAC 3-5 applies to boilers EU-011A, EU-011B, EU-011C, and EU-011D, because they are fossil fuel-fired steam generating units each with a heat input capacity of 218 MMBtu/hr. The applicant is not required to continuously monitor opacity; because, all four units combust a gaseous fuel, natural gas. The applicant is not required to continuously monitor sulfur dioxide; because, SO_2 control equipment is not installed on the boilers. The Permittee is required to continuously monitor NO_x emissions; because, the source has installed a NO_x control system, Flue Gas Recirculation (FGR).

326 IAC 6-2 (Particulate Emissions Limitations for Sources of Indirect Heating)
This rule establishes particulate matter limitations for sources of indirect heating. Boiler EU-011A, Boiler EU-011B, Boiler EU-011C, and Boiler EU-011D will be constructed after September 21, 1983 and are located in Spencer County, Indiana. Sources of indirect heating subject to a particulate matter emission limitation in a 40 CFR 60 standard are not subject to 326 IAC 6-2. Sources subject to a particulate matter emission limitation in 326 IAC 2-2 are also not subject to 326 IAC 6-2. These boilers have an emission limitation established in accordance with 326 IAC 2-2 Prevention of Significant Deterioration (PSD); therefore, 326 IAC 6-2 does not apply.

326 IAC 7-1.1 (Sulfur Dioxide Emission Limitations)
This rule applies to all emission units with a potential to emit twenty-five (25) tons per year or ten (10) pounds per hour of sulfur dioxide. Boiler EU-011A, Boiler EU-011B, Boiler EU-011C, and Boiler EU-011D each combust low sulfur natural gas with the potential to emit sulfur dioxide of less than 25 tons per year. Therefore, 326 IAC 7-1.1 does not apply.

326 IAC 8-1-6 BACT (General Reduction Requirements)
This rule applies to new facilities as of January 1, 1980, with potential emissions of twenty-five (25) tons per year or more of VOC, are located anywhere in the state, and are not otherwise regulated by 326 IAC 20-48 or 326 IAC 20-56. Each boiler has potential emissions of VOC of less than 25 TPY; therefore, 326 IAC 8-1-6 does not apply.

326 IAC 9 (Carbon Monoxide Emission Rules)
326 IAC 9 limits carbon monoxide emissions from petroleum refining operations, ferrous metal smelters, and refuse incineration and refuse burning equipment. The boilers proposed at this source are located at a fertilizer production facility and will combust natural gas. Therefore, this rule does not apply to Boiler EU-011A, Boiler EU-011B, Boiler EU-011C, and Boiler EU-011D.

326 IAC 24 (Trading Programs: Nitrogen Oxides (NO_x) and Sulfur Dioxide (SO_2))
326 IAC 24-1 creates an annual NO_x trading program. 326 IAC 24-2 creates an annual SO_2 trading program. 326 IAC 24-4 creates a mercury emissions budget and mercury trading program for coal-fired generating units. Boiler EU-011A, Boiler EU-011B, Boiler EU-011C, and Boiler EU-011D are not generating units selling electricity to the grid. Therefore, 326 IAC 24-1, 24-2 and 24-4 do not apply to the boilers. 326 IAC 24-3 creates an ozone season NO_x trading program. 326 IAC 24-3 applies to electric utility steam generating units and large affected units, defined as boilers and combustion turbines with a heat input capacity of 250 MMBtu/hr or more. Boiler EU-011A, Boiler EU-011B, Boiler EU-011C, and Boiler EU-011D are not generating units selling electricity to the grid and each has a heat input capacity of less than 250 MMBtu/hr. Therefore, 326 IAC 24-3 does not apply to the boilers.

Primary Reformer (EU-003)

326 IAC 2-2-3 (PSD Rule: Control Technology Review Requirements)
Pursuant to PSD/Operating Permit T 147-32322-00062 and 326 IAC 2-2-3 (Prevention of Significant Deterioration), the best available control technology (BACT) for the Primary Reformer (EU-003) shall be as follows:

(a) **Primary Reformer (EU-003):**

Common PM, PM_{10}, $PM_{2.5}$, NO_x, CO, VOC and GHG Conditions:

(1) PM, PM_{10}, $PM_{2.5}$, NO_x, CO, VOC and GHG emissions from the operation of Primary Reformer (EU-003) shall be controlled through the use of good combustion practices.

(2) The Primary Reformer (EU-003) shall combust natural gas and/or process off gas streams.

PM, PM_{10}, $PM_{2.5}$:

(3) PM, PM_{10} and $PM_{2.5}$ emissions from the operation of Primary Reformer (EU-003) shall not exceed 1.9, 7.6 and 7.6 lb/MMCF respectively, based on a three-hour average. PM includes filterable particulate matter, while, PM_{10} and $PM_{2.5}$ include both filterable and condensable particulate matter.

NO_x:

(4) NO_x emissions from the Primary Reformer (EU-003) shall be controlled by selective catalytic reduction (SCR) at all times the reformer is in operation.

(5) NO_x emissions from the Primary Reformer (EU-003) shall not exceed 9 ppm_{vd}, based on a thirty-day rolling average.

CO:

(6) CO emissions from the Primary Reformer (EU-003) shall not exceed 43.45 lb/MMCF, based on a three-hour average.

VOC:

(7) VOC emissions from the Primary Reformer (EU-003) shall not exceed 5.51 lb/MMCF, based on a three-hour average.

GHG:

(8) CO_2 emissions from the Primary Reformer (EU-003) shall not exceed 59.61 tons/MMCF, based on a three-hour average.

(9) The Primary Reformer (EU-003) shall be equipped with the following energy efficiency features: air inlet controls and flue gas heat recovery to pre-heat inlet fuel, inlet air and inlet steam flows.

(10) The Primary Reformer (EU-003) shall be designed to achieve a thermal efficiency of 90% (HHV).

(11) CO_2 emissions from the Primary Reformer (EU-003) shall not exceed 515,246 tons per twelve consecutive month period with compliance determined at the end of each month.

326 IAC 2-4.1 (Major Sources of Hazardous Air Pollutants (HAP))
The Primary Reformer (EU-003) is subject to 40 CFR 63, Subpart DDDDD. Therefore, 326 IAC 2-4.1 does not apply.

326 IAC 3-5 (Continuous Monitoring of Emissions)
This rule applies to fossil fuel-fired steam generators of greater than 100 MMBtu/hr heat input capacity. The Primary Reformer has a heat input capacity of greater than 100 MMBtu/hr, but it is not a steam generating unit. The Primary Reformer is a process heater. Therefore, the Primary Reformer (EU-003) is not subject to 326 IAC 3-5. The Applicant will install a NO_x CEMS for compliance monitoring purposes.

326 IAC 6-2 (Particulate Emissions Limitations for Sources of Indirect Heating)
This rule establishes particulate matter limitations for sources of indirect heating. The Primary Reformer (EU-003) will be constructed after September 21, 1983 and is located in Spencer County, Indiana. Sources of indirect heating subject to a particulate matter emission limitation in a 40 CFR 60 standard are not subject to 326 IAC 6-2. Sources subject to a particulate matter emission limitation in 326 IAC 2-2 are also not subject to 326 IAC 6-2. The Primary Reformer (EU-003) is subject to an emission limitation established in accordance with 326 IAC 2-2 Prevention of Significant Deterioration (PSD); therefore, 326 IAC 6-2 does not apply.

326 IAC 7-1.1 (Sulfur Dioxide Emission Limitations)
This rule applies to all emission units with a potential to emit twenty-five (25) tons per year or ten (10) pounds per hour of sulfur dioxide. The Primary Reformer (EU-003) combusts low sulfur natural gas with the potential to emit sulfur dioxide of less than 25 tons per year. Therefore, 326 IAC 7-1.1 does not apply.

326 IAC 8-1-6 BACT (General Reduction Requirements)
This rule applies to new facilities as of January 1, 1980, with potential emissions of twenty-five (25) tons per year or more of VOC, are located anywhere in the state, and are not otherwise regulated by 326 IAC 20-48 or 326 IAC 20-56. The Primary Reformer (EU-003) has potential emissions of VOC of less than 25 TPY; therefore, 326 IAC 8-1-6 does not apply.

326 IAC 9 (Carbon Monoxide Emission Rules)
326 IAC 9 limits carbon monoxide emissions from petroleum refining operations, ferrous metal smelters, and refuse incineration and refuse burning equipment. The Primary Reformer proposed at this source is located at a fertilizer production facility and will combust natural gas. Therefore, 326 IAC 9 does not apply to the Primary Reformer.

326 IAC 24 (Trading Programs: Nitrogen Oxides (NO_x) and Sulfur Dioxide (SO_2))
326 IAC 24-1 creates an annual NO_x trading program. 326 IAC 24-2 creates an annual SO_2 trading program. 326 IAC 24-4 creates a mercury emissions budget and mercury trading program for coal-fired generating units. The Primary Reformer is not considered an electric generating unit selling electricity to the grid. Therefore, 326 IAC 24-1, 24-2 and 24-4 do not apply to the Primary Reformer. 326 IAC 24-3 creates an ozone season NO_x trading program. 326 IAC 24-3 applies to electric utility steam generating units and large affected units, defined as boilers and combustion turbines with a heat input capacity of 250 MMBtu/hr or more. The Primary Reformer is a process heater and not a steam generating unit (boiler). Therefore, the Primary Reformer is not subject to 326 IAC 24-3.

Ammonia Catalyst Startup Heater (EU-010)

326 IAC 2-2-3 (PSD Rule: Control Technology Review Requirements)
Pursuant to PSD/Operating Permit T 147-32322-00062 and 326 IAC 2-2-3 (Prevention of Significant Deterioration), the best available control technology (BACT) for the Ammonia Catalyst Startup Heater (EU-010) shall be as follows:

Common PM, PM_{10}, $PM_{2.5}$, NO_x, CO, VOC and GHG Conditions:

(1) In order to control PM, PM_{10}, $PM_{2.5}$, NO_x, CO, VOC and GHG emissions, the Ammonia Catalyst Startup Heater (EU-010) shall combust natural gas.

(2) In order to control PM, PM_{10}, $PM_{2.5}$, NO_x, CO, VOC and GHG emissions, the Ammonia Catalyst Startup Heater (EU-010) shall be controlled by good heater design and good combustion practices.

(3) Fuel usage in the Ammonia Catalyst Startup Heater (EU-010) shall not exceed 20.84 MMCF per twelve consecutive month period with compliance determined at the end of each month.

PM, PM_{10}, $PM_{2.5}$:

(4) PM, PM_{10} and $PM_{2.5}$ emissions from the Ammonia Catalyst Startup Heater (EU-010) shall not exceed 1.9, 7.6, and 7.6 lb/MMCF respectively, based on a three-hour average. PM includes filterable particulate matter, while, PM_{10} and $PM_{2.5}$ include both filterable and condensable particulate matter.

NO_x:

(5) NO_x emissions from the Ammonia Catalyst Startup Heater (EU-010) shall not exceed 183.70 lb/MMCF, based on a three-hour average.

CO:

(6) CO emissions from the Ammonia Catalyst Startup Heater (EU-010) shall not exceed 37.23 lb/MMCF, based on a three-hour average.

VOC:

(7) VOC emissions from the Ammonia Catalyst Startup Heater (EU-010) shall not exceed 5.50 lb/MMCF, based on a three-hour average.

GHG:

(8) CO_2 emissions from the Ammonia Catalyst Startup Heater (EU-010) shall not exceed 59.61 ton/MMCF, based on a three-hour average.

326 IAC 2-4.1 (Major Sources of Hazardous Air Pollutants (HAP))
The Ammonia Catalyst Startup Heater (EU-010) is subject to the requirements of 40 CFR 63, Subpart DDDDD. Therefore, 326 IAC 2-4.1 does not apply.

326 IAC 3-5 (Continuous Monitoring of Emissions)
This rule applies to fossil fuel-fired steam generators of greater than 100 MMBtu/hr heat input capacity. 326 IAC 3-5 does not apply to the Ammonia Catalyst Startup Heater (EU-010) because it is not a fossil fuel-fired steam generating unit. It is a process heater with a heat input capacity of 106.3 MMBtu/hr.

326 IAC 6-2 (Particulate Emissions Limitations for Sources of Indirect Heating)
This rule establishes particulate matter limitations for sources of indirect heating. The Ammonia Catalyst Startup Heater (EU-010) will be constructed after September 21, 1983 and is located in Spencer County, Indiana. Sources of indirect heating subject to a particulate matter emission limitation in a 40 CFR 60 standard are not subject to 326 IAC 6-2. Sources subject to a particulate matter emission limitation in 326 IAC 2-2 are also not subject to 326 IAC 6-2. The Ammonia Catalyst Startup Heater (EU-010) is subject to an emission limitation established in accordance with 326 IAC 2-2 Prevention of Significant Deterioration (PSD); therefore, 326 IAC 6-2 does not apply.

326 IAC 7-1.1 (Sulfur Dioxide Emission Limitations)
This rule applies to all emission units with a potential to emit twenty-five (25) tons per year or ten (10) pounds per hour of sulfur dioxide. The Ammonia Catalyst Startup Heater (EU-010) combusts low sulfur natural gas with the potential to emit sulfur dioxide of less than 25 tons per year. Therefore, 326 IAC 7-1.1 does not apply.

326 IAC 8-1-6 BACT (General Reduction Requirements)
This rule applies to new facilities as of January 1, 1980, with potential emissions of twenty-five (25) tons per year or more of VOC, are located anywhere in the state, and are not otherwise regulated by 326 IAC 20-48 or 326 IAC 20-56. The Ammonia Catalyst Startup Heater (EU-010) has potential emissions of VOC of less than 25 TPY; therefore, 326 IAC 8-1-6 does not apply.

326 IAC 9 (Carbon Monoxide Emission Rules)
326 IAC 9 limits carbon monoxide emissions from petroleum refining operations, ferrous metal smelters, and refuse incineration and refuse burning equipment. The Primary Reformer proposed at this source is located at a fertilizer production facility and will combust natural gas. Therefore, 326 IAC 9 does not apply to the Primary Reformer.

326 IAC 24 (Trading Programs: Nitrogen Oxides (NO_x) and Sulfur Dioxide (SO_2))
326 IAC 24-1 creates an annual NO_x trading program. 326 IAC 24-2 creates an annual SO_2 trading program. 326 IAC 24-4 creates a mercury emissions budget and mercury trading program for coal-fired generating units. The Ammonia Catalyst Startup Heater (EU-010) is not considered an electric generating unit. Therefore, 326 IAC 24-1, 24-2 and 24-4 do not apply to the Ammonia Catalyst Startup Heater (EU-010). 326 IAC 24-3 creates an ozone season NO_x trading program. 326 IAC 24-3 applies to electric utility steam generating units and large affected units, defined as boilers and combustion turbines with a heat input capacity of 250 MMBtu/hr or more. The Ammonia Catalyst Startup Heater (EU-010) is a process heater and not a steam generating unit (boiler) and has a heat input capacity of less than 250 MMBtu/hr. Therefore, the Ammonia Catalyst Startup Heater (EU-010) is not subject to 326 IAC 24-3.

UAN Process Vents (EU-002A and EU-002B)

326 IAC 2-2-3 (PSD Rule: Control Technology Review Requirements)
Pursuant to PSD/Operating Permit T 147-32322-00062 and 326 IAC 2-2-3 (Prevention of Significant Deterioration), the best available control technology (BACT) for the UAN Process Vents (EU-002A and EU-002B) shall be as follows:

Common PM, PM_{10}, $PM_{2.5}$ and GHG Conditions

(1) The maximum combined production of urea ammonium nitrate (UAN) for the Ammonium Nitrate Plants (EU-002A and EU-002B) shall not exceed 1,314,000 tons per year.

PM, PM_{10}, $PM_{2.5}$:

(2) The PM, PM_{10} and $PM_{2.5}$ emissions from the operation of each Ammonium Nitrate Plants (EU-002A and EU-002B) shall not exceed 0.0128 lb per ton of urea ammonium nitrate (UAN), based on a three-hour average, through the use of a wet scrubber with demister.

GHG:

(3) CO_2 emissions from the Ammonium Nitrate Plants (EU-002A and EU-002B) shall be controlled by good operational practices in the reformer process including the Primary Reformer (EU-003) and CO_2 Purification Process (EU-004).

(4) CO_2 emissions from each of the Ammonium Nitrate Plants (EU-002A and EU-002B) shall not exceed 132.31 lb CO_2 per ton UAN, based on a three-hour average.

326 IAC 6-3 (Particulate Emission Limitations for Manufacturing Processes)
This rule applies to emission units or groups of emission units that meet the definition of a manufacturing process, have the potential to emit particulate emissions and are not otherwise identified as exempt in the rule. A manufacturing process involves any single or series of actions, operations, or treatments in which a mechanical, physical or chemical transformation of material occurs that emits or has the potential to emit, particulate in the production of the product. Manufacturing process includes transference, conveyance, or repair of a product. The UAN process creates the product UAN and it results in the generation of particulate emissions. However, the UAN Process is subject to an emission limitation in accordance with 326 IAC 2-2 Prevention of Significant Deterioration (PSD), therefore, 326 IAC 6-3 does not apply.

CO_2 Purification Vent (EU-004)

326 IAC 2-2-3 (PSD Rule: Control Technology Review Requirements)
Pursuant to PSD/Operating Permit T 147-32322-00062 and 326 IAC 2-2-3 (Prevention of Significant Deterioration), the best available control technology (BACT) for the CO_2 Purification Vent (EU-004) shall be as follows:

Common CO, VOC and GHG Conditions:

(1) Ammonia production shall not exceed 1,022,000 tons per twelve consecutive month period with compliance determined at the end of each month.

CO:

(2) CO emissions from the CO_2 Purification Process Vent (EU-004) shall be controlled by the use of good operational procedures and the use of a process catalyst.

(3) The CO emission rate shall not exceed 0.0117 lb/ton of ammonia produced, based on a three-hour average.

VOC:

(4) The use of a low VOC catalyst providing a maximum VOC emission rate of 0.0558 lb VOC per ton of ammonia produced or less, based on a three-hour average.

GHG:

(5) Good Operational Practices to achieve a CO_2 emission rate of 1.28 tons CO_2 per ton of ammonia, based on a three-hour average.

326 IAC 8-1-6 (General Reduction Requirements)
This rule applies to new facilities as of January 1, 1980, with potential emissions of twenty-five (25) tons per year or more of VOC, are located anywhere in the state, and are not otherwise regulated by 326 IAC 20-48 or 326 IAC 20-56. The CO_2 Purification Process has potential emissions of VOC in excess of twenty-five (25) tons per year. Therefore, 326 IAC 8-1-6 applies to the CO_2 Purification Process. IDEM, OAQ has performed a PSD-BACT for this process and it is identical to the 326 IAC 8-1-6 BACT. The PSD-BACT will serve as the 326 IAC 8-1-6 BACT.

Front End Process Flare (EU-007)

326 IAC 2-2-3 (PSD Rule: Control Technology Review Requirements)
Pursuant to PSD/Operating Permit T 147-32322-00062 and 326 IAC 2-2-3 (Prevention of Significant Deterioration), the best available control technology (BACT) for the Front End Process Flare (EU-007) shall be as follows:

Common PM, PM_{10}, $PM_{2.5}$, NO_x, CO, VOC and GHG Conditions:

(1) In order to control PM, PM_{10}, $PM_{2.5}$, NO_x, CO, VOC and GHG emissions, the pilot and purge gas fuels used in the flare shall be natural gas.

(2) Venting in the Front End Process Flare (EU-007) shall not exceed 336 hours per twelve consecutive month period with compliance determined at the end of each month.

(3) Comply with the following flare minimization practices to reduce emissions during startups, shutdowns, and other flaring events:

(A) Flare Use Minimization: Process syngas streams to flare EU-007 shall not contain ammonia. During the startup of the sequential reformer, only one process stream at a time shall be sent to the flare to the extent practicable. Maximize the use of process syngas during the startup of the Ammonia Unit;

(B) The Permittee shall train all operators responsible for the day-to-day operation of the flares on the flare minimization practices and the specific procedures to follow during process startup, shutdown, and other flaring events; and

(C) The Permittee shall investigate the “root cause” of malfunction events that cause flaring events other than at startup or shutdown. This root cause analysis shall identify the apparent cause of unanticipated flaring event and shall recommend additional preventive measures that will minimize the chance of a repeat event. The Permittee shall implement the recommended preventive measures.

(4) NO_x, CO, PM, PM_{10} and $PM_{2.5}$, VOC, and GHG emissions shall be controlled by the use of the following practices:

(A) Flares shall be designed for and operated with no visible emissions, except for periods not to exceed 5 minutes during any two consecutive hours;

(B) Flares shall be operated with a flame present at all times; and

(C) Flares shall be continuously monitored to assure the presence of a pilot flame with a thermocouple, infrared monitor, or other approved device.

PM, PM_{10}, $PM_{2.5}$:

(5) PM emissions shall not exceed 0.0019 lb/MMBtu, based on a three-hour average.

(6) PM_{10} and $PM_{2.5}$ emissions shall not exceed 0.0075 lb/MMBtu, based on a three-hour average.

NO_x:

(7) NO_x emissions from the Front End Process Flare (EU-007) shall not exceed 0.068 lb /MMBtu, based on a three-hour average, during normal operation, non-venting periods.

(8) NO_x emissions from the Front End Process Flare (EU-007) shall not exceed 595.47 lb/hr, based on a three-hour average, during venting events.

CO:

(9) CO emissions from the Front End Process Flare (EU-007) shall not exceed 0.37 lb/MMBtu, based on a three-hour average, during normal operations, non-venting periods.

(10) CO emissions from the Front End Process Flare (EU-007) shall not exceed 3,240.16 lb/hr, based on a three-hour average, during venting events.

VOC:

(11) VOC emissions from the Front End Process Flare (EU-007) shall not exceed 0.0054 lb/MMBtu, based on a three-hour average, during normal operations, non-venting periods.

(12) VOC emissions from the Front End Process Flare (EU-007) shall not exceed 47.26 lb/hr, based on a three-hour average, during venting events.

GHG:

(13) CO_2 emissions from the Front End Process Flare (EU-007) shall not exceed 116.89 lb CO_2/MMBtu, based on a three-hour average, during normal operation, non-venting periods.

(14) CO_2 emissions from the Front End Process Flare (EU-007) shall not exceed 511.80 ton CO_2/hr, based on a three-hour average, during venting events.

Back End Ammonia Process Vent Flare (EU-006)

326 IAC 2-2-3 (PSD Rule: Control Technology Review Requirements)
Pursuant to PSD/Operating Permit T 147-32322-00062 and 326 IAC 2-2-3 (Prevention of Significant Deterioration), the best available control technology (BACT) for the Back End Ammonia Process Flare (EU-006) shall be as follows:

Common PM, PM_{10}, $PM_{2.5}$, NO_x, CO, VOC and GHG Conditions:

(1) In order to control PM, PM_{10}, $PM_{2.5}$, NO_x, CO, VOC and GHG emissions, the pilot and purge gas fuels used in the flare shall be natural gas.

(2) Venting in the Back End Ammonia Process Flare (EU-006) shall not exceed 336 hours per twelve consecutive month period with compliance determined at the end of each month.

(3) Comply with the following flare minimization practices to reduce emissions during startups, shutdowns, and other flaring events:

(A) Flare Use Minimization: Flare EU-006 shall be limited to flaring ammonia during high-pressure events to the extent practicable. The ammonia compressor main shall be depressurized prior to compressor maintenance. The Permittee shall limit venting ammonia rich streams to Flare EU-006 to the extent practicable during non-emergency startup and shutdown operations;

(B) The Permittee shall train all operators responsible for the day-to-day operation of the flares on the flare minimization practices and the specific procedures to follow during process startup, shutdown, and other flaring events; and

(C) The Permittee shall investigate the “root cause” of malfunction events that cause flaring events other than at startup or shutdown. This root cause analysis shall identify the apparent cause of unanticipated flaring event and shall recommend additional preventive measures that will minimize the chance of a repeat event. The Permittee shall implement the recommended preventive measures.

(4) PM, PM_{10}, $PM_{2.5}$, NO_x, CO, VOC and GHG emissions from the Back End Ammonia Process Vent Flare (EU-006) shall be controlled by the use of the following practices:

(A) Flares shall be designed for and operated with no visible emissions, except for periods not to exceed 5 minutes during any two consecutive hours;

(B) Flares shall be operated with a flame present at all times; and

(C) Flares shall be continuously monitored to assure the presence of a pilot flame with a thermocouple, infrared monitor, or other approved device.

PM, PM_{10}, $PM_{2.5}$:

(5) PM emissions in the Back End Ammonia Process Flare (EU-006) shall not exceed 0.0019 lb/MMBtu, based on a three-hour average.

(6) PM_{10} and $PM_{2.5}$ emissions in the Back End Ammonia Process Flare (EU-006) shall not exceed 0.0075 lb/MMBtu, based on a three-hour average.

NO_x:

(7) NO_x emissions from the Back End Ammonia Process Vent Flare (EU-006) shall not exceed 0.068 lb/MMBtu, based on a three-hour average, during normal operation, non-venting periods.

(8) NO_x emissions from the Back End Ammonia Process Vent Flare (EU-006) shall not exceed 624.94 lb/hr, based on a three-hour average, during venting events.

CO:

(9) CO emissions from the Back End Ammonia Process Flare (EU-006) shall not exceed 0.37 lb/MMBtu, based on a three-hour average, during normal operations, non-venting periods.

(10) CO emissions from the Back End Ammonia Process Flare (EU-006) shall not exceed 804.76 lb/hr, based on a three-hour average, during venting events.

VOC:

(11) VOC emissions from the Back End Process Flare (EU-006) shall not exceed 0.0054 lb/MMBtu, based on a three-hour average, during normal operations, non-venting period.

(12) VOC emission from the Back End Process Flare (EU-006) shall not exceed 11.73 lb/hr, based on a three-hour average, during venting events.

GHG:

(13) CO_2 emissions from the Back End Ammonia Process Vent Flare (EU-006) shall not exceed 116.89 lb/MMBtu, based on a three-hour average, during normal operations, non-venting periods.

(14) CO_2 emissions from the Back End Ammonia Process Vent Flare (EU-006) shall not exceed 127.12 ton CO_2/hr, based on a three-hour average, during venting events.

Ammonia Storage Flare (EU-005)

326 IAC 2-2-3 (PSD Rule: Control Technology Review Requirements)
Pursuant to PSD/Operating Permit T 147-32322-00062 and 326 IAC 2-2-3 (Prevention of Significant Deterioration), the best available control technology (BACT) for the Ammonia Storage Flare (EU-005) shall be as follows:

Common PM, PM_{10}, $PM_{2.5}$, NO_x, CO, VOC and GHG Conditions:

(1) In order to control PM, PM_{10}, $PM_{2.5}$, NO_x, CO, VOC and GHG emissions, the pilot and purge gas fuels used in the flare shall be natural gas.

(2) Venting for Startup, Shutdown and Malfunction shall not exceed 168 hours per twelve consecutive month period with compliance determined at the end of each month.

(3) Comply with the following flare minimization practices to reduce emissions during startups, shutdowns, and other flaring events:

  (A) Flare Use Minimization: The Permittee shall limit periods when the backup storage compressor and the ammonia refrigeration compressor are offline at the same time to the extent practicable;

  (B) The Permittee shall train all operators responsible for the day-to-day operation of the flares on the flare minimization practices and the specific procedures to follow during process startup, shutdown, and other flaring events; and

  (C) The Permittee shall investigate the “root cause” of malfunction events that cause flaring events other than at startup or shutdown. This root cause analysis shall identify the apparent cause of unanticipated flaring event and shall recommend additional preventive measures that will minimize the chance of a repeat event. The Permittee shall implement the recommended preventive measures.

(4) PM, PM_{10}, $PM_{2.5}$, NO_x, CO, VOC and GHG emissions shall be controlled by the use of the following practices:

  (A) Flares shall be designed for and operated with no visible emissions, except for periods not to exceed 5 minutes during any two consecutive hours;

  (B) Flares shall be operated with a flame present at all times; and

  (C) Flares shall be continuously monitored to assure the presence of a pilot flame with a thermocouple, infrared monitor, or other approved device.

PM, PM_{10}, $PM_{2.5}$:

(5) PM emissions from the Ammonia Storage Flare (EU-005) shall not exceed 0.0019 lb/MMBtu, based on a three-hour average.

(6) PM_{10} and $PM_{2.5}$ emissions Ammonia Storage Flare (EU-005) shall not exceed 0.0075 lb/MMBtu, based on a three-hour average.

NO_x:

(7) NO_x emissions from the Ammonia Storage Flare (EU-005) shall not exceed 0.068 lb/MMBtu, based on a three-hour average, during normal operation, non-venting periods.

(8) NO_x emissions from the Ammonia Storage Flare (EU-005) shall not exceed 125.0 lb/hour, based on a three-hour average, during venting events.

CO:

(9) CO emissions from the Ammonia Storage Flare (EU-005) shall not exceed 0.37 lb/MMBtu, based on a three-hour average.

VOC:

(10) VOC emissions from the Ammonia Storage System Flare (EU-005) shall not exceed 0.0054 lb/MMBtu, based on a three-hour average.

GHG:

(11) CO_2 emissions from the Ammonia Storage Flare (EU-005) shall not exceed 52.02 lb/hr, based on a three-hour average.

Two Identical Nitric Acid Plants (EU-001A and EU-001B)

326 IAC 2-2-3 (PSD Rule: Control Technology Review Requirements)
Pursuant to PSD/Operating Permit T 147-32322-00062 and 326 IAC 2-2-3 (Prevention of Significant Deterioration), the best available control technology (BACT) for the Nitric Acid Plants (EU-001A and EU-001B) shall be as follows:

Common NO_x and GHG Conditions:

(1) The combined nitric acid production from Nitric Acid Plants (EU-001A and EU-001B) shall not exceed 459,900 tons of 100% nitric acid per twelve consecutive month period with compliance determined at the end of each month.

NO_x:

(2) NO_x emissions from the Nitric Acid Plants (EU-001A and EU-001B) shall not exceed 0.5 lb NO_x per ton acid, based on a thirty day average, each, using Selective Catalytic Reduction (SCR).

GHG:

(3) N_2O emissions from each of the Nitric Acid Units (EU-001A and EU-001B) shall be controlled at all times by a catalytic decomposition process.

(4) N_2O emissions from each of the Nitric Acid Units (EU-001A and EU-001B) shall not exceed 1.05 lb N_2O per ton of nitric acid, based on a three-hour average.

Two Identical Nitric Acid Storage Tanks (EU-022A and EU-022B)

326 IAC 2-2-3 (PSD Rule: Control Technology Review Requirements)
Pursuant to PSD/Operating Permit T 147-32322-00062 and 326 IAC 2-2-3 (Prevention of Significant Deterioration), the best available control technology (BACT) for the Nitric Acid Storage Tanks (EU-022A and EU-022B) shall be as follows:

NO_x:

(1) NO_x emissions from each of the Nitric Acid Storage Tanks (EU-022A and EU-022B) shall be controlled by the use of submerged/bottom fill.

(2) Combined throughput of the Nitric Acid Storage Tanks (EU-022A and EU-022B) shall not exceed 806,842 tons of 57% nitric acid per twelve consecutive month period with compliance determined at the end of each month.

(3) NO_x emissions from each of the Nitric Acid Storage Tanks (EU-022A and EU-022B) shall not exceed 0.0015 lb NO_x per ton of 57% nitric acid.

Two Identical UAN Storage Tanks (EU-012A and EU-012B)

326 IAC 2-2-3 (PSD Rule: Control Technology Review Requirements)
Pursuant to PSD/Operating Permit T 147-32322-00062 and 326 IAC 2-2-3 (Prevention of Significant Deterioration), the best available control technology (BACT) for the UAN Storage Tanks (EU-012A and EU-012B) shall be as follows:

VOC:

(1) The use of white tank shells.

(2) The use of submerged/bottom fills.

Three Identical UAN Day Tanks (EU-020A, EU-020B and EU-020C)

326 IAC 2-2-3 (PSD Rule: Control Technology Review Requirements)
Pursuant to PSD/Operating Permit T 147-32322-00062 and 326 IAC 2-2-3 (Prevention of Significant Deterioration), the best available control technology (BACT) for the UAN Day Tanks (EU-020A, EU-020B and EU-020C) shall be as follows:

VOC:

(1) The use of white tank shells.

(2) The use of submerged/bottom fills.

UAN Loadout Facilities (EU-024A and EU-024B)

326 IAC 2-2-3 (PSD Rule: Control Technology Review Requirements)
Pursuant to PSD/Operating Permit T 147-32322-00062 and 326 IAC 2-2-3 (Prevention of Significant Deterioration), the best available control technology (BACT) for the UAN Loadout Facilities (EU-024A and EU-024B) shall be as follows:

VOC:

VOC emissions from the UAN Loadout Facilities (EU-024A and EU-024B) shall each be controlled by the use of submerged/bottom fill and dedicated or clean cargo carrier operation.

UAN Plant Vent Flare (EU-017)

326 IAC 2-2-3 (PSD Rule: Control Technology Review Requirements)
Pursuant to PSD/Operating Permit T 147-32322-00062 and 326 IAC 2-2-3 (Prevention of Significant Deterioration), the best available control technology (BACT) for the UAN Plant Vent Flare (EU-017) shall be as follows:

Common PM, PM_{10}, $PM_{2.5}$, NO_x, CO, VOC and GHG Conditions:

(1) In order to control PM, PM_{10}, $PM_{2.5}$, NO_x, CO, VOC and GHG emissions, the pilot and purge gas fuels used in the flare shall be natural gas.

(2) Venting for Startup, Shutdown and Malfunction shall not exceed 336 hours per twelve consecutive month period with compliance determined at the end of each month.

(3) Comply with the following flare minimization practices to reduce emissions during startups, shutdowns, and other flaring events:

(A) Flare Use Minimization: The UAN process shall be properly operated to avoid emergency upsets. Startup time of the Nitric Acid Units shall be minimized. During emergency upsets of the Nitric Acid Units, the Permittee shall return some of the high and low-pressure off-gas back to the urea process as soon as urea production is reduced to a level that safely allows this;

(B) The Permittee shall train all operators responsible for the day-to-day operation of the flares on the flare minimization practices and the specific procedures to follow during process startup, shutdown, and other flaring events; and

(C) The Permittee shall investigate the “root cause” of malfunction events that cause flaring events other than at startup or shutdown. This root cause analysis shall identify the apparent cause of unanticipated flaring event and shall recommend additional preventive measures that will minimize the chance of a repeat event. The Permittee shall implement the recommended preventive measures.

(4) PM, PM_{10}, $PM_{2.5}$, NO_x, CO, VOC and GHG emissions shall be controlled by the use of the following practices:

(A) Flares shall be designed for and operated with no visible emissions, except for periods not to exceed 5 minutes during any two consecutive hours;

(B) Flares shall be operated with a flame present at all times; and

(C) Flares shall be continuously monitored to assure the presence of a pilot flame with a thermocouple, infrared monitor, or other approved device.

PM, PM_{10}, $PM_{2.5}$:

(5) PM emissions from the UAN Plant Vent Flare (EU-017) shall not exceed 0.0019 lb/MMBtu, based on a three-hour average.

(6) PM_{10} and $PM_{2.5}$ emissions from the UAN Plant Vent Flare (EU-017) shall not exceed 0.0075 lb/MMBtu, based on a three-hour average.

NO_x:

(7) NO_x emissions from the UAN Plant Vent Flare (EU-017) shall not exceed 0.068 lb/MMBtu, based on a three-hour average, during normal operation, non-venting periods.

(8) NO_x emissions from the UAN Plant Vent Flare (EU-017) shall not exceed 332.08 lb/hr, based on a three-hour average, during venting events.

CO:

(9) CO emissions from the UAN Plant Vent Flare (EU-017) shall not exceed 0.37 lb/MMBtu, based on a three-hour average.

VOC:

(10) VOC emissions from the UAN Plant Vent Flare (EU-017) shall not exceed 0.0054 lb/MMBtu, based on a three-hour average.

GHG:

(11) CO_2 emissions from the UAN Plant Vent Flare (EU-017) shall not exceed 116.89 lb/MMBtu, based on a three-hour average, during normal operations, non-venting events.

(12) CO_2 emissions from the UAN Plant Vent Flare (EU-017) shall not exceed 5.59 tons/hr, based on a three-hour average, during venting events.

Diesel Exhaust Fluid (DEF) Storage Tank (EU-021)

326 IAC 2-2-3 (PSD Rule: Control Technology Review Requirements)
Pursuant to PSD/Operating Permit T 147-32322-00062 and 326 IAC 2-2-3 (Prevention of Significant Deterioration), the best available control technology (BACT) for the DEF Tank (EU-021) shall be as follows:

VOC:

(1) The use of a white tank shell.

(2) The use of submerged/bottom fill.

Diesel Exhaust Fluid (DEF) Truck Loadout (EU-025)

326 IAC 2-2-3 (PSD Rule: Control Technology Review Requirements)
Pursuant to PSD/Operating Permit T 147-32322-00062 and 326 IAC 2-2-3 (Prevention of Significant Deterioration), the best available control technology (BACT) for the DEF Truck Loadout (EU-025) shall be as follows:

VOC:

The use of submerged/bottom fill.

Diesel-Fired Emergency Generator (EU-009)

326 IAC 2-2-3 (PSD Rule: Control Technology Review Requirements)
Pursuant to PSD/Operating Permit T 147-32322-00062 and 326 IAC 2-2-3 (Prevention of Significant Deterioration), the best available control technology (BACT) for the diesel-fired emergency generator (EU-009) shall be as follows:

Common PM, PM_{10}, $PM_{2.5}$, NO_x, CO, VOC and GHG Conditions:

(1) The hours of operation of the diesel-fired emergency generator (EU-009) shall not exceed 200 hours per twelve consecutive month period with compliance determined at the end of each month.

(2) PM, PM_{10}, $PM_{2.5}$, NO_x, CO, VOC and GHG emissions shall be controlled by the use of good combustion practices.

PM, PM_{10}, $PM_{2.5}$:

(3) The PM, PM_{10} and $PM_{2.5}$ emissions from the operation of the diesel-fired emergency generator (EU-0009) shall not exceed 0.15 g/hp-hr, based on a three-hour average.

NO_x:

(4) NO_x emissions from the diesel-fired emergency generator (EU-009) shall not exceed 4.46 g/hp-hr, based on a three-hour average.

CO:

(5) CO emissions from the diesel-fired emergency generator (EU-009) shall not exceed 2.61 g/hp-hr, based on a three-hour average.

VOC:

(6) VOC emissions from the diesel-fired emergency generator (EU-009) shall not exceed 0.31 g/hp-hr, based on a three-hour average.

GHG:

(7) CO_2 emissions from the diesel-fired emergency generator (EU-009) shall not exceed 526.39 g/hp-hr, based on a three-hour average.

Paved Roadways and Parking Lots

326 IAC 2-2-3 (PSD Rule: Control Technology Review Requirements)

Pursuant to PSD/Operating Permit T 147-32322-00062 and 326 IAC 2-2-3 (Prevention of Significant Deterioration), the best available control technology (BACT) for the paved roadways and parking lots shall be as follows:

PM, PM_{10}, $PM_{2.5}$:

The PM, PM_{10}, and $PM_{2.5}$ emissions from paved haul roads shall be controlled to an overall control efficiency of 90% by employing the following work practices:

(1) Paving all plant haul roads;

(2) Daily sweeping with wet suppression as needed; and

(3) Prompt cleanup of any spilled materials.

Diesel–Fired Emergency Firewater Pump (EU-016)

326 IAC 2-2-3 (PSD Rule: Control Technology Review Requirements)

Pursuant to PSD/Operating Permit T 147-32322-00062 and 326 IAC 2-2-3 (Prevention of Significant Deterioration), the best available control technology (BACT) for the diesel-fired emergency firewater pump (EU-016) shall be as follows:

Common PM, PM_{10}, $PM_{2.5}$, NO_x, CO, VOC, and GHG Conditions:

(1) Operation of the Diesel-Fired Emergency Firewater Pump (EU-016) shall not exceed 200 hours per twelve consecutive month period with compliance determined at the end of each month.

(2) PM, PM_{10}, $PM_{2.5}$, NO_x, CO, VOC and GHG emissions from the Diesel-Fired Emergency Firewater Pump (EU-016) shall be controlled by the use of good combustion practices.

PM, PM_{10}, $PM_{2.5}$:

(3) The PM, PM_{10} and $PM_{2.5}$ emissions from the operation of the Diesel-Fired Emergency Firewater Pump (EU-016) shall not exceed 0.15 g/hp-hr, based on a three-hour average.

NO_x:

(4) NO_x emissions from the diesel-fired emergency firewater pump (EU-016) shall not exceed 2.86 g/hp-hr, based on a three-hour average.

CO:

(5) CO emissions from the diesel-fired fire pump (EU-016) shall not exceed 2.60 g/hp-hr, based on a three-hour average.

VOC:

(6) VOC emissions from the diesel-fired fire pump (EU-016) shall not exceed 0.141 g/hp-hr, based on a three-hour average.

GHG:

(7) CO_2 emissions from the diesel-fired emergency firewater pump (EU-016) shall not exceed 527.40 g/hp-hr, based on a three-hour average.

Gasoline Transfer Dispensing Operation (EU-015)

326 IAC 2-2-3 (PSD Rule: Control Technology Review Requirements)
Pursuant to PSD/Operating Permit T 147-32322-00062 and 326 IAC 2-2-3 (Prevention of Significant Deterioration), the best available control technology (BACT) for the gasoline transfer dispensing operation (EU-015) shall be as follows:

VOC:

The gasoline transfer and dispensing operation is an insignificant activity with negligible emissions. This operation involves dispensing of gasoline into portable equipment like lawn mowers and portable generators. There are no feasible control options for the gasoline transfer dispensing operation (EU-015) due to its size. Therefore, BACT is no control.

Petroleum Fuel Other Than Gasoline Dispensing Operations (EU-014)

326 IAC 2-2-3 (PSD Rule: Control Technology Review Requirements)
Pursuant to PSD/Operating Permit T 147-32322-00062 and 326 IAC 2-2-3 (Prevention of Significant Deterioration), the best available control technology (BACT) for the petroleum fuel other than gasoline dispensing operation (EU-014) shall be as follows:

VOC:

The petroleum fuel transfer and dispensing operation is an insignificant activity with negligible emissions. This operation involves dispensing of diesel into portable equipment like portable generators. There are no feasible control options for EU-014 due to its size. Therefore, BACT is no control.

Fugitive NO_x, VOC and Greenhouse Gas (GHG) Emissions from Equipment Leaks

326 IAC 2-2-3 (PSD Rule: Control Technology Review Requirements)
Pursuant to PSD/Operating Permit T 147-32322-00062 and 326 IAC 2-2-3 (Prevention of Significant Deterioration), the best available control technology (BACT) for fugitive NO_x, VOC and GHG emissions from equipment leaks shall be as follows:

NO_x:

Fugitive emissions from equipment leaks have the potential to emit NO_x of less than 0.01 ton per year. NO_x emissions from these units are insignificant and no additional add-on controls or operational practices are required. The source is required to implement an LDAR program for VOC and greenhouse gases (GHGs).

VOC:

IDEM, OAQ has approved the proposed VOC BACT for fugitive VOC emissions from equipment leaks as the use of a leak detection and repair (LDAR) program. The leak detection and repair program specified in 40 CFR 60, Subpart VVa, as identified in Condition D.4.7 shall serve as BACT for VOC fugitive emissions.

GHG:

Fugitive emissions from equipment leaks are insignificant and no additional add-on controls or operational practices are required.

Cooling Towers (EU-008A to H and EU-019A to F)

326 IAC 2-2-3 (PSD Rule: Control Technology Review Requirements)
Pursuant to PSD/Operating Permit T 147-32322-00062 and 326 IAC 2-2-3 (Prevention of Significant Deterioration), the best available control technology (BACT) for cooling towers (EU-008A to H and EU-019A to F) shall be as follows:

PM, PM_{10}, $PM_{2.5}$:

(1) The PM, PM_{10} and $PM_{2.5}$ emissions from the Cooling Towers (EU-008A to H and EU-019A to F) shall be controlled by high efficiency drift eliminators designed with a drift loss rate of less than 0.0005%.

(2) The total dissolved solids in the water used in Cooling Towers (EU-008A to H and EU-019A to F) shall not exceed 2,000 mg/l, averaged on a daily basis.

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 Requirements applicable to this new source construction are as follows:

Emission Unit	Parameter	Frequency
Boilers EU-011A, EU-011B, EU-011C and EU-011D	The use of ultra low NO_x burners and FGR	At all times process is in operation.
Primary Reformer (EU-003)	The use of SCR	At all times process is in operation.
Nitric Acid Units (EU-001A and EU-001B)	The use of SCR for NO_x and Catalytic Decomposition N_2O	At all times process is in operation.
Ammonium Nitrate Plants (EU-002A and EU-002B)	Scrubber and Demister for PM, PM_{10} and $PM_{2.5}$ control	At all times process is in operation.

Summary of Testing Requirements

Emission Unit	Control Device	Timeframe for Testing	Pollutant	Frequency of Testing
Boilers EU-011A, EU-011B, EU-011C and EU-011D	None	Within 60 days max capacity but no later than 180 days after startup	CO	One Time
			CO_2	One Time
			Thermal Efficiency	One Time
Primary Reformer (EU-003)	SCR	Within 60 days max capacity but no later than 180 days after startup	CO	One Time
			CO_2	Every 5 Years
			Thermal Efficiency	One Time
CO_2 Purification (EU-004)	None	Within 60 days max capacity but no later than 180 days after startup	CO	One Time
			VOC	One Time
			CO_2	Every 5 Years
Nitric Acid Units (EU-001A and EU-001B)	Catalytic Decomposition	Within 60 days max capacity but no later than 180 days after startup	N_2O	One Time
Ammonium Nitrate Plants (EU-002A and EU-002B)	Scrubber and Demister	Within 60 days max capacity but no later than 180 days after startup	PM, PM_{10} and $PM_{2.5}$	Every 5 Years
	None		CO_2	One Time

The compliance monitoring requirements applicable to this new source construction are as follows:

Summary of Monitoring Requirements

Emission Unit	Parameter	Frequency	Response
Primary Reformer (EU-003)	NO_x	Continuous	A Reasonable Response
Boilers (EU-011A, EU-011B, EU-011C and EU-011D)	NO_x	Continuous	A Reasonable Response
Nitric Acid Units (EU-001A and EU-001B)	NO_x	Continuous	A Reasonable Response
AN Plants Scrubbers (EU-002A and EU-002B)	Pressure Drop	Once Per Day	A Reasonable Response
Cooling Towers (EU-008A to H and EU-019A to F)	Total Dissolved Solids	Once Per Week	A Reasonable Response
Ammonia Storage Flare (EU-005)	Presence of Flame	Continuous	A Reasonable Response
Diesel Generator (EU-009)	Operating Hours	Once per month	A Reasonable Response
Backend Process Flare (EU-006)	Presence of Flame	Continuous	A Reasonable Response
Diesel Firewater Pump (EU-016)	Operating Hours	Once per month	A Reasonable Response
Cooling Towers (EU-008A to H and EU-019A to F)	Total Dissolved Solids	Once per month	A Reasonable Response
UAN Plant Vent Flare (EU-017)	Presence of Flame	Continuous	A Reasonable Response
Paved Roads and Parking Lots	Ambient Temperature	Temp below 32 F	A Reasonable Response
Front End Process Flare (EU-007)	Presence of Flame	Continuous	A Reasonable Response

These monitoring conditions are necessary because the control devices must perform properly to ensure compliance with 326 IAC 2-2.

Proposed Changes – During Public Notice

Upon further review, IDEM, OAQ is making additional changes to the draft permit. Each change to the permit document and its attachments follows with new language shown in bold and deleted language shown in ~~strikeout~~. IDEM, OAQ did not show changes to the supporting documents other than the TSD but these documents have been updated to reflect changes to the permit document. IDEM, OAQ revisions during the public notice period follow:

Modification No. 1: **Attachments A through H**
The header of these documents indicates they are attachments to the technical support document. They are actually attachments to the Part 70 Operating Permit. A sample revision follows:

Ohio Valley Resources, LLC Attachment A – 40 CFR 63, Subpart FFFF Page 41 of 434
Rockport, Indiana ~~TSD for~~ T 147-32322-00062
Permit Reviewer: David Matousek

Modification No. 2: **40 CFR 63, Subpart ZZZZ Updates**
On January 30, 2013, the U.S. EPA had a notice published in the Federal Register indicating U.S. EPA was finalizing amendments to the national emission standards for hazardous air pollutants for stationary reciprocating internal combustion engines. Revisions to 40 CFR 63, Subpart ZZZZ became effective on April 1, 2013. IDEM, OAQ has removed and replaced permit Attachment B with the revised rule.

~~Old Attachment B~~

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

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

~~Source Background and Description~~

~~Source Name: Ohio Valley Resources, LLC~~
~~Source Location: 300-400 East CR 350 North, Rockport, Indiana 47635~~
~~County: Spencer~~
~~SIC Code: 2873~~
~~Permit No.: T 147-32322-00062~~
~~Permit Reviewer: David Matousek~~

~~40 CFR 63, Subpart ZZZZ~~

~~40 CFR 63, Subpart ZZZZ~~ **~~National Emissions Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines~~**

~~Source: 69 FR 33506, June 15, 2004, unless otherwise noted.~~

~~What This Subpart Covers~~

~~§ 63.6580 What is the purpose of subpart ZZZZ?~~

~~Subpart ZZZZ establishes national emission limitations and operating limitations for hazardous air pollutants (HAP) emitted from stationary reciprocating internal combustion engines (RICE) located at major and area~~

~~sources of HAP emissions. This subpart also establishes requirements to demonstrate initial and continuous compliance with the emission limitations and operating limitations.~~

~~[73 FR 3603, Jan. 18, 2008]~~

~~§ 63.6585 Am I subject to this subpart?~~

~~You are subject to this subpart if you own or operate a stationary RICE at a major or area source of HAP emissions, except if the stationary RICE is being tested at a stationary RICE test cell/stand.~~

~~(a) A stationary RICE is any internal combustion engine which uses reciprocating motion to convert heat energy into mechanical work and which is not mobile. Stationary RICE differ from mobile RICE in that a stationary RICE is not a non-road engine as defined at 40 CFR 1068.30, and is not used to propel a motor vehicle or a vehicle used solely for competition.~~

~~(b) 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, except that for oil and gas production facilities, a major source of HAP emissions is determined for each surface site.~~

~~(c) An area source of HAP emissions is a source that is not a major source.~~

~~(d) If you are an owner or operator of an area source subject to this subpart, your status as an entity subject to a standard or other requirements under this subpart does not subject you to the obligation to obtain a permit under 40 CFR part 70 or 71, provided you are not required to obtain a permit under 40 CFR 70.3(a) or 40 CFR 71.3(a) for a reason other than your status as an area source under this subpart. Notwithstanding the previous sentence, you must continue to comply with the provisions of this subpart as applicable.~~

~~(e) If you are an owner or operator of a stationary RICE used for national security purposes, you may be eligible to request an exemption from the requirements of this subpart as described in 40 CFR part 1068, subpart C.~~

~~[69 FR 33506, June 15, 2004, as amended at 73 FR 3603, Jan. 18, 2008]~~

~~§ 63.6590 What parts of my plant does this subpart cover?~~

~~This subpart applies to each affected source.~~

~~(a) *Affected source.* An affected source is any existing, new, or reconstructed stationary RICE located at a major or area source of HAP emissions, excluding stationary RICE being tested at a stationary RICE test cell/stand.~~

~~(1) *Existing stationary RICE.*~~

~~(i) For stationary RICE with a site rating of more than 500 brake horsepower (HP) located at a major source of HAP emissions, a stationary RICE is existing if you commenced construction or reconstruction of the stationary RICE before December 19, 2002.~~

~~(ii) For stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions, a stationary RICE is existing if you commenced construction or reconstruction of the stationary RICE before June 12, 2006.~~

~~(iii) For stationary RICE located at an area source of HAP emissions, a stationary RICE is existing if you commenced construction or reconstruction of the stationary RICE before June 12, 2006.~~

~~(iv) A change in ownership of an existing stationary RICE does not make that stationary RICE a new or reconstructed stationary RICE.~~

~~(2) *New stationary RICE.* (i) A stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions is new if you commenced construction of the stationary RICE on or after December 19, 2002.~~

~~(ii) A stationary RICE with a site rating of equal to or less than 500 brake HP located at a major source of HAP emissions is new if you commenced construction of the stationary RICE on or after June 12, 2006.~~

~~(iii) A stationary RICE located at an area source of HAP emissions is new if you commenced construction of the stationary RICE on or after June 12, 2006.~~

~~(3) *Reconstructed stationary RICE.* (i) A stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions is reconstructed if you meet the definition of reconstruction in § 63.2 and reconstruction is commenced on or after December 19, 2002.~~

~~(ii) A stationary RICE with a site rating of equal to or less than 500 brake HP located at a major source of HAP emissions is reconstructed if you meet the definition of reconstruction in § 63.2 and reconstruction is commenced on or after June 12, 2006.~~

~~(iii) A stationary RICE located at an area source of HAP emissions is reconstructed if you meet the definition of reconstruction in § 63.2 and reconstruction is commenced on or after June 12, 2006.~~

~~(b) *Stationary RICE subject to limited requirements.* (1) An affected source which meets either of the criteria in paragraphs (b)(1)(i) through (ii) of this section does not have to meet the requirements of this subpart and of subpart A of this part except for the initial notification requirements of § 63.6645(f).~~

~~(i) The stationary RICE is a new or reconstructed emergency stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions.~~

~~(ii) The stationary RICE is a new or reconstructed limited use stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions.~~

~~(2) A new or reconstructed stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions which combusts landfill or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis must meet the initial notification requirements of § 63.6645(f) and the requirements of §§ 63.6625(c), 63.6650(g), and 63.6655(c). These stationary RICE do not have to meet the emission limitations and operating limitations of this subpart.~~

~~(3) The following stationary RICE do not have to meet the requirements of this subpart and of subpart A of this part, including initial notification requirements:~~

~~(i) Existing spark ignition 2 stroke lean burn (2SLB) stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions;~~

~~(ii) Existing spark ignition 4 stroke lean burn (4SLB) stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions;~~

~~(iii) Existing emergency stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions;~~

~~(iv) Existing limited use stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions;~~

~~(v) Existing stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions that combusts landfill gas or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis;~~

~~(vi) Existing residential emergency stationary RICE located at an area source of HAP emissions;~~

~~(vii) Existing commercial emergency stationary RICE located at an area source of HAP emissions; or~~

~~(viii) Existing institutional emergency stationary RICE located at an area source of HAP emissions.~~

~~(c) *Stationary RICE subject to Regulations under 40 CFR Part 60.* An affected source that meets any of the criteria in paragraphs (c)(1) through (7) of this section must meet the requirements of this part by meeting the requirements of 40 CFR part 60 subpart IIII, for compression ignition engines or 40 CFR part 60 subpart JJJJ, for spark ignition engines. No further requirements apply for such engines under this part.~~

~~(1) A new or reconstructed stationary RICE located at an area source;~~

~~(2) A new or reconstructed 2SLB stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions;~~

~~(3) A new or reconstructed 4SLB stationary RICE with a site rating of less than 250 brake HP located at a major source of HAP emissions;~~

~~(4) A new or reconstructed spark ignition 4 stroke rich burn (4SRB) stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions;~~

~~(5) A new or reconstructed stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions which combusts landfill or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis;~~

~~(6) A new or reconstructed emergency or limited use stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions;~~

~~(7) A new or reconstructed compression ignition (CI) stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions.~~

~~[69 FR 33506, June 15, 2004, as amended at 73 FR 3604, Jan. 18, 2008; 75 FR 9674, Mar. 3, 2010; 75 FR 37733, June 30, 2010; 75 FR 51588, Aug. 20, 2010]~~

~~§ 63.6595 When do I have to comply with this subpart?~~

~~(a) *Affected sources.* (1) If you have an existing stationary RICE, excluding existing non-emergency CI stationary RICE, with a site rating of more than 500 brake HP located at a major source of HAP emissions, you must comply with the applicable emission limitations and operating limitations no later than June 15, 2007. If you have an existing non-emergency CI stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions, an existing stationary CI RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions, or an existing stationary CI RICE located at an area source of HAP emissions, you must comply with the applicable emission limitations and operating limitations no later than May 3, 2013. If you have an existing stationary SI RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions, or an existing stationary SI RICE located at an area source of HAP emissions, you must comply with the applicable emission limitations and operating limitations no later than October 19, 2013.~~

~~(2) If you start up your new or reconstructed stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions before August 16, 2004, you must comply with the applicable emission limitations and operating limitations in this subpart no later than August 16, 2004.~~

~~(3) If you start up your new or reconstructed stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions after August 16, 2004, you must comply with the applicable emission limitations and operating limitations in this subpart upon startup of your affected source.~~

~~(4) If you start up your new or reconstructed stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions before January 18, 2008, you must comply with the applicable emission limitations and operating limitations in this subpart no later than January 18, 2008.~~

~~(5) If you start up your new or reconstructed stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions after January 18, 2008, you must comply with the applicable emission limitations and operating limitations in this subpart upon startup of your affected source.~~

~~(6) If you start up your new or reconstructed stationary RICE located at an area source of HAP emissions before January 18, 2008, you must comply with the applicable emission limitations and operating limitations in this subpart no later than January 18, 2008.~~

~~(7) If you start up your new or reconstructed stationary RICE located at an area source of HAP emissions after January 18, 2008, you must comply with the applicable emission limitations and operating limitations in this subpart upon startup of your affected source.~~

~~(b)~~ ~~*Area sources that become major sources.*~~ ~~If you have an area source that increases its emissions or its potential to emit such that it becomes a major source of HAP, the compliance dates in paragraphs (b)(1) and (2) of this section apply to you.~~

~~(1) Any stationary RICE for which construction or reconstruction is commenced after the date when your area source becomes a major source of HAP must be in compliance with this subpart upon startup of your affected source.~~

~~(2) Any stationary RICE for which construction or reconstruction is commenced before your area source becomes a major source of HAP must be in compliance with the provisions of this subpart that are applicable to RICE located at major sources within 3 years after your area source becomes a major source of HAP.~~

~~(c) If you own or operate an affected source, you must meet the applicable notification requirements in § 63.6645 and in 40 CFR part 63, subpart A.~~

~~[69 FR 33506, June 15, 2004, as amended at 73 FR 3604, Jan. 18, 2008; 75 FR 9675, Mar. 3, 2010; 75 FR 51589, Aug. 20, 2010]~~

~~Emission and Operating Limitations~~

~~§ 63.6600 What emission limitations and operating limitations must I meet if I own or operate a stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions?~~

~~Compliance with the numerical emission limitations established in this subpart is based on the results of testing the average of three 1-hour runs using the testing requirements and procedures in § 63.6620 and Table 4 to this subpart.~~

~~(a) If you own or operate an existing, new, or reconstructed spark ignition 4SRB stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions, you must comply with the~~

~~emission limitations in Table 1a to this subpart and the operating limitations in Table 1b to this subpart which apply to you.~~

~~(b) If you own or operate a new or reconstructed 2SLB stationary RICE with a site rating of more than 500 brake HP located at major source of HAP emissions, a new or reconstructed 4SLB stationary RICE with a site rating of more than 500 brake HP located at major source of HAP emissions, or a new or reconstructed CI stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions, you must comply with the emission limitations in Table 2a to this subpart and the operating limitations in Table 2b to this subpart which apply to you.~~

~~(c) If you own or operate any of the following stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions, you do not need to comply with the emission limitations in Tables 1a, 2a, 2c, and 2d to this subpart or operating limitations in Tables 1b and 2b to this subpart: an existing 2SLB stationary RICE; an existing 4SLB stationary RICE; a stationary RICE that combusts landfill gas or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis; an emergency stationary RICE; or a limited use stationary RICE.~~

~~(d) If you own or operate an existing non-emergency stationary CI RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions, you must comply with the emission limitations in Table 2c to this subpart and the operating limitations in Table 2b to this subpart which apply to you.~~

~~[73 FR 3605, Jan. 18, 2008, as amended at 75 FR 9675, Mar. 3, 2010]~~

~~§ 63.6601 What emission limitations must I meet if I own or operate a new or reconstructed 4SLB stationary RICE with a site rating of greater than or equal to 250 brake HP and less than or equal to 500 brake HP located at a major source of HAP emissions?~~

~~Compliance with the numerical emission limitations established in this subpart is based on the results of testing the average of three 1-hour runs using the testing requirements and procedures in § 63.6620 and Table 4 to this subpart. If you own or operate a new or reconstructed 4SLB stationary RICE with a site rating of greater than or equal to 250 and less than or equal to 500 brake HP located at major source of HAP emissions manufactured on or after January 1, 2008, you must comply with the emission limitations in Table 2a to this subpart and the operating limitations in Table 2b to this subpart which apply to you.~~

~~[73 FR 3605, Jan. 18, 2008, as amended at 75 FR 9675, Mar. 3, 2010; 75 FR 51589, Aug. 20, 2010]~~

~~§ 63.6602 What emission limitations must I meet if I own or operate an existing stationary RICE with a site rating of equal to or less than 500 brake HP located at a major source of HAP emissions?~~

~~If you own or operate an existing stationary RICE with a site rating of equal to or less than 500 brake HP located at a major source of HAP emissions, you must comply with the emission limitations in Table 2c to this subpart which apply to you. Compliance with the numerical emission limitations established in this subpart is based on the results of testing the average of three 1-hour runs using the testing requirements and procedures in § 63.6620 and Table 4 to this subpart.~~

~~[75 FR 51589, Aug. 20, 2010]~~

~~§ 63.6603 What emission limitations and operating limitations must I meet if I own or operate an existing stationary RICE located at an area source of HAP emissions?~~

~~Compliance with the numerical emission limitations established in this subpart is based on the results of testing the average of three 1-hour runs using the testing requirements and procedures in § 63.6620 and Table 4 to this subpart.~~

~~(a) If you own or operate an existing stationary RICE located at an area source of HAP emissions, you must comply with the requirements in Table 2d to this subpart and the operating limitations in Table 1b and Table 2b to this subpart that apply to you.~~

~~(b) If you own or operate an existing stationary non-emergency CI RICE greater than 300 HP located at area sources in areas of Alaska not accessible by the Federal Aid Highway System (FAHS) you do not have to meet the numerical CO emission limitations specified in Table 2d to this subpart. Existing stationary non-emergency CI RICE greater than 300 HP located at area sources in areas of Alaska not accessible by the FAHS must meet the management practices that are shown for stationary non-emergency CI RICE less than or equal to 300 HP in Table 2d to this subpart.~~

~~[75 FR 9675, Mar. 3, 2010, as amended at 75 FR 51589, Aug. 20, 2010; 76 FR 12866, Mar. 9, 2011]~~

~~§ 63.6604 What fuel requirements must I meet if I own or operate an existing stationary CI RICE?~~

~~If you own or operate an existing non-emergency, non-black start CI stationary RICE with a site rating of more than 300 brake HP with a displacement of less than 30 liters per cylinder that uses diesel fuel, you must use diesel fuel that meets the requirements in 40 CFR 80.510(b) for nonroad diesel fuel. Existing non-emergency CI stationary RICE located in Guam, American Samoa, the Commonwealth of the Northern Mariana Islands, or at area sources in areas of Alaska not accessible by the FAHS are exempt from the requirements of this section.~~

~~[75 FR 51589, Aug. 20, 2010]~~

~~General Compliance Requirements~~

~~§ 63.6605 What are my general requirements for complying with this subpart?~~

~~(a) You must be in compliance with the emission limitations and operating limitations in this subpart that apply to you at all times.~~

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

~~[75 FR 9675, Mar. 3, 2010]~~

~~Testing and Initial Compliance Requirements~~

~~§ 63.6610 By what date must I conduct the initial performance tests or other initial compliance demonstrations if I own or operate a stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions?~~

~~If you own or operate a stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions you are subject to the requirements of this section.~~

~~(a) You must conduct the initial performance test or other initial compliance demonstrations in Table 4 to this subpart that apply to you within 180 days after the compliance date that is specified for your stationary RICE in § 63.6595 and according to the provisions in § 63.7(a)(2).~~

~~(b) If you commenced construction or reconstruction between December 19, 2002 and June 15, 2004 and own or operate stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions, you must demonstrate initial compliance with either the proposed emission limitations or the promulgated emission limitations no later than February 10, 2005 or no later than 180 days after startup of the source, whichever is later, according to § 63.7(a)(2)(ix).~~

~~(c) If you commenced construction or reconstruction between December 19, 2002 and June 15, 2004 and own or operate stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions, and you chose to comply with the proposed emission limitations when demonstrating initial compliance, you must conduct a second performance test to demonstrate compliance with the promulgated emission limitations by December 13, 2007 or after startup of the source, whichever is later, according to § 63.7(a)(2)(ix).~~

~~(d) An owner or operator is not required to conduct an initial performance test on units for which a performance test has been previously conducted, but the test must meet all of the conditions described in paragraphs (d)(1) through (5) of this section.~~

~~(1) The test must have been conducted using the same methods specified in this subpart, and these methods must have been followed correctly.~~

~~(2) The test must not be older than 2 years.~~

~~(3) The test must be reviewed and accepted by the Administrator.~~

~~(4) Either no process or equipment changes must have been made since the test was performed, or the owner or operator must be able to demonstrate that the results of the performance test, with or without adjustments, reliably demonstrate compliance despite process or equipment changes.~~

~~(5) The test must be conducted at any load condition within plus or minus 10 percent of 100 percent load.~~

~~[69 FR 33506, June 15, 2004, as amended at 73 FR 3605, Jan. 18, 2008]~~

~~§ 63.6611 By what date must I conduct the initial performance tests or other initial compliance demonstrations if I own or operate a new or reconstructed 4SLB SI stationary RICE with a site rating of greater than or equal to 250 and less than or equal to 500 brake HP located at a major source of HAP emissions?~~

~~If you own or operate a new or reconstructed 4SLB stationary RICE with a site rating of greater than or equal to 250 and less than or equal to 500 brake HP located at a major source of HAP emissions, you must conduct an initial performance test within 240 days after the compliance date that is specified for your stationary RICE in § 63.6595 and according to the provisions specified in Table 4 to this subpart, as appropriate.~~

~~[73 FR 3605, Jan. 18, 2008, as amended at 75 FR 51589, Aug. 20, 2010]~~

~~§ 63.6612 By what date must I conduct the initial performance tests or other initial compliance demonstrations if I own or operate an existing stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions or an existing stationary RICE located at an area source of HAP emissions?~~

~~If you own or operate an existing stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions or an existing stationary RICE located at an area source of HAP emissions you are subject to the requirements of this section.~~

~~(a) You must conduct any initial performance test or other initial compliance demonstration according to Tables 4 and 5 to this subpart that apply to you within 180 days after the compliance date that is specified for your stationary RICE in § 63.6595 and according to the provisions in § 63.7(a)(2).~~

~~(b) An owner or operator is not required to conduct an initial performance test on a unit for which a performance test has been previously conducted, but the test must meet all of the conditions described in paragraphs (b)(1) through (4) of this section.~~

~~(1) The test must have been conducted using the same methods specified in this subpart, and these methods must have been followed correctly.~~

~~(2) The test must not be older than 2 years.~~

~~(3) The test must be reviewed and accepted by the Administrator.~~

~~(4) Either no process or equipment changes must have been made since the test was performed, or the owner or operator must be able to demonstrate that the results of the performance test, with or without adjustments, reliably demonstrate compliance despite process or equipment changes.~~

~~[75 FR 9676, Mar. 3, 2010, as amended at 75 FR 51589, Aug. 20, 2010]~~

~~§ 63.6615 When must I conduct subsequent performance tests?~~

~~If you must comply with the emission limitations and operating limitations, you must conduct subsequent performance tests as specified in Table 3 of this subpart.~~

~~§ 63.6620 What performance tests and other procedures must I use?~~

~~(a) You must conduct each performance test in Tables 3 and 4 of this subpart that applies to you.~~

~~(b) Each performance test must be conducted according to the requirements that this subpart specifies in Table 4 to this subpart. If you own or operate a non-operational stationary RICE that is subject to performance testing, you do not need to start up the engine solely to conduct the performance test. Owners and operators of a non-operational engine can conduct the performance test when the engine is started up again.~~

~~(c) [Reserved]~~

~~(d) 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.~~

~~(e)(1) You must use Equation 1 of this section to determine compliance with the percent reduction requirement:~~

$$\frac{C_i - C_o}{C_i} \times 100 = R \qquad \text{(Eq. 1)}$$

~~Where:~~

~~C_i = concentration of CO or formaldehyde at the control device inlet,~~

~~C_o = concentration of CO or formaldehyde at the control device outlet, and~~

~~R = percent reduction of CO or formaldehyde emissions.~~

~~(2) You must normalize the carbon monoxide (CO) or formaldehyde concentrations at the inlet and outlet of the control device to a dry basis and to 15 percent oxygen, or an equivalent percent carbon dioxide (CO_2). If pollutant concentrations are to be corrected to 15 percent oxygen and CO_2 concentration is measured in lieu of oxygen concentration measurement, a CO_2 correction factor is needed. Calculate the CO_2 correction factor as described in paragraphs (e)(2)(i) through (iii) of this section.~~

~~(i) Calculate the fuel-specific F_o value for the fuel burned during the test using values obtained from Method 19, section 5.2, and the following equation:~~

$$F_o = \frac{0.209\,F_d}{F_c} \qquad \text{(Eq. 2)}$$

~~Where:~~

~~F_o = Fuel factor based on the ratio of oxygen volume to the ultimate CO_2 volume produced by the fuel at zero percent excess air.~~

~~0.209 = Fraction of air that is oxygen, percent/100.~~

~~F_d = Ratio of the volume of dry effluent gas to the gross calorific value of the fuel from Method 19, dsm^3 /J ($dscf/10^6$ Btu).~~

~~F_c = Ratio of the volume of CO_2 produced to the gross calorific value of the fuel from Method 19, dsm^3 /J ($dscf/10^6$ Btu).~~

~~(ii) Calculate the CO_2 correction factor for correcting measurement data to 15 percent oxygen, as follows:~~

$$X_{co_2} = \frac{5.9}{F_o} \qquad \text{(Eq. 3)}$$

~~Where:~~

~~X_{co2} = CO_2 correction factor, percent.~~

~~5.9 = 20.9 percent O_2 −15 percent O_2 , the defined O_2 correction value, percent.~~

~~(iii) Calculate the NO_X and SO_2 gas concentrations adjusted to 15 percent O_2 using CO_2 as follows:~~

$$C_{adj} = C_d \frac{X_{co_2}}{\%CO_2} \qquad \text{(Eq. 4)}$$

~~Where:~~

~~$\%CO_2$ = Measured CO_2 concentration measured, dry basis, percent.~~

~~(f) If you comply with the emission limitation to reduce CO and you are not using an oxidation catalyst, if you comply with the emission limitation to reduce formaldehyde and you are not using NSCR, or if you comply with the emission limitation to limit the concentration of formaldehyde in the stationary RICE exhaust and you are not using an oxidation catalyst or NSCR, you must petition the Administrator for operating limitations to be established during the initial performance test and continuously monitored thereafter; or for approval of no operating limitations. You must not conduct the initial performance test until after the petition has been approved by the Administrator.~~

~~(g) If you petition the Administrator for approval of operating limitations, your petition must include the information described in paragraphs (g)(1) through (5) of this section.~~

~~(1) Identification of the specific parameters you propose to use as operating limitations;~~

~~(2) A discussion of the relationship between these parameters and HAP emissions, identifying how HAP emissions change with changes in these parameters, and how limitations on these parameters will serve to limit HAP emissions;~~

~~(3) A discussion of how you will establish the upper and/or lower values for these parameters which will establish the limits on these parameters in the operating limitations;~~

~~(4) A discussion identifying the methods you will use to measure and the instruments you will use to monitor these parameters, as well as the relative accuracy and precision of these methods and instruments; and~~

~~(5) A discussion identifying the frequency and methods for recalibrating the instruments you will use for monitoring these parameters.~~

~~(h) If you petition the Administrator for approval of no operating limitations, your petition must include the information described in paragraphs (h)(1) through (7) of this section.~~

~~(1) Identification of the parameters associated with operation of the stationary RICE and any emission control device which could change intentionally (*e.g.,* operator adjustment, automatic controller adjustment, etc.) or unintentionally (*e.g.,* wear and tear, error, etc.) on a routine basis or over time;~~

~~(2) A discussion of the relationship, if any, between changes in the parameters and changes in HAP emissions;~~

~~(3) For the parameters which could change in such a way as to increase HAP emissions, a discussion of whether establishing limitations on the parameters would serve to limit HAP emissions;~~

~~(4) For the parameters which could change in such a way as to increase HAP emissions, a discussion of how you could establish upper and/or lower values for the parameters which would establish limits on the parameters in operating limitations;~~

~~(5) For the parameters, a discussion identifying the methods you could use to measure them and the instruments you could use to monitor them, as well as the relative accuracy and precision of the methods and instruments;~~

~~(6) For the parameters, a discussion identifying the frequency and methods for recalibrating the instruments you could use to monitor them; and~~

~~(7) A discussion of why, from your point of view, it is infeasible or unreasonable to adopt the parameters as operating limitations.~~

~~(i) The engine percent load during a performance test must be determined by documenting the calculations, assumptions, and measurement devices used to measure or estimate the percent load in a specific application. A written report of the average percent load determination must be included in the notification of compliance status. The following information must be included in the written report: the engine model number, the engine manufacturer, the year of purchase, the manufacturer's site-rated brake horsepower, the ambient temperature, pressure, and humidity during the performance test, and all assumptions that were made to estimate or calculate percent load during the performance test must be clearly explained. If measurement devices such as flow meters, kilowatt meters, beta analyzers, stain gauges, etc. are used, the model number of the measurement device, and an estimate of its accurate in percentage of true value must be provided.~~

~~[69 FR 33506, June 15, 2004, as amended at 75 FR 9676, Mar. 3, 2010]~~

~~§ 63.6625 What are my monitoring, installation, collection, operation, and maintenance requirements?~~

~~(a) If you elect to install a CEMS as specified in Table 5 of this subpart, you must install, operate, and maintain a CEMS to monitor CO and either oxygen or CO_2 at both the inlet and the outlet of the control device according to the requirements in paragraphs (a)(1) through (4) of this section.~~

~~(1) Each CEMS must be installed, operated, and maintained according to the applicable performance specifications of 40 CFR part 60, appendix B.~~

~~(2) You must conduct an initial performance evaluation and an annual relative accuracy test audit (RATA) of each CEMS according to the requirements in § 63.8 and according to the applicable performance specifications of 40 CFR part 60, appendix B as well as daily and periodic data quality checks in accordance with 40 CFR part 60, appendix F, procedure 1.~~

~~(3) As specified in § 63.8(c)(4)(ii), each CEMS must complete a minimum of one cycle of operation (sampling, analyzing, and data recording) for each successive 15-minute period. You must have at least two data points, with each representing a different 15-minute period, to have a valid hour of data.~~

~~(4) The CEMS data must be reduced as specified in § 63.8(g)(2) and recorded in parts per million or parts per billion (as appropriate for the applicable limitation) at 15 percent oxygen or the equivalent CO_2 concentration.~~

~~(b) If you are required to install a continuous parameter monitoring system (CPMS) as specified in Table 5 of this subpart, you must install, operate, and maintain each CPMS according to the requirements in paragraphs (b)(1) through (5) of this section. For an affected source that is complying with the emission limitations and operating limitations on March 9, 2011, the requirements in paragraph (b) of this section are applicable September 6, 2011.~~

~~(1) You must prepare a site-specific monitoring plan that addresses the monitoring system design, data collection, and the quality assurance and quality control elements outlined in paragraphs (b)(1)(i) through (v) of this section and in § 63.8(d). As specified in § 63.8(f)(4), you may request approval of monitoring system quality assurance and quality control procedures alternative to those specified in paragraphs (b)(1) through (5) of this section in your site-specific monitoring plan.~~

~~(i) The performance criteria and design specifications for the monitoring system equipment, including the sample interface, detector signal analyzer, and data acquisition and calculations;~~

~~(ii) Sampling interface (*e.g.*, thermocouple) location such that the monitoring system will provide representative measurements;~~

~~(iii) Equipment performance evaluations, system accuracy audits, or other audit procedures;~~

~~(iv) Ongoing operation and maintenance procedures in accordance with provisions in § 63.8(c)(1) and (c)(3); and~~

~~(v) Ongoing reporting and recordkeeping procedures in accordance with provisions in § 63.10(c), (e)(1), and (e)(2)(i).~~

~~(2) You must install, operate, and maintain each CPMS in continuous operation according to the procedures in your site-specific monitoring plan.~~

~~(3) The CPMS must collect data at least once every 15 minutes (see also § 63.6635).~~

~~(4) For a CPMS for measuring temperature range, the temperature sensor must have a minimum tolerance of 2.8 degrees Celsius (5 degrees Fahrenheit) or 1 percent of the measurement range, whichever is larger.~~

~~(5) You must conduct the CPMS equipment performance evaluation, system accuracy audits, or other audit procedures specified in your site-specific monitoring plan at least annually.~~

~~(6) You must conduct a performance evaluation of each CPMS in accordance with your site-specific monitoring plan.~~

~~(c) If you are operating a new or reconstructed stationary RICE which fires landfill gas or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis, you must monitor and record your fuel usage daily with separate fuel meters to measure the volumetric flow rate of each fuel. In addition, you must operate your stationary RICE in a manner which reasonably minimizes HAP emissions.~~

~~(d) If you are operating a new or reconstructed emergency 4SLB stationary RICE with a site rating of greater than or equal to 250 and less than or equal to 500 brake HP located at a major source of HAP emissions, you must install a non-resettable hour meter prior to the startup of the engine.~~

~~(e) If you own or operate any of the following stationary RICE, you must operate and maintain the stationary RICE and after-treatment control device (if any) according to the manufacturer's emission-related written instructions or develop your own maintenance plan which must provide to the extent practicable for the maintenance and operation of the engine in a manner consistent with good air pollution control practice for minimizing emissions:~~

~~(1) An existing stationary RICE with a site rating of less than 100 HP located at a major source of HAP emissions;~~

~~(2) An existing emergency or black start stationary RICE with a site rating of less than or equal to 500 HP located at a major source of HAP emissions;~~

~~(3) An existing emergency or black start stationary RICE located at an area source of HAP emissions;~~

~~(4) An existing non-emergency, non-black start stationary CI RICE with a site rating less than or equal to 300 HP located at an area source of HAP emissions;~~

~~(5) An existing non-emergency, non-black start 2SLB stationary RICE located at an area source of HAP emissions;~~

~~(6) An existing non-emergency, non-black start landfill or digester gas stationary RICE located at an area source of HAP emissions;~~

~~(7) An existing non-emergency, non-black start 4SLB stationary RICE with a site rating less than or equal to 500 HP located at an area source of HAP emissions;~~

~~(8) An existing non-emergency, non-black start 4SRB stationary RICE with a site rating less than or equal to 500 HP located at an area source of HAP emissions;~~

~~(9) An existing, non-emergency, non-black start 4SLB stationary RICE with a site rating greater than 500 HP located at an area source of HAP emissions that is operated 24 hours or less per calendar year; and~~

~~(10) An existing, non-emergency, non-black start 4SRB stationary RICE with a site rating greater than 500 HP located at an area source of HAP emissions that is operated 24 hours or less per calendar year.~~

~~(f) If you own or operate an existing emergency stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions or an existing emergency stationary RICE located at an area source of HAP emissions, you must install a non-resettable hour meter if one is not already installed.~~

~~(g) If you own or operate an existing non-emergency, non-black start CI engine greater than or equal to 300 HP that is not equipped with a closed crankcase ventilation system, you must comply with either paragraph (g)(1) or paragraph (g)(2) of this section. Owners and operators must follow the manufacturer's specified maintenance requirements for operating and maintaining the open or closed crankcase ventilation systems and replacing the crankcase filters, or can request the Administrator to approve different maintenance requirements that are as protective as manufacturer requirements. Existing CI engines located at area sources in areas of Alaska not accessible by the FAHS do not have to meet the requirements of paragraph (g) of this section.~~

~~(1) Install a closed crankcase ventilation system that prevents crankcase emissions from being emitted to the atmosphere, or~~

~~(2) Install an open crankcase filtration emission control system that reduces emissions from the crankcase by filtering the exhaust stream to remove oil mist, particulates, and metals.~~

~~(h) If you operate a new, reconstructed, or existing stationary engine, you must minimize the engine's time spent at idle during startup and minimize the engine's startup time to a period needed for appropriate and safe loading of the engine, not to exceed 30 minutes, after which time the emission standards applicable to all times other than startup in Tables 1a, 2a, 2c, and 2d to this subpart apply.~~

~~(i) If you own or operate a stationary CI engine that is subject to the work, operation or management practices in items 1 or 2 of Table 2c to this subpart or in items 1 or 4 of Table 2d to this subpart, you have the option of utilizing an oil analysis program in order to extend the specified oil change requirement in Tables 2c and 2d to this subpart. The oil analysis must be performed at the same frequency specified for changing the oil in Table 2c or 2d to this subpart. The analysis program must at a minimum analyze the following three parameters: Total Base Number, viscosity, and percent water content. The condemning limits for these parameters are as follows: Total Base Number is less than 30 percent of the Total Base Number of the oil when new; viscosity of the oil has changed by more than 20 percent from the viscosity of the oil when new; or percent water content (by volume) is greater than 0.5. If all of these condemning limits are not exceeded, the engine owner or operator is not required to change the oil. If any of the limits are exceeded, the engine owner or operator must change the oil within 2 days of receiving the results of the analysis; if the engine is not in operation when the results of the analysis are received, the engine owner or operator must change the oil within 2 days or before commencing operation, whichever is later. The owner or operator must keep records of the parameters that are analyzed as part of the program, the results of the analysis, and the oil changes for the engine. The analysis program must be part of the maintenance plan for the engine.~~

~~(j) If you own or operate a stationary SI engine that is subject to the work, operation or management practices in items 6, 7, or 8 of Table 2c to this subpart or in items 5, 6, 7, 9, or 11 of Table 2d to this subpart, you have the option of utilizing an oil analysis program in order to extend the specified oil change requirement in Tables 2c and 2d to this subpart. The oil analysis must be performed at the same frequency specified for changing the oil in Table 2c or 2d to this subpart. The analysis program must at a minimum analyze the following three parameters: Total Acid Number, viscosity, and percent water content. The condemning limits for these parameters are as follows: Total Acid Number increases by more than 3.0 milligrams of potassium hydroxide (KOH) per gram from Total Acid Number of the oil when new; viscosity of the oil has changed by more than 20 percent from the viscosity of the oil when new; or percent water content (by volume) is greater than 0.5. If all of these condemning limits are not exceeded, the engine owner or operator is not required to change the oil. If any of the limits are exceeded, the engine owner or operator must change the oil within 2 days of receiving the results of the analysis; if the engine is not in operation when the results of the analysis are received, the engine owner or operator must change the oil within 2 days or before commencing operation, whichever is later. The owner or operator must keep records of the parameters that are analyzed as part of the program, the results of the analysis, and the oil changes for the engine. The analysis program must be part of the maintenance plan for the engine.~~

~~[69 FR 33506, June 15, 2004, as amended at 73 FR 3606, Jan. 18, 2008; 75 FR 9676, Mar. 3, 2010; 75 FR 51589, Aug. 20, 2010; 76 FR 12866, Mar. 9, 2011]~~

~~§ 63.6630 How do I demonstrate initial compliance with the emission limitations and operating limitations?~~

~~(a) You must demonstrate initial compliance with each emission and operating limitation that applies to you according to Table 5 of this subpart.~~

~~(b) During the initial performance test, you must establish each operating limitation in Tables 1b and 2b of this subpart that applies to you.~~

~~(c) You must submit the Notification of Compliance Status containing the results of the initial compliance demonstration according to the requirements in § 63.6645.~~

~~Continuous Compliance Requirements~~

~~§ 63.6635 How do I monitor and collect data to demonstrate continuous compliance?~~

~~(a) If you must comply with emission and operating limitations, you must monitor and collect data according to this section.~~

~~(b) Except for monitor malfunctions, associated repairs, required performance evaluations, and required quality assurance or control activities, you must monitor continuously at all times that the stationary RICE 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.~~

~~(c) You may not use data recorded during monitoring malfunctions, associated repairs, and required quality assurance or control activities in data averages and calculations used to report emission or operating levels. You must, however, use all the valid data collected during all other periods.~~

~~[69 FR 33506, June 15, 2004, as amended at 76 FR 12867, Mar. 9, 2011]~~

~~§ 63.6640 How do I demonstrate continuous compliance with the emission limitations and operating limitations?~~

~~(a) You must demonstrate continuous compliance with each emission limitation and operating limitation in Tables 1a and 1b, Tables 2a and 2b, Table 2c, and Table 2d to this subpart that apply to you according to methods specified in Table 6 to this subpart.~~

~~(b) You must report each instance in which you did not meet each emission limitation or operating limitation in Tables 1a and 1b, Tables 2a and 2b, Table 2c, and Table 2d to this subpart that apply to you. These instances are deviations from the emission and operating limitations in this subpart. These deviations must be reported according to the requirements in § 63.6650. If you change your catalyst, you must reestablish the values of the operating parameters measured during the initial performance test. When you reestablish the values of your operating parameters, you must also conduct a performance test to demonstrate that you are meeting the required emission limitation applicable to your stationary RICE.~~

~~(c) [Reserved]~~

~~(d) For new, reconstructed, and rebuilt stationary RICE, deviations from the emission or operating limitations that occur during the first 200 hours of operation from engine startup (engine burn-in period) are not violations.~~

~~Rebuilt stationary RICE means a stationary RICE that has been rebuilt as that term is defined in 40 CFR 94.11(a).~~

~~(e) You must also report each instance in which you did not meet the requirements in Table 8 to this subpart that apply to you. If you own or operate a new or reconstructed stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions (except new or reconstructed 4SLB engines greater than or equal to 250 and less than or equal to 500 brake HP), a new or reconstructed stationary RICE located at an area source of HAP emissions, or any of the following RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions, you do not need to comply with the requirements in Table 8 to this subpart: An existing 2SLB stationary RICE, an existing 4SLB stationary RICE, an existing emergency stationary RICE, an existing limited use stationary RICE, or an existing stationary RICE which fires landfill gas or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis. If you own or operate any of the following RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions, you do not need to comply with the requirements in Table 8 to this subpart, except for the initial notification requirements: a new or reconstructed stationary RICE that combusts landfill gas or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis, a new or reconstructed emergency stationary RICE, or a new or reconstructed limited use stationary RICE.~~

~~(f) *Requirements for emergency stationary RICE.* (1) If you own or operate an existing emergency stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions, a new or reconstructed emergency stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions that was installed on or after June 12, 2006, or an existing emergency stationary RICE located at an area source of HAP emissions, you must operate the emergency stationary RICE according to the requirements in paragraphs (f)(1)(i) through (iii) of this section. Any operation other than emergency operation, maintenance and testing, and operation in non-emergency situations for 50 hours per year, as described in paragraphs (f)(1)(i) through (iii) of this section, is prohibited. If you do not operate the engine according to the requirements in paragraphs (f)(1)(i) through (iii) of this section, the engine will not be considered an emergency engine under this subpart and will need to meet all requirements for non-emergency engines.~~

~~(i) There is no time limit on the use of emergency stationary RICE in emergency situations.~~

~~(ii) You may operate your emergency stationary RICE for the purpose of maintenance checks and readiness testing, provided that the tests are recommended by Federal, State or local government, the manufacturer, the vendor, or the insurance company associated with the engine. Maintenance checks and readiness testing of such units is limited to 100 hours per year. The owner or operator may petition the Administrator for approval of additional hours to be used for maintenance checks and readiness testing, but a petition is not required if the owner or operator maintains records indicating that Federal, State, or local standards require maintenance and testing of emergency RICE beyond 100 hours per year.~~

~~(iii) You may operate your emergency stationary RICE up to 50 hours per year in non-emergency situations, but those 50 hours are counted towards the 100 hours per year provided for maintenance and testing. The 50 hours per year for non-emergency situations cannot be used for peak shaving or to generate income for a facility to supply power to an electric grid or otherwise supply power as part of a financial arrangement with another entity; except that owners and operators may operate the emergency engine for a maximum of 15 hours per year as part of a demand response program if the regional transmission organization or equivalent balancing authority and transmission operator has determined there are emergency conditions that could lead to a potential electrical blackout, such as unusually low frequency, equipment overload, capacity or energy deficiency, or unacceptable voltage level. The engine may not be operated for more than 30 minutes prior to the time when the emergency condition is expected to occur, and the engine operation must be terminated immediately after the facility is notified that the emergency condition is no longer imminent. The 15 hours per year of demand response operation are counted as part of the 50 hours of operation per year provided for non-emergency situations. The supply of emergency power to another entity or entities pursuant to financial arrangement is not limited by this paragraph (f)(1)(iii), as long as the power provided by the financial arrangement is limited to emergency power.~~

~~(2) If you own or operate an emergency stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions that was installed prior to June 12, 2006, you must operate the engine according to the conditions described in paragraphs (f)(2)(i) through (iii) of this section. If you do not operate the engine according to the requirements in paragraphs (f)(2)(i) through (iii) of this section, the engine will not be considered an emergency engine under this subpart and will need to meet all requirements for non-emergency engines.~~

~~(i) There is no time limit on the use of emergency stationary RICE in emergency situations.~~

~~(ii) You may operate your emergency stationary RICE for the purpose of maintenance checks and readiness testing, provided that the tests are recommended by the manufacturer, the vendor, or the insurance company associated with the engine. Required testing of such units should be minimized, but there is no time limit on the use of emergency stationary RICE in emergency situations and for routine testing and maintenance.~~

~~(iii) You may operate your emergency stationary RICE for an additional 50 hours per year in non-emergency situations. The 50 hours per year for non-emergency situations cannot be used for peak shaving or to generate income for a facility to supply power to an electric grid or otherwise supply power as part of a financial arrangement with another entity.~~

~~[69 FR 33506, June 15, 2004, as amended at 71 FR 20467, Apr. 20, 2006; 73 FR 3606, Jan. 18, 2008; 75 FR 9676, Mar. 3, 2010; 75 FR 51591, Aug. 20, 2010]~~

~~Notifications, Reports, and Records~~

~~§ 63.6645 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 (f)(6), 63.9(b) through (e), and (g) and (h) that apply to you by the dates specified if you own or operate any of the following;~~

~~(1) An existing stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions.~~

~~(2) An existing stationary RICE located at an area source of HAP emissions.~~

~~(3) A stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions.~~

~~(4) A new or reconstructed 4SLB stationary RICE with a site rating of greater than or equal to 250 HP located at a major source of HAP emissions.~~

~~(5) This requirement does not apply if you own or operate an existing stationary RICE less than 100 HP, an existing stationary emergency RICE, or an existing stationary RICE that is not subject to any numerical emission standards.~~

~~(b) As specified in § 63.9(b)(2), if you start up your stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions before the effective date of this subpart, you must submit an Initial Notification not later than December 13, 2004.~~

~~(c) If you start up your new or reconstructed stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions on or after August 16, 2004, you must submit an Initial Notification not later than 120 days after you become subject to this subpart.~~

~~(d) As specified in § 63.9(b)(2), if you start up your stationary RICE with a site rating of equal to or less than 500 brake HP located at a major source of HAP emissions before the effective date of this subpart and you are required to submit an initial notification, you must submit an Initial Notification not later than July 16, 2008.~~

~~(e) If you start up your new or reconstructed stationary RICE with a site rating of equal to or less than 500 brake HP located at a major source of HAP emissions on or after March 18, 2008 and you are required to submit an initial notification, you must submit an Initial Notification not later than 120 days after you become subject to this subpart.~~

~~(f) If you are required to submit an Initial Notification but are otherwise not affected by the requirements of this subpart, in accordance with § 63.6590(b), your notification should include the information in § 63.9(b)(2)(i) through (v), and a statement that your stationary RICE has no additional requirements and explain the basis of the exclusion (for example, that it operates exclusively as an emergency stationary RICE if it has a site rating of more than 500 brake HP located at a major source of HAP emissions).~~

~~(g) If you are required to conduct a performance test, you must submit a Notification of Intent to conduct a performance test at least 60 days before the performance test is scheduled to begin as required in § 63.7(b)(1).~~

~~(h) If you are required to conduct a performance test or other initial compliance demonstration as specified in Tables 4 and 5 to this subpart, you must submit a Notification of Compliance Status according to § 63.9(h)(2)(ii).~~

~~(1) For each initial compliance demonstration required in Table 5 to this subpart that does not include a performance test, you must submit the Notification of Compliance Status before the close of business on the 30th day following the completion of the initial compliance demonstration.~~

~~(2) For each initial compliance demonstration required in Table 5 to this subpart that includes a performance test conducted according to the requirements in Table 3 to this subpart, you must submit the Notification of Compliance Status, including the performance test results, before the close of business on the 60th day following the completion of the performance test according to § 63.10(d)(2).~~

~~[73 FR 3606, Jan. 18, 2008, as amended at 75 FR 9677, Mar. 3, 2010; 75 FR 51591, Aug. 20, 2010]~~

~~§ 63.6650 What reports must I submit and when?~~

~~(a) You must submit each report in Table 7 of this subpart that applies to you.~~

~~(b) Unless the Administrator has approved a different schedule for submission of reports under § 63.10(a), you must submit each report by the date in Table 7 of this subpart and according to the requirements in paragraphs (b)(1) through (b)(9) of this section.~~

~~(1) For semiannual Compliance reports, the first Compliance report must cover the period beginning on the compliance date that is specified for your affected source in § 63.6595 and ending on June 30 or December 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 § 63.6595.~~

~~(2) For semiannual Compliance reports, the first Compliance report must be postmarked or delivered no later than July 31 or January 31, whichever date follows the end of the first calendar half after the compliance date that is specified for your affected source in § 63.6595.~~

~~(3) For semiannual Compliance reports, 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) For semiannual Compliance reports, 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 stationary RICE that is subject to permitting regulations pursuant to 40 CFR part 70 or 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 (b)(4) of this section.~~

~~(6) For annual Compliance reports, the first Compliance report must cover the period beginning on the compliance date that is specified for your affected source in § 63.6595 and ending on December 31.~~

~~(7) For annual Compliance reports, the first Compliance report must be postmarked or delivered no later than January 31 following the end of the first calendar year after the compliance date that is specified for your affected source in § 63.6595.~~

~~(8) For annual Compliance reports, each subsequent Compliance report must cover the annual reporting period from January 1 through December 31.~~

~~(9) For annual Compliance reports, each subsequent Compliance report must be postmarked or delivered no later than January 31.~~

~~(c) The Compliance report must contain the information in paragraphs (c)(1) through (6) of this section.~~

~~(1) Company name and address.~~

~~(2) Statement by a responsible official, with that official's name, title, and signature, certifying the accuracy of the content of the report.~~

~~(3) Date of report and beginning and ending dates of the reporting period.~~

~~(4) If you had a malfunction during the reporting period, the compliance report must include the number, duration, and a brief description for each type of malfunction which occurred during the reporting period and which caused or may have caused any applicable emission limitation to be exceeded. The report must also include a description of actions taken by an owner or operator during a malfunction of an affected source to minimize emissions in accordance with § 63.6605(b), including actions taken to correct a malfunction.~~

~~(5) If there are no deviations from any emission or operating limitations that apply to you, a statement that there were no deviations from the emission or operating limitations during the reporting period.~~

~~(6) If there were no periods during which the continuous monitoring system (CMS), including CEMS and CPMS, was out-of-control, as specified in § 63.8(c)(7), a statement that there were no periods during which the CMS was out-of-control during the reporting period.~~

~~(d) For each deviation from an emission or operating limitation that occurs for a stationary RICE where you are not using a CMS to comply with the emission or operating limitations in this subpart, the Compliance report must contain the information in paragraphs (c)(1) through (4) of this section and the information in paragraphs (d)(1) and (2) of this section.~~

~~(1) The total operating time of the stationary RICE at which the deviation occurred during the reporting period.~~

~~(2) Information on the number, duration, and cause of deviations (including unknown cause, if applicable), as applicable, and the corrective action taken.~~

~~(e) For each deviation from an emission or operating limitation occurring for a stationary RICE where you are using a CMS to comply with the emission and operating limitations in this subpart, you must include information in paragraphs (c)(1) through (4) and (e)(1) through (12) of this section.~~

~~(1) The date and time that each malfunction started and stopped.~~

~~(2) The date, time, and duration 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 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 control equipment problems, process problems, other known causes, and other unknown causes.~~

~~(7) A summary of the total duration of CMS downtime during the reporting period, and the total duration of CMS downtime as a percent of the total operating time of the stationary RICE at which the CMS downtime occurred during that reporting period.~~

~~(8) An identification of each parameter and pollutant (CO or formaldehyde) that was monitored at the stationary RICE.~~

~~(9) A brief description of the stationary RICE.~~

~~(10) A brief description of the CMS.~~

~~(11) The date of the latest CMS certification or audit.~~

~~(12) A description of any changes in CMS, processes, or controls since the last reporting period.~~

~~(f) Each affected source that has obtained a title V operating permit pursuant to 40 CFR part 70 or 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 7 of 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 or operating limitation in this subpart, submission of the Compliance report shall be deemed to satisfy any obligation to report the same deviations in the semiannual monitoring report. However, submission of a Compliance report shall not otherwise affect any obligation the affected source may have to report deviations from permit requirements to the permit authority.~~

~~(g) If you are operating as a new or reconstructed stationary RICE which fires landfill gas or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis, you must submit an annual report according to Table 7 of this subpart by the date specified unless the Administrator has approved a different schedule, according to the information described in paragraphs (b)(1) through (b)(5) of this section. You must report the data specified in (g)(1) through (g)(3) of this section.~~

~~(1) Fuel flow rate of each fuel and the heating values that were used in your calculations. You must also demonstrate that the percentage of heat input provided by landfill gas or digester gas is equivalent to 10 percent or more of the total fuel consumption on an annual basis.~~

~~(2) The operating limits provided in your federally enforceable permit, and any deviations from these limits.~~

~~(3) Any problems or errors suspected with the meters.~~

~~[69 FR 33506, June 15, 2004, as amended at 75 FR 9677, Mar. 3, 2010]~~

~~§ 63.6655 What records must I keep?~~

~~(a) If you must comply with the emission and operating limitations, you must keep the records described in paragraphs (a)(1) through (a)(5), (b)(1) through (b)(3) and (c) 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 that you submitted, according to the requirement in § 63.10(b)(2)(xiv).~~

~~(2) Records of the occurrence and duration of each malfunction of operation (*i.e.*, process equipment) or the air pollution control and monitoring equipment.~~

~~(3) Records of performance tests and performance evaluations as required in § 63.10(b)(2)(viii).~~

~~(4) Records of all required maintenance performed on the air pollution control and monitoring equipment.~~

~~(5) Records of actions taken during periods of malfunction to minimize emissions in accordance with § 63.6605(b), including corrective actions to restore malfunctioning process and air pollution control and monitoring equipment to its normal or usual manner of operation.~~

~~(b) For each CEMS or CPMS, you must keep the records listed in paragraphs (b)(1) through (3) of this section.~~

~~(1) Records described in § 63.10(b)(2)(vi) through (xi).~~

~~(2) Previous (*i.e.,* superseded) versions of the performance evaluation plan as required in § 63.8(d)(3).~~

~~(3) Requests for alternatives to the relative accuracy test for CEMS or CPMS as required in § 63.8(f)(6)(i), if applicable.~~

~~(c) If you are operating a new or reconstructed stationary RICE which fires landfill gas or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis, you must keep the records of your daily fuel usage monitors.~~

~~(d) You must keep the records required in Table 6 of this subpart to show continuous compliance with each emission or operating limitation that applies to you.~~

~~(e) You must keep records of the maintenance conducted on the stationary RICE in order to demonstrate that you operated and maintained the stationary RICE and after-treatment control device (if any) according to your own maintenance plan if you own or operate any of the following stationary RICE;~~

~~(1) An existing stationary RICE with a site rating of less than 100 brake HP located at a major source of HAP emissions.~~

~~(2) An existing stationary emergency RICE.~~

~~(3) An existing stationary RICE located at an area source of HAP emissions subject to management practices as shown in Table 2d to this subpart.~~

~~(f) If you own or operate any of the stationary RICE in paragraphs (f)(1) or (2) of this section, you must keep records of the hours of operation of the engine that is recorded through the non-resettable hour meter. The owner or operator must document how many hours are spent for emergency operation, including what classified~~

~~the operation as emergency and how many hours are spent for non-emergency operation. If the engines are used for demand response operation, the owner or operator must keep records of the notification of the emergency situation, and the time the engine was operated as part of demand response.~~

~~(1) An existing emergency stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions that does not meet the standards applicable to non-emergency engines.~~

~~(2) An existing emergency stationary RICE located at an area source of HAP emissions that does not meet the standards applicable to non-emergency engines.~~

~~[69 FR 33506, June 15, 2004, as amended at 75 FR 9678, Mar. 3, 2010; 75 FR 51592, Aug. 20, 2010]~~

~~§ 63.6660 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 readily accessible in hard copy or electronic form for at least 5 years after the date of each occurrence, measurement, maintenance, corrective action, report, or record, according to § 63.10(b)(1).~~

~~[69 FR 33506, June 15, 2004, as amended at 75 FR 9678, Mar. 3, 2010]~~

~~Other Requirements and Information~~

~~§ 63.6665 What parts of the General Provisions apply to me?~~

~~Table 8 to this subpart shows which parts of the General Provisions in §§ 63.1 through 63.15 apply to you. If you own or operate a new or reconstructed stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions (except new or reconstructed 4SLB engines greater than or equal to 250 and less than or equal to 500 brake HP), a new or reconstructed stationary RICE located at an area source of HAP emissions, or any of the following RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions, you do not need to comply with any of the requirements of the General Provisions specified in Table 8: An existing 2SLB stationary RICE, an existing 4SLB stationary RICE, an existing stationary RICE that combusts landfill or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis, an existing emergency stationary RICE, or an existing limited use stationary RICE. If you own or operate any of the following RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions, you do not need to comply with the requirements in the General Provisions specified in Table 8 except for the initial notification requirements: A new stationary RICE that combusts landfill gas or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis, a new emergency stationary RICE, or a new limited use stationary RICE.~~

~~[75 FR 9678, Mar. 3, 2010]~~

~~§ 63.6670 Who implements and enforces this subpart?~~

~~(a) This subpart is implemented and enforced by 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 whether this subpart is delegated to your State, local, or tribal agency.~~

~~(b) In delegating implementation and enforcement authority of this subpart to a State, local, or tribal agency under 40 CFR part 63, subpart E, the authorities contained in 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:~~

~~(1) Approval of alternatives to the non-opacity emission limitations and operating limitations in § 63.6600 under § 63.6(g).~~

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

~~(3) Approval of major alternatives to monitoring under § 63.8(f) and as defined in § 63.90.~~

~~(4) Approval of major alternatives to recordkeeping and reporting under § 63.10(f) and as defined in § 63.90.~~

~~(5) Approval of a performance test which was conducted prior to the effective date of the rule, as specified in § 63.6610(b).~~

~~§ 63.6675 What definitions apply to this subpart?~~

~~Terms used in this subpart are defined in the Clean Air Act (CAA); in 40 CFR 63.2, the General Provisions of this part; and in this section as follows:~~

~~*Area source* means any stationary source of HAP that is not a major source as defined in part 63.~~

~~*Associated equipment* as used in this subpart and as referred to in section 112(n)(4) of the CAA, means equipment associated with an oil or natural gas exploration or production well, and includes all equipment from the well bore to the point of custody transfer, except glycol dehydration units, storage vessels with potential for flash emissions, combustion turbines, and stationary RICE.~~

~~*Black start engine* means an engine whose only purpose is to start up a combustion turbine.~~

~~*CAA* means the Clean Air Act (42 U.S.C. 7401 *et seq.*, as amended by Public Law 101-549, 104 Stat. 2399).~~

~~*Commercial emergency stationary RICE* means an emergency stationary RICE used in commercial establishments such as office buildings, hotels, stores, telecommunications facilities, restaurants, financial institutions such as banks, doctor's offices, and sports and performing arts facilities.~~

~~*Compression ignition* means relating to a type of stationary internal combustion engine that is not a spark ignition engine.~~

~~*Custody transfer* means the transfer of hydrocarbon liquids or natural gas: After processing and/or treatment in the producing operations, or from storage vessels or automatic transfer facilities or other such equipment, including product loading racks, to pipelines or any other forms of transportation. For the purposes of this subpart, the point at which such liquids or natural gas enters a natural gas processing plant is a point of custody transfer.~~

~~*Deviation* means any instance in which an affected source subject to this subpart, or an owner or operator of such a source:~~

~~(1) Fails to meet any requirement or obligation established by this subpart, including but not limited to any emission limitation or operating limitation;~~

~~(2) 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~~

~~(3) Fails to meet any emission limitation or operating limitation in this subpart during malfunction, regardless or whether or not such failure is permitted by this subpart.~~

~~(4) Fails to satisfy the general duty to minimize emissions established by § 63.6(e)(1)(i).~~

~~*Diesel engine* means any stationary RICE in which a high boiling point liquid fuel injected into the combustion chamber ignites when the air charge has been compressed to a temperature sufficiently high for auto-ignition. This process is also known as compression ignition.~~

~~*Diesel fuel* means any liquid obtained from the distillation of petroleum with a boiling point of approximately 150 to 360 degrees Celsius. One commonly used form is fuel oil number 2. Diesel fuel also includes any non-distillate fuel with comparable physical and chemical properties (*e.g.* biodiesel) that is suitable for use in compression ignition engines.~~

~~*Digester gas* means any gaseous by-product of wastewater treatment typically formed through the anaerobic decomposition of organic waste materials and composed principally of methane and CO_2 .~~

~~*Dual-fuel engine* means any stationary RICE in which a liquid fuel (typically diesel fuel) is used for compression ignition and gaseous fuel (typically natural gas) is used as the primary fuel.~~

~~*Emergency stationary RICE* means any stationary internal combustion engine whose operation is limited to emergency situations and required testing and maintenance. Examples include stationary RICE used to produce power for critical networks or equipment (including power supplied to portions of a facility) when electric power from the local utility (or the normal power source, if the facility runs on its own power production) is interrupted, or stationary RICE used to pump water in the case of fire or flood, *etc.* Stationary RICE used for peak shaving are not considered emergency stationary RICE. Stationary RICE used to supply power to an electric grid or that supply non-emergency power as part of a financial arrangement with another entity are not considered to be emergency engines, except as permitted under § 63.6640(f). All emergency stationary RICE must comply with the requirements specified in § 63.6640(f) in order to be considered emergency stationary RICE. If the engine does not comply with the requirements specified in § 63.6640(f), then it is not considered to be an emergency stationary RICE under this subpart.~~

~~*Engine startup* means the time from initial start until applied load and engine and associated equipment reaches steady state or normal operation. For stationary engine with catalytic controls, engine startup means the time from initial start until applied load and engine and associated equipment, including the catalyst, reaches steady state or normal operation.~~

~~*Four-stroke engine* means any type of engine which completes the power cycle in two crankshaft revolutions, with intake and compression strokes in the first revolution and power and exhaust strokes in the second revolution.~~

~~*Gaseous fuel* means a material used for combustion which is in the gaseous state at standard atmospheric temperature and pressure conditions.~~

~~*Gasoline* means any fuel sold in any State for use in motor vehicles and motor vehicle engines, or nonroad or stationary engines, and commonly or commercially known or sold as gasoline.~~

~~*Glycol dehydration unit* means a device in which a liquid glycol (including, but not limited to, ethylene glycol, diethylene glycol, or triethylene glycol) absorbent directly contacts a natural gas stream and absorbs water in a contact tower or absorption column (absorber). The glycol contacts and absorbs water vapor and other gas~~

~~stream constituents from the natural gas and becomes “rich” glycol. This glycol is then regenerated in the glycol dehydration unit reboiler. The “lean” glycol is then recycled.~~

~~*Hazardous air pollutants (HAP)* means any air pollutants listed in or pursuant to section 112(b) of the CAA.~~

~~*Institutional emergency stationary RICE* means an emergency stationary RICE used in institutional establishments such as medical centers, nursing homes, research centers, institutions of higher education, correctional facilities, elementary and secondary schools, libraries, religious establishments, police stations, and fire stations.~~

~~*ISO standard day conditions* means 288 degrees Kelvin (15 degrees Celsius), 60 percent relative humidity and 101.3 kilopascals pressure.~~

~~*Landfill gas* means a gaseous by-product of the land application of municipal refuse typically formed through the anaerobic decomposition of waste materials and composed principally of methane and CO_2 .~~

~~*Lean burn engine* means any two-stroke or four-stroke spark ignited engine that does not meet the definition of a rich burn engine.~~

~~*Limited use stationary RICE* means any stationary RICE that operates less than 100 hours per year.~~

~~*Liquefied petroleum gas* means any liquefied hydrocarbon gas obtained as a by-product in petroleum refining of natural gas production.~~

~~*Liquid fuel* means any fuel in liquid form at standard temperature and pressure, including but not limited to diesel, residual/crude oil, kerosene/naphtha (jet fuel), and gasoline.~~

~~*Major Source,* as used in this subpart, shall have the same meaning as in § 63.2, except that:~~

~~(1) Emissions from any oil or gas exploration or production well (with its associated equipment (as defined in this section)) and emissions from any pipeline compressor station or pump station shall not be aggregated with emissions from other similar units, to determine whether such emission points or stations are major sources, even when emission points are in a contiguous area or under common control;~~

~~(2) For oil and gas production facilities, emissions from processes, operations, or equipment that are not part of the same oil and gas production facility, as defined in § 63.1271 of subpart HHH of this part, shall not be aggregated;~~

~~(3) For production field facilities, only HAP emissions from glycol dehydration units, storage vessel with the potential for flash emissions, combustion turbines and reciprocating internal combustion engines shall be aggregated for a major source determination; and~~

~~(4) Emissions from processes, operations, and equipment that are not part of the same natural gas transmission and storage facility, as defined in § 63.1271 of subpart HHH of this part, shall not be aggregated.~~

~~*Malfunction* means any sudden, infrequent, and not reasonably preventable failure of air pollution control equipment, process equipment, or a process to operate in a normal or usual manner which causes, or has the potential to cause, the emission limitations in an applicable standard to be exceeded. Failures that are caused in part by poor maintenance or careless operation are not malfunctions.~~

~~*Natural gas* means a naturally occurring mixture of hydrocarbon and non-hydrocarbon gases found in geologic formations beneath the Earth's surface, of which the principal constituent is methane. Natural gas may be field or pipeline quality.~~

~~*Non-selective catalytic reduction (NSCR)* means an add-on catalytic nitrogen oxides (NO_X) control device for rich burn engines that, in a two-step reaction, promotes the conversion of excess oxygen, NO_X, CO, and volatile organic compounds (VOC) into CO_2, nitrogen, and water.~~

~~*Oil and gas production facility* as used in this subpart means any grouping of equipment where hydrocarbon liquids are processed, upgraded (*i.e.*, remove impurities or other constituents to meet contract specifications), or stored prior to the point of custody transfer; or where natural gas is processed, upgraded, or stored prior to entering the natural gas transmission and storage source category. For purposes of a major source determination, facility (including a building, structure, or installation) means oil and natural gas production and processing equipment that is located within the boundaries of an individual surface site as defined in this section. Equipment that is part of a facility will typically be located within close proximity to other equipment located at the same facility. Pieces of production equipment or groupings of equipment located on different oil and gas leases, mineral fee tracts, lease tracts, subsurface or surface unit areas, surface fee tracts, surface lease tracts, or separate surface sites, whether or not connected by a road, waterway, power line or pipeline, shall not be considered part of the same facility. Examples of facilities in the oil and natural gas production source category include, but are not limited to, well sites, satellite tank batteries, central tank batteries, a compressor station that transports natural gas to a natural gas processing plant, and natural gas processing plants.~~

~~*Oxidation catalyst* means an add-on catalytic control device that controls CO and VOC by oxidation.~~

~~*Peaking unit or engine* means any standby engine intended for use during periods of high demand that are not emergencies.~~

~~*Percent load* means the fractional power of an engine compared to its maximum manufacturer's design capacity at engine site conditions. Percent load may range between 0 percent to above 100 percent.~~

~~*Potential to emit* means the maximum capacity of a stationary source to emit a pollutant under its physical and operational design. Any physical or operational limitation on the capacity of the stationary source to emit a pollutant, including air pollution control equipment and restrictions on hours of operation or on the type or amount of material combusted, stored, or processed, shall be treated as part of its design if the limitation or the effect it would have on emissions is federally enforceable. For oil and natural gas production facilities subject to subpart HH of this part, the potential to emit provisions in § 63.760(a) may be used. For natural gas transmission and storage facilities subject to subpart HHH of this part, the maximum annual facility gas throughput for storage facilities may be determined according to § 63.1270(a)(1) and the maximum annual throughput for transmission facilities may be determined according to § 63.1270(a)(2).~~

~~*Production field facility* means those oil and gas production facilities located prior to the point of custody transfer.~~

~~*Production well* means any hole drilled in the earth from which crude oil, condensate, or field natural gas is extracted.~~

~~*Propane* means a colorless gas derived from petroleum and natural gas, with the molecular structure C_3H_8.~~

~~*Residential emergency stationary RICE* means an emergency stationary RICE used in residential establishments such as homes or apartment buildings.~~

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

~~*Rich burn engine* means any four-stroke spark ignited engine where the manufacturer's recommended operating air/fuel ratio divided by the stoichiometric air/fuel ratio at full load conditions is less than or equal to 1.1. Engines originally manufactured as rich burn engines, but modified prior to December 19, 2002 with passive emission control technology for NO_X (such as pre-combustion chambers) will be considered lean burn engines. Also, existing engines where there are no manufacturer's recommendations regarding air/fuel ratio will be considered~~

~~a rich burn engine if the excess oxygen content of the exhaust at full load conditions is less than or equal to 2 percent.~~

~~*Site-rated HP* means the maximum manufacturer's design capacity at engine site conditions.~~

~~*Spark ignition* means relating to either: A gasoline-fueled engine; or any other type of engine with a spark plug (or other sparking device) and with operating characteristics significantly similar to the theoretical Otto combustion cycle. Spark ignition engines usually use a throttle to regulate intake air flow to control power during normal operation. Dual-fuel engines in which a liquid fuel (typically diesel fuel) is used for CI and gaseous fuel (typically natural gas) is used as the primary fuel at an annual average ratio of less than 2 parts diesel fuel to 100 parts total fuel on an energy equivalent basis are spark ignition engines.~~

~~*Stationary reciprocating internal combustion engine (RICE)* means any reciprocating internal combustion engine which uses reciprocating motion to convert heat energy into mechanical work and which is not mobile. Stationary RICE differ from mobile RICE in that a stationary RICE is not a non-road engine as defined at 40 CFR 1068.30, and is not used to propel a motor vehicle or a vehicle used solely for competition.~~

~~*Stationary RICE test cell/stand* means an engine test cell/stand, as defined in subpart PPPPP of this part, that tests stationary RICE.~~

~~*Stoichiometric* means the theoretical air-to-fuel ratio required for complete combustion.~~

~~*Storage vessel with the potential for flash emissions* means any storage vessel that contains a hydrocarbon liquid with a stock tank gas-to-oil ratio equal to or greater than 0.31 cubic meters per liter and an American Petroleum Institute gravity equal to or greater than 40 degrees and an actual annual average hydrocarbon liquid throughput equal to or greater than 79,500 liters per day. Flash emissions occur when dissolved hydrocarbons in the fluid evolve from solution when the fluid pressure is reduced.~~

~~*Subpart* means 40 CFR part 63, subpart ZZZZ.~~

~~*Surface site* means any combination of one or more graded pad sites, gravel pad sites, foundations, platforms, or the immediate physical location upon which equipment is physically affixed.~~

~~*Two-stroke engine* means a type of engine which completes the power cycle in single crankshaft revolution by combining the intake and compression operations into one stroke and the power and exhaust operations into a second stroke. This system requires auxiliary scavenging and inherently runs lean of stoichiometric.~~

~~[69 FR 33506, June 15, 2004, as amended at 71 FR 20467, Apr. 20, 2006; 73 FR 3607, Jan. 18, 2008; 75 FR 9679, Mar. 3, 2010; 75 FR 51592, Aug. 20, 2010; 76 FR 12867, Mar. 9, 2011]~~

~~Table 1~~ a ~~to Subpart ZZZZ of Part 63—Emission Limitations for Existing, New, and Reconstructed Spark Ignition, 4SRB Stationary RICE > 500 HP Located at a Major Source of HAP Emissions~~

~~As stated in §§ 63.6600 and 63.6640, you must comply with the following emission limitations at 100 percent load plus or minus 10 percent for existing, new and reconstructed 4SRB stationary RICE >500 HP located at a major source of HAP emissions:~~

~~**For each . . .**~~	~~**You must meet the following emission limitation, except during periods of startup . . .**~~	~~**During periods of startup you must . . .**~~
~~1. 4SRB stationary RICE~~	~~a. Reduce formaldehyde emissions by 76 percent or more. If you commenced construction or reconstruction between December 19, 2002 and June 15, 2004, you may reduce formaldehyde~~	~~Minimize the engine's time spent at idle and minimize the engine's startup time at startup to a period needed for appropriate and safe loading of the engine, not to exceed 30 minutes,~~

	~~emissions by 75 percent or more until June 15, 2007 or~~	~~after which time the non-startup emission limitations apply.~~[1]
	~~b. Limit the concentration of formaldehyde in the stationary RICE exhaust to 350 ppbvd or less at 15 percent~~ ~~O_2~~	

~~[1] Sources can petition the Administrator pursuant to the requirements of 40 CFR 63.6(g) for alternative work practices.~~

~~[75 FR 9679, Mar. 3, 2010, as amended at 75 FR 51592, Aug. 20, 2010]~~

~~Table 1 b to Subpart ZZZZ of Part 63—Operating Limitations for Existing, New, and Reconstructed Spark Ignition 4SRB Stationary RICE >500 HP Located at a Major Source of HAP Emissions and Existing Spark Ignition 4SRB Stationary RICE >500 HP Located at an Area Source of HAP Emissions~~

~~As stated in §§ 63.6600, 63.6603, 63.6630 and 63.6640, you must comply with the following operating limitations for existing, new and reconstructed 4SRB stationary RICE >500 HP located at a major source of HAP emissions and existing 4SRB stationary RICE >500 HP located at an area source of HAP emissions that operate more than 24 hours per calendar year:~~

~~**For each . . .**~~	~~**You must meet the following operating limitation . . .**~~
~~1. 4SRB stationary RICE complying with the requirement to reduce formaldehyde emissions by 76 percent or more (or by 75 percent or more, if applicable) and using NSCR; or~~ ~~4SRB stationary RICE complying with the requirement to limit the concentration of formaldehyde in the stationary RICE exhaust to 350 ppbvd or less at 15 percent O2 and using NSCR; or~~ ~~4SRB stationary RICE complying with the requirement to limit the concentration of formaldehyde in the stationary RICE exhaust to 2.7 ppmvd or less at 15 percent O2 and using NSCR.~~	~~a. Maintain your catalyst so that the pressure drop across the catalyst does not change by more than 2 inches of water at 100 percent load plus or minus 10 percent from the pressure drop across the catalyst measured during the initial performance test; and~~ ~~b. Maintain the temperature of your stationary RICE exhaust so that the catalyst inlet temperature is greater than or equal to 750 °F and less than or equal to 1250 °F.~~
~~2. 4SRB stationary RICE complying with the requirement to reduce formaldehyde emissions by 76 percent or more (or by 75 percent or more, if applicable) and not using NSCR; or~~ ~~4SRB stationary RICE complying with the requirement to limit the concentration of formaldehyde in the stationary RICE exhaust to 350 ppbvd or less at 15 percent O2 and not using NSCR; or~~ ~~4SRB stationary RICE complying with the requirement to limit the concentration of formaldehyde in the stationary RICE exhaust to 2.7 ppmvd or less at 15 percent O2 and not using NSCR.~~	~~Comply with any operating limitations approved by the Administrator.~~

~~[76 FR 12867, Mar. 9, 2011]~~

~~Table 2~~ a ~~to Subpart ZZZZ of Part 63—Emission Limitations for New and Reconstructed 2SLB and Compression Ignition Stationary RICE >500 HP and New and Reconstructed 4SLB Stationary RICE ≥250 HP Located at a Major Source of HAP Emissions~~

~~As stated in §§ 63.6600 and 63.6640, you must comply with the following emission limitations for new and reconstructed lean burn and new and reconstructed compression ignition stationary RICE at 100 percent load plus or minus 10 percent:~~

~~For each . . .~~	~~You must meet the following emission limitation, except during periods of startup . . .~~	~~During periods of startup you must . . .~~
~~1. 2SLB stationary RICE~~	~~a. Reduce CO emissions by 58 percent or more; or~~ ~~b. Limit concentration of formaldehyde in the stationary RICE exhaust to 12 ppmvd or less at 15 percent O_2. If you commenced construction or reconstruction between December 19, 2002 and June 15, 2004, you may limit concentration of formaldehyde to 17 ppmvd or less at 15 percent O_2until June 15, 2007~~	~~Minimize the engine's time spent at idle and minimize the engine's startup time at startup to a period needed for appropriate and safe loading of the engine, not to exceed 30 minutes, after which time the non-startup emission limitations apply.~~[1]
~~2. 4SLB stationary RICE~~	~~a. Reduce CO emissions by 93 percent or more; or~~	
	~~b. Limit concentration of formaldehyde in the stationary RICE exhaust to 14 ppmvd or less at 15 percent O_2~~	
~~3. CI stationary RICE~~	~~a. Reduce CO emissions by 70 percent or more; or~~	
	~~b. Limit concentration of formaldehyde in the stationary RICE exhaust to 580 ppbvd or less at 15 percent O_2~~	

[1] ~~Sources can petition the Administrator pursuant to the requirements of 40 CFR 63.6(g) for alternative work practices.~~

~~[75 FR 9680, Mar. 3, 2010]~~

~~Table 2~~ b ~~to Subpart ZZZZ of Part 63— Operating Limitations for New and Reconstructed 2SLB and Compression Ignition Stationary RICE >500 HP Located at a Major Source of HAP Emissions, New and Reconstructed 4SLB Stationary RICE ≥250 HP Located at a Major Source of HAP Emissions, Existing Compression Ignition Stationary RICE >500 HP, and Existing 4SLB Stationary RICE >500 HP Located at an Area Source of HAP Emissions~~

~~As stated in §§ 63.6600, 63.6601, 63.6603, 63.6630, and 63.6640, you must comply with the following operating limitations for new and reconstructed 2SLB and compression ignition stationary RICE located at a major source of HAP emissions; new and reconstructed 4SLB stationary RICE ≥250 HP located at a major source of HAP emissions; existing compression ignition stationary RICE >500 HP; and existing 4SLB stationary RICE >500 HP located at an area source of HAP emissions that operate more than 24 hours per calendar year:~~

~~For each . . .~~	~~You must meet the following operating limitation . . .~~
~~1. 2SLB and 4SLB stationary RICE and CI stationary RICE complying with the requirement to reduce CO emissions and using an oxidation catalyst; or 2SLB and 4SLB stationary~~	~~a. maintain your catalyst so that the pressure drop across the catalyst does not change by more than 2 inches of water at 100 percent load~~

~~**For each . . .**~~	~~**You must meet the following operating limitation . . .**~~
~~RICE and CI stationary RICE complying with the requirement to limit the concentration of formaldehyde in the stationary RICE exhaust and using an oxidation catalyst; or 4SLB stationary RICE and CI stationary RICE complying with the requirement to limit the concentration of CO in the stationary RICE exhaust and using an oxidation catalyst~~	~~plus or minus 10 percent from the pressure drop across the catalyst that was measured during the initial performance test; and~~ ~~b. maintain the temperature of your stationary RICE exhaust so that the catalyst inlet temperature is greater than or equal to 450 °F and less than or equal to 1350 °F.[1]~~
~~2. 2SLB and 4SLB stationary RICE and CI stationary RICE complying with the requirement to reduce CO emissions and not using an oxidation catalyst; or 2SLB and 4SLB stationary RICE and CI stationary RICE complying with the requirement to limit the concentration of formaldehyde in the stationary RICE exhaust and not using an oxidation catalyst; or 4SLB stationary RICE and CI stationary RICE complying with the requirement to limit the concentration of CO in the stationary RICE exhaust and not using an oxidation catalyst~~	~~Comply with any operating limitations approved by the Administrator.~~

~~[1] Sources can petition the Administrator pursuant to the requirements of 40 CFR 63.8(g) for a different temperature range.~~

~~[75 FR 51593, Aug. 20, 2010, as amended at 76 FR 12867, Mar. 9, 2011]~~

~~**Table 2**~~ **c** ~~**to Subpart ZZZZ of Part 63—Requirements for Existing Compression Ignition Stationary RICE Located at a Major Source of HAP Emissions and Existing Spark Ignition Stationary RICE ≤ 500 HP Located at a Major Source of HAP Emissions**~~

~~As stated in §§ 63.6600, 63.6602, and 63.6640, you must comply with the following requirements for existing compression ignition stationary RICE located at a major source of HAP emissions and existing spark ignition stationary RICE ≤ 500 HP located at a major source of HAP emissions:~~

~~**For each . . .**~~	~~**You must meet the following requirement, except during periods of startup . . .**~~	~~**During periods of startup you must . . .**~~
~~1. Emergency stationary CI RICE and black start stationary CI RICE.[1]~~	~~a. Change oil and filter every 500 hours of operation or annually, whichever comes first;[2]~~ ~~b. Inspect air cleaner every 1,000 hours of operation or annually, whichever comes first;~~ ~~c. Inspect all hoses and belts every 500 hours of operation or annually, whichever comes first, and replace as necessary.[3]~~	~~Minimize the engine's time spent at idle and minimize the engine's startup time at startup to a period needed for appropriate and safe loading of the engine, not to exceed 30 minutes, after which time the non-startup emission limitations apply.[3]~~
~~2. Non-Emergency, non-black start stationary CI RICE < 100 HP~~	~~a. Change oil and filter every 1,000 hours of operation or annually, whichever comes first;[2]~~	
	~~b. Inspect air cleaner every~~	

~~For each . . .~~	~~You must meet the following requirement, except during periods of startup . . .~~	~~During periods of startup you must . . .~~
	~~1,000 hours of operation or annually, whichever comes first;~~	
	~~c. Inspect all hoses and belts every 500 hours of operation or annually, whichever comes first, and replace as necessary.~~[3]	
~~3. Non-Emergency, non-black start CI stationary RICE 100 ≤ HP ≤ 300 HP~~	~~Limit concentration of CO in the stationary RICE exhaust to 230 ppmvd or less at 15 percent O_2~~	
~~4. Non-Emergency, non-black start CI stationary RICE 300 < HP ≤ 500~~	~~a. Limit concentration of CO in the stationary RICE exhaust to 49 ppmvd or less at 15 percent O_2; or~~	
	~~b. Reduce CO emissions by 70 percent or more.~~	
~~5. Non-Emergency, non-black start stationary CI RICE >500 HP~~	~~a. Limit concentration of CO in the stationary RICE exhaust to 23 ppmvd or less at 15 percent O_2; or~~	
	~~b. Reduce CO emissions by 70 percent or more.~~	
~~6. Emergency stationary SI RICE and black start stationary SI RICE.~~[1]	~~a. Change oil and filter every 500 hours of operation or annually, whichever comes first;~~[2]	
	~~b. Inspect spark plugs every 1,000 hours of operation or annually, whichever comes first;~~	
	~~c. Inspect all hoses and belts every 500 hours of operation or annually, whichever comes first, and replace as necessary.~~[3]	
~~7. Non-Emergency, non-black start stationary SI RICE < 100 HP that are not 2SLB stationary RICE~~	~~a. Change oil and filter every 1,440 hours of operation or annually, whichever comes first;~~[2]	
	~~b. Inspect spark plugs every 1,440 hours of operation or annually, whichever comes first;~~	
	~~c. Inspect all hoses and belts every 1,440 hours of operation or annually, whichever comes first, and replace as necessary.~~[3]	
~~8. Non-Emergency, non-black start 2SLB stationary~~	~~a. Change oil and filter every 4,320 hours of operation or~~	

~~**For each . . .**~~	~~**You must meet the following requirement, except during periods of startup . . .**~~	~~**During periods of startup you must . . .**~~
~~SI RICE < 100 HP~~	~~annually, whichever comes first;[2]~~	
	~~b. Inspect spark plugs every 4,320 hours of operation or annually, whichever comes first;~~	
	~~c. Inspect all hoses and belts every 4,320 hours of operation or annually, whichever comes first, and replace as necessary.~~[3]	
~~9. Non-emergency, non-black start 2SLB stationary RICE 100 ≤ HP ≤ 500~~	~~Limit concentration of CO in the stationary RICE exhaust to 225 ppmvd or less at 15 percent O_2~~	
~~10. Non-emergency, non-black start 4SLB stationary RICE 100 ≤ HP ≤ 500~~	~~Limit concentration of CO in the stationary RICE exhaust to 47 ppmvd or less at 15 percent O_2~~	
~~11. Non-emergency, non-black start 4SRB stationary RICE 100 ≤ HP ≤ 500~~	~~Limit concentration of formaldehyde in the stationary RICE exhaust to 10.3 ppmvd or less at 15 percent O_2~~	
~~12. Non-emergency, non-black start landfill or digester gas-fired stationary RICE 100 ≤ HP ≤ 500~~	~~Limit concentration of CO in the stationary RICE exhaust to 177 ppmvd or less at 15 percent O_2~~	

[1] ~~If an emergency engine is operating during an emergency and it is not possible to shut down the engine in order to perform the work practice requirements on the schedule required in Table 2c of this subpart, or if performing the work practice on the required schedule would otherwise pose an unacceptable risk under Federal, State, or local law, the work practice can be delayed until the emergency is over or the unacceptable risk under Federal, State, or local law has abated. The work practice should be performed as soon as practicable after the emergency has ended or the unacceptable risk under Federal, State, or local law has abated. Sources must report any failure to perform the work practice on the schedule required and the Federal, State or local law under which the risk was deemed unacceptable.~~

[2] ~~Sources have the option to utilize an oil analysis program as described in § 63.6625(i) in order to extend the specified oil change requirement in Table 2c of this subpart.~~

[3] ~~Sources can petition the Administrator pursuant to the requirements of 40 CFR 63.6(g) for alternative work practices.~~

~~[75 FR 51593, Aug. 20, 2010]~~

~~Table 2~~ d ~~to Subpart ZZZZ of Part 63—Requirements for Existing Stationary RICE Located at Area Sources of HAP Emissions~~

~~As stated in §§ 63.6603 and 63.6640, you must comply with the following requirements for existing stationary RICE located at area sources of HAP emissions:~~

~~**For each . . .**~~	~~**You must meet the following requirement, except during periods of startup . . .**~~	~~**During periods of startup you must . . .**~~
~~1. Non-Emergency, non-black start CI stationary RICE ≤ 300 HP~~	~~a. Change oil and filter every 1,000 hours of operation or annually, whichever comes first; [1]~~	~~Minimize the engine's time spent at idle and minimize the engine's startup time at startup to a period needed for appropriate and safe loading of the engine, not to exceed 30 minutes, after which time the non-startup emission limitations apply.~~
	~~b. Inspect air cleaner every 1,000 hours of operation or annually, whichever comes first;~~ ~~c. Inspect all hoses and belts every 500 hours of operation or annually, whichever comes first, and replace as necessary.~~	
~~2. Non-Emergency, non-black start CI stationary RICE 300 <HP≤ 500~~	~~a. Limit concentration of CO in the stationary RICE exhaust to 49 ppmvd at 15 percent O_2; or~~	
	~~b. Reduce CO emissions by 70 percent or more.~~	
~~3. Non-Emergency, non-black start CI stationary RICE > 500 HP~~	~~a. Limit concentration of CO in the stationary RICE exhaust to 23 ppmvd at 15 percent O_2; or~~	
	~~b. Reduce CO emissions by 70 percent or more.~~	
~~4. Emergency stationary CI RICE and black start stationary CI RICE.[2]~~	~~a. Change oil and filter every 500 hours of operation or annually, whichever comes first; [1]~~	
	~~b. Inspect air cleaner every 1,000 hours of operation or annually, whichever comes first; and~~	
	~~c. Inspect all hoses and belts every 500 hours of operation or annually, whichever comes first, and replace as necessary.~~	
~~5. Emergency stationary SI RICE; black start stationary SI RICE; non-emergency, non-black start 4SLB stationary RICE > 500 HP that operate 24 hours or less per calendar year; non-emergency, non-black start 4SRB~~	~~a. Change oil and filter every 500 hours of operation or annually, whichever comes first; [1]~~ ~~b. Inspect spark plugs~~	

~~**For each . . .**~~	~~**You must meet the following requirement, except during periods of startup . . .**~~	~~**During periods of startup you must . . .**~~
~~stationary RICE > 500 HP that operate 24 hours or less per calendar year.~~[2]	~~every 1,000 hours of operation or annually, whichever comes first; and~~ ~~c. Inspect all hoses and belts every 500 hours of operation or annually, whichever comes first, and replace as necessary.~~	
~~6. Non-emergency, non-black start 2SLB stationary RICE~~	~~a. Change oil and filter every 4,320 hours of operation or annually, whichever comes first;~~ [1]	
	~~b. Inspect spark plugs every 4,320 hours of operation or annually, whichever comes first; and~~	
	~~c. Inspect all hoses and belts every 4,320 hours of operation or annually, whichever comes first, and replace as necessary.~~	
~~7. Non-emergency, non-black start 4SLB stationary RICE ≤ 500 HP~~	~~a. Change oil and filter every 1,440 hours of operation or annually, whichever comes first;~~ [1]	
	~~b. Inspect spark plugs every 1,440 hours of operation or annually, whichever comes first; and~~	
	~~c. Inspect all hoses and belts every 1,440 hours of operation or annually, whichever comes first, and replace as necessary.~~	
~~8. Non-emergency, non-black start 4SLB stationary RICE > 500 HP~~	~~a. Limit concentration of CO in the stationary RICE exhaust to 47 ppmvd at 15 percent O_2; or~~	
	~~b. Reduce CO emissions by 93 percent or more.~~	
~~9. Non-emergency, non-black start 4SRB stationary RICE ≤ 500 HP~~	~~a. Change oil and filter every 1,440 hours of operation or annually, whichever comes first;~~ [1]	
	~~b. Inspect spark plugs~~	

~~**For each . . .**~~	~~**You must meet the following requirement, except during periods of startup . . .**~~	~~**During periods of startup you must . . .**~~
	~~every 1,440 hours of operation or annually, whichever comes first; and~~	
	~~c. Inspect all hoses and belts every 1,440 hours of operation or annually, whichever comes first, and replace as necessary.~~	
~~10. Non-emergency, non-black start 4SRB stationary RICE > 500 HP~~	~~a. Limit concentration of formaldehyde in the stationary RICE exhaust to 2.7 ppmvd at 15 percent O_2; or~~	
	~~b. Reduce formaldehyde emissions by 76 percent or more.~~	
~~11. Non-emergency, non-black start landfill or digester gas-fired stationary RICE~~	~~a. Change oil and filter every 1,440 hours of operation or annually, whichever comes first; [1]~~	
	~~b. Inspect spark plugs every 1,440 hours of operation or annually, whichever comes first; and~~	
	~~c. Inspect all hoses and belts every 1,440 hours of operation or annually, whichever comes first, and replace as necessary.~~	

~~[1] Sources have the option to utilize an oil analysis program as described in § 63.6625(i) in order to extend the specified oil change requirement in Table 2d of this subpart.~~

~~[2] If an emergency engine is operating during an emergency and it is not possible to shut down the engine in order to perform the management practice requirements on the schedule required in Table 2d of this subpart, or if performing the management practice on the required schedule would otherwise pose an unacceptable risk under Federal, State, or local law, the management practice can be delayed until the emergency is over or the unacceptable risk under Federal, State, or local law has abated. The management practice should be performed as soon as practicable after the emergency has ended or the unacceptable risk under Federal, State, or local law has abated. Sources must report any failure to perform the management practice on the schedule required and the Federal, State or local law under which the risk was deemed unacceptable.~~

~~[75 FR 51595, Aug. 20, 2010]~~

~~Table 3 to Subpart ZZZZ of Part 63—Subsequent Performance Tests~~

~~As stated in §§ 63.6615 and 63.6620, you must comply with the following subsequent performance test requirements:~~

~~**For each . . .**~~	~~**Complying with the requirement to . . .**~~	~~**You must . . .**~~
~~1. New or reconstructed 2SLB stationary RICE with a brake horsepower > 500 located at major sources; new or reconstructed 4SLB stationary RICE with a brake horsepower ≥ 250 located at major sources; and new or reconstructed CI stationary RICE with a brake horsepower > 500 located at major sources~~	~~Reduce CO emissions and not using a CEMS~~	~~Conduct subsequent performance tests semiannually.~~[1]
~~2. 4SRB stationary RICE with a brake horsepower ≥ 5,000 located at major sources~~	~~Reduce formaldehyde emissions~~	~~Conduct subsequent performance tests semiannually.~~[1]
~~3. Stationary RICE with a brake horsepower > 500 located at major sources and new or reconstructed 4SLB stationary RICE with a brake horsepower 250 ≤ HP ≤ 500 located at major sources~~	~~Limit the concentration of formaldehyde in the stationary RICE exhaust~~	~~Conduct subsequent performance tests semiannually.~~[1]
~~4. Existing non-emergency, non-black start CI stationary RICE with a brake horsepower > 500 that are not limited use stationary RICE; existing non-emergency, non-black start 4SLB and 4SRB stationary RICE located at an area source of HAP emissions with a brake horsepower > 500 that are operated more than 24 hours per calendar year that are not limited use stationary RICE~~	~~Limit or reduce CO or formaldehyde emissions~~	~~Conduct subsequent performance tests every 8,760 hrs. or 3 years, whichever comes first.~~
~~5. Existing non-emergency, non-black start CI stationary RICE with a brake horsepower > 500 that are limited use stationary RICE; existing non-emergency, non-black start 4SLB and 4SRB stationary RICE located at an area source of HAP emissions with a brake horsepower > 500 that are operated more than 24 hours per calendar year and are limited use stationary RICE~~	~~Limit or reduce CO or formaldehyde emissions~~	~~Conduct subsequent performance tests every 8,760 hrs. or 5 years, whichever comes first.~~

[1] ~~After you have demonstrated compliance for two consecutive tests, you may reduce the frequency of subsequent performance tests to annually. If the results of any subsequent annual performance test indicate the stationary RICE is not in compliance with the CO or formaldehyde emission limitation, or you deviate from any of your operating limitations, you must resume semiannual performance tests.~~

~~[75 FR 51596, Aug. 20, 2010]~~

~~Table 4 to Subpart ZZZZ of Part 63—Requirements for Performance Tests~~

~~As stated in §§ 63.6610, 63.6611, 63.6612, 63.6620, and 63.6640, you must comply with the following requirements for performance tests for stationary RICE:~~

~~For each . . .~~	~~Complying with the requirement to . . .~~	~~You must . . .~~	~~Using . . .~~	~~According to the following requirements . . .~~
~~1. 2SLB, 4SLB, and CI stationary RICE~~	~~a. Reduce CO emissions~~	~~i. Measure the O_2 at the inlet and outlet of the control device; and~~	~~(1) Portable CO and O_2 analyzer~~	~~(a) Using ASTM D6522-00 (2005)~~ [a] ~~(incorporated by reference, see § 63.14). Measurements to determine O_2 must be made at the same time as the measurements for CO concentration.~~
		~~ii. Measure the CO at the inlet and the outlet of the control device~~	~~(1) Portable CO and O_2 analyzer~~	~~(a) Using ASTM D6522-00 (2005)~~ [a][b] ~~(incorporated by reference, see § 63.14) or Method 10 of 40 CFR appendix A. The CO concentration must be at 15 percent O_2, dry basis.~~
~~2. 4SRB stationary RICE~~	~~a. Reduce formaldehyde emissions~~	~~i. Select the sampling port location and the number of traverse points; and~~	~~(1) Method 1 or 1A of 40 CFR part 60, appendix A § 63.7(d)(1)(i)~~	~~(a) Sampling sites must be located at the inlet and outlet of the control device.~~
		~~ii. Measure O_2 at the inlet and outlet of the control device; and~~	~~(1) Method 3 or 3A or 3B of 40 CFR part 60, appendix A, or ASTM Method D6522-00m (2005)~~	~~(a) Measurements to determine O_2 concentration must be made at the same time as the measurements for formaldehyde concentration.~~
		~~iii. Measure moisture content at the inlet and outlet of the control device; and~~	~~(1) Method 4 of 40 CFR part 60, appendix A, or Test Method 320 of 40 CFR part 63, appendix A, or ASTM D 6348-03~~	~~(a) Measurements to determine moisture content must be made at the same time and location as the measurements for formaldehyde concentration.~~
		~~iv. Measure formaldehyde at the inlet and the outlet of the control device~~	~~(1) Method 320 or 323 of 40 CFR part 63, appendix A; or ASTM D6348-03,~~ [c] ~~provided in ASTM D6348-03 Annex A5 (Analyte Spiking Technique), the percent R must be greater than or equal to 70 and less than or equal to 130~~	~~(a) Formaldehyde concentration must be at 15 percent O_2, dry basis. Results of this test consist of the average of the three 1-hour or longer runs.~~
~~3. Stationary RICE~~	~~a. Limit the concentration of formaldehyde or~~	~~i. Select the sampling port location and the number of traverse~~	~~(1) Method 1 or 1A of 40 CFR part 60, appendix A § 63.7(d)(1)(i)~~	~~(a) If using a control device, the sampling site must be located at the outlet of the~~

~~**For each . . .**~~	~~**Complying with the requirement to . . .**~~	~~**You must . . .**~~	~~**Using . . .**~~	~~**According to the following requirements . . .**~~
	~~CO in the stationary RICE exhaust~~	~~points; and~~		~~control device.~~
		~~ii. Determine the O_2concentration of the stationary RICE exhaust at the sampling port location; and~~	~~(1) Method 3 or 3A or 3B of 40 CFR part 60, appendix A, or ASTM Method D6522-00 (2005)~~	~~(a) Measurements to determine O_2concentration must be made at the same time and location as the measurements for formaldehyde concentration.~~
		~~iii. Measure moisture content of the stationary RICE exhaust at the sampling port location; and~~	~~(1) Method 4 of 40 CFR part 60, appendix A, or Test Method 320 of 40 CFR part 63, appendix A, or ASTM D 6348-03~~	~~(a) Measurements to determine moisture content must be made at the same time and location as the measurements for formaldehyde concentration.~~
		~~iv. Measure formaldehyde at the exhaust of the stationary RICE; or~~	~~(1) Method 320 or 323 of 40 CFR part 63, appendix A; or ASTM D6348-03,~~[c]~~provided in ASTM D6348-03 Annex A5 (Analyte Spiking Technique), the percent R must be greater than or equal to 70 and less than or equal to 130~~	~~(a) Formaldehyde concentration must be at 15 percent O_2, dry basis. Results of this test consist of the average of the three 1-hour or longer runs.~~
		~~v. Measure CO at the exhaust of the stationary RICE~~	~~(1) Method 10 of 40 CFR part 60, appendix A, ASTM Method D6522-00 (2005),~~[a]~~Method 320 of 40 CFR part 63, appendix A, or ASTM D6348-03~~	~~(a) CO Concentration must be at 15 percent O_2, dry basis. Results of this test consist of the average of the three 1-hour longer runs.~~

[a] ~~You may also use Methods 3A and 10 as options to ASTM-D6522-00 (2005). You may obtain a copy of ASTM-D6522-00 (2005) from at least one of the following addresses: American Society for Testing and Materials, 100 Barr Harbor Drive, West Conshohocken, PA 19428-2959, or University Microfilms International, 300 North Zeeb Road, Ann Arbor, MI 48106. ASTM-D6522-00 (2005) may be used to test both CI and SI stationary RICE.~~

[b] ~~You may also use Method 320 of 40 CFR part 63, appendix A, or ASTM D6348-03.~~

[c] ~~You may obtain a copy of ASTM-D6348-03 from at least one of the following addresses: American Society for Testing and Materials, 100 Barr Harbor Drive, West Conshohocken, PA 19428-2959, or University Microfilms International, 300 North Zeeb Road, Ann Arbor, MI 48106.~~

~~[75 FR 51597, Aug. 20, 2010]~~

~~Table 5 to Subpart ZZZZ of Part 63—Initial Compliance With Emission Limitations and Operating Limitations~~

~~As stated in §§ 63.6612, 63.6625 and 63.6630, you must initially comply with the emission and operating limitations as required by the following:~~

~~For each . . .~~	~~Complying with the requirement to . . .~~	~~You have demonstrated initial compliance if . . .~~
~~1. New or reconstructed non-emergency 2SLB stationary RICE >500 HP located at a major source of HAP, new or reconstructed non-emergency 4SLB stationary RICE ≥250 HP located at a major source of HAP, non-emergency stationary CI RICE >500 HP located at a major source of HAP, existing non-emergency stationary CI RICE >500 HP located at an area source of HAP, and existing non-emergency 4SLB stationary RICE >500 HP located at an area source of HAP that are operated more than 24 hours per calendar year~~	~~a. Reduce CO emissions and using oxidation catalyst, and using a CPMS~~	~~i. The average reduction of emissions of CO determined from the initial performance test achieves the required CO percent reduction; and~~ ~~ii. You have installed a CPMS to continuously monitor catalyst inlet temperature according to the requirements in § 63.6625(b); and~~ ~~iii. You have recorded the catalyst pressure drop and catalyst inlet temperature during the initial performance test.~~
~~2. Non-emergency stationary CI RICE >500 HP located at a major source of HAP, existing non-emergency stationary CI RICE >500 HP located at an area source of HAP, and existing non-emergency 4SLB stationary RICE >500 HP located at an area source of HAP that are operated more than 24 hours per calendar year~~	~~a. Limit the concentration of CO, using oxidation catalyst, and using a CPMS~~	~~i. The average CO concentration determined from the initial performance test is less than or equal to the CO emission limitation; and~~ ~~ii. You have installed a CPMS to continuously monitor catalyst inlet temperature according to the requirements in § 63.6625(b); and~~ ~~iii. You have recorded the catalyst pressure drop and catalyst inlet temperature during the initial performance test.~~
~~3. New or reconstructed non-emergency 2SLB stationary RICE >500 HP located at a major source of HAP, new or reconstructed non-emergency 4SLB stationary RICE ≥250 HP located at a major source of HAP, non-emergency stationary CI RICE >500 HP located at a major source of HAP, existing non-emergency stationary CI RICE >500 HP located at an area source of HAP, and existing non-emergency 4SLB stationary RICE >500 HP located at an area source of HAP that are operated more than 24 hours per calendar year~~	~~a. Reduce CO emissions and not using oxidation catalyst~~	~~i. The average reduction of emissions of CO determined from the initial performance test achieves the required CO percent reduction; and~~ ~~ii. You have installed a CPMS to continuously monitor operating parameters approved by the Administrator (if any) according to the requirements in § 63.6625(b); and~~ ~~iii. You have recorded the approved operating parameters (if any) during the initial performance test.~~
~~4. Non-emergency stationary CI RICE >500 HP located at a major source of HAP, existing non-emergency stationary CI RICE >500 HP located at an area source of HAP, and existing non-emergency 4SLB stationary RICE >500 HP located at an area source of HAP that are operated more than 24 hours per calendar~~	~~a. Limit the concentration of CO, and not using oxidation catalyst~~	~~i. The average CO concentration determined from the initial performance test is less than or equal to the CO emission limitation; and~~ ~~ii. You have installed a CPMS to continuously monitor operating parameters approved by the~~

~~For each . . .~~	~~Complying with the requirement to . . .~~	~~You have demonstrated initial compliance if . . .~~
~~year~~		~~Administrator (if any) according to the requirements in § 63.6625(b); and~~ ~~iii. You have recorded the approved operating parameters (if any) during the initial performance test.~~
~~5. New or reconstructed non-emergency 2SLB stationary RICE >500 HP located at a major source of HAP, new or reconstructed non-emergency 4SLB stationary RICE ≥250 HP located at a major source of HAP, non-emergency stationary CI RICE >500 HP located at a major source of HAP, existing non-emergency stationary CI RICE >500 HP located at an area source of HAP, and existing non-emergency 4SLB stationary RICE >500 HP located at an area source of HAP that are operated more than 24 hours per calendar year~~	~~a. Reduce CO emissions, and using a CEMS~~	~~i. You have installed a CEMS to continuously monitor CO and either O_2or CO_2at both the inlet and outlet of the oxidation catalyst according to the requirements in § 63.6625(a); and~~ ~~ii. You have conducted a performance evaluation of your CEMS using PS 3 and 4A of 40 CFR part 60, appendix B; and~~ ~~iii. The average reduction of CO calculated using § 63.6620 equals or exceeds the required percent reduction. The initial test comprises the first 4-hour period after successful validation of the CEMS. Compliance is based on the average percent reduction achieved during the 4-hour period.~~
~~6. Non-emergency stationary CI RICE >500 HP located at a major source of HAP, existing non-emergency stationary CI RICE >500 HP located at an area source of HAP, and existing non-emergency 4SLB stationary RICE >500 HP located at an area source of HAP that are operated more than 24 hours per calendar year~~	~~a. Limit the concentration of CO, and using a CEMS~~	~~i. You have installed a CEMS to continuously monitor CO and either O_2or CO_2at the outlet of the oxidation catalyst according to the requirements in § 63.6625(a); and~~ ~~ii. You have conducted a performance evaluation of your CEMS using PS 3 and 4A of 40 CFR part 60, appendix B; and~~
		~~iii. The average concentration of CO calculated using § 63.6620 is less than or equal to the CO emission limitation. The initial test comprises the first 4-hour period after successful validation of the CEMS. Compliance is based on the average concentration measured during the 4-hour period.~~
~~7. Non-emergency 4SRB stationary RICE >500 HP located at a major source of HAP, and existing non-emergency 4SRB stationary RICE >500 HP located at an area source of HAP that are operated more than 24 hours per calendar year~~	~~a. Reduce formaldehyde emissions and using NSCR~~	~~i. The average reduction of emissions of formaldehyde determined from the initial performance test is equal to or greater than the required formaldehyde percent reduction; and~~ ~~ii. You have installed a CPMS to continuously monitor catalyst inlet temperature according to the requirements in § 63.6625(b); and~~
		~~iii. You have recorded the catalyst pressure drop and catalyst inlet temperature during the initial performance test.~~

~~**For each . . .**~~	~~**Complying with the requirement to . . .**~~	~~**You have demonstrated initial compliance if . . .**~~
~~8. Non-emergency 4SRB stationary RICE >500 HP located at a major source of HAP, and existing non-emergency 4SRB stationary RICE >500 HP located at an area source of HAP that are operated more than 24 hours per calendar year~~	~~a. Reduce formaldehyde emissions and not using NSCR~~	~~i. The average reduction of emissions of formaldehyde determined from the initial performance test is equal to or greater than the required formaldehyde percent reduction; and~~ ~~ii. You have installed a CPMS to continuously monitor operating parameters approved by the Administrator (if any) according to the requirements in § 63.6625(b); and~~
		~~iii. You have recorded the approved operating parameters (if any) during the initial performance test.~~
~~9. Existing non-emergency 4SRB stationary RICE >500 HP located at an area source of HAP that are operated more than 24 hours per calendar year~~	~~a. Limit the concentration of formaldehyde and not using NSCR~~	~~i. The average formaldehyde concentration determined from the initial performance test is less than or equal to the formaldehyde emission limitation; and~~
		~~ii. You have installed a CPMS to continuously monitor operating parameters approved by the Administrator (if any) according to the requirements in § 63.6625(b); and~~
		~~iii. You have recorded the approved operating parameters (if any) during the initial performance test.~~
~~10. New or reconstructed non-emergency stationary RICE >500 HP located at a major source of HAP, new or reconstructed non-emergency 4SLB stationary RICE 250≤HP≤500 located at a major source of HAP, and existing non-emergency 4SRB stationary RICE >500 HP~~	~~a. Limit the concentration of formaldehyde in the stationary RICE exhaust and using oxidation catalyst or NSCR~~	~~i. The average formaldehyde concentration, corrected to 15 percent O_2, dry basis, from the three test runs is less than or equal to the formaldehyde emission limitation; and~~ ~~ii. You have installed a CPMS to continuously monitor catalyst inlet temperature according to the requirements in § 63.6625(b); and~~
		~~iii. You have recorded the catalyst pressure drop and catalyst inlet temperature during the initial performance test.~~
~~11. New or reconstructed non-emergency stationary RICE >500 HP located at a major source of HAP, new or reconstructed non-emergency 4SLB stationary RICE 250≤HP≤500 located at a major source of HAP, and existing non-emergency 4SRB stationary RICE >500 HP~~	~~a. Limit the concentration of formaldehyde in the stationary RICE exhaust and not using oxidation catalyst or NSCR~~	~~i. The average formaldehyde concentration, corrected to 15 percent O_2, dry basis, from the three test runs is less than or equal to the formaldehyde emission limitation; and~~ ~~ii. You have installed a CPMS to continuously monitor operating parameters approved by the Administrator (if any) according to the requirements in § 63.6625(b); and~~

~~**For each . . .**~~	~~**Complying with the requirement to . . .**~~	~~**You have demonstrated initial compliance if . . .**~~
		~~iii. You have recorded the approved operating parameters (if any) during the initial performance test.~~
~~12. Existing non-emergency stationary RICE 100≤HP≤500 located at a major source of HAP, and existing non-emergency stationary CI RICE 300<HP≤500 located at an area source of HAP~~	~~a. Reduce CO or formaldehyde emissions~~	~~i. The average reduction of emissions of CO or formaldehyde, as applicable determined from the initial performance test is equal to or greater than the required CO or formaldehyde, as applicable, percent reduction.~~
~~13. Existing non-emergency stationary RICE 100≤HP≤500 located at a major source of HAP, and existing non-emergency stationary CI RICE 300<HP≤500 located at an area source of HAP~~	~~a. Limit the concentration of formaldehyde or CO in the stationary RICE exhaust~~	~~i. The average formaldehyde or CO concentration, as applicable, corrected to 15 percent O_2, dry basis, from the three test runs is less than or equal to the formaldehyde or CO emission limitation, as applicable.~~

~~[76 FR 12867, Mar. 9, 2011]~~

~~Table 6 to Subpart ZZZZ of Part 63—Continuous Compliance With Emission Limitations, Operating Limitations, Work Practices, and Management Practices~~

~~As stated in § 63.6640, you must continuously comply with the emissions and operating limitations and work or management practices as required by the following:~~

~~**For each . . .**~~	~~**Complying with the requirement to . . .**~~	~~**You must demonstrate continuous compliance by . . .**~~
~~1. New or reconstructed non-emergency 2SLB stationary RICE >500 HP located at a major source of HAP, new or reconstructed non-emergency 4SLB stationary RICE ≥250 HP located at a major source of HAP, and new or reconstructed non-emergency CI stationary RICE >500 HP located at a major source of HAP~~	~~a. Reduce CO emissions and using an oxidation catalyst, and using a CPMS~~	~~i. Conducting semiannual performance tests for CO to demonstrate that the required CO percent reduction is achieved;~~ [a] ~~and~~ ~~ii. Collecting the catalyst inlet temperature data according to § 63.6625(b); and~~ ~~iii. Reducing these data to 4-hour rolling averages; and~~ ~~iv. Maintaining the 4-hour rolling averages within the operating limitations for the catalyst inlet temperature; and~~
		~~v. Measuring the pressure drop across the catalyst once per month and demonstrating that the pressure drop across the catalyst is within the operating limitation established during the performance test.~~
~~2. New or reconstructed non-emergency 2SLB stationary RICE >500 HP located at a major source of HAP, new or reconstructed non-emergency 4SLB stationary RICE ≥250 HP located at a~~	~~a. Reduce CO emissions and not using an oxidation catalyst, and using a CPMS~~	~~i. Conducting semiannual performance tests for CO to demonstrate that the required CO percent reduction is achieved;~~ [a] ~~and~~ ~~ii. Collecting the approved operating~~

~~For each . . .~~	~~Complying with the requirement to . . .~~	~~You must demonstrate continuous compliance by . . .~~
~~major source of HAP, and new or reconstructed non-emergency CI stationary RICE >500 HP located at a major source of HAP~~		~~parameter (if any) data according to § 63.6625(b); and~~ ~~iii. Reducing these data to 4-hour rolling averages; and~~
		~~iv. Maintaining the 4-hour rolling averages within the operating limitations for the operating parameters established during the performance test.~~
~~3. New or reconstructed non-emergency 2SLB stationary RICE >500 HP located at a major source of HAP, new or reconstructed non-emergency 4SLB stationary RICE ≥250 HP located at a major source of HAP, new or reconstructed non-emergency stationary CI RICE >500 HP located at a major source of HAP, existing non-emergency stationary CI RICE >500 HP, existing non-emergency 4SLB stationary RICE >500 HP located at an area source of HAP that are operated more than 24 hours per calendar year~~	~~a. Reduce CO emissions or limit the concentration of CO in the stationary RICE exhaust, and using a CEMS~~	~~i. Collecting the monitoring data according to § 63.6625(a), reducing the measurements to 1-hour averages, calculating the percent reduction or concentration of CO emissions according to § 63.6620; and~~ ~~ii. Demonstrating that the catalyst achieves the required percent reduction of CO emissions over the 4-hour averaging period, or that the emission remain at or below the CO concentration limit; and~~ ~~iii. Conducting an annual RATA of your CEMS using PS 3 and 4A of 40 CFR part 60, appendix B, as well as daily and periodic data quality checks in accordance with 40 CFR part 60, appendix F, procedure 1.~~
~~4. Non-emergency 4SRB stationary RICE >500 HP located at a major source of HAP~~	~~a. Reduce formaldehyde emissions and using NSCR~~	~~i. Collecting the catalyst inlet temperature data according to § 63.6625(b); and~~
		~~ii. Reducing these data to 4-hour rolling averages; and~~
		~~iii. Maintaining the 4-hour rolling averages within the operating limitations for the catalyst inlet temperature; and~~
		~~iv. Measuring the pressure drop across the catalyst once per month and demonstrating that the pressure drop across the catalyst is within the operating limitation established during the performance test.~~
~~5. Non-emergency 4SRB stationary RICE >500 HP located at a major source of HAP~~	~~a. Reduce formaldehyde emissions and not using NSCR~~	~~i. Collecting the approved operating parameter (if any) data according to § 63.6625(b); and~~ ~~ii. Reducing these data to 4-hour rolling averages; and~~
		~~iii. Maintaining the 4-hour rolling averages within the operating limitations for the operating parameters established during the performance test.~~

~~**For each . . .**~~	~~**Complying with the requirement to . . .**~~	~~**You must demonstrate continuous compliance by . . .**~~
~~6. Non-emergency 4SRB stationary RICE with a brake HP ≥5,000 located at a major source of HAP~~	~~a. Reduce formaldehyde emissions~~	~~Conducting semiannual performance tests for formaldehyde to demonstrate that the required formaldehyde percent reduction is achieved.~~[a]
~~7. New or reconstructed non-emergency stationary RICE >500 HP located at a major source of HAP and new or reconstructed non-emergency 4SLB stationary RICE 250 ≤HP≤500 located at a major source of HAP~~	~~a. Limit the concentration of formaldehyde in the stationary RICE exhaust and using oxidation catalyst or NSCR~~	~~i. Conducting semiannual performance tests for formaldehyde to demonstrate that your emissions remain at or below the formaldehyde concentration limit;~~ [a]~~and~~ ~~ii. Collecting the catalyst inlet temperature data according to § 63.6625(b); and~~
		~~iii. Reducing these data to 4-hour rolling averages; and~~
		~~iv. Maintaining the 4-hour rolling averages within the operating limitations for the catalyst inlet temperature; and~~
		~~v. Measuring the pressure drop across the catalyst once per month and demonstrating that the pressure drop across the catalyst is within the operating limitation established during the performance test.~~
~~8. New or reconstructed non-emergency stationary RICE >500 HP located at a major source of HAP and new or reconstructed non-emergency 4SLB stationary RICE 250 ≤HP≤500 located at a major source of HAP~~	~~a. Limit the concentration of formaldehyde in the stationary RICE exhaust and not using oxidation catalyst or NSCR~~	~~i. Conducting semiannual performance tests for formaldehyde to demonstrate that your emissions remain at or below the formaldehyde concentration limit;~~ [a]~~and~~ ~~ii. Collecting the approved operating parameter (if any) data according to § 63.6625(b); and~~
		~~iii. Reducing these data to 4-hour rolling averages; and~~
		~~iv. Maintaining the 4-hour rolling averages within the operating limitations for the operating parameters established during the performance test.~~
~~9. Existing emergency and black start stationary RICE ≤500 HP located at a major source of HAP, existing non-emergency stationary RICE <100 HP located at a major source of HAP, existing emergency and black start stationary RICE located at an area source of HAP, existing non-emergency stationary CI RICE ≤300 HP located at an area source of HAP, existing non-emergency 2SLB stationary RICE located at an area source of HAP, existing non-emergency landfill or digester~~	~~a. Work or Management practices~~	~~i. Operating and maintaining the stationary RICE according to the manufacturer's emission-related operation and maintenance instructions; or~~ ~~ii. Develop and follow your own maintenance plan which must provide to the extent practicable for the maintenance and operation of the engine in a manner consistent with good air pollution control practice for minimizing emissions.~~

~~**For each . . .**~~	~~**Complying with the requirement to . . .**~~	~~**You must demonstrate continuous compliance by . . .**~~
~~gas stationary SI RICE located at an area source of HAP, existing non-emergency 4SLB and 4SRB stationary RICE ≤500 HP located at an area source of HAP, existing non-emergency 4SLB and 4SRB stationary RICE >500 HP located at an area source of HAP that operate 24 hours or less per calendar year~~		
~~10. Existing stationary CI RICE >500 HP that are not limited use stationary RICE, and existing 4SLB and 4SRB stationary RICE >500 HP located at an area source of HAP that operate more than 24 hours per calendar year and are not limited use stationary RICE~~	~~a. Reduce CO or formaldehyde emissions, or limit the concentration of formaldehyde or CO in the stationary RICE exhaust, and using oxidation catalyst or NSCR~~	~~i. Conducting performance tests every 8,760 hours or 3 years, whichever comes first, for CO or formaldehyde, as appropriate, to demonstrate that the required CO or formaldehyde, as appropriate, percent reduction is achieved or that your emissions remain at or below the CO or formaldehyde concentration limit; and~~
		~~ii. Collecting the catalyst inlet temperature data according to § 63.6625(b); and~~
		~~iii. Reducing these data to 4-hour rolling averages; and~~
		~~iv. Maintaining the 4-hour rolling averages within the operating limitations for the catalyst inlet temperature; and~~
		~~v. Measuring the pressure drop across the catalyst once per month and demonstrating that the pressure drop across the catalyst is within the operating limitation established during the performance test.~~
~~11. Existing stationary CI RICE >500 HP that are not limited use stationary RICE, and existing 4SLB and 4SRB stationary RICE >500 HP located at an area source of HAP that operate more than 24 hours per calendar year and are not limited use stationary RICE~~	~~a. Reduce CO or formaldehyde emissions, or limit the concentration of formaldehyde or CO in the stationary RICE exhaust, and not using oxidation catalyst or NSCR~~	~~i. Conducting performance tests every 8,760 hours or 3 years, whichever comes first, for CO or formaldehyde, as appropriate, to demonstrate that the required CO or formaldehyde, as appropriate, percent reduction is achieved or that your emissions remain at or below the CO or formaldehyde concentration limit; and~~
		~~ii. Collecting the approved operating parameter (if any) data according to § 63.6625(b); and~~
		~~iii. Reducing these data to 4-hour rolling averages; and~~
		~~iv. Maintaining the 4-hour rolling averages within the operating limitations for the operating parameters established~~

~~**For each . . .**~~	~~**Complying with the requirement to . . .**~~	~~**You must demonstrate continuous compliance by . . .**~~
		~~during the performance test.~~
~~12. Existing limited use CI stationary RICE >500 HP and existing limited use 4SLB and 4SRB stationary RICE >500 HP located at an area source of HAP that operate more than 24 hours per calendar year~~	~~a. Reduce CO or formaldehyde emissions or limit the concentration of formaldehyde or CO in the stationary RICE exhaust, and using an oxidation catalyst or NSCR~~	~~i. Conducting performance tests every 8,760 hours or 5 years, whichever comes first, for CO or formaldehyde, as appropriate, to demonstrate that the required CO or formaldehyde, as appropriate, percent reduction is achieved or that your emissions remain at or below the CO or formaldehyde concentration limit; and~~
		~~ii. Collecting the catalyst inlet temperature data according to § 63.6625(b); and~~
		~~iii. Reducing these data to 4-hour rolling averages; and~~
		~~iv. Maintaining the 4-hour rolling averages within the operating limitations for the catalyst inlet temperature; and~~
		~~v. Measuring the pressure drop across the catalyst once per month and demonstrating that the pressure drop across the catalyst is within the operating limitation established during the performance test.~~
~~13. Existing limited use CI stationary RICE >500 HP and existing limited use 4SLB and 4SRB stationary RICE >500 HP located at an area source of HAP that operate more than 24 hours per calendar year~~	~~a. Reduce CO or formaldehyde emissions or limit the concentration of formaldehyde or CO in the stationary RICE exhaust, and not using an oxidation catalyst or NSCR~~	~~i. Conducting performance tests every 8,760 hours or 5 years, whichever comes first, for CO or formaldehyde, as appropriate, to demonstrate that the required CO or formaldehyde, as appropriate, percent reduction is achieved or that your emissions remain at or below the CO or formaldehyde concentration limit; and~~
		~~ii. Collecting the approved operating parameter (if any) data according to § 63.6625(b); and~~
		~~iii. Reducing these data to 4-hour rolling averages; and~~
		~~iv. Maintaining the 4-hour rolling averages within the operating limitations for the operating parameters established during the performance test.~~

[a] ~~After you have demonstrated compliance for two consecutive tests, you may reduce the frequency of subsequent performance tests to annually. If the results of any subsequent annual performance test indicate the stationary RICE is not in compliance with the CO or formaldehyde emission limitation, or you deviate from any of your operating limitations, you must resume semiannual performance tests.~~

~~[76 FR 12870, Mar. 9, 2011]~~

~~Table 7 to Subpart ZZZZ of Part 63—Requirements for Reports~~

~~As stated in § 63.6650, you must comply with the following requirements for reports:~~

~~For each ...~~	~~You must submit a ...~~	~~The report must contain ...~~	~~You must submit the report ...~~
~~1. Existing non-emergency, non-black start stationary RICE 100 ≤ HP ≤ 500 located at a major source of HAP; existing non-emergency, non-black start stationary CI RICE > 500 HP located at a major source of HAP; existing non-emergency 4SRB stationary RICE > 500 HP located at a major source of HAP; existing non-emergency, non-black start stationary CI RICE > 300 HP located at an area source of HAP; existing non-emergency, non-black start 4SLB and 4SRB stationary RICE > 500 HP located at an area source of HAP and operated more than 24 hours per calendar year; new or reconstructed non-emergency stationary RICE > 500 HP located at a major source of HAP; and new or reconstructed non-emergency 4SLB stationary RICE 250 ≤ HP ≤ 500 located at a major source of HAP~~	~~Compliance report~~	~~a. If there are no deviations from any emission limitations or operating limitations that apply to you, a statement that there were no deviations from the emission limitations or operating limitations during the reporting period. If there were no periods during which the CMS, including CEMS and CPMS, was out-of-control, as specified in § 63.8(c)(7), a statement that there were not periods during which the CMS was out-of-control during the reporting period; or~~ ~~b. If you had a deviation from any emission limitation or operating limitation during the reporting period, the information in § 63.6650(d). If there were periods during which the CMS, including CEMS and CPMS, was out-of-control, as specified in § 63.8(c)(7), the information in § 63.6650(e); or~~ ~~c. If you had a malfunction during the reporting period, the information in § 63.6650(c)(4)~~ ~~i. Semiannually according to the requirements in § 63.6650(b)(1)-(5) for engines that are not limited use stationary RICE subject to numerical emission limitations; and~~ ~~ii. Annually according to the requirements in § 63.6650(b)(6)-(9) for engines that are limited use stationary RICE subject to numerical emission limitations.~~ ~~i. Semiannually according to the requirements in § 63.6650(b).~~ ~~i. Semiannually according to the requirements in § 63.6650(b).~~	
~~2. New or reconstructed non-emergency stationary RICE that combusts landfill gas or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis~~	~~Report~~	~~a. The fuel flow rate of each fuel and the heating values that were used in your calculations, and you must demonstrate that the percentage of heat input provided by landfill gas or digester gas, is equivalent to 10 percent or more of the gross heat input on an annual basis; and~~ ~~i. Annually, according to the requirements in~~	

~~For each ...~~	~~You must submit a ...~~	~~The report must contain ...~~	~~You must submit the report ...~~
		~~§ 63.6650.~~	
		~~b. The operating limits provided in your federally enforceable permit, and any deviations from these limits; and~~ ~~i. See item 2.a.i.~~	
		~~c. Any problems or errors suspected with the meters.~~ ~~i. See item 2.a.i.~~	

~~[75 FR 51603, Aug. 20, 2010]~~

~~Table 8 to Subpart ZZZZ of Part 63—Applicability of General Provisions to Subpart ZZZZ.~~

~~As stated in § 63.6665, you must comply with the following applicable general provisions.~~

~~General provisions citation~~	~~Subject of citation~~	~~Applies to subpart~~	~~Explanation~~
~~§ 63.1~~	~~General applicability of the General Provisions~~	~~Yes.~~	
~~§ 63.2~~	~~Definitions~~	~~Yes~~	~~Additional terms defined in § 63.6675.~~
~~§ 63.3~~	~~Units and abbreviations~~	~~Yes.~~	
~~§ 63.4~~	~~Prohibited activities and circumvention~~	~~Yes.~~	
~~§ 63.5~~	~~Construction and reconstruction~~	~~Yes.~~	
~~§ 63.6(a)~~	~~Applicability~~	~~Yes.~~	
~~§ 63.6(b)(1)-(4)~~	~~Compliance dates for new and reconstructed sources~~	~~Yes.~~	
~~§ 63.6(b)(5)~~	~~Notification~~	~~Yes.~~	
~~§ 63.6(b)(6)~~	~~[Reserved]~~		
~~§ 63.6(b)(7)~~	~~Compliance dates for new and reconstructed area sources that become major sources~~	~~Yes.~~	
~~§ 63.6(c)(1)-(2)~~	~~Compliance dates for existing sources~~	~~Yes.~~	
~~§ 63.6(c)(3)-(4)~~	~~[Reserved]~~		
~~§ 63.6(c)(5)~~	~~Compliance dates for existing area sources that become major sources~~	~~Yes.~~	
~~§ 63.6(d)~~	~~[Reserved]~~		
~~§ 63.6(e)~~	~~Operation and maintenance~~	~~No.~~	

~~General provisions citation~~	~~Subject of citation~~	~~Applies to subpart~~	~~Explanation~~
~~§ 63.6(f)(1)~~	~~Applicability of standards~~	~~No.~~	
~~§ 63.6(f)(2)~~	~~Methods for determining compliance~~	~~Yes.~~	
~~§ 63.6(f)(3)~~	~~Finding of compliance~~	~~Yes.~~	
~~§ 63.6(g)(1)-(3)~~	~~Use of alternate standard~~	~~Yes.~~	
~~§ 63.6(h)~~	~~Opacity and visible emission standards~~	~~No~~	~~Subpart ZZZZ does not contain opacity or visible emission standards.~~
~~§ 63.6(i)~~	~~Compliance extension procedures and criteria~~	~~Yes.~~	
~~§ 63.6(j)~~	~~Presidential compliance exemption~~	~~Yes.~~	
~~§ 63.7(a)(1)-(2)~~	~~Performance test dates~~	~~Yes~~	~~Subpart ZZZZ contains performance test dates at §§ 63.6610, 63.6611, and 63.6612.~~
~~§ 63.7(a)(3)~~	~~CAA section 114 authority~~	~~Yes.~~	
~~§ 63.7(b)(1)~~	~~Notification of performance test~~	~~Yes~~	~~Except that § 63.7(b)(1) only applies as specified in § 63.6645.~~
~~§ 63.7(b)(2)~~	~~Notification of rescheduling~~	~~Yes~~	~~Except that § 63.7(b)(2) only applies as specified in § 63.6645.~~
~~§ 63.7(c)~~	~~Quality assurance/test plan~~	~~Yes~~	~~Except that § 63.7(c) only applies as specified in § 63.6645.~~
~~§ 63.7(d)~~	~~Testing facilities~~	~~Yes.~~	
~~§ 63.7(e)(1)~~	~~Conditions for conducting performance tests~~	~~No.~~	~~Subpart ZZZZ specifies conditions for conducting performance tests at § 63.6620.~~
~~§ 63.7(e)(2)~~	~~Conduct of performance tests and reduction of data~~	~~Yes~~	~~Subpart ZZZZ specifies test methods at § 63.6620.~~
~~§ 63.7(e)(3)~~	~~Test run duration~~	~~Yes.~~	
~~§ 63.7(e)(4)~~	~~Administrator may require other testing under section 114 of the CAA~~	~~Yes.~~	
~~§ 63.7(f)~~	~~Alternative test method provisions~~	~~Yes.~~	
~~§ 63.7(g)~~	~~Performance test data analysis, recordkeeping, and reporting~~	~~Yes.~~	
~~§ 63.7(h)~~	~~Waiver of tests~~	~~Yes.~~	
~~§ 63.8(a)(1)~~	~~Applicability of monitoring requirements~~	~~Yes~~	~~Subpart ZZZZ contains specific requirements for monitoring at § 63.6625.~~
~~§ 63.8(a)(2)~~	~~Performance specifications~~	~~Yes.~~	
~~§ 63.8(a)(3)~~	~~[Reserved]~~		
~~§ 63.8(a)(4)~~	~~Monitoring for control devices~~	~~No.~~	

~~**General provisions citation**~~	~~**Subject of citation**~~	~~**Applies to subpart**~~	~~**Explanation**~~
~~§ 63.8(b)(1)~~	~~Monitoring~~	~~Yes.~~	
~~§ 63.8(b)(2)-(3)~~	~~Multiple effluents and multiple monitoring systems~~	~~Yes.~~	
~~§ 63.8(c)(1)~~	~~Monitoring system operation and maintenance~~	~~Yes.~~	
~~§ 63.8(c)(1)(i)~~	~~Routine and predictable SSM~~	~~Yes.~~	
~~§ 63.8(c)(1)(ii)~~	~~SSM not in Startup Shutdown Malfunction Plan~~	~~Yes.~~	
~~§ 63.8(c)(1)(iii)~~	~~Compliance with operation and maintenance requirements~~	~~Yes.~~	
~~§ 63.8(c)(2)-(3)~~	~~Monitoring system installation~~	~~Yes.~~	
~~§ 63.8(c)(4)~~	~~Continuous monitoring system (CMS) requirements~~	~~Yes~~	~~Except that subpart ZZZZ does not require Continuous Opacity Monitoring System (COMS).~~
~~§ 63.8(c)(5)~~	~~COMS minimum procedures~~	~~No~~	~~Subpart ZZZZ does not require COMS.~~
~~§ 63.8(c)(6)-(8)~~	~~CMS requirements~~	~~Yes~~	~~Except that subpart ZZZZ does not require COMS.~~
~~§ 63.8(d)~~	~~CMS quality control~~	~~Yes.~~	
~~§ 63.8(e)~~	~~CMS performance evaluation~~	~~Yes~~	~~Except for § 63.8(e)(5)(ii), which applies to COMS.~~
		~~Except that § 63.8(e) only applies as specified in § 63.6645.~~	
~~§ 63.8(f)(1)-(5)~~	~~Alternative monitoring method~~	~~Yes~~	~~Except that § 63.8(f)(4) only applies as specified in § 63.6645.~~
~~§ 63.8(f)(6)~~	~~Alternative to relative accuracy test~~	~~Yes~~	~~Except that § 63.8(f)(6) only applies as specified in § 63.6645.~~
~~§ 63.8(g)~~	~~Data reduction~~	~~Yes~~	~~Except that provisions for COMS are not applicable. Averaging periods for demonstrating compliance are specified at §§ 63.6635 and 63.6640.~~
~~§ 63.9(a)~~	~~Applicability and State delegation of notification requirements~~	~~Yes.~~	
~~§ 63.9(b)(1)-(5)~~	~~Initial notifications~~	~~Yes~~	~~Except that § 63.9(b)(3) is reserved.~~
		~~Except that § 63.9(b) only applies as specified in §~~	

~~**General provisions citation**~~	~~**Subject of citation**~~	~~**Applies to subpart**~~	~~**Explanation**~~
		~~63.6645.~~	
~~§ 63.9(c)~~	~~Request for compliance extension~~	~~Yes~~	~~Except that § 63.9(c) only applies as specified in § 63.6645.~~
~~§ 63.9(d)~~	~~Notification of special compliance requirements for new sources~~	~~Yes~~	~~Except that § 63.9(d) only applies as specified in § 63.6645.~~
~~§ 63.9(e)~~	~~Notification of performance test~~	~~Yes~~	~~Except that § 63.9(e) only applies as specified in § 63.6645.~~
~~§ 63.9(f)~~	~~Notification of visible emission (VE)/opacity test~~	~~No~~	~~Subpart ZZZZ does not contain opacity or VE standards.~~
~~§ 63.9(g)(1)~~	~~Notification of performance evaluation~~	~~Yes~~	~~Except that § 63.9(g) only applies as specified in § 63.6645.~~
~~§ 63.9(g)(2)~~	~~Notification of use of COMS data~~	~~No~~	~~Subpart ZZZZ does not contain opacity or VE standards.~~
~~§ 63.9(g)(3)~~	~~Notification that criterion for alternative to RATA is exceeded~~	~~Yes~~	~~If alternative is in use.~~
		~~Except that § 63.9(g) only applies as specified in § 63.6645.~~	
~~§ 63.9(h)(1)-(6)~~	~~Notification of compliance status~~	~~Yes~~	~~Except that notifications for sources using a CEMS are due 30 days after completion of performance evaluations. § 63.9(h)(4) is reserved.~~
			~~Except that § 63.9(h) only applies as specified in § 63.6645.~~
~~§ 63.9(i)~~	~~Adjustment of submittal deadlines~~	~~Yes.~~	
~~§ 63.9(j)~~	~~Change in previous information~~	~~Yes.~~	
~~§ 63.10(a)~~	~~Administrative provisions for recordkeeping/reporting~~	~~Yes.~~	
~~§ 63.10(b)(1)~~	~~Record retention~~	~~Yes.~~	
~~§ 63.10(b)(2)(i)-(v)~~	~~Records related to SSM~~	~~No.~~	
~~§ 63.10(b)(2)(vi)-(xi)~~	~~Records~~	~~Yes.~~	
~~§ 63.10(b)(2)(xii)~~	~~Record when under waiver~~	~~Yes.~~	
~~§ 63.10(b)(2)(xiii)~~	~~Records when using alternative to RATA~~	~~Yes~~	~~For CO standard if using RATA alternative.~~
~~§ 63.10(b)(2)(xiv)~~	~~Records of supporting documentation~~	~~Yes.~~	
~~§ 63.10(b)(3)~~	~~Records of applicability determination~~	~~Yes.~~	

~~General provisions citation~~	~~Subject of citation~~	~~Applies to subpart~~	~~Explanation~~
~~§ 63.10(c)~~	~~Additional records for sources using CEMS~~	~~Yes~~	~~Except that § 63.10(c)(2)-(4) and (9) are reserved.~~
~~§ 63.10(d)(1)~~	~~General reporting requirements~~	~~Yes.~~	
~~§ 63.10(d)(2)~~	~~Report of performance test results~~	~~Yes.~~	
~~§ 63.10(d)(3)~~	~~Reporting opacity or VE observations~~	~~No~~	~~Subpart ZZZZ does not contain opacity or VE standards.~~
~~§ 63.10(d)(4)~~	~~Progress reports~~	~~Yes.~~	
~~§ 63.10(d)(5)~~	~~Startup, shutdown, and malfunction reports~~	~~No.~~	
~~§ 63.10(e)(1) and (2)(i)~~	~~Additional CMS Reports~~	~~Yes.~~	
~~§ 63.10(e)(2)(ii)~~	~~COMS-related report~~	~~No~~	~~Subpart ZZZZ does not require COMS.~~
~~§ 63.10(e)(3)~~	~~Excess emission and parameter exceedances reports~~	~~Yes.~~	~~Except that § 63.10(e)(3)(i) (C) is reserved.~~
~~§ 63.10(e)(4)~~	~~Reporting COMS data~~	~~No~~	~~Subpart ZZZZ does not require COMS.~~
~~§ 63.10(f)~~	~~Waiver for recordkeeping/reporting~~	~~Yes.~~	
~~§ 63.11~~	~~Flares~~	~~No.~~	
~~§ 63.12~~	~~State authority and delegations~~	~~Yes.~~	
~~§ 63.13~~	~~Addresses~~	~~Yes.~~	
~~§ 63.14~~	~~Incorporation by reference~~	~~Yes.~~	
~~§ 63.15~~	~~Availability of information~~	~~Yes.~~	

~~[75 FR 9688, Mar. 3, 2010]~~

Revised Attachment B – 40 CFR 63, Subpart ZZZZ

Indiana Department of Environmental Management
Office of Air Quality

Attachment B to a Part 70 Operating Permit

Source Background and Description

Source Name:	**Ohio Valley Resources, LLC**
Source Location:	**300-400 East CR 350 North, Rockport, Indiana 47635**
County:	**Spencer**
SIC Code:	**2873**
Permit No.:	**T 147-32322-00062**
Permit Reviewer:	**David Matousek**

40 CFR 63, Subpart ZZZZ

40 CFR 63, Subpart ZZZZ **National Emissions Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines**

Source: 69 FR 33506, June 15, 2004, unless otherwise noted.

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What This Subpart Covers

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§ 63.6580 What is the purpose of subpart ZZZZ?

Subpart ZZZZ establishes national emission limitations and operating limitations for hazardous air pollutants (HAP) emitted from stationary reciprocating internal combustion engines (RICE) located at major and area sources of HAP emissions. This subpart also establishes requirements to demonstrate initial and continuous compliance with the emission limitations and operating limitations.

[73 FR 3603, Jan. 18, 2008]

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§ 63.6585 Am I subject to this subpart?

You are subject to this subpart if you own or operate a stationary RICE at a major or area source of HAP emissions, except if the stationary RICE is being tested at a stationary RICE test cell/stand.

(a) A stationary RICE is any internal combustion engine which uses reciprocating motion to convert heat energy into mechanical work and which is not mobile. Stationary RICE differ from mobile RICE in that a stationary RICE is not a non-road engine as defined at 40 CFR 1068.30, and is not used to propel a motor vehicle or a vehicle used solely for competition.

(b) 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, except that for oil and gas production facilities, a major source of HAP emissions is determined for each surface site.

(c) An area source of HAP emissions is a source that is not a major source.

(d) If you are an owner or operator of an area source subject to this subpart, your status as an entity subject to a standard or other requirements under this subpart does not subject you to the obligation to obtain a permit under 40 CFR part 70 or 71, provided you are not required to obtain a permit under 40 CFR 70.3(a) or 40 CFR 71.3(a) for a reason other than your status as an area source under this subpart. Notwithstanding the previous sentence, you must continue to comply with the provisions of this subpart as applicable.

(e) If you are an owner or operator of a stationary RICE used for national security purposes, you may be eligible to request an exemption from the requirements of this subpart as described in 40 CFR part 1068, subpart C.

(f) The emergency stationary RICE listed in paragraphs (f)(1) through (3) of this section are not subject to this subpart. The stationary RICE must meet the definition of an emergency stationary RICE in § 63.6675, which includes operating according to the provisions specified in § 63.6640(f).

(1) Existing residential emergency stationary RICE located at an area source of HAP emissions that do not operate or are not contractually obligated to be available for more than 15 hours per calendar year for the purposes specified in § 63.6640(f)(2)(ii) and (iii) and that do not operate for the purpose specified in § 63.6640(f)(4)(ii).

(2) Existing commercial emergency stationary RICE located at an area source of HAP emissions that do not operate or are not contractually obligated to be available for more than 15 hours per calendar year for the purposes specified in § 63.6640(f)(2)(ii) and (iii) and that do not operate for the purpose specified in § 63.6640(f)(4)(ii).

(3) Existing institutional emergency stationary RICE located at an area source of HAP emissions that do not operate or are not contractually obligated to be available for more than 15 hours per calendar year for the purposes specified in § 63.6640(f)(2)(ii) and (iii) and that do not operate for the purpose specified in § 63.6640(f)(4)(ii).

[69 FR 33506, June 15, 2004, as amended at 73 FR 3603, Jan. 18, 2008; 78 FR 6700, Jan. 30, 2013]

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§ 63.6590 What parts of my plant does this subpart cover?

This subpart applies to each affected source.

(a) *Affected source.* An affected source is any existing, new, or reconstructed stationary RICE located at a major or area source of HAP emissions, excluding stationary RICE being tested at a stationary RICE test cell/stand.

(1) *Existing stationary RICE.*

(i) For stationary RICE with a site rating of more than 500 brake horsepower (HP) located at a major source of HAP emissions, a stationary RICE is existing if you commenced construction or reconstruction of the stationary RICE before December 19, 2002.

(ii) For stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions, a stationary RICE is existing if you commenced construction or reconstruction of the stationary RICE before June 12, 2006.

(iii) For stationary RICE located at an area source of HAP emissions, a stationary RICE is existing if you commenced construction or reconstruction of the stationary RICE before June 12, 2006.

(iv) A change in ownership of an existing stationary RICE does not make that stationary RICE a new or reconstructed stationary RICE.

(2) *New stationary RICE.* (i) A stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions is new if you commenced construction of the stationary RICE on or after December 19, 2002.

(ii) A stationary RICE with a site rating of equal to or less than 500 brake HP located at a major source of HAP emissions is new if you commenced construction of the stationary RICE on or after June 12, 2006.

(iii) A stationary RICE located at an area source of HAP emissions is new if you commenced construction of the stationary RICE on or after June 12, 2006.

(3) *Reconstructed stationary RICE.* (i) A stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions is reconstructed if you meet the definition of reconstruction in § 63.2 and reconstruction is commenced on or after December 19, 2002.

(ii) A stationary RICE with a site rating of equal to or less than 500 brake HP located at a major source of HAP emissions is reconstructed if you meet the definition of reconstruction in § 63.2 and reconstruction is commenced on or after June 12, 2006.

(iii) A stationary RICE located at an area source of HAP emissions is reconstructed if you meet the definition of reconstruction in § 63.2 and reconstruction is commenced on or after June 12, 2006.

(b) *Stationary RICE subject to limited requirements.* (1) An affected source which meets either of the criteria in paragraphs (b)(1)(i) through (ii) of this section does not have to meet the requirements of this subpart and of subpart A of this part except for the initial notification requirements of § 63.6645(f).

(i) The stationary RICE is a new or reconstructed emergency stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions that does not operate or is not contractually obligated to be available for more than 15 hours per calendar year for the purposes specified in § 63.6640(f)(2)(ii) and (iii).

(ii) The stationary RICE is a new or reconstructed limited use stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions.

(2) A new or reconstructed stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions which combusts landfill or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis must meet the initial notification requirements of § 63.6645(f) and the requirements of §§ 63.6625(c), 63.6650(g), and 63.6655(c). These stationary RICE do not have to meet the emission limitations and operating limitations of this subpart.

(3) The following stationary RICE do not have to meet the requirements of this subpart and of subpart A of this part, including initial notification requirements:

(i) Existing spark ignition 2 stroke lean burn (2SLB) stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions;

(ii) Existing spark ignition 4 stroke lean burn (4SLB) stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions;

(iii) Existing emergency stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions that does not operate or is not contractually obligated to be available for more than 15 hours per calendar year for the purposes specified in § 63.6640(f)(2)(ii) and (iii).

(iv) Existing limited use stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions;

(v) Existing stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions that combusts landfill gas or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis;

(c) *Stationary RICE subject to Regulations under 40 CFR Part 60.* An affected source that meets any of the criteria in paragraphs (c)(1) through (7) of this section must meet the requirements of this part by

meeting the requirements of 40 CFR part 60 subpart IIII, for compression ignition engines or 40 CFR part 60 subpart JJJJ, for spark ignition engines. No further requirements apply for such engines under this part.

(1) A new or reconstructed stationary RICE located at an area source;

(2) A new or reconstructed 2SLB stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions;

(3) A new or reconstructed 4SLB stationary RICE with a site rating of less than 250 brake HP located at a major source of HAP emissions;

(4) A new or reconstructed spark ignition 4 stroke rich burn (4SRB) stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions;

(5) A new or reconstructed stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions which combusts landfill or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis;

(6) A new or reconstructed emergency or limited use stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions;

(7) A new or reconstructed compression ignition (CI) stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions.

[69 FR 33506, June 15, 2004, as amended at 73 FR 3604, Jan. 18, 2008; 75 FR 9674, Mar. 3, 2010; 75 FR 37733, June 30, 2010; 75 FR 51588, Aug. 20, 2010; 78 FR 6700, Jan. 30, 2013]

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§ 63.6595 When do I have to comply with this subpart?

(a) *Affected sources.* (1) If you have an existing stationary RICE, excluding existing non-emergency CI stationary RICE, with a site rating of more than 500 brake HP located at a major source of HAP emissions, you must comply with the applicable emission limitations, operating limitations and other requirements no later than June 15, 2007. If you have an existing non-emergency CI stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions, an existing stationary CI RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions, or an existing stationary CI RICE located at an area source of HAP emissions, you must comply with the applicable emission limitations, operating limitations, and other requirements no later than May 3, 2013. If you have an existing stationary SI RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions, or an existing stationary SI RICE located at an area source of HAP emissions, you must comply with the applicable emission limitations, operating limitations, and other requirements no later than October 19, 2013.

(2) If you start up your new or reconstructed stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions before August 16, 2004, you must comply with the applicable emission limitations and operating limitations in this subpart no later than August 16, 2004.

(3) If you start up your new or reconstructed stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions after August 16, 2004, you must comply with the applicable emission limitations and operating limitations in this subpart upon startup of your affected source.

(4) If you start up your new or reconstructed stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions before January 18, 2008, you must comply with the applicable emission limitations and operating limitations in this subpart no later than January 18, 2008.

(5) If you start up your new or reconstructed stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions after January 18, 2008, you must comply with the applicable emission limitations and operating limitations in this subpart upon startup of your affected source.

(6) If you start up your new or reconstructed stationary RICE located at an area source of HAP emissions before January 18, 2008, you must comply with the applicable emission limitations and operating limitations in this subpart no later than January 18, 2008.

(7) If you start up your new or reconstructed stationary RICE located at an area source of HAP emissions after January 18, 2008, you must comply with the applicable emission limitations and operating limitations in this subpart upon startup of your affected source.

(b) *Area sources that become major sources.* If you have an area source that increases its emissions or its potential to emit such that it becomes a major source of HAP, the compliance dates in paragraphs (b)(1) and (2) of this section apply to you.

(1) Any stationary RICE for which construction or reconstruction is commenced after the date when your area source becomes a major source of HAP must be in compliance with this subpart upon startup of your affected source.

(2) Any stationary RICE for which construction or reconstruction is commenced before your area source becomes a major source of HAP must be in compliance with the provisions of this subpart that are applicable to RICE located at major sources within 3 years after your area source becomes a major source of HAP.

(c) If you own or operate an affected source, you must meet the applicable notification requirements in § 63.6645 and in 40 CFR part 63, subpart A.

[69 FR 33506, June 15, 2004, as amended at 73 FR 3604, Jan. 18, 2008; 75 FR 9675, Mar. 3, 2010; 75 FR 51589, Aug. 20, 2010; 78 FR 6701, Jan. 30, 2013]

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Emission and Operating Limitations

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§ 63.6600 What emission limitations and operating limitations must I meet if I own or operate a stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions?

Compliance with the numerical emission limitations established in this subpart is based on the results of testing the average of three 1-hour runs using the testing requirements and procedures in § 63.6620 and Table 4 to this subpart.

(a) If you own or operate an existing, new, or reconstructed spark ignition 4SRB stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions, you must comply

with the emission limitations in Table 1a to this subpart and the operating limitations in Table 1b to this subpart which apply to you.

(b) If you own or operate a new or reconstructed 2SLB stationary RICE with a site rating of more than 500 brake HP located at major source of HAP emissions, a new or reconstructed 4SLB stationary RICE with a site rating of more than 500 brake HP located at major source of HAP emissions, or a new or reconstructed CI stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions, you must comply with the emission limitations in Table 2a to this subpart and the operating limitations in Table 2b to this subpart which apply to you.

(c) If you own or operate any of the following stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions, you do not need to comply with the emission limitations in Tables 1a, 2a, 2c, and 2d to this subpart or operating limitations in Tables 1b and 2b to this subpart: an existing 2SLB stationary RICE; an existing 4SLB stationary RICE; a stationary RICE that combusts landfill gas or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis; an emergency stationary RICE; or a limited use stationary RICE.

(d) If you own or operate an existing non-emergency stationary CI RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions, you must comply with the emission limitations in Table 2c to this subpart and the operating limitations in Table 2b to this subpart which apply to you.

[73 FR 3605, Jan. 18, 2008, as amended at 75 FR 9675, Mar. 3, 2010]

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§ 63.6601 What emission limitations must I meet if I own or operate a new or reconstructed 4SLB stationary RICE with a site rating of greater than or equal to 250 brake HP and less than or equal to 500 brake HP located at a major source of HAP emissions?

Compliance with the numerical emission limitations established in this subpart is based on the results of testing the average of three 1-hour runs using the testing requirements and procedures in § 63.6620 and Table 4 to this subpart. If you own or operate a new or reconstructed 4SLB stationary RICE with a site rating of greater than or equal to 250 and less than or equal to 500 brake HP located at major source of HAP emissions manufactured on or after January 1, 2008, you must comply with the emission limitations in Table 2a to this subpart and the operating limitations in Table 2b to this subpart which apply to you.

[73 FR 3605, Jan. 18, 2008, as amended at 75 FR 9675, Mar. 3, 2010; 75 FR 51589, Aug. 20, 2010]

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§ 63.6602 What emission limitations and other requirements must I meet if I own or operate an existing stationary RICE with a site rating of equal to or less than 500 brake HP located at a major source of HAP emissions?

If you own or operate an existing stationary RICE with a site rating of equal to or less than 500 brake HP located at a major source of HAP emissions, you must comply with the emission limitations and other requirements in Table 2c to this subpart which apply to you. Compliance with the numerical emission limitations established in this subpart is based on the results of testing the average of three 1-hour runs using the testing requirements and procedures in § 63.6620 and Table 4 to this subpart.

[78 FR 6701, Jan. 30, 2013]

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§ 63.6603 What emission limitations, operating limitations, and other requirements must I meet if I own or operate an existing stationary RICE located at an area source of HAP emissions?

Compliance with the numerical emission limitations established in this subpart is based on the results of testing the average of three 1-hour runs using the testing requirements and procedures in § 63.6620 and Table 4 to this subpart.

(a) If you own or operate an existing stationary RICE located at an area source of HAP emissions, you must comply with the requirements in Table 2d to this subpart and the operating limitations in Table 2b to this subpart that apply to you.

(b) If you own or operate an existing stationary non-emergency CI RICE with a site rating of more than 300 HP located at an area source of HAP that meets either paragraph (b)(1) or (2) of this section, you do not have to meet the numerical CO emission limitations specified in Table 2d of this subpart. Existing stationary non-emergency CI RICE with a site rating of more than 300 HP located at an area source of HAP that meet either paragraph (b)(1) or (2) of this section must meet the management practices that are shown for stationary non-emergency CI RICE with a site rating of less than or equal to 300 HP in Table 2d of this subpart.

(1) The area source is located in an area of Alaska that is not accessible by the Federal Aid Highway System (FAHS).

(2) The stationary RICE is located at an area source that meets paragraphs (b)(2)(i), (ii), and (iii) of this section.

(i) The only connection to the FAHS is through the Alaska Marine Highway System (AMHS), or the stationary RICE operation is within an isolated grid in Alaska that is not connected to the statewide electrical grid referred to as the Alaska Railbelt Grid.

(ii) At least 10 percent of the power generated by the stationary RICE on an annual basis is used for residential purposes.

(iii) The generating capacity of the area source is less than 12 megawatts, or the stationary RICE is used exclusively for backup power for renewable energy.

(c) If you own or operate an existing stationary non-emergency CI RICE with a site rating of more than 300 HP located on an offshore vessel that is an area source of HAP and is a nonroad vehicle that is an Outer Continental Shelf (OCS) source as defined in 40 CFR 55.2, you do not have to meet the numerical CO emission limitations specified in Table 2d of this subpart. You must meet all of the following management practices:

(1) Change oil every 1,000 hours of operation or annually, whichever comes first. Sources have the option to utilize an oil analysis program as described in § 63.6625(i) in order to extend the specified oil change requirement.

(2) Inspect and clean air filters every 750 hours of operation or annually, whichever comes first, and replace as necessary.

(3) Inspect fuel filters and belts, if installed, every 750 hours of operation or annually, whichever comes first, and replace as necessary.

(4) Inspect all flexible hoses every 1,000 hours of operation or annually, whichever comes first, and replace as necessary.

(d) If you own or operate an existing non-emergency CI RICE with a site rating of more than 300 HP located at an area source of HAP emissions that is certified to the Tier 1 or Tier 2 emission standards in Table 1 of 40 CFR 89.112 and that is subject to an enforceable state or local standard that requires the engine to be replaced no later than June 1, 2018, you may until January 1, 2015, or 12 years after the installation date of the engine (whichever is later), but not later than June 1, 2018, choose to comply with the management practices that are shown for stationary non-emergency CI RICE with a site rating of less than or equal to 300 HP in Table 2d of this subpart instead of the applicable emission limitations in Table 2d, operating limitations in Table 2b, and crankcase ventilation system requirements in § 63.6625(g). You must comply with the emission limitations in Table 2d and operating limitations in Table 2b that apply for non-emergency CI RICE with a site rating of more than 300 HP located at an area source of HAP emissions by January 1, 2015, or 12 years after the installation date of the engine (whichever is later), but not later than June 1, 2018. You must also comply with the crankcase ventilation system requirements in § 63.6625(g) by January 1, 2015, or 12 years after the installation date of the engine (whichever is later), but not later than June 1, 2018.

(e) If you own or operate an existing non-emergency CI RICE with a site rating of more than 300 HP located at an area source of HAP emissions that is certified to the Tier 3 (Tier 2 for engines above 560 kilowatt (kW)) emission standards in Table 1 of 40 CFR 89.112, you may comply with the requirements under this part by meeting the requirements for Tier 3 engines (Tier 2 for engines above 560 kW) in 40 CFR part 60 subpart IIII instead of the emission limitations and other requirements that would otherwise apply under this part for existing non-emergency CI RICE with a site rating of more than 300 HP located at an area source of HAP emissions.

(f) An existing non-emergency SI 4SLB and 4SRB stationary RICE with a site rating of more than 500 HP located at area sources of HAP must meet the definition of remote stationary RICE in § 63.6675 on the initial compliance date for the engine, October 19, 2013, in order to be considered a remote stationary RICE under this subpart. Owners and operators of existing non-emergency SI 4SLB and 4SRB stationary RICE with a site rating of more than 500 HP located at area sources of HAP that meet the definition of remote stationary RICE in § 63.6675 of this subpart as of October 19, 2013 must evaluate the status of their stationary RICE every 12 months. Owners and operators must keep records of the initial and annual evaluation of the status of the engine. If the evaluation indicates that the stationary RICE no longer meets the definition of remote stationary RICE in § 63.6675 of this subpart, the owner or operator must comply with all of the requirements for existing non-emergency SI 4SLB and 4SRB stationary RICE with a site rating of more than 500 HP located at area sources of HAP that are not remote stationary RICE within 1 year of the evaluation.

[75 FR 9675, Mar. 3, 2010, as amended at 75 FR 51589, Aug. 20, 2010; 76 FR 12866, Mar. 9, 2011; 78 FR 6701, Jan. 30, 2013]

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§ 63.6604 What fuel requirements must I meet if I own or operate a stationary CI RICE?

(a) If you own or operate an existing non-emergency, non-black start CI stationary RICE with a site rating of more than 300 brake HP with a displacement of less than 30 liters per cylinder that uses diesel fuel, you must use diesel fuel that meets the requirements in 40 CFR 80.510(b) for nonroad diesel fuel.

(b) Beginning January 1, 2015, if you own or operate an existing emergency CI stationary RICE with a site rating of more than 100 brake HP and a displacement of less than 30 liters per cylinder that uses diesel fuel and operates or is contractually obligated to be available for more than 15 hours per calendar year for the purposes specified in § 63.6640(f)(2)(ii) and (iii) or that operates for the purpose specified in § 63.6640(f)(4)(ii), you must use diesel fuel that meets the requirements in 40 CFR 80.510(b) for nonroad

diesel fuel, except that any existing diesel fuel purchased (or otherwise obtained) prior to January 1, 2015, may be used until depleted.

(c) Beginning January 1, 2015, if you own or operate a new emergency CI stationary RICE with a site rating of more than 500 brake HP and a displacement of less than 30 liters per cylinder located at a major source of HAP that uses diesel fuel and operates or is contractually obligated to be available for more than 15 hours per calendar year for the purposes specified in § 63.6640(f)(2)(ii) and (iii), you must use diesel fuel that meets the requirements in 40 CFR 80.510(b) for nonroad diesel fuel, except that any existing diesel fuel purchased (or otherwise obtained) prior to January 1, 2015, may be used until depleted.

**(d) Existing CI stationary RICE located in Guam, American Samoa, the Commonwealth of the Northern Mariana Islands, at area sources in areas of Alaska that meet either § 63.6603(b)(1) or § 63.6603(b)(2), or are on offshore vessels that meet § 63.6603(c) are exempt from the requirements of this section.
[78 FR 6702, Jan. 30, 2013]**

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General Compliance Requirements

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§ 63.6605 What are my general requirements for complying with this subpart?

(a) You must be in compliance with the emission limitations, operating limitations, and other requirements in this subpart that apply to you at all times.

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

[75 FR 9675, Mar. 3, 2010, as amended at 78 FR 6702, Jan. 30, 2013]

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Testing and Initial Compliance Requirements

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§ 63.6610 By what date must I conduct the initial performance tests or other initial compliance demonstrations if I own or operate a stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions?

If you own or operate a stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions you are subject to the requirements of this section.

(a) You must conduct the initial performance test or other initial compliance demonstrations in Table 4 to this subpart that apply to you within 180 days after the compliance date that is specified for your stationary RICE in § 63.6595 and according to the provisions in § 63.7(a)(2).

(b) If you commenced construction or reconstruction between December 19, 2002 and June 15, 2004 and own or operate stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions, you must demonstrate initial compliance with either the proposed emission limitations or the promulgated emission limitations no later than February 10, 2005 or no later than 180 days after startup of the source, whichever is later, according to § 63.7(a)(2)(ix).

(c) If you commenced construction or reconstruction between December 19, 2002 and June 15, 2004 and own or operate stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions, and you chose to comply with the proposed emission limitations when demonstrating initial compliance, you must conduct a second performance test to demonstrate compliance with the promulgated emission limitations by December 13, 2007 or after startup of the source, whichever is later, according to § 63.7(a)(2)(ix).

(d) An owner or operator is not required to conduct an initial performance test on units for which a performance test has been previously conducted, but the test must meet all of the conditions described in paragraphs (d)(1) through (5) of this section.

(1) The test must have been conducted using the same methods specified in this subpart, and these methods must have been followed correctly.

(2) The test must not be older than 2 years.

(3) The test must be reviewed and accepted by the Administrator.

(4) Either no process or equipment changes must have been made since the test was performed, or the owner or operator must be able to demonstrate that the results of the performance test, with or without adjustments, reliably demonstrate compliance despite process or equipment changes.

(5) The test must be conducted at any load condition within plus or minus 10 percent of 100 percent load.

[69 FR 33506, June 15, 2004, as amended at 73 FR 3605, Jan. 18, 2008]

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§ 63.6611 By what date must I conduct the initial performance tests or other initial compliance demonstrations if I own or operate a new or reconstructed 4SLB SI stationary RICE with a site rating of greater than or equal to 250 and less than or equal to 500 brake HP located at a major source of HAP emissions?

If you own or operate a new or reconstructed 4SLB stationary RICE with a site rating of greater than or equal to 250 and less than or equal to 500 brake HP located at a major source of HAP emissions, you must conduct an initial performance test within 240 days after the compliance date that is specified for your stationary RICE in § 63.6595 and according to the provisions specified in Table 4 to this subpart, as appropriate.

[73 FR 3605, Jan. 18, 2008, as amended at 75 FR 51589, Aug. 20, 2010]

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§ 63.6612 By what date must I conduct the initial performance tests or other initial compliance demonstrations if I own or operate an existing stationary RICE with a site rating of less than or equal to

500 brake HP located at a major source of HAP emissions or an existing stationary RICE located at an area source of HAP emissions?

If you own or operate an existing stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions or an existing stationary RICE located at an area source of HAP emissions you are subject to the requirements of this section.

(a) You must conduct any initial performance test or other initial compliance demonstration according to Tables 4 and 5 to this subpart that apply to you within 180 days after the compliance date that is specified for your stationary RICE in § 63.6595 and according to the provisions in § 63.7(a)(2).

(b) An owner or operator is not required to conduct an initial performance test on a unit for which a performance test has been previously conducted, but the test must meet all of the conditions described in paragraphs (b)(1) through (4) of this section.

(1) The test must have been conducted using the same methods specified in this subpart, and these methods must have been followed correctly.

(2) The test must not be older than 2 years.

(3) The test must be reviewed and accepted by the Administrator.

(4) Either no process or equipment changes must have been made since the test was performed, or the owner or operator must be able to demonstrate that the results of the performance test, with or without adjustments, reliably demonstrate compliance despite process or equipment changes.

[75 FR 9676, Mar. 3, 2010, as amended at 75 FR 51589, Aug. 20, 2010]

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§ 63.6615 When must I conduct subsequent performance tests?

If you must comply with the emission limitations and operating limitations, you must conduct subsequent performance tests as specified in Table 3 of this subpart.

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§ 63.6620 What performance tests and other procedures must I use?

(a) You must conduct each performance test in Tables 3 and 4 of this subpart that applies to you.

(b) Each performance test must be conducted according to the requirements that this subpart specifies in Table 4 to this subpart. If you own or operate a non-operational stationary RICE that is subject to performance testing, you do not need to start up the engine solely to conduct the performance test. Owners and operators of a non-operational engine can conduct the performance test when the engine is started up again. The test must be conducted at any load condition within plus or minus 10 percent of 100 percent load for the stationary RICE listed in paragraphs (b)(1) through (4) of this section.

(1) Non-emergency 4SRB stationary RICE with a site rating of greater than 500 brake HP located at a major source of HAP emissions.

(2) New non-emergency 4SLB stationary RICE with a site rating of greater than or equal to 250 brake HP located at a major source of HAP emissions.

(3) New non-emergency 2SLB stationary RICE with a site rating of greater than 500 brake HP located at a major source of HAP emissions.

(4) New non-emergency CI stationary RICE with a site rating of greater than 500 brake HP located at a major source of HAP emissions.

(c) [Reserved]

(d) 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, unless otherwise specified in this subpart.

(e)(1) You must use Equation 1 of this section to determine compliance with the percent reduction requirement:

$$\frac{C_i - C_o}{C_i} \times 100 = R \quad (Eq.\ 1)$$

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Where:

C_i = concentration of carbon monoxide (CO), total hydrocarbons (THC), or formaldehyde at the control device inlet,

C_o = concentration of CO, THC, or formaldehyde at the control device outlet, and

R = percent reduction of CO, THC, or formaldehyde emissions.

(2) You must normalize the CO, THC, or formaldehyde concentrations at the inlet and outlet of the control device to a dry basis and to 15 percent oxygen, or an equivalent percent carbon dioxide (CO_2). If pollutant concentrations are to be corrected to 15 percent oxygen and CO_2 concentration is measured in lieu of oxygen concentration measurement, a CO_2 correction factor is needed. Calculate the CO_2 correction factor as described in paragraphs (e)(2)(i) through (iii) of this section.

(i) Calculate the fuel-specific F_o value for the fuel burned during the test using values obtained from Method 19, Section 5.2, and the following equation:

$$F_o = \frac{0.209\ F_d}{F_c} \quad (Eq.\ 2)$$

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Where:

F_o = Fuel factor based on the ratio of oxygen volume to the ultimate CO_2 volume produced by the fuel at zero percent excess air.

0.209 = Fraction of air that is oxygen, percent/100.

F_d = Ratio of the volume of dry effluent gas to the gross calorific value of the fuel from Method 19, dsm^3 /J ($dscf/10^6$ Btu).

F_c = Ratio of the volume of CO_2 produced to the gross calorific value of the fuel from Method 19, dsm^3 /J ($dscf/10^6$ Btu)

(ii) Calculate the CO_2 correction factor for correcting measurement data to 15 percent O_2 , as follows:

$$X_{CO2} = \frac{5.9}{F_O} \quad (Eq.\ 3)$$

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Where:

X_{CO2} = CO_2 correction factor, percent.

5.9 = 20.9 percent O_2 —15 percent O_2 , the defined O_2 correction value, percent.

(iii) Calculate the CO, THC, and formaldehyde gas concentrations adjusted to 15 percent O_2 using CO_2 as follows:

$$C_{adj} = C_d \frac{X_{CO2}}{\%CO_2} \quad (Eq.\ 4)$$

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Where:

C_{adj} = Calculated concentration of CO, THC, or formaldehyde adjusted to 15 percent O_2.

C_d = Measured concentration of CO, THC, or formaldehyde, uncorrected.

X_{CO2} = CO_2 correction factor, percent.

$\%CO_2$ = Measured CO_2 concentration measured, dry basis, percent.

(f) If you comply with the emission limitation to reduce CO and you are not using an oxidation catalyst, if you comply with the emission limitation to reduce formaldehyde and you are not using NSCR, or if you comply with the emission limitation to limit the concentration of formaldehyde in the stationary RICE exhaust and you are not using an oxidation catalyst or NSCR, you must petition the Administrator for operating limitations to be established during the initial performance test and continuously monitored thereafter; or for approval of no operating limitations. You must not conduct the initial performance test until after the petition has been approved by the Administrator.

(g) If you petition the Administrator for approval of operating limitations, your petition must include the information described in paragraphs (g)(1) through (5) of this section.

(1) Identification of the specific parameters you propose to use as operating limitations;

(2) A discussion of the relationship between these parameters and HAP emissions, identifying how HAP emissions change with changes in these parameters, and how limitations on these parameters will serve to limit HAP emissions;

(3) A discussion of how you will establish the upper and/or lower values for these parameters which will establish the limits on these parameters in the operating limitations;

(4) A discussion identifying the methods you will use to measure and the instruments you will use to monitor these parameters, as well as the relative accuracy and precision of these methods and instruments; and

(5) A discussion identifying the frequency and methods for recalibrating the instruments you will use for monitoring these parameters.

(h) If you petition the Administrator for approval of no operating limitations, your petition must include the information described in paragraphs (h)(1) through (7) of this section.

(1) Identification of the parameters associated with operation of the stationary RICE and any emission control device which could change intentionally (*e.g.,* operator adjustment, automatic controller adjustment, etc.) or unintentionally (*e.g.,* wear and tear, error, etc.) on a routine basis or over time;

(2) A discussion of the relationship, if any, between changes in the parameters and changes in HAP emissions;

(3) For the parameters which could change in such a way as to increase HAP emissions, a discussion of whether establishing limitations on the parameters would serve to limit HAP emissions;

(4) For the parameters which could change in such a way as to increase HAP emissions, a discussion of how you could establish upper and/or lower values for the parameters which would establish limits on the parameters in operating limitations;

(5) For the parameters, a discussion identifying the methods you could use to measure them and the instruments you could use to monitor them, as well as the relative accuracy and precision of the methods and instruments;

(6) For the parameters, a discussion identifying the frequency and methods for recalibrating the instruments you could use to monitor them; and

(7) A discussion of why, from your point of view, it is infeasible or unreasonable to adopt the parameters as operating limitations.

(i) The engine percent load during a performance test must be determined by documenting the calculations, assumptions, and measurement devices used to measure or estimate the percent load in a specific application. A written report of the average percent load determination must be included in the notification of compliance status. The following information must be included in the written report: the engine model number, the engine manufacturer, the year of purchase, the manufacturer's site-rated brake horsepower, the ambient temperature, pressure, and humidity during the performance test, and all assumptions that were made to estimate or calculate percent load during the performance test must be clearly explained. If measurement devices such as flow meters, kilowatt meters, beta analyzers, stain gauges, etc. are used, the model number of the measurement device, and an estimate of its accurate in percentage of true value must be provided.

[69 FR 33506, June 15, 2004, as amended at 75 FR 9676, Mar. 3, 2010; 78 FR 6702, Jan. 30, 2013]

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§ 63.6625 What are my monitoring, installation, collection, operation, and maintenance requirements?

(a) If you elect to install a CEMS as specified in Table 5 of this subpart, you must install, operate, and maintain a CEMS to monitor CO and either O_2 or CO_2 according to the requirements in paragraphs (a)(1) through (4) of this section. If you are meeting a requirement to reduce CO emissions, the CEMS must be installed at both the inlet and outlet of the control device. If you are meeting a requirement to limit the concentration of CO, the CEMS must be installed at the outlet of the control device.

(1) Each CEMS must be installed, operated, and maintained according to the applicable performance specifications of 40 CFR part 60, appendix B.

(2) You must conduct an initial performance evaluation and an annual relative accuracy test audit (RATA) of each CEMS according to the requirements in § 63.8 and according to the applicable performance specifications of 40 CFR part 60, appendix B as well as daily and periodic data quality checks in accordance with 40 CFR part 60, appendix F, procedure 1.

(3) As specified in § 63.8(c)(4)(ii), each CEMS must complete a minimum of one cycle of operation (sampling, analyzing, and data recording) for each successive 15-minute period. You must have at least two data points, with each representing a different 15-minute period, to have a valid hour of data.

(4) The CEMS data must be reduced as specified in § 63.8(g)(2) and recorded in parts per million or parts per billion (as appropriate for the applicable limitation) at 15 percent oxygen or the equivalent CO_2 concentration.

(b) If you are required to install a continuous parameter monitoring system (CPMS) as specified in Table 5 of this subpart, you must install, operate, and maintain each CPMS according to the requirements in paragraphs (b)(1) through (6) of this section. For an affected source that is complying with the emission limitations and operating limitations on March 9, 2011, the requirements in paragraph (b) of this section are applicable September 6, 2011.

(1) You must prepare a site-specific monitoring plan that addresses the monitoring system design, data collection, and the quality assurance and quality control elements outlined in paragraphs (b)(1)(i) through (v) of this section and in § 63.8(d). As specified in § 63.8(f)(4), you may request approval of monitoring system quality assurance and quality control procedures alternative to those specified in paragraphs (b)(1) through (5) of this section in your site-specific monitoring plan.

(i) The performance criteria and design specifications for the monitoring system equipment, including the sample interface, detector signal analyzer, and data acquisition and calculations;

(ii) Sampling interface (*e.g.,* thermocouple) location such that the monitoring system will provide representative measurements;

(iii) Equipment performance evaluations, system accuracy audits, or other audit procedures;

(iv) Ongoing operation and maintenance procedures in accordance with provisions in § 63.8(c)(1)(ii) and (c)(3); and

(v) Ongoing reporting and recordkeeping procedures in accordance with provisions in § 63.10(c), (e)(1), and (e)(2)(i).

(2) You must install, operate, and maintain each CPMS in continuous operation according to the procedures in your site-specific monitoring plan.

(3) The CPMS must collect data at least once every 15 minutes (see also § 63.6635).

(4) For a CPMS for measuring temperature range, the temperature sensor must have a minimum tolerance of 2.8 degrees Celsius (5 degrees Fahrenheit) or 1 percent of the measurement range, whichever is larger.

(5) You must conduct the CPMS equipment performance evaluation, system accuracy audits, or other audit procedures specified in your site-specific monitoring plan at least annually.

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

(c) If you are operating a new or reconstructed stationary RICE which fires landfill gas or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis, you must monitor and record your fuel usage daily with separate fuel meters to measure the volumetric flow rate of each fuel. In addition, you must operate your stationary RICE in a manner which reasonably minimizes HAP emissions.

(d) If you are operating a new or reconstructed emergency 4SLB stationary RICE with a site rating of greater than or equal to 250 and less than or equal to 500 brake HP located at a major source of HAP emissions, you must install a non-resettable hour meter prior to the startup of the engine.

(e) If you own or operate any of the following stationary RICE, you must operate and maintain the stationary RICE and after-treatment control device (if any) according to the manufacturer's emission-related written instructions or develop your own maintenance plan which must provide to the extent practicable for the maintenance and operation of the engine in a manner consistent with good air pollution control practice for minimizing emissions:

(1) An existing stationary RICE with a site rating of less than 100 HP located at a major source of HAP emissions;

(2) An existing emergency or black start stationary RICE with a site rating of less than or equal to 500 HP located at a major source of HAP emissions;

(3) An existing emergency or black start stationary RICE located at an area source of HAP emissions;

(4) An existing non-emergency, non-black start stationary CI RICE with a site rating less than or equal to 300 HP located at an area source of HAP emissions;

(5) An existing non-emergency, non-black start 2SLB stationary RICE located at an area source of HAP emissions;

(6) An existing non-emergency, non-black start stationary RICE located at an area source of HAP emissions which combusts landfill or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis.

(7) An existing non-emergency, non-black start 4SLB stationary RICE with a site rating less than or equal to 500 HP located at an area source of HAP emissions;

(8) An existing non-emergency, non-black start 4SRB stationary RICE with a site rating less than or equal to 500 HP located at an area source of HAP emissions;

(9) An existing, non-emergency, non-black start 4SLB stationary RICE with a site rating greater than 500 HP located at an area source of HAP emissions that is operated 24 hours or less per calendar year; and

(10) An existing, non-emergency, non-black start 4SRB stationary RICE with a site rating greater than 500 HP located at an area source of HAP emissions that is operated 24 hours or less per calendar year.

(f) If you own or operate an existing emergency stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions or an existing emergency stationary RICE located at an area source of HAP emissions, you must install a non-resettable hour meter if one is not already installed.

(g) If you own or operate an existing non-emergency, non-black start CI engine greater than or equal to 300 HP that is not equipped with a closed crankcase ventilation system, you must comply with either paragraph (g)(1) or paragraph (2) of this section. Owners and operators must follow the manufacturer's specified maintenance requirements for operating and maintaining the open or closed crankcase ventilation systems and replacing the crankcase filters, or can request the Administrator to approve different maintenance requirements that are as protective as manufacturer requirements. Existing CI engines located at area sources in areas of Alaska that meet either § 63.6603(b)(1) or § 63.6603(b)(2) do not have to meet the requirements of this paragraph (g). Existing CI engines located on offshore vessels that meet § 63.6603(c) do not have to meet the requirements of this paragraph (g).

(1) Install a closed crankcase ventilation system that prevents crankcase emissions from being emitted to the atmosphere, or

(2) Install an open crankcase filtration emission control system that reduces emissions from the crankcase by filtering the exhaust stream to remove oil mist, particulates and metals.

(h) If you operate a new, reconstructed, or existing stationary engine, you must minimize the engine's time spent at idle during startup and minimize the engine's startup time to a period needed for appropriate and safe loading of the engine, not to exceed 30 minutes, after which time the emission standards applicable to all times other than startup in Tables 1a, 2a, 2c, and 2d to this subpart apply.

(i) If you own or operate a stationary CI engine that is subject to the work, operation or management practices in items 1 or 2 of Table 2c to this subpart or in items 1 or 4 of Table 2d to this subpart, you have the option of utilizing an oil analysis program in order to extend the specified oil change requirement in Tables 2c and 2d to this subpart. The oil analysis must be performed at the same frequency specified for changing the oil in Table 2c or 2d to this subpart. The analysis program must at a minimum analyze the following three parameters: Total Base Number, viscosity, and percent water content. The condemning limits for these parameters are as follows: Total Base Number is less than 30 percent of the Total Base Number of the oil when new; viscosity of the oil has changed by more than 20 percent from the viscosity of the oil when new; or percent water content (by volume) is greater than 0.5. If all of these condemning limits are not exceeded, the engine owner or operator is not required to change the oil. If any of the limits are exceeded, the engine owner or operator must change the oil within 2 business days of receiving the results of the analysis; if the engine is not in operation when the results of the analysis are received, the engine owner or operator must change the oil within 2 business days or before commencing operation, whichever is later. The owner or operator must keep records of the parameters that are analyzed as part of the program, the results of the analysis, and the oil changes for the engine. The analysis program must be part of the maintenance plan for the engine.

(j) If you own or operate a stationary SI engine that is subject to the work, operation or management practices in items 6, 7, or 8 of Table 2c to this subpart or in items 5, 6, 7, 9, or 11 of Table 2d to this subpart, you have the option of utilizing an oil analysis program in order to extend the specified oil change requirement in Tables 2c and 2d to this subpart. The oil analysis must be performed at the same frequency specified for changing the oil in Table 2c or 2d to this subpart. The analysis program must at a minimum analyze the following three parameters: Total Acid Number, viscosity, and percent water content. The condemning limits for these parameters are as follows: Total Acid Number increases by more than 3.0 milligrams of potassium hydroxide (KOH) per gram from Total Acid Number of the oil when new; viscosity of the oil has changed by more than 20 percent from the viscosity of the oil when new; or percent water content (by volume) is greater than 0.5. If all of these condemning limits are not exceeded, the engine owner or operator is not required to change the oil. If any of the limits are exceeded, the engine owner or operator must change the oil within 2 business days of receiving the results of the analysis; if the engine is not in operation when the results of the analysis are received, the engine owner or operator must change the oil within 2 business days or before commencing operation, whichever is later. The owner or operator must keep records of the parameters that are analyzed as part of the program, the results of the analysis, and the oil changes for the engine. The analysis program must be part of the maintenance plan for the engine.

[69 FR 33506, June 15, 2004, as amended at 73 FR 3606, Jan. 18, 2008; 75 FR 9676, Mar. 3, 2010; 75 FR 51589, Aug. 20, 2010; 76 FR 12866, Mar. 9, 2011; 78 FR 6703, Jan. 30, 2013]

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§ 63.6630 How do I demonstrate initial compliance with the emission limitations, operating limitations, and other requirements?

(a) You must demonstrate initial compliance with each emission limitation, operating limitation, and other requirement that applies to you according to Table 5 of this subpart.

(b) During the initial performance test, you must establish each operating limitation in Tables 1b and 2b of this subpart that applies to you.

(c) You must submit the Notification of Compliance Status containing the results of the initial compliance demonstration according to the requirements in § 63.6645.

(d) Non-emergency 4SRB stationary RICE complying with the requirement to reduce formaldehyde emissions by 76 percent or more can demonstrate initial compliance with the formaldehyde emission limit by testing for THC instead of formaldehyde. The testing must be conducted according to the requirements in Table 4 of this subpart. The average reduction of emissions of THC determined from the performance test must be equal to or greater than 30 percent.

(e) The initial compliance demonstration required for existing non-emergency 4SLB and 4SRB stationary RICE with a site rating of more than 500 HP located at an area source of HAP that are not remote stationary RICE and that are operated more than 24 hours per calendar year must be conducted according to the following requirements:

(1) The compliance demonstration must consist of at least three test runs.

(2) Each test run must be of at least 15 minute duration, except that each test conducted using the method in appendix A to this subpart must consist of at least one measurement cycle and include at least 2 minutes of test data phase measurement.

(3) If you are demonstrating compliance with the CO concentration or CO percent reduction requirement, you must measure CO emissions using one of the CO measurement methods specified in Table 4 of this subpart, or using appendix A to this subpart.

(4) If you are demonstrating compliance with the THC percent reduction requirement, you must measure THC emissions using Method 25A, reported as propane, of 40 CFR part 60, appendix A.

(5) You must measure O_2 using one of the O_2 measurement methods specified in Table 4 of this subpart. Measurements to determine O_2 concentration must be made at the same time as the measurements for CO or THC concentration.

(6) If you are demonstrating compliance with the CO or THC percent reduction requirement, you must measure CO or THC emissions and O_2 emissions simultaneously at the inlet and outlet of the control device.

[69 FR 33506, June 15, 2004, as amended at 78 FR 6704, Jan. 30, 2013]

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Continuous Compliance Requirements

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§ 63.6635 How do I monitor and collect data to demonstrate continuous compliance?

(a) If you must comply with emission and operating limitations, you must monitor and collect data according to this section.

(b) Except for monitor malfunctions, associated repairs, required performance evaluations, and required quality assurance or control activities, you must monitor continuously at all times that the stationary RICE 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.

(c) You may not use data recorded during monitoring malfunctions, associated repairs, and required quality assurance or control activities in data averages and calculations used to report emission or operating levels. You must, however, use all the valid data collected during all other periods.

[69 FR 33506, June 15, 2004, as amended at 76 FR 12867, Mar. 9, 2011]

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§ 63.6640 How do I demonstrate continuous compliance with the emission limitations, operating limitations, and other requirements?

(a) You must demonstrate continuous compliance with each emission limitation, operating limitation, and other requirements in Tables 1a and 1b, Tables 2a and 2b, Table 2c, and Table 2d to this subpart that apply to you according to methods specified in Table 6 to this subpart.

(b) You must report each instance in which you did not meet each emission limitation or operating limitation in Tables 1a and 1b, Tables 2a and 2b, Table 2c, and Table 2d to this subpart that apply to you. These instances are deviations from the emission and operating limitations in this subpart. These deviations must be reported according to the requirements in § 63.6650. If you change your catalyst, you must reestablish the values of the operating parameters measured during the initial performance test. When you reestablish the values of your operating parameters, you must also conduct a performance test to demonstrate that you are meeting the required emission limitation applicable to your stationary RICE.

(c) The annual compliance demonstration required for existing non-emergency 4SLB and 4SRB stationary RICE with a site rating of more than 500 HP located at an area source of HAP that are not remote stationary RICE and that are operated more than 24 hours per calendar year must be conducted according to the following requirements:

(1) The compliance demonstration must consist of at least one test run.

(2) Each test run must be of at least 15 minute duration, except that each test conducted using the method in appendix A to this subpart must consist of at least one measurement cycle and include at least 2 minutes of test data phase measurement.

(3) If you are demonstrating compliance with the CO concentration or CO percent reduction requirement, you must measure CO emissions using one of the CO measurement methods specified in Table 4 of this subpart, or using appendix A to this subpart.

(4) If you are demonstrating compliance with the THC percent reduction requirement, you must measure THC emissions using Method 25A, reported as propane, of 40 CFR part 60, appendix A.

(5) You must measure O_2 using one of the O_2 measurement methods specified in Table 4 of this subpart. Measurements to determine O_2 concentration must be made at the same time as the measurements for CO or THC concentration.

(6) If you are demonstrating compliance with the CO or THC percent reduction requirement, you must measure CO or THC emissions and O_2 emissions simultaneously at the inlet and outlet of the control device.

(7) If the results of the annual compliance demonstration show that the emissions exceed the levels specified in Table 6 of this subpart, the stationary RICE must be shut down as soon as safely possible, and appropriate corrective action must be taken (e.g., repairs, catalyst cleaning, catalyst replacement). The stationary RICE must be retested within 7 days of being restarted and the emissions must meet the levels specified in Table 6 of this subpart. If the retest shows that the emissions continue to exceed the specified levels, the stationary RICE must again be shut down as soon as safely possible, and the stationary RICE may not operate, except for purposes of startup and testing, until the owner/operator demonstrates through testing that the emissions do not exceed the levels specified in Table 6 of this subpart.

(d) For new, reconstructed, and rebuilt stationary RICE, deviations from the emission or operating limitations that occur during the first 200 hours of operation from engine startup (engine burn-in period) are not violations. Rebuilt stationary RICE means a stationary RICE that has been rebuilt as that term is defined in 40 CFR 94.11(a).

(e) You must also report each instance in which you did not meet the requirements in Table 8 to this subpart that apply to you. If you own or operate a new or reconstructed stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions (except new or reconstructed 4SLB engines greater than or equal to 250 and less than or equal to 500 brake HP), a new or reconstructed stationary RICE located at an area source of HAP emissions, or any of the following RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions, you do not need to comply with the requirements in Table 8 to this subpart: An existing 2SLB stationary RICE, an existing 4SLB stationary RICE, an existing emergency stationary RICE, an existing limited use stationary RICE, or an existing stationary RICE which fires landfill gas or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis. If you own or operate any of the following RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions, you do not need to comply with the requirements in Table 8 to this subpart, except for the initial notification requirements: a new or reconstructed stationary RICE that combusts landfill gas or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis, a new or reconstructed emergency stationary RICE, or a new or reconstructed limited use stationary RICE.

(f) If you own or operate an emergency stationary RICE, you must operate the emergency stationary RICE according to the requirements in paragraphs (f)(1) through (4) of this section. In order for the engine to be considered an emergency stationary RICE under this subpart, any operation other than emergency operation, maintenance and testing, emergency demand response, and operation in non-emergency situations for 50 hours per year, as described in paragraphs (f)(1) through (4) of this section, is prohibited. If you do not operate the engine according to the requirements in paragraphs (f)(1) through (4) of this section, the engine will not be considered an emergency engine under this subpart and must meet all requirements for non-emergency engines.

(1) There is no time limit on the use of emergency stationary RICE in emergency situations.

(2) You may operate your emergency stationary RICE for any combination of the purposes specified in paragraphs (f)(2)(i) through (iii) of this section for a maximum of 100 hours per calendar year. Any

operation for non-emergency situations as allowed by paragraphs (f)(3) and (4) of this section counts as part of the 100 hours per calendar year allowed by this paragraph (f)(2).

(i) Emergency stationary RICE may be operated for maintenance checks and readiness testing, provided that the tests are recommended by federal, state or local government, the manufacturer, the vendor, the regional transmission organization or equivalent balancing authority and transmission operator, or the insurance company associated with the engine. The owner or operator may petition the Administrator for approval of additional hours to be used for maintenance checks and readiness testing, but a petition is not required if the owner or operator maintains records indicating that federal, state, or local standards require maintenance and testing of emergency RICE beyond 100 hours per calendar year.

(ii) Emergency stationary RICE may be operated for emergency demand response for periods in which the Reliability Coordinator under the North American Electric Reliability Corporation (NERC) Reliability Standard EOP-002-3, Capacity and Energy Emergencies (incorporated by reference, see § 63.14), or other authorized entity as determined by the Reliability Coordinator, has declared an Energy Emergency Alert Level 2 as defined in the NERC Reliability Standard EOP-002-3.

(iii) Emergency stationary RICE may be operated for periods where there is a deviation of voltage or frequency of 5 percent or greater below standard voltage or frequency.

(3) Emergency stationary RICE located at major sources of HAP may be operated for up to 50 hours per calendar year in non-emergency situations. The 50 hours of operation in non-emergency situations are counted as part of the 100 hours per calendar year for maintenance and testing and emergency demand response provided in paragraph (f)(2) of this section. The 50 hours per year for non-emergency situations cannot be used for peak shaving or non-emergency demand response, or to generate income for a facility to supply power to an electric grid or otherwise supply power as part of a financial arrangement with another entity.

(4) Emergency stationary RICE located at area sources of HAP may be operated for up to 50 hours per calendar year in non-emergency situations. The 50 hours of operation in non-emergency situations are counted as part of the 100 hours per calendar year for maintenance and testing and emergency demand response provided in paragraph (f)(2) of this section. Except as provided in paragraphs (f)(4)(i) and (ii) of this section, the 50 hours per year for non-emergency situations cannot be used for peak shaving or non-emergency demand response, or to generate income for a facility to an electric grid or otherwise supply power as part of a financial arrangement with another entity.

(i) Prior to May 3, 2014, the 50 hours per year for non-emergency situations can be used for peak shaving or non-emergency demand response to generate income for a facility, or to otherwise supply power as part of a financial arrangement with another entity if the engine is operated as part of a peak shaving (load management program) with the local distribution system operator and the power is provided only to the facility itself or to support the local distribution system.

(ii) The 50 hours per year for non-emergency situations can be used to supply power as part of a financial arrangement with another entity if all of the following conditions are met:

(A) The engine is dispatched by the local balancing authority or local transmission and distribution system operator.

(B) The dispatch is intended to mitigate local transmission and/or distribution limitations so as to avert potential voltage collapse or line overloads that could lead to the interruption of power supply in a local area or region.

(C) The dispatch follows reliability, emergency operation or similar protocols that follow specific NERC, regional, state, public utility commission or local standards or guidelines.

(D) The power is provided only to the facility itself or to support the local transmission and distribution system.

(E) The owner or operator identifies and records the entity that dispatches the engine and the specific NERC, regional, state, public utility commission or local standards or guidelines that are being followed for dispatching the engine. The local balancing authority or local transmission and distribution system operator may keep these records on behalf of the engine owner or operator.

[69 FR 33506, June 15, 2004, as amended at 71 FR 20467, Apr. 20, 2006; 73 FR 3606, Jan. 18, 2008; 75 FR 9676, Mar. 3, 2010; 75 FR 51591, Aug. 20, 2010; 78 FR 6704, Jan. 30, 2013]

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Notifications, Reports, and Records

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§ 63.6645 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 (f)(6), 63.9(b) through (e), and (g) and (h) that apply to you by the dates specified if you own or operate any of the following;

(1) An existing stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions.

(2) An existing stationary RICE located at an area source of HAP emissions.

(3) A stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions.

(4) A new or reconstructed 4SLB stationary RICE with a site rating of greater than or equal to 250 HP located at a major source of HAP emissions.

(5) This requirement does not apply if you own or operate an existing stationary RICE less than 100 HP, an existing stationary emergency RICE, or an existing stationary RICE that is not subject to any numerical emission standards.

(b) As specified in § 63.9(b)(2), if you start up your stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions before the effective date of this subpart, you must submit an Initial Notification not later than December 13, 2004.

(c) If you start up your new or reconstructed stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions on or after August 16, 2004, you must submit an Initial Notification not later than 120 days after you become subject to this subpart.

(d) As specified in § 63.9(b)(2), if you start up your stationary RICE with a site rating of equal to or less than 500 brake HP located at a major source of HAP emissions before the effective date of this subpart and you are required to submit an initial notification, you must submit an Initial Notification not later than July 16, 2008.

(e) If you start up your new or reconstructed stationary RICE with a site rating of equal to or less than 500 brake HP located at a major source of HAP emissions on or after March 18, 2008 and you are

required to submit an initial notification, you must submit an Initial Notification not later than 120 days after you become subject to this subpart.

(f) If you are required to submit an Initial Notification but are otherwise not affected by the requirements of this subpart, in accordance with § 63.6590(b), your notification should include the information in § 63.9(b)(2)(i) through (v), and a statement that your stationary RICE has no additional requirements and explain the basis of the exclusion (for example, that it operates exclusively as an emergency stationary RICE if it has a site rating of more than 500 brake HP located at a major source of HAP emissions).

(g) If you are required to conduct a performance test, you must submit a Notification of Intent to conduct a performance test at least 60 days before the performance test is scheduled to begin as required in § 63.7(b)(1).

(h) If you are required to conduct a performance test or other initial compliance demonstration as specified in Tables 4 and 5 to this subpart, you must submit a Notification of Compliance Status according to § 63.9(h)(2)(ii).

(1) For each initial compliance demonstration required in Table 5 to this subpart that does not include a performance test, you must submit the Notification of Compliance Status before the close of business on the 30th day following the completion of the initial compliance demonstration.

(2) For each initial compliance demonstration required in Table 5 to this subpart that includes a performance test conducted according to the requirements in Table 3 to this subpart, you must submit the Notification of Compliance Status, including the performance test results, before the close of business on the 60th day following the completion of the performance test according to § 63.10(d)(2).

(i) If you own or operate an existing non-emergency CI RICE with a site rating of more than 300 HP located at an area source of HAP emissions that is certified to the Tier 1 or Tier 2 emission standards in Table 1 of 40 CFR 89.112 and subject to an enforceable state or local standard requiring engine replacement and you intend to meet management practices rather than emission limits, as specified in § 63.6603(d), you must submit a notification by March 3, 2013, stating that you intend to use the provision in § 63.6603(d) and identifying the state or local regulation that the engine is subject to.

[73 FR 3606, Jan. 18, 2008, as amended at 75 FR 9677, Mar. 3, 2010; 75 FR 51591, Aug. 20, 2010; 78 FR 6705, Jan. 30, 2013]

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§ 63.6650 What reports must I submit and when?

(a) You must submit each report in Table 7 of this subpart that applies to you.

(b) Unless the Administrator has approved a different schedule for submission of reports under § 63.10(a), you must submit each report by the date in Table 7 of this subpart and according to the requirements in paragraphs (b)(1) through (b)(9) of this section.

(1) For semiannual Compliance reports, the first Compliance report must cover the period beginning on the compliance date that is specified for your affected source in § 63.6595 and ending on June 30 or December 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 § 63.6595.

(2) For semiannual Compliance reports, the first Compliance report must be postmarked or delivered no later than July 31 or January 31, whichever date follows the end of the first calendar half after the compliance date that is specified for your affected source in § 63.6595.

(3) For semiannual Compliance reports, 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) For semiannual Compliance reports, 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 stationary RICE that is subject to permitting regulations pursuant to 40 CFR part 70 or 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 (b)(4) of this section.

(6) For annual Compliance reports, the first Compliance report must cover the period beginning on the compliance date that is specified for your affected source in § 63.6595 and ending on December 31.

(7) For annual Compliance reports, the first Compliance report must be postmarked or delivered no later than January 31 following the end of the first calendar year after the compliance date that is specified for your affected source in § 63.6595.

(8) For annual Compliance reports, each subsequent Compliance report must cover the annual reporting period from January 1 through December 31.

(9) For annual Compliance reports, each subsequent Compliance report must be postmarked or delivered no later than January 31.

(c) The Compliance report must contain the information in paragraphs (c)(1) through (6) of this section.

(1) Company name and address.

(2) Statement by a responsible official, with that official's name, title, and signature, certifying the accuracy of the content of the report.

(3) Date of report and beginning and ending dates of the reporting period.

(4) If you had a malfunction during the reporting period, the compliance report must include the number, duration, and a brief description for each type of malfunction which occurred during the reporting period and which caused or may have caused any applicable emission limitation to be exceeded. The report must also include a description of actions taken by an owner or operator during a malfunction of an affected source to minimize emissions in accordance with § 63.6605(b), including actions taken to correct a malfunction.

(5) If there are no deviations from any emission or operating limitations that apply to you, a statement that there were no deviations from the emission or operating limitations during the reporting period.

(6) If there were no periods during which the continuous monitoring system (CMS), including CEMS and CPMS, was out-of-control, as specified in § 63.8(c)(7), a statement that there were no periods during which the CMS was out-of-control during the reporting period.

(d) For each deviation from an emission or operating limitation that occurs for a stationary RICE where you are not using a CMS to comply with the emission or operating limitations in this subpart, the Compliance report must contain the information in paragraphs (c)(1) through (4) of this section and the information in paragraphs (d)(1) and (2) of this section.

(1) The total operating time of the stationary RICE at which the deviation occurred during the reporting period.

(2) Information on the number, duration, and cause of deviations (including unknown cause, if applicable), as applicable, and the corrective action taken.

(e) For each deviation from an emission or operating limitation occurring for a stationary RICE where you are using a CMS to comply with the emission and operating limitations in this subpart, you must include information in paragraphs (c)(1) through (4) and (e)(1) through (12) of this section.

(1) The date and time that each malfunction started and stopped.

(2) The date, time, and duration 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 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 control equipment problems, process problems, other known causes, and other unknown causes.

(7) A summary of the total duration of CMS downtime during the reporting period, and the total duration of CMS downtime as a percent of the total operating time of the stationary RICE at which the CMS downtime occurred during that reporting period.

(8) An identification of each parameter and pollutant (CO or formaldehyde) that was monitored at the stationary RICE.

(9) A brief description of the stationary RICE.

(10) A brief description of the CMS.

(11) The date of the latest CMS certification or audit.

(12) A description of any changes in CMS, processes, or controls since the last reporting period.

(f) Each affected source that has obtained a title V operating permit pursuant to 40 CFR part 70 or 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 7 of 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 or operating limitation in this subpart, submission of the Compliance report shall be deemed to satisfy any obligation to report the same deviations in the semiannual monitoring report. However, submission of a Compliance report shall not otherwise affect any obligation the affected source may have to report deviations from permit requirements to the permit authority.

(g) If you are operating as a new or reconstructed stationary RICE which fires landfill gas or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis, you must submit an annual report according to Table 7 of this subpart by the date specified unless the Administrator has approved a different schedule, according to the information described in paragraphs (b)(1) through (b)(5) of this section. You must report the data specified in (g)(1) through (g)(3) of this section.

(1) Fuel flow rate of each fuel and the heating values that were used in your calculations. You must also demonstrate that the percentage of heat input provided by landfill gas or digester gas is equivalent to 10 percent or more of the total fuel consumption on an annual basis.

(2) The operating limits provided in your federally enforceable permit, and any deviations from these limits.

(3) Any problems or errors suspected with the meters.

(h) If you own or operate an emergency stationary RICE with a site rating of more than 100 brake HP that operates or is contractually obligated to be available for more than 15 hours per calendar year for the purposes specified in § 63.6640(f)(2)(ii) and (iii) or that operates for the purpose specified in § 63.6640(f)(4)(ii), you must submit an annual report according to the requirements in paragraphs (h)(1) through (3) of this section.

(1) The report must contain the following information:

(i) Company name and address where the engine is located.

(ii) Date of the report and beginning and ending dates of the reporting period.

(iii) Engine site rating and model year.

(iv) Latitude and longitude of the engine in decimal degrees reported to the fifth decimal place.

(v) Hours operated for the purposes specified in § 63.6640(f)(2)(ii) and (iii), including the date, start time, and end time for engine operation for the purposes specified in § 63.6640(f)(2)(ii) and (iii).

(vi) Number of hours the engine is contractually obligated to be available for the purposes specified in § 63.6640(f)(2)(ii) and (iii).

(vii) Hours spent for operation for the purpose specified in § 63.6640(f)(4)(ii), including the date, start time, and end time for engine operation for the purposes specified in § 63.6640(f)(4)(ii). The report must also identify the entity that dispatched the engine and the situation that necessitated the dispatch of the engine.

(viii) If there were no deviations from the fuel requirements in § 63.6604 that apply to the engine (if any), a statement that there were no deviations from the fuel requirements during the reporting period.

(ix) If there were deviations from the fuel requirements in § 63.6604 that apply to the engine (if any), information on the number, duration, and cause of deviations, and the corrective action taken.

(2) The first annual report must cover the calendar year 2015 and must be submitted no later than March 31, 2016. Subsequent annual reports for each calendar year must be submitted no later than March 31 of the following calendar year.

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

[69 FR 33506, June 15, 2004, as amended at 75 FR 9677, Mar. 3, 2010; 78 FR 6705, Jan. 30, 2013]

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§ 63.6655 What records must I keep?

(a) If you must comply with the emission and operating limitations, you must keep the records described in paragraphs (a)(1) through (a)(5), (b)(1) through (b)(3) and (c) 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 that you submitted, according to the requirement in § 63.10(b)(2)(xiv).

(2) Records of the occurrence and duration of each malfunction of operation (*i.e.,* process equipment) or the air pollution control and monitoring equipment.

(3) Records of performance tests and performance evaluations as required in § 63.10(b)(2)(viii).

(4) Records of all required maintenance performed on the air pollution control and monitoring equipment.

(5) Records of actions taken during periods of malfunction to minimize emissions in accordance with § 63.6605(b), including corrective actions to restore malfunctioning process and air pollution control and monitoring equipment to its normal or usual manner of operation.

(b) For each CEMS or CPMS, you must keep the records listed in paragraphs (b)(1) through (3) of this section.

(1) Records described in § 63.10(b)(2)(vi) through (xi).

(2) Previous (*i.e.,* superseded) versions of the performance evaluation plan as required in § 63.8(d)(3).

(3) Requests for alternatives to the relative accuracy test for CEMS or CPMS as required in § 63.8(f)(6)(i), if applicable.

(c) If you are operating a new or reconstructed stationary RICE which fires landfill gas or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis, you must keep the records of your daily fuel usage monitors.

(d) You must keep the records required in Table 6 of this subpart to show continuous compliance with each emission or operating limitation that applies to you.

(e) You must keep records of the maintenance conducted on the stationary RICE in order to demonstrate that you operated and maintained the stationary RICE and after-treatment control device (if any) according to your own maintenance plan if you own or operate any of the following stationary RICE;

(1) An existing stationary RICE with a site rating of less than 100 brake HP located at a major source of HAP emissions.

(2) An existing stationary emergency RICE.

(3) An existing stationary RICE located at an area source of HAP emissions subject to management practices as shown in Table 2d to this subpart.

(f) If you own or operate any of the stationary RICE in paragraphs (f)(1) through (2) of this section, you must keep records of the hours of operation of the engine that is recorded through the non-resettable hour meter. The owner or operator must document how many hours are spent for emergency operation, including what classified the operation as emergency and how many hours are spent for non-emergency operation. If the engine is used for the purposes specified in § 63.6640(f)(2)(ii) or (iii) or § 63.6640(f)(4)(ii), the owner or operator must keep records of the notification of the emergency situation, and the date, start time, and end time of engine operation for these purposes.

(1) An existing emergency stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions that does not meet the standards applicable to non-emergency engines.

(2) An existing emergency stationary RICE located at an area source of HAP emissions that does not meet the standards applicable to non-emergency engines.

[69 FR 33506, June 15, 2004, as amended at 75 FR 9678, Mar. 3, 2010; 75 FR 51592, Aug. 20, 2010; 78 FR 6706, Jan. 30, 2013]

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§ 63.6660 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 readily accessible in hard copy or electronic form for at least 5 years after the date of each occurrence, measurement, maintenance, corrective action, report, or record, according to § 63.10(b)(1).

[69 FR 33506, June 15, 2004, as amended at 75 FR 9678, Mar. 3, 2010]

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Other Requirements and Information

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§ 63.6665 What parts of the General Provisions apply to me?

Table 8 to this subpart shows which parts of the General Provisions in §§ 63.1 through 63.15 apply to you. If you own or operate a new or reconstructed stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions (except new or reconstructed 4SLB engines greater than or equal to 250 and less than or equal to 500 brake HP), a new or reconstructed stationary RICE located at an area source of HAP emissions, or any of the following RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions, you do not need to comply with any of the requirements of the General Provisions specified in Table 8: An existing 2SLB stationary RICE, an existing 4SLB stationary RICE, an existing stationary RICE that combusts landfill or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis, an existing emergency stationary RICE, or an existing limited use stationary RICE. If you own or operate any of the following RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions, you do not need to comply with the requirements in the General Provisions specified in Table 8 except for the initial notification requirements: A new stationary RICE that combusts landfill gas or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis, a new emergency stationary RICE, or a new limited use stationary RICE.

[75 FR 9678, Mar. 3, 2010]

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§ 63.6670 Who implements and enforces this subpart?

(a) This subpart is implemented and enforced by 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 whether this subpart is delegated to your State, local, or tribal agency.

(b) In delegating implementation and enforcement authority of this subpart to a State, local, or tribal agency under 40 CFR part 63, subpart E, the authorities contained in 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:

(1) Approval of alternatives to the non-opacity emission limitations and operating limitations in § 63.6600 under § 63.6(g).

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

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

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

(5) Approval of a performance test which was conducted prior to the effective date of the rule, as specified in § 63.6610(b).

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§ 63.6675 What definitions apply to this subpart?

Terms used in this subpart are defined in the Clean Air Act (CAA); in 40 CFR 63.2, the General Provisions of this part; and in this section as follows:

Alaska Railbelt Grid **means the service areas of the six regulated public utilities that extend from Fairbanks to Anchorage and the Kenai Peninsula. These utilities are Golden Valley Electric Association; Chugach Electric Association; Matanuska Electric Association; Homer Electric Association; Anchorage Municipal Light & Power; and the City of Seward Electric System.**

Area source **means any stationary source of HAP that is not a major source as defined in part 63.**

Associated equipment **as used in this subpart and as referred to in section 112(n)(4) of the CAA, means equipment associated with an oil or natural gas exploration or production well, and includes all equipment from the well bore to the point of custody transfer, except glycol dehydration units, storage vessels with potential for flash emissions, combustion turbines, and stationary RICE.**

Backup power for renewable energy **means an engine that provides backup power to a facility that generates electricity from renewable energy resources, as that term is defined in Alaska Statute 42.45.045(l)(5) (incorporated by reference, see § 63.14).**

Black start engine **means an engine whose only purpose is to start up a combustion turbine.**

CAA **means the Clean Air Act (42 U.S.C. 7401** ***et seq.,*** **as amended by Public Law 101-549, 104 Stat. 2399).**

Commercial emergency stationary RICE **means an emergency stationary RICE used in commercial establishments such as office buildings, hotels, stores, telecommunications facilities, restaurants, financial institutions such as banks, doctor's offices, and sports and performing arts facilities.**

Compression ignition **means relating to a type of stationary internal combustion engine that is not a spark ignition engine.**

Custody transfer **means the transfer of hydrocarbon liquids or natural gas: After processing and/or treatment in the producing operations, or from storage vessels or automatic transfer facilities or other such equipment, including product loading racks, to pipelines or any other forms of transportation. For the purposes of this subpart, the point at which such liquids or natural gas enters a natural gas processing plant is a point of custody transfer.**

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

(1) Fails to meet any requirement or obligation established by this subpart, including but not limited to any emission limitation or operating limitation;

(2) 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

(3) Fails to meet any emission limitation or operating limitation in this subpart during malfunction, regardless or whether or not such failure is permitted by this subpart.

(4) Fails to satisfy the general duty to minimize emissions established by § 63.6(e)(1)(i).

***Diesel engine* means any stationary RICE in which a high boiling point liquid fuel injected into the combustion chamber ignites when the air charge has been compressed to a temperature sufficiently high for auto-ignition. This process is also known as compression ignition.**

***Diesel fuel* means any liquid obtained from the distillation of petroleum with a boiling point of approximately 150 to 360 degrees Celsius. One commonly used form is fuel oil number 2. Diesel fuel also includes any non-distillate fuel with comparable physical and chemical properties (*e.g.* biodiesel) that is suitable for use in compression ignition engines.**

***Digester gas* means any gaseous by-product of wastewater treatment typically formed through the anaerobic decomposition of organic waste materials and composed principally of methane and CO_2 .**

***Dual-fuel engine* means any stationary RICE in which a liquid fuel (typically diesel fuel) is used for compression ignition and gaseous fuel (typically natural gas) is used as the primary fuel.**

***Emergency stationary RICE* means any stationary reciprocating internal combustion engine that meets all of the criteria in paragraphs (1) through (3) of this definition. All emergency stationary RICE must comply with the requirements specified in § 63.6640(f) in order to be considered emergency stationary RICE. If the engine does not comply with the requirements specified in § 63.6640(f), then it is not considered to be an emergency stationary RICE under this subpart.**

(1) The stationary RICE is operated to provide electrical power or mechanical work during an emergency situation. Examples include stationary RICE used to produce power for critical networks or equipment (including power supplied to portions of a facility) when electric power from the local utility (or the normal power source, if the facility runs on its own power production) is interrupted, or stationary RICE used to pump water in the case of fire or flood, etc.

(2) The stationary RICE is operated under limited circumstances for situations not included in paragraph (1) of this definition, as specified in § 63.6640(f).

(3) The stationary RICE operates as part of a financial arrangement with another entity in situations not included in paragraph (1) of this definition only as allowed in § 63.6640(f)(2)(ii) or (iii) and § 63.6640(f)(4)(i) or (ii).

***Engine startup* means the time from initial start until applied load and engine and associated equipment reaches steady state or normal operation. For stationary engine with catalytic controls, engine startup means the time from initial start until applied load and engine and associated equipment, including the catalyst, reaches steady state or normal operation.**

***Four-stroke engine* means any type of engine which completes the power cycle in two crankshaft revolutions, with intake and compression strokes in the first revolution and power and exhaust strokes in the second revolution.**

***Gaseous fuel* means a material used for combustion which is in the gaseous state at standard atmospheric temperature and pressure conditions.**

***Gasoline* means any fuel sold in any State for use in motor vehicles and motor vehicle engines, or nonroad or stationary engines, and commonly or commercially known or sold as gasoline.**

***Glycol dehydration unit* means a device in which a liquid glycol (including, but not limited to, ethylene glycol, diethylene glycol, or triethylene glycol) absorbent directly contacts a natural gas stream and absorbs water in a contact tower or absorption column (absorber). The glycol contacts and absorbs water vapor and other gas stream constituents from the natural gas and becomes “rich” glycol. This glycol is then regenerated in the glycol dehydration unit reboiler. The “lean” glycol is then recycled.**

Hazardous air pollutants (HAP) **means any air pollutants listed in or pursuant to section 112(b) of the CAA.**

Institutional emergency stationary RICE **means an emergency stationary RICE used in institutional establishments such as medical centers, nursing homes, research centers, institutions of higher education, correctional facilities, elementary and secondary schools, libraries, religious establishments, police stations, and fire stations.**

ISO standard day conditions **means 288 degrees Kelvin (15 degrees Celsius), 60 percent relative humidity and 101.3 kilopascals pressure.**

Landfill gas **means a gaseous by-product of the land application of municipal refuse typically formed through the anaerobic decomposition of waste materials and composed principally of methane and CO_2 .**

Lean burn engine **means any two-stroke or four-stroke spark ignited engine that does not meet the definition of a rich burn engine.**

Limited use stationary RICE **means any stationary RICE that operates less than 100 hours per year.**

Liquefied petroleum gas **means any liquefied hydrocarbon gas obtained as a by-product in petroleum refining of natural gas production.**

Liquid fuel **means any fuel in liquid form at standard temperature and pressure, including but not limited to diesel, residual/crude oil, kerosene/naphtha (jet fuel), and gasoline.**

Major Source, **as used in this subpart, shall have the same meaning as in § 63.2, except that:**

(1) Emissions from any oil or gas exploration or production well (with its associated equipment (as defined in this section)) and emissions from any pipeline compressor station or pump station shall not be aggregated with emissions from other similar units, to determine whether such emission points or stations are major sources, even when emission points are in a contiguous area or under common control;

(2) For oil and gas production facilities, emissions from processes, operations, or equipment that are not part of the same oil and gas production facility, as defined in § 63.1271 of subpart HHH of this part, shall not be aggregated;

(3) For production field facilities, only HAP emissions from glycol dehydration units, storage vessel with the potential for flash emissions, combustion turbines and reciprocating internal combustion engines shall be aggregated for a major source determination; and

(4) Emissions from processes, operations, and equipment that are not part of the same natural gas transmission and storage facility, as defined in § 63.1271 of subpart HHH of this part, shall not be aggregated.

Malfunction **means any sudden, infrequent, and not reasonably preventable failure of air pollution control equipment, process equipment, or a process to operate in a normal or usual manner which causes, or has the potential to cause, the emission limitations in an applicable standard to be exceeded. Failures that are caused in part by poor maintenance or careless operation are not malfunctions.**

Natural gas **means a naturally occurring mixture of hydrocarbon and non-hydrocarbon gases found in geologic formations beneath the Earth's surface, of which the principal constituent is methane. Natural gas may be field or pipeline quality.**

Non-selective catalytic reduction (NSCR) **means an add-on catalytic nitrogen oxides (NO_X) control device for rich burn engines that, in a two-step reaction, promotes the conversion of excess oxygen, NO_X , CO, and volatile organic compounds (VOC) into CO_2 , nitrogen, and water.**

Oil and gas production facility **as used in this subpart means any grouping of equipment where hydrocarbon liquids are processed, upgraded (** ***i.e.,*** **remove impurities or other constituents to meet contract specifications), or stored prior to the point of custody transfer; or where natural gas is processed, upgraded, or stored prior to entering the natural gas transmission and storage source category. For purposes of a major source determination, facility (including a building, structure, or installation) means oil and natural gas production and processing equipment that is located within the boundaries of an individual surface site as defined in this section. Equipment that is part of a facility will typically be located within close proximity to other equipment located at the same facility. Pieces of production equipment or groupings of equipment located on different oil and gas leases, mineral fee tracts, lease tracts, subsurface or surface unit areas, surface fee tracts, surface lease tracts, or separate surface sites, whether or not connected by a road, waterway, power line or pipeline, shall not be considered part of the same facility. Examples of facilities in the oil and natural gas production source category include, but are not limited to, well sites, satellite tank batteries, central tank batteries, a compressor station that transports natural gas to a natural gas processing plant, and natural gas processing plants.**

Oxidation catalyst **means an add-on catalytic control device that controls CO and VOC by oxidation.**

Peaking unit or engine **means any standby engine intended for use during periods of high demand that are not emergencies.**

Percent load **means the fractional power of an engine compared to its maximum manufacturer's design capacity at engine site conditions. Percent load may range between 0 percent to above 100 percent.**

Potential to emit **means the maximum capacity of a stationary source to emit a pollutant under its physical and operational design. Any physical or operational limitation on the capacity of the stationary source to emit a pollutant, including air pollution control equipment and restrictions on hours of operation or on the type or amount of material combusted, stored, or processed, shall be treated as part of its design if the limitation or the effect it would have on emissions is federally enforceable. For oil and natural gas production facilities subject to subpart HH of this part, the potential to emit provisions in § 63.760(a) may be used. For natural gas transmission and storage facilities subject to subpart HHH of this part, the maximum annual facility gas throughput for storage facilities may be determined according to § 63.1270(a)(1) and the maximum annual throughput for transmission facilities may be determined according to § 63.1270(a)(2).**

Production field facility **means those oil and gas production facilities located prior to the point of custody transfer.**

Production well **means any hole drilled in the earth from which crude oil, condensate, or field natural gas is extracted.**

Propane **means a colorless gas derived from petroleum and natural gas, with the molecular structure $C_3 H_8$.**

Remote stationary RICE **means stationary RICE meeting any of the following criteria:**

(1) Stationary RICE located in an offshore area that is beyond the line of ordinary low water along that portion of the coast of the United States that is in direct contact with the open seas and beyond the line marking the seaward limit of inland waters.

(2) Stationary RICE located on a pipeline segment that meets both of the criteria in paragraphs (2)(i) and (ii) of this definition.

(i) A pipeline segment with 10 or fewer buildings intended for human occupancy and no buildings with four or more stories within 220 yards (200 meters) on either side of the centerline of any continuous 1-mile (1.6 kilometers) length of pipeline. Each separate dwelling unit in a multiple dwelling unit building is counted as a separate building intended for human occupancy.

(ii) The pipeline segment does not lie within 100 yards (91 meters) of either a building or a small, well-defined outside area (such as a playground, recreation area, outdoor theater, or other place of public assembly) that is occupied by 20 or more persons on at least 5 days a week for 10 weeks in any 12-month period. The days and weeks need not be consecutive. The building or area is considered occupied for a full day if it is occupied for any portion of the day.

(iii) For purposes of this paragraph (2), the term pipeline segment means all parts of those physical facilities through which gas moves in transportation, including but not limited to pipe, valves, and other appurtenance attached to pipe, compressor units, metering stations, regulator stations, delivery stations, holders, and fabricated assemblies. Stationary RICE located within 50 yards (46 meters) of the pipeline segment providing power for equipment on a pipeline segment are part of the pipeline segment. Transportation of gas means the gathering, transmission, or distribution of gas by pipeline, or the storage of gas. A building is intended for human occupancy if its primary use is for a purpose involving the presence of humans.

(3) Stationary RICE that are not located on gas pipelines and that have 5 or fewer buildings intended for human occupancy and no buildings with four or more stories within a 0.25 mile radius around the engine. A building is intended for human occupancy if its primary use is for a purpose involving the presence of humans.

***Residential emergency stationary RICE* means an emergency stationary RICE used in residential establishments such as homes or apartment buildings.**

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

***Rich burn engine* means any four-stroke spark ignited engine where the manufacturer's recommended operating air/fuel ratio divided by the stoichiometric air/fuel ratio at full load conditions is less than or equal to 1.1. Engines originally manufactured as rich burn engines, but modified prior to December 19, 2002 with passive emission control technology for NO_X (such as pre-combustion chambers) will be considered lean burn engines. Also, existing engines where there are no manufacturer's recommendations regarding air/fuel ratio will be considered a rich burn engine if the excess oxygen content of the exhaust at full load conditions is less than or equal to 2 percent.**

***Site-rated HP* means the maximum manufacturer's design capacity at engine site conditions.**

***Spark ignition* means relating to either: A gasoline-fueled engine; or any other type of engine with a spark plug (or other sparking device) and with operating characteristics significantly similar to the theoretical Otto combustion cycle. Spark ignition engines usually use a throttle to regulate intake air flow to control power during normal operation. Dual-fuel engines in which a liquid fuel (typically diesel fuel) is used for CI and gaseous fuel (typically natural gas) is used as the primary fuel at an annual average ratio of less than 2 parts diesel fuel to 100 parts total fuel on an energy equivalent basis are spark ignition engines.**

Stationary reciprocating internal combustion engine (RICE) **means any reciprocating internal combustion engine which uses reciprocating motion to convert heat energy into mechanical work and which is not mobile. Stationary RICE differ from mobile RICE in that a stationary RICE is not a non-road engine as defined at 40 CFR 1068.30, and is not used to propel a motor vehicle or a vehicle used solely for competition.**

Stationary RICE test cell/stand **means an engine test cell/stand, as defined in subpart PPPPP of this part, that tests stationary RICE.**

Stoichiometric **means the theoretical air-to-fuel ratio required for complete combustion.**

Storage vessel with the potential for flash emissions **means any storage vessel that contains a hydrocarbon liquid with a stock tank gas-to-oil ratio equal to or greater than 0.31 cubic meters per liter and an American Petroleum Institute gravity equal to or greater than 40 degrees and an actual annual average hydrocarbon liquid throughput equal to or greater than 79,500 liters per day. Flash emissions occur when dissolved hydrocarbons in the fluid evolve from solution when the fluid pressure is reduced.**

Subpart **means 40 CFR part 63, subpart ZZZZ.**

Surface site **means any combination of one or more graded pad sites, gravel pad sites, foundations, platforms, or the immediate physical location upon which equipment is physically affixed.**

Two-stroke engine **means a type of engine which completes the power cycle in single crankshaft revolution by combining the intake and compression operations into one stroke and the power and exhaust operations into a second stroke. This system requires auxiliary scavenging and inherently runs lean of stoichiometric.**

[69 FR 33506, June 15, 2004, as amended at 71 FR 20467, Apr. 20, 2006; 73 FR 3607, Jan. 18, 2008; 75 FR 9679, Mar. 3, 2010; 75 FR 51592, Aug. 20, 2010; 76 FR 12867, Mar. 9, 2011; 78 FR 6706, Jan. 30, 2013]

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Table 1 a to Subpart ZZZZ of Part 63—Emission Limitations for Existing, New, and Reconstructed Spark Ignition, 4SRB Stationary RICE > 500 HP Located at a Major Source of HAP Emissions

As stated in §§ 63.6600 and 63.6640, you must comply with the following emission limitations at 100 percent load plus or minus 10 percent for existing, new and reconstructed 4SRB stationary RICE >500 HP located at a major source of HAP emissions:

For each . . .	You must meet the following emission limitation, except during periods of startup . . .	During periods of startup you must . . .
1. 4SRB stationary RICE	a. Reduce formaldehyde emissions by 76 percent or more. If you commenced construction or reconstruction between December 19, 2002 and June 15, 2004, you may reduce formaldehyde emissions by 75 percent or more until June 15, 2007 or	Minimize the engine's time spent at idle and minimize the engine's startup time at startup to a period needed for appropriate and safe loading of the engine, not to exceed 30 minutes, after which time the non-startup emission limitations apply.[1]
	b. Limit the concentration of formaldehyde in the stationary RICE exhaust to 350 ppbvd or less at 15 percent O_2	

[1]Sources can petition the Administrator pursuant to the requirements of 40 CFR 63.6(g) for alternative work practices.

[75 FR 9679, Mar. 3, 2010, as amended at 75 FR 51592, Aug. 20, 2010]

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Table 1 b to Subpart ZZZZ of Part 63—Operating Limitations for Existing, New, and Reconstructed SI 4SRB Stationary RICE >500 HP Located at a Major Source of HAP Emissions

As stated in §§ 63.6600, 63.6603, 63.6630 and 63.6640, you must comply with the following operating limitations for existing, new and reconstructed 4SRB stationary RICE >500 HP located at a major source of HAP emissions:

Table 1b to Subpart ZZZZ of Part 63—Operating Limitations for Existing, New, and Reconstructed SI 4SRB Stationary RICE >500 HP Located at a Major Source of HAP Emissions

For each . . .	You must meet the following operating limitation, except during periods of startup . . .
1. existing, new and reconstructed 4SRB stationary RICE >500 HP located at a major source of HAP emissions complying with the requirement to reduce formaldehyde emissions by 76 percent or more (or by 75 percent or more, if applicable) and using NSCR; or existing, new and reconstructed 4SRB stationary RICE >500 HP located at a major source of HAP emissions complying with the requirement to limit the concentration of formaldehyde in the stationary RICE exhaust to 350 ppbvd or less at 15 percent $O_2$and using NSCR;	a. maintain your catalyst so that the pressure drop across the catalyst does not change by more than 2 inches of water at 100 percent load plus or minus 10 percent from the pressure drop across the catalyst measured during the initial performance test; and b. maintain the temperature of your stationary RICE exhaust so that the catalyst inlet temperature is greater than or equal to 750 °F and less than or equal to 1250 °F.[1]
2. existing, new and reconstructed 4SRB stationary RICE >500 HP located at a major source of HAP emissions complying with the requirement to reduce formaldehyde emissions by 76 percent or more (or by 75 percent or more, if applicable) and not using NSCR; or	Comply with any operating limitations approved by the Administrator.
existing, new and reconstructed 4SRB stationary RICE >500 HP located at a major source of HAP emissions complying with the requirement to limit the concentration of formaldehyde in the stationary RICE exhaust to 350 ppbvd or less at 15 percent $O_2$and not using NSCR.	

[1] Sources can petition the Administrator pursuant to the requirements of 40 CFR 63.8(f) for a different temperature range.

[78 FR 6706, Jan. 30, 2013]

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Table 2 a to Subpart ZZZZ of Part 63—Emission Limitations for New and Reconstructed 2SLB and Compression Ignition Stationary RICE >500 HP and New and Reconstructed 4SLB Stationary RICE ≥250 HP Located at a Major Source of HAP Emissions

As stated in §§ 63.6600 and 63.6640, you must comply with the following emission limitations for new and reconstructed lean burn and new and reconstructed compression ignition stationary RICE at 100 percent load plus or minus 10 percent:

For each . . .	You must meet the following emission limitation, except during periods of startup . . .	During periods of startup you must . . .
1. 2SLB stationary RICE	a. Reduce CO emissions by 58 percent or more; or b. Limit concentration of formaldehyde in the stationary RICE exhaust to 12 ppmvd or less at 15 percent O_2. If you commenced construction or reconstruction between December 19, 2002 and June 15, 2004, you may limit concentration of formaldehyde to 17 ppmvd or less at 15 percent O_2until June 15, 2007	Minimize the engine's time spent at idle and minimize the engine's startup time at startup to a period needed for appropriate and safe loading of the engine, not to exceed 30 minutes, after which time the non-startup emission limitations apply.[1]
2. 4SLB stationary RICE	a. Reduce CO emissions by 93 percent or more; or	
	b. Limit concentration of formaldehyde in the stationary RICE exhaust to 14 ppmvd or less at 15 percent O_2	
3. CI stationary RICE	a. Reduce CO emissions by 70 percent or more; or	
	b. Limit concentration of formaldehyde in the stationary RICE exhaust to 580 ppbvd or less at 15 percent O_2	

[1] Sources can petition the Administrator pursuant to the requirements of 40 CFR 63.6(g) for alternative work practices.

[75 FR 9680, Mar. 3, 2010]

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Table 2 b to Subpart ZZZZ of Part 63—Operating Limitations for New and Reconstructed 2SLB and CI Stationary RICE >500 HP Located at a Major Source of HAP Emissions, New and Reconstructed 4SLB Stationary RICE ≥250 HP Located at a Major Source of HAP Emissions, Existing CI Stationary RICE >500 HP

As stated in §§ 63.6600, 63.6601, 63.6603, 63.6630, and 63.6640, you must comply with the following operating limitations for new and reconstructed 2SLB and CI stationary RICE >500 HP located at a major source of HAP emissions; new and reconstructed 4SLB stationary RICE ≥250 HP located at a major source of HAP emissions; and existing CI stationary RICE >500 HP:

Table 2b to Subpart ZZZZ of Part 63—Operating Limitations for New and Reconstructed 2SLB and CI Stationary RICE >500 HP Located at a Major Source of HAP Emissions, New and Reconstructed 4SLB Stationary RICE ≥250 HP Located at a Major Source of HAP Emissions, Existing CI Stationary RICE >500 HP

For each . . .	You must meet the following operating limitation, except during periods of startup . . .
1. New and reconstructed 2SLB and CI stationary RICE >500 HP located at a major source of HAP emissions and new and reconstructed 4SLB stationary RICE ≥250 HP located at a major source of HAP emissions complying with the requirement to reduce CO emissions and using an oxidation catalyst; and New and reconstructed 2SLB and CI stationary RICE >500 HP located at a major source of HAP emissions and new and reconstructed 4SLB stationary RICE ≥250 HP located at a major source of HAP emissions complying with the requirement to limit the concentration of formaldehyde in the stationary RICE exhaust and using an oxidation catalyst.	a. maintain your catalyst so that the pressure drop across the catalyst does not change by more than 2 inches of water at 100 percent load plus or minus 10 percent from the pressure drop across the catalyst that was measured during the initial performance test; and b. maintain the temperature of your stationary RICE exhaust so that the catalyst inlet temperature is greater than or equal to 450 °F and less than or equal to 1350 °F.[1]
2. Existing CI stationary RICE >500 HP complying with the requirement to limit or reduce the concentration of CO in the stationary RICE exhaust and using an oxidation catalyst	a. maintain your catalyst so that the pressure drop across the catalyst does not change by more than 2 inches of water from the pressure drop across the catalyst that was measured during the initial performance test; and
	b. maintain the temperature of your stationary RICE exhaust so that the catalyst inlet temperature is greater than or equal to 450 °F and less than or equal to 1350 °F.[1]
3. New and reconstructed 2SLB and CI stationary RICE >500 HP located at a major source of HAP emissions and new and reconstructed 4SLB stationary RICE ≥250 HP located at a major source of HAP emissions complying with the requirement to reduce CO emissions and not using an oxidation catalyst; and	Comply with any operating limitations approved by the Administrator.
New and reconstructed 2SLB and CI stationary RICE >500 HP located at a major source of HAP emissions and new and reconstructed 4SLB stationary RICE ≥250 HP located at a major source of HAP emissions complying with the requirement to limit the concentration of formaldehyde in the stationary RICE exhaust and not using an oxidation catalyst; and	
existing CI stationary RICE >500 HP complying with the requirement to limit or reduce the concentration of CO in the stationary RICE exhaust and not using an oxidation catalyst.	

[1] Sources can petition the Administrator pursuant to the requirements of 40 CFR 63.8(f) for a different temperature range.

[78 FR 6707, Jan. 30, 2013]

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Requirements for Existing Compression Ignition Stationary RICE Located at a Major Source of HAP Emissions and Existing Spark Ignition Stationary RICE ≤500 HP Located at a Major Source of HAP Emissions

As stated in §§ 63.6600, 63.6602, and 63.6640, you must comply with the following requirements for existing compression ignition stationary RICE located at a major source of HAP emissions and existing spark ignition stationary RICE ≤500 HP located at a major source of HAP emissions:

Table 2c to Subpart ZZZZ of Part 63—Requirements for Existing Compression Ignition Stationary RICE Located at a Major Source of HAP Emissions and Existing Spark Ignition Stationary RICE ≤500 HP Located at a Major Source of HAP Emissions

For each . . .	You must meet the following requirement, except during periods of startup . . .	During periods of startup you must . . .
1. Emergency stationary CI RICE and black start stationary CI RICE [1]	a. Change oil and filter every 500 hours of operation or annually, whichever comes first.[2] b. Inspect air cleaner every 1,000 hours of operation or annually, whichever comes first, and replace as necessary; c. Inspect all hoses and belts every 500 hours of operation or annually, whichever comes first, and replace as necessary.[3]	Minimize the engine's time spent at idle and minimize the engine's startup time at startup to a period needed for appropriate and safe loading of the engine, not to exceed 30 minutes, after which time the non-startup emission limitations apply.[3]
2. Non-Emergency, non-black start stationary CI RICE <100 HP	a. Change oil and filter every 1,000 hours of operation or annually, whichever comes first.[2] b. Inspect air cleaner every 1,000 hours of operation or annually, whichever comes first, and replace as necessary; c. Inspect all hoses and belts every 500 hours of operation or annually, whichever comes first, and replace as necessary.[3]	
3. Non-Emergency, non-black start CI stationary RICE 100≤HP≤300 HP	Limit concentration of CO in the stationary RICE exhaust to 230 ppmvd or less at 15 percent O_2.	

For each . . .	**You must meet the following requirement, except during periods of startup . . .**	**During periods of startup you must . . .**
4. Non-Emergency, non-black start CI stationary RICE 300>HP≤500." is corrected to read "4. Non-Emergency, non-black start CI stationary RICE 300<HP≤500.	**a. Limit concentration of CO in the stationary RICE exhaust to 49 ppmvd or less at 15 percent O_2; or** **b. Reduce CO emissions by 70 percent or more.**	
5. Non-Emergency, non-black start stationary CI RICE >500 HP	**a. Limit concentration of CO in the stationary RICE exhaust to 23 ppmvd or less at 15 percent O_2; or** **b. Reduce CO emissions by 70 percent or more.**	
6. Emergency stationary SI RICE and black start stationary SI RICE.[1]	**a. Change oil and filter every 500 hours of operation or annually, whichever comes first;**[2] **b. Inspect spark plugs every 1,000 hours of operation or annually, whichever comes first, and replace as necessary;** **c. Inspect all hoses and belts every 500 hours of operation or annually, whichever comes first, and replace as necessary.**[3]	
7. Non-Emergency, non-black start stationary SI RICE <100 HP that are not 2SLB stationary RICE	**a. Change oil and filter every 1,440 hours of operation or annually, whichever comes first;**[2] **b. Inspect spark plugs every 1,440 hours of operation or annually, whichever comes first, and replace as necessary;**	
	c. Inspect all hoses and belts every 1,440 hours of operation or annually, whichever comes first, and replace as necessary.[3]	

For each . . .	You must meet the following requirement, except during periods of startup . . .	During periods of startup you must . . .
8. Non-Emergency, non-black start 2SLB stationary SI RICE <100 HP	**a. Change oil and filter every 4,320 hours of operation or annually, whichever comes first;[2]** **b. Inspect spark plugs every 4,320 hours of operation or annually, whichever comes first, and replace as necessary;**	
	c. Inspect all hoses and belts every 4,320 hours of operation or annually, whichever comes first, and replace as necessary.[3]	
9. Non-emergency, non-black start 2SLB stationary RICE 100≤HP≤500	**Limit concentration of CO in the stationary RICE exhaust to 225 ppmvd or less at 15 percent O_2.**	
10. Non-emergency, non-black start 4SLB stationary RICE 100≤HP≤500	**Limit concentration of CO in the stationary RICE exhaust to 47 ppmvd or less at 15 percent O_2.**	
11. Non-emergency, non-black start 4SRB stationary RICE 100≤HP≤500	**Limit concentration of formaldehyde in the stationary RICE exhaust to 10.3 ppmvd or less at 15 percent O_2.**	
12. Non-emergency, non-black start stationary RICE 100≤HP≤500 which combusts landfill or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis	**Limit concentration of CO in the stationary RICE exhaust to 177 ppmvd or less at 15 percent O_2.**	

[1] If an emergency engine is operating during an emergency and it is not possible to shut down the engine in order to perform the work practice requirements on the schedule required in Table 2c of this subpart, or if performing the work practice on the required schedule would otherwise pose an unacceptable risk under federal, state, or local law, the work practice can be delayed until the emergency is over or the unacceptable risk under federal, state, or local law has abated. The work practice should be performed as soon as practicable after the emergency has ended or the unacceptable risk under federal, state, or local law has abated. Sources must report any failure to perform the work practice on the schedule required and the federal, state or local law under which the risk was deemed unacceptable.

[2] Sources have the option to utilize an oil analysis program as described in § 63.6625(i) or (j) in order to extend the specified oil change requirement in Table 2c of this subpart.

[3] Sources can petition the Administrator pursuant to the requirements of 40 CFR 63.6(g) for alternative work practices.

[78 FR 6708, Jan. 30, 2013, as amended at 78 FR 14457, Mar. 6, 2013]

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Requirements for Existing Stationary RICE Located at Area Sources of HAP Emissions

As stated in §§ 63.6603 and 63.6640, you must comply with the following requirements for existing stationary RICE located at area sources of HAP emissions:

Table 2d to Subpart ZZZZ of Part 63—Requirements for Existing Stationary RICE Located at Area Sources of HAP Emissions

For each . . .	You must meet the following requirement, except during periods of startup . . .	During periods of startup you must . . .
1. Non-Emergency, non-black start CI stationary RICE ≤300 HP	a. Change oil and filter every 1,000 hours of operation or annually, whichever comes first;[1] b. Inspect air cleaner every 1,000 hours of operation or annually, whichever comes first, and replace as necessary; c. Inspect all hoses and belts every 500 hours of operation or annually, whichever comes first, and replace as necessary.	Minimize the engine's time spent at idle and minimize the engine's startup time at startup to a period needed for appropriate and safe loading of the engine, not to exceed 30 minutes, after which time the non-startup emission limitations apply.
2. Non-Emergency, non-black start CI stationary RICE 300<HP≤500	a. Limit concentration of CO in the stationary RICE exhaust to 49 ppmvd at 15 percent O_2; or	
	b. Reduce CO emissions by 70 percent or more.	
3. Non-Emergency, non-black start CI stationary RICE >500 HP	a. Limit concentration of CO in the stationary RICE exhaust to 23 ppmvd at 15 percent O_2; or	
	b. Reduce CO emissions by 70 percent or more.	
4. Emergency stationary CI RICE and black start stationary CI RICE.[2]	a. Change oil and filter every 500 hours of operation or annually, whichever comes first;[1]	

For each . . .	You must meet the following requirement, except during periods of startup . . .	During periods of startup you must . . .
	b. Inspect air cleaner every 1,000 hours of operation or annually, whichever comes first, and replace as necessary; and	
	c. Inspect all hoses and belts every 500 hours of operation or annually, whichever comes first, and replace as necessary.	
5. Emergency stationary SI RICE; black start stationary SI RICE; non-emergency, non-black start 4SLB stationary RICE >500 HP that operate 24 hours or less per calendar year; non-emergency, non-black start 4SRB stationary RICE >500 HP that operate 24 hours or less per calendar year.[2]	a. Change oil and filter every 500 hours of operation or annually, whichever comes first;[1]; b. Inspect spark plugs every 1,000 hours of operation or annually, whichever comes first, and replace as necessary; and c. Inspect all hoses and belts every 500 hours of operation or annually, whichever comes first, and replace as necessary.	
6. Non-emergency, non-black start 2SLB stationary RICE	a. Change oil and filter every 4,320 hours of operation or annually, whichever comes first;[1]	
	b. Inspect spark plugs every 4,320 hours of operation or annually, whichever comes first, and replace as necessary; and	
	c. Inspect all hoses and belts every 4,320 hours of operation or annually, whichever comes first, and replace as necessary.	
7. Non-emergency, non-black start 4SLB stationary RICE ≤500 HP	a. Change oil and filter every 1,440 hours of operation or annually, whichever comes first;[1]	

For each . . .	**You must meet the following requirement, except during periods of startup . . .**	**During periods of startup you must . . .**
	b. Inspect spark plugs every 1,440 hours of operation or annually, whichever comes first, and replace as necessary; and	
	c. Inspect all hoses and belts every 1,440 hours of operation or annually, whichever comes first, and replace as necessary.	
8. Non-emergency, non-black start 4SLB remote stationary RICE >500 HP	**a. Change oil and filter every 2,160 hours of operation or annually, whichever comes first;[1]**	
	b. Inspect spark plugs every 2,160 hours of operation or annually, whichever comes first, and replace as necessary; and	
	c. Inspect all hoses and belts every 2,160 hours of operation or annually, whichever comes first, and replace as necessary.	
9. Non-emergency, non-black start 4SLB stationary RICE >500 HP that are not remote stationary RICE and that operate more than 24 hours per calendar year	**Install an oxidation catalyst to reduce HAP emissions from the stationary RICE.**	
10. Non-emergency, non-black start 4SRB stationary RICE ≤500 HP	**a. Change oil and filter every 1,440 hours of operation or annually, whichever comes first;[1]**	
	b. Inspect spark plugs every 1,440 hours of operation or annually, whichever comes first, and replace as necessary; and	

For each . . .	**You must meet the following requirement, except during periods of startup . . .**	**During periods of startup you must . . .**
	c. Inspect all hoses and belts every 1,440 hours of operation or annually, whichever comes first, and replace as necessary.	
11. Non-emergency, non-black start 4SRB remote stationary RICE >500 HP	**a. Change oil and filter every 2,160 hours of operation or annually, whichever comes first;[1]**	
	b. Inspect spark plugs every 2,160 hours of operation or annually, whichever comes first, and replace as necessary; and	
	c. Inspect all hoses and belts every 2,160 hours of operation or annually, whichever comes first, and replace as necessary.	
12. Non-emergency, non-black start 4SRB stationary RICE >500 HP that are not remote stationary RICE and that operate more than 24 hours per calendar year	**Install NSCR to reduce HAP emissions from the stationary RICE.**	
13. Non-emergency, non-black start stationary RICE which combusts landfill or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis	**a. Change oil and filter every 1,440 hours of operation or annually, whichever comes first;[1]** **b. Inspect spark plugs every 1,440 hours of operation or annually, whichever comes first, and replace as necessary; and**	
	c. Inspect all hoses and belts every 1,440 hours of operation or annually, whichever comes first, and replace as necessary.	

[1] Sources have the option to utilize an oil analysis program as described in § 63.6625(i) or (j) in order to extend the specified oil change requirement in Table 2d of this subpart.

[2] If an emergency engine is operating during an emergency and it is not possible to shut down the engine in order to perform the management practice requirements on the schedule required in Table 2d of this subpart, or if performing the management practice on the required schedule would otherwise pose an unacceptable risk under federal, state, or local law, the management practice can be delayed until the emergency is over or the unacceptable risk under federal, state, or local law has abated. The management practice should be performed as soon as practicable after the emergency has ended or the unacceptable risk under federal, state, or local law has abated. Sources must report any failure to perform the management practice on the schedule required and the federal, state or local law under which the risk was deemed unacceptable.

[78 FR 6709, Jan. 30, 2013]

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Subsequent Performance Tests

As stated in §§ 63.6615 and 63.6620, you must comply with the following subsequent performance test requirements:

Table 3 to Subpart ZZZZ of Part 63—Subsequent Performance Tests

For each . . .	Complying with the requirement to . . .	You must . . .
1. New or reconstructed 2SLB stationary RICE >500 HP located at major sources; new or reconstructed 4SLB stationary RICE ≥250 HP located at major sources; and new or reconstructed CI stationary RICE >500 HP located at major sources	Reduce CO emissions and not using a CEMS	Conduct subsequent performance tests semiannually.[1]
2. 4SRB stationary RICE ≥5,000 HP located at major sources	Reduce formaldehyde emissions	Conduct subsequent performance tests semiannually.[1]
3. Stationary RICE >500 HP located at major sources and new or reconstructed 4SLB stationary RICE 250≤HP≤500 located at major sources	Limit the concentration of formaldehyde in the stationary RICE exhaust	Conduct subsequent performance tests semiannually.[1]
4. Existing non-emergency, non-black start CI stationary RICE >500 HP that are not limited use stationary RICE	Limit or reduce CO emissions and not using a CEMS	Conduct subsequent performance tests every 8,760 hours or 3 years, whichever comes first.
5. Existing non-emergency, non-black start CI stationary RICE >500 HP that are limited use stationary RICE	Limit or reduce CO emissions and not using a CEMS	Conduct subsequent performance tests every 8,760 hours or 5 years, whichever comes first.

[1] After you have demonstrated compliance for two consecutive tests, you may reduce the frequency of subsequent performance tests to annually. If the results of any subsequent annual performance test indicate the stationary RICE is not in compliance with the CO or formaldehyde emission limitation, or you deviate from any of your operating limitations, you must resume semiannual performance tests.

[78 FR 6711, Jan. 30, 2013]

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Table 4 to Subpart ZZZZ of Part 63—Requirements for Performance Tests

As stated in §§ 63.6610, 63.6611, 63.6612, 63.6620, and 63.6640, you must comply with the following requirements for performance tests for stationary RICE:

Table 4 to Subpart ZZZZ of Part 63. Requirements for Performance Tests

For each . . .	Complying with the requirement to . . .	You must . . .	Using . . .	According to the following requirements . . .
1. 2SLB, 4SLB, and CI stationary RICE	a. reduce CO emissions	i. Measure the O_2at the inlet and outlet of the control device; and	(1) Method 3 or 3A or 3B of 40 CFR part 60, appendix A, or ASTM Method D6522-00 (Reapproved 2005).[a c]	(a) Measurements to determine O_2must be made at the same time as the measurements for CO concentration.
		ii. Measure the CO at the inlet and the outlet of the control device	(1) ASTM D6522-00 (Reapproved 2005) [a b c]or Method 10 of 40 CFR part 60, appendix A	(a) The CO concentration must be at 15 percent O_2, dry basis.
2. 4SRB stationary RICE	a. reduce formaldehyde emissions	i. Select the sampling port location and the number of traverse points; and	(1) Method 1 or 1A of 40 CFR part 60, appendix A § 63.7(d)(1)(i)	(a) sampling sites must be located at the inlet and outlet of the control device.
		ii. Measure O_2at the inlet and outlet of the control device; and	(1) Method 3 or 3A or 3B of 40 CFR part 60, appendix A, or ASTM Method D6522-00 (Reapproved 2005).[a]	(a) measurements to determine O_2concentration must be made at the same time as the measurements for formaldehyde or THC concentration.
		iii. Measure moisture content at the inlet and outlet of the control device; and	(1) Method 4 of 40 CFR part 60, appendix A, or Test Method 320 of 40 CFR part 63, appendix A, or ASTM D 6348-03.[a]	(a) measurements to determine moisture content must be made at the same time and location as the measurements for formaldehyde or THC concentration.
		iv. If demonstrating compliance with the formaldehyde percent reduction requirement, measure formaldehyde at the inlet and the outlet of the control device	(1) Method 320 or 323 of 40 CFR part 63, appendix A; or ASTM D6348-03,[a]provided in ASTM D6348-03 Annex A5 (Analyte Spiking Technique), the percent R must be greater than or equal to 70 and less than or equal to 130	(a) formaldehyde concentration must be at 15 percent O_2, dry basis. Results of this test consist of the average of the three 1-hour or longer runs.

For each . . .	Complying with the requirement to . . .	You must . . .	Using . . .	According to the following requirements . . .
		v. If demonstrating compliance with the THC percent reduction requirement, measure THC at the inlet and the outlet of the control device	(1) Method 25A, reported as propane, of 40 CFR part 60, appendix A	(a) THC concentration must be at 15 percent O_2, dry basis. Results of this test consist of the average of the three 1-hour or longer runs.
3. Stationary RICE	a. limit the concentration of formaldehyde or CO in the stationary RICE exhaust	i. Select the sampling port location and the number of traverse points; and	(1) Method 1 or 1A of 40 CFR part 60, appendix A § 63.7(d)(1)(i)	(a) if using a control device, the sampling site must be located at the outlet of the control device.
		ii. Determine the O_2concentration of the stationary RICE exhaust at the sampling port location; and	(1) Method 3 or 3A or 3B of 40 CFR part 60, appendix A, or ASTM Method D6522-00 (Reapproved 2005).[a]	(a) measurements to determine O_2concentration must be made at the same time and location as the measurements for formaldehyde or CO concentration.
		iii. Measure moisture content of the stationary RICE exhaust at the sampling port location; and	(1) Method 4 of 40 CFR part 60, appendix A, or Test Method 320 of 40 CFR part 63, appendix A, or ASTM D 6348-03.[a]	(a) measurements to determine moisture content must be made at the same time and location as the measurements for formaldehyde or CO concentration.
		iv. Measure formaldehyde at the exhaust of the stationary RICE; or	(1) Method 320 or 323 of 40 CFR part 63, appendix A; or ASTM D6348-03,[a]provided in ASTM D6348-03 Annex A5 (Analyte Spiking Technique), the percent R must be greater than or equal to 70 and less than or equal to 130	(a) Formaldehyde concentration must be at 15 percent O_2, dry basis. Results of this test consist of the average of the three 1-hour or longer runs.
		v. measure CO at the exhaust of the stationary RICE.	(1) Method 10 of 40 CFR part 60, appendix A, ASTM Method D6522-00 (2005),[a] [c]Method 320 of 40 CFR part 63, appendix A, or ASTM D6348-03.[a]	(a) CO concentration must be at 15 percent O_2, dry basis. Results of this test consist of the average of the three 1-hour or longer runs.

[a] Incorporated by reference, see 40 CFR 63.14. You may also obtain copies from University Microfilms International, 300 North Zeeb Road, Ann Arbor, MI 48106.

[b] **You may also use Method 320 of 40 CFR part 63, appendix A, or ASTM D6348-03.**

[c] **ASTM-D6522-00 (2005) may be used to test both CI and SI stationary RICE.**

[78 FR 6711, Jan. 30, 2013]

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Table 5 to Subpart ZZZZ of Part 63—Initial Compliance With Emission Limitations, Operating Limitations, and Other Requirements

As stated in §§ 63.6612, 63.6625 and 63.6630, you must initially comply with the emission and operating limitations as required by the following:

Table 5 to Subpart ZZZZ of Part 63—Initial Compliance With Emission Limitations, Operating Limitations, and Other Requirements

For each . . .	Complying with the requirement to . . .	You have demonstrated initial compliance if . . .
1. New or reconstructed non-emergency 2SLB stationary RICE >500 HP located at a major source of HAP, new or reconstructed non-emergency 4SLB stationary RICE ≥250 HP located at a major source of HAP, non-emergency stationary CI RICE >500 HP located at a major source of HAP, and existing non-emergency stationary CI RICE >500 HP located at an area source of HAP	a. Reduce CO emissions and using oxidation catalyst, and using a CPMS	i. The average reduction of emissions of CO determined from the initial performance test achieves the required CO percent reduction; and ii. You have installed a CPMS to continuously monitor catalyst inlet temperature according to the requirements in § 63.6625(b); and iii. You have recorded the catalyst pressure drop and catalyst inlet temperature during the initial performance test.
2. Non-emergency stationary CI RICE >500 HP located at a major source of HAP, and existing non-emergency stationary CI RICE >500 HP located at an area source of HAP	a. Limit the concentration of CO, using oxidation catalyst, and using a CPMS	i. The average CO concentration determined from the initial performance test is less than or equal to the CO emission limitation; and
		ii. You have installed a CPMS to continuously monitor catalyst inlet temperature according to the requirements in § 63.6625(b); and
		iii. You have recorded the catalyst pressure drop and catalyst inlet temperature during the initial performance test.

For each . . .	Complying with the requirement to . . .	You have demonstrated initial compliance if . . .
3. New or reconstructed non-emergency 2SLB stationary RICE >500 HP located at a major source of HAP, new or reconstructed non-emergency 4SLB stationary RICE ≥250 HP located at a major source of HAP, non-emergency stationary CI RICE >500 HP located at a major source of HAP, and existing non-emergency stationary CI RICE >500 HP located at an area source of HAP	**a. Reduce CO emissions and not using oxidation catalyst**	**i. The average reduction of emissions of CO determined from the initial performance test achieves the required CO percent reduction; and ii. You have installed a CPMS to continuously monitor operating parameters approved by the Administrator (if any) according to the requirements in § 63.6625(b); and iii. You have recorded the approved operating parameters (if any) during the initial performance test.**
4. Non-emergency stationary CI RICE >500 HP located at a major source of HAP, and existing non-emergency stationary CI RICE >500 HP located at an area source of HAP	**a. Limit the concentration of CO, and not using oxidation catalyst**	**i. The average CO concentration determined from the initial performance test is less than or equal to the CO emission limitation; and ii. You have installed a CPMS to continuously monitor operating parameters approved by the Administrator (if any) according to the requirements in § 63.6625(b); and**
		iii. You have recorded the approved operating parameters (if any) during the initial performance test.
5. New or reconstructed non-emergency 2SLB stationary RICE >500 HP located at a major source of HAP, new or reconstructed non-emergency 4SLB stationary RICE ≥250 HP located at a major source of HAP, non-emergency stationary CI RICE >500 HP located at a major source of HAP, and existing non-emergency stationary CI RICE >500 HP located at an area source of HAP	**a. Reduce CO emissions, and using a CEMS**	**i. You have installed a CEMS to continuously monitor CO and either O_2or CO_2at both the inlet and outlet of the oxidation catalyst according to the requirements in § 63.6625(a); and ii. You have conducted a performance evaluation of your CEMS using PS 3 and 4A of 40 CFR part 60, appendix B; and**
		iii. The average reduction of CO calculated using § 63.6620 equals or exceeds the required percent reduction. The initial test comprises the first 4-hour period after successful validation of the CEMS. Compliance is based on the average percent reduction achieved during the 4-hour period.
6. Non-emergency stationary CI RICE >500 HP located at a major source of HAP, and existing non-emergency stationary CI RICE >500 HP located at an area source of HAP	**a. Limit the concentration of CO, and using a CEMS**	**i. You have installed a CEMS to continuously monitor CO and either O_2or CO_2at the outlet of the oxidation catalyst according to the requirements in § 63.6625(a); and**

For each . . .	Complying with the requirement to . . .	You have demonstrated initial compliance if . . .
		ii. You have conducted a performance evaluation of your CEMS using PS 3 and 4A of 40 CFR part 60, appendix B; and
		iii. The average concentration of CO calculated using § 63.6620 is less than or equal to the CO emission limitation. The initial test comprises the first 4-hour period after successful validation of the CEMS. Compliance is based on the average concentration measured during the 4-hour period.
7. Non-emergency 4SRB stationary RICE >500 HP located at a major source of HAP	a. Reduce formaldehyde emissions and using NSCR	i. The average reduction of emissions of formaldehyde determined from the initial performance test is equal to or greater than the required formaldehyde percent reduction, or the average reduction of emissions of THC determined from the initial performance test is equal to or greater than 30 percent; and
		ii. You have installed a CPMS to continuously monitor catalyst inlet temperature according to the requirements in § 63.6625(b); and
		iii. You have recorded the catalyst pressure drop and catalyst inlet temperature during the initial performance test.
8. Non-emergency 4SRB stationary RICE >500 HP located at a major source of HAP	a. Reduce formaldehyde emissions and not using NSCR	i. The average reduction of emissions of formaldehyde determined from the initial performance test is equal to or greater than the required formaldehyde percent reduction or the average reduction of emissions of THC determined from the initial performance test is equal to or greater than 30 percent; and
		ii. You have installed a CPMS to continuously monitor operating parameters approved by the Administrator (if any) according to the requirements in § 63.6625(b); and
		iii. You have recorded the approved operating parameters (if any) during the initial performance test.

For each . . .	**Complying with the requirement to . . .**	**You have demonstrated initial compliance if . . .**
9. New or reconstructed non-emergency stationary RICE >500 HP located at a major source of HAP, new or reconstructed non-emergency 4SLB stationary RICE 250≤HP≤500 located at a major source of HAP, and existing non-emergency 4SRB stationary RICE >500 HP located at a major source of HAP	**a. Limit the concentration of formaldehyde in the stationary RICE exhaust and using oxidation catalyst or NSCR**	**i. The average formaldehyde concentration, corrected to 15 percent O_2, dry basis, from the three test runs is less than or equal to the formaldehyde emission limitation; and** **ii. You have installed a CPMS to continuously monitor catalyst inlet temperature according to the requirements in § 63.6625(b); and**
		iii. You have recorded the catalyst pressure drop and catalyst inlet temperature during the initial performance test.
10. New or reconstructed non-emergency stationary RICE >500 HP located at a major source of HAP, new or reconstructed non-emergency 4SLB stationary RICE 250≤HP≤500 located at a major source of HAP, and existing non-emergency 4SRB stationary RICE >500 HP located at a major source of HAP	**a. Limit the concentration of formaldehyde in the stationary RICE exhaust and not using oxidation catalyst or NSCR**	**i. The average formaldehyde concentration, corrected to 15 percent O_2, dry basis, from the three test runs is less than or equal to the formaldehyde emission limitation; and** **ii. You have installed a CPMS to continuously monitor operating parameters approved by the Administrator (if any) according to the requirements in § 63.6625(b); and**
		iii. You have recorded the approved operating parameters (if any) during the initial performance test.
11. Existing non-emergency stationary RICE 100≤HP≤500 located at a major source of HAP, and existing non-emergency stationary CI RICE 300<HP≤500 located at an area source of HAP	**a. Reduce CO emissions**	**i. The average reduction of emissions of CO or formaldehyde, as applicable determined from the initial performance test is equal to or greater than the required CO or formaldehyde, as applicable, percent reduction.**
12. Existing non-emergency stationary RICE 100≤HP≤500 located at a major source of HAP, and existing non-emergency stationary CI RICE 300<HP≤500 located at an area source of HAP	**a. Limit the concentration of formaldehyde or CO in the stationary RICE exhaust**	**i. The average formaldehyde or CO concentration, as applicable, corrected to 15 percent O_2, dry basis, from the three test runs is less than or equal to the formaldehyde or CO emission limitation, as applicable.**
13. Existing non-emergency 4SLB stationary RICE >500 HP located at an area source of HAP that are not remote stationary RICE and that are operated more than 24 hours per calendar year	**a. Install an oxidation catalyst**	**i. You have conducted an initial compliance demonstration as specified in § 63.6630(e) to show that the average reduction of emissions of CO is 93 percent or more, or the average CO concentration is less than or equal to 47 ppmvd at 15 percent O_2;**

For each . . .	Complying with the requirement to . . .	You have demonstrated initial compliance if . . .
		ii. You have installed a CPMS to continuously monitor catalyst inlet temperature according to the requirements in § 63.6625(b), or you have installed equipment to automatically shut down the engine if the catalyst inlet temperature exceeds 1350 °F.
14. Existing non-emergency 4SRB stationary RICE >500 HP located at an area source of HAP that are not remote stationary RICE and that are operated more than 24 hours per calendar year	a. Install NSCR	i. You have conducted an initial compliance demonstration as specified in § 63.6630(e) to show that the average reduction of emissions of CO is 75 percent or more, the average CO concentration is less than or equal to 270 ppmvd at 15 percent O_2, or the average reduction of emissions of THC is 30 percent or more;
		ii. You have installed a CPMS to continuously monitor catalyst inlet temperature according to the requirements in § 63.6625(b), or you have installed equipment to automatically shut down the engine if the catalyst inlet temperature exceeds 1250 °F.

[78 FR 6712, Jan. 30, 2013]

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Table 6 to Subpart ZZZZ of Part 63—Continuous Compliance With Emission Limitations, and Other Requirements

As stated in § 63.6640, you must continuously comply with the emissions and operating limitations and work or management practices as required by the following:

Table 6 to Subpart ZZZZ of Part 63—Continuous Compliance With Emission Limitations, and Other Requirements

For each . . .	Complying with the requirement to . . .	You must demonstrate continuous compliance by . . .
1. New or reconstructed non-emergency 2SLB stationary RICE >500 HP located at a major source of HAP, new or reconstructed non-emergency 4SLB stationary RICE ≥250 HP located at a major source of HAP, and new or reconstructed non-emergency CI stationary RICE >500 HP located at a major source of HAP	a. Reduce CO emissions and using an oxidation catalyst, and using a CPMS	i. Conducting semiannual performance tests for CO to demonstrate that the required CO percent reduction is achieved [a]; and ii. Collecting the catalyst inlet temperature data according to § 63.6625(b); and iii. Reducing these data to 4-hour rolling averages; and

For each . . .	Complying with the requirement to . . .	You must demonstrate continuous compliance by . . .
		iv. Maintaining the 4-hour rolling averages within the operating limitations for the catalyst inlet temperature; and
		v. Measuring the pressure drop across the catalyst once per month and demonstrating that the pressure drop across the catalyst is within the operating limitation established during the performance test.
2. New or reconstructed non-emergency 2SLB stationary RICE >500 HP located at a major source of HAP, new or reconstructed non-emergency 4SLB stationary RICE ≥250 HP located at a major source of HAP, and new or reconstructed non-emergency CI stationary RICE >500 HP located at a major source of HAP	a. Reduce CO emissions and not using an oxidation catalyst, and using a CPMS	i. Conducting semiannual performance tests for CO to demonstrate that the required CO percent reduction is achieved [a]; and ii. Collecting the approved operating parameter (if any) data according to § 63.6625(b); and iii. Reducing these data to 4-hour rolling averages; and
		iv. Maintaining the 4-hour rolling averages within the operating limitations for the operating parameters established during the performance test.
3. New or reconstructed non-emergency 2SLB stationary RICE >500 HP located at a major source of HAP, new or reconstructed non-emergency 4SLB stationary RICE ≥250 HP located at a major source of HAP, new or reconstructed non-emergency stationary CI RICE >500 HP located at a major source of HAP, and existing non-emergency stationary CI RICE >500 HP	a. Reduce CO emissions or limit the concentration of CO in the stationary RICE exhaust, and using a CEMS	i. Collecting the monitoring data according to § 63.6625(a), reducing the measurements to 1-hour averages, calculating the percent reduction or concentration of CO emissions according to § 63.6620; and ii. Demonstrating that the catalyst achieves the required percent reduction of CO emissions over the 4-hour averaging period, or that the emission remain at or below the CO concentration limit; and
		iii. Conducting an annual RATA of your CEMS using PS 3 and 4A of 40 CFR part 60, appendix B, as well as daily and periodic data quality checks in accordance with 40 CFR part 60, appendix F, procedure 1.
4. Non-emergency 4SRB stationary RICE >500 HP located at a major source of HAP	a. Reduce formaldehyde emissions and using NSCR	i. Collecting the catalyst inlet temperature data according to § 63.6625(b); and
		ii. Reducing these data to 4-hour rolling averages; and

For each . . .	**Complying with the requirement to . . .**	**You must demonstrate continuous compliance by . . .**
		iii. Maintaining the 4-hour rolling averages within the operating limitations for the catalyst inlet temperature; and
		iv. Measuring the pressure drop across the catalyst once per month and demonstrating that the pressure drop across the catalyst is within the operating limitation established during the performance test.
5. Non-emergency 4SRB stationary RICE >500 HP located at a major source of HAP	**a. Reduce formaldehyde emissions and not using NSCR**	**i. Collecting the approved operating parameter (if any) data according to § 63.6625(b); and**
		ii. Reducing these data to 4-hour rolling averages; and
		iii. Maintaining the 4-hour rolling averages within the operating limitations for the operating parameters established during the performance test.
6. Non-emergency 4SRB stationary RICE with a brake HP ≥5,000 located at a major source of HAP	**a. Reduce formaldehyde emissions**	**Conducting semiannual performance tests for formaldehyde to demonstrate that the required formaldehyde percent reduction is achieved, or to demonstrate that the average reduction of emissions of THC determined from the performance test is equal to or greater than 30 percent.[a]**
7. New or reconstructed non-emergency stationary RICE >500 HP located at a major source of HAP and new or reconstructed non-emergency 4SLB stationary RICE 250≤HP≤500 located at a major source of HAP	**a. Limit the concentration of formaldehyde in the stationary RICE exhaust and using oxidation catalyst or NSCR**	**i. Conducting semiannual performance tests for formaldehyde to demonstrate that your emissions remain at or below the formaldehyde concentration limit [a]; and** **ii. Collecting the catalyst inlet temperature data according to § 63.6625(b); and**
		iii. Reducing these data to 4-hour rolling averages; and
		iv. Maintaining the 4-hour rolling averages within the operating limitations for the catalyst inlet temperature; and

For each . . .	Complying with the requirement to . . .	You must demonstrate continuous compliance by . . .
		v. Measuring the pressure drop across the catalyst once per month and demonstrating that the pressure drop across the catalyst is within the operating limitation established during the performance test.
8. New or reconstructed non-emergency stationary RICE >500 HP located at a major source of HAP and new or reconstructed non-emergency 4SLB stationary RICE 250≤HP≤500 located at a major source of HAP	a. Limit the concentration of formaldehyde in the stationary RICE exhaust and not using oxidation catalyst or NSCR	i. Conducting semiannual performance tests for formaldehyde to demonstrate that your emissions remain at or below the formaldehyde concentration limit [a]; and ii. Collecting the approved operating parameter (if any) data according to § 63.6625(b); and
		iii. Reducing these data to 4-hour rolling averages; and
		iv. Maintaining the 4-hour rolling averages within the operating limitations for the operating parameters established during the performance test.
9. Existing emergency and black start stationary RICE ≤500 HP located at a major source of HAP, existing non-emergency stationary RICE <100 HP located at a major source of HAP, existing emergency and black start stationary RICE located at an area source of HAP, existing non-emergency stationary CI RICE ≤300 HP located at an area source of HAP, existing non-emergency 2SLB stationary RICE located at an area source of HAP, existing non-emergency stationary SI RICE located at an area source of HAP which combusts landfill or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis, existing non-emergency 4SLB and 4SRB stationary RICE ≤500 HP located at an area source of HAP, existing non-emergency 4SLB and 4SRB stationary RICE >500 HP located at an area source of HAP that operate 24 hours or less per calendar year, and existing non-emergency 4SLB and 4SRB stationary RICE >500 HP located at an area source of HAP that are remote stationary RICE	a. Work or Management practices	i. Operating and maintaining the stationary RICE according to the manufacturer's emission-related operation and maintenance instructions; or ii. Develop and follow your own maintenance plan which must provide to the extent practicable for the maintenance and operation of the engine in a manner consistent with good air pollution control practice for minimizing emissions.

For each . . .	**Complying with the requirement to . . .**	**You must demonstrate continuous compliance by . . .**
10. Existing stationary CI RICE >500 HP that are not limited use stationary RICE	**a. Reduce CO emissions, or limit the concentration of CO in the stationary RICE exhaust, and using oxidation catalyst**	**i. Conducting performance tests every 8,760 hours or 3 years, whichever comes first, for CO or formaldehyde, as appropriate, to demonstrate that the required CO or formaldehyde, as appropriate, percent reduction is achieved or that your emissions remain at or below the CO or formaldehyde concentration limit; and**
		ii. Collecting the catalyst inlet temperature data according to § 63.6625(b); and
		iii. Reducing these data to 4-hour rolling averages; and
		iv. Maintaining the 4-hour rolling averages within the operating limitations for the catalyst inlet temperature; and
		v. Measuring the pressure drop across the catalyst once per month and demonstrating that the pressure drop across the catalyst is within the operating limitation established during the performance test.
11. Existing stationary CI RICE >500 HP that are not limited use stationary RICE	**a. Reduce CO emissions, or limit the concentration of CO in the stationary RICE exhaust, and not using oxidation catalyst**	**i. Conducting performance tests every 8,760 hours or 3 years, whichever comes first, for CO or formaldehyde, as appropriate, to demonstrate that the required CO or formaldehyde, as appropriate, percent reduction is achieved or that your emissions remain at or below the CO or formaldehyde concentration limit; and**
		ii. Collecting the approved operating parameter (if any) data according to § 63.6625(b); and
		iii. Reducing these data to 4-hour rolling averages; and
		iv. Maintaining the 4-hour rolling averages within the operating limitations for the operating parameters established during the performance test.

For each . . .	**Complying with the requirement to . . .**	**You must demonstrate continuous compliance by . . .**
12. Existing limited use CI stationary RICE >500 HP	**a. Reduce CO emissions or limit the concentration of CO in the stationary RICE exhaust, and using an oxidation catalyst**	**i. Conducting performance tests every 8,760 hours or 5 years, whichever comes first, for CO or formaldehyde, as appropriate, to demonstrate that the required CO or formaldehyde, as appropriate, percent reduction is achieved or that your emissions remain at or below the CO or formaldehyde concentration limit; and**
		ii. Collecting the catalyst inlet temperature data according to § 63.6625(b); and
		iii. Reducing these data to 4-hour rolling averages; and
		iv. Maintaining the 4-hour rolling averages within the operating limitations for the catalyst inlet temperature; and
		v. Measuring the pressure drop across the catalyst once per month and demonstrating that the pressure drop across the catalyst is within the operating limitation established during the performance test.
13. Existing limited use CI stationary RICE >500 HP	**a. Reduce CO emissions or limit the concentration of CO in the stationary RICE exhaust, and not using an oxidation catalyst**	**i. Conducting performance tests every 8,760 hours or 5 years, whichever comes first, for CO or formaldehyde, as appropriate, to demonstrate that the required CO or formaldehyde, as appropriate, percent reduction is achieved or that your emissions remain at or below the CO or formaldehyde concentration limit; and**
		ii. Collecting the approved operating parameter (if any) data according to § 63.6625(b); and
		iii. Reducing these data to 4-hour rolling averages; and
		iv. Maintaining the 4-hour rolling averages within the operating limitations for the operating parameters established during the performance test.

For each . . .	**Complying with the requirement to . . .**	**You must demonstrate continuous compliance by . . .**
14. Existing non-emergency 4SLB stationary RICE >500 HP located at an area source of HAP that are not remote stationary RICE and that are operated more than 24 hours per calendar year	**a. Install an oxidation catalyst**	**i. Conducting annual compliance demonstrations as specified in § 63.6640(c) to show that the average reduction of emissions of CO is 93 percent or more, or the average CO concentration is less than or equal to 47 ppmvd at 15 percent O_2; and either** **ii. Collecting the catalyst inlet temperature data according to § 63.6625(b), reducing these data to 4-hour rolling averages; and maintaining the 4-hour rolling averages within the limitation of greater than 450 °F and less than or equal to 1350 °F for the catalyst inlet temperature; or** **iii. Immediately shutting down the engine if the catalyst inlet temperature exceeds 1350 °F.**
15. Existing non-emergency 4SRB stationary RICE >500 HP located at an area source of HAP that are not remote stationary RICE and that are operated more than 24 hours per calendar year	**a. Install NSCR**	**i. Conducting annual compliance demonstrations as specified in § 63.6640(c) to show that the average reduction of emissions of CO is 75 percent or more, the average CO concentration is less than or equal to 270 ppmvd at 15 percent O_2, or the average reduction of emissions of THC is 30 percent or more; and either** **ii. Collecting the catalyst inlet temperature data according to § 63.6625(b), reducing these data to 4-hour rolling averages; and maintaining the 4-hour rolling averages within the limitation of greater than or equal to 750 °F and less than or equal to 1250 °F for the catalyst inlet temperature; or** **iii. Immediately shutting down the engine if the catalyst inlet temperature exceeds 1250 °F.**

[a] After you have demonstrated compliance for two consecutive tests, you may reduce the frequency of subsequent performance tests to annually. If the results of any subsequent annual performance test indicate the stationary RICE is not in compliance with the CO or formaldehyde emission limitation, or you deviate from any of your operating limitations, you must resume semiannual performance tests.

[78 FR 6715, Jan. 30, 2013]

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Table 7 to Subpart ZZZZ of Part 63—Requirements for Reports

As stated in § 63.6650, you must comply with the following requirements for reports:

Table 7 to Subpart ZZZZ of Part 63—Requirements for Reports

For each . . .	You must submit a . . .	The report must contain . . .	You must submit the report . . .
1. Existing non-emergency, non-black start stationary RICE 100≤HP≤500 located at a major source of HAP; existing non-emergency, non-black start stationary CI RICE >500 HP located at a major source of HAP; existing non-emergency 4SRB stationary RICE >500 HP located at a major source of HAP; existing non-emergency, non-black start stationary CI RICE >300 HP located at an area source of HAP; new or reconstructed non-emergency stationary RICE >500 HP located at a major source of HAP; and new or reconstructed non-emergency 4SLB stationary RICE 250≤HP≤500 located at a major source of HAP	**Compliance report**	**a. If there are no deviations from any emission limitations or operating limitations that apply to you, a statement that there were no deviations from the emission limitations or operating limitations during the reporting period. If there were no periods during which the CMS, including CEMS and CPMS, was out-of-control, as specified in § 63.8(c)(7), a statement that there were not periods during which the CMS was out-of-control during the reporting period; or**	**i. Semiannually according to the requirements in § 63.6650(b)(1)-(5) for engines that are not limited use stationary RICE subject to numerical emission limitations; and ii. Annually according to the requirements in § 63.6650(b)(6)-(9) for engines that are limited use stationary RICE subject to numerical emission limitations.**
		b. If you had a deviation from any emission limitation or operating limitation during the reporting period, the information in § 63.6650(d). If there were periods during which the CMS, including CEMS and CPMS, was out-of-control, as specified in § 63.8(c)(7), the information in § 63.6650(e); or	**i. Semiannually according to the requirements in § 63.6650(b).**
		c. If you had a malfunction during the reporting period, the information in § 63.6650(c)(4).	**i. Semiannually according to the requirements in § 63.6650(b).**
2. New or reconstructed non-emergency stationary RICE that combusts landfill gas or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis	**Report**	**a. The fuel flow rate of each fuel and the heating values that were used in your calculations, and you must demonstrate that the percentage of heat input provided by landfill gas or digester gas, is equivalent to 10 percent or more of the gross heat input on an annual basis; and**	**i. Annually, according to the requirements in § 63.6650.**

For each . . .	You must submit a . . .	The report must contain . . .	You must submit the report . . .
		b. The operating limits provided in your federally enforceable permit, and any deviations from these limits; and	i. See item 2.a.i.
		c. Any problems or errors suspected with the meters.	i. See item 2.a.i.
3. Existing non-emergency, non-black start 4SLB and 4SRB stationary RICE >500 HP located at an area source of HAP that are not remote stationary RICE and that operate more than 24 hours per calendar year	Compliance report	a. The results of the annual compliance demonstration, if conducted during the reporting period.	i. Semiannually according to the requirements in § 63.6650(b)(1)-(5).
4. Emergency stationary RICE that operate or are contractually obligated to be available for more than 15 hours per year for the purposes specified in § 63.6640(f)(2)(ii) and (iii) or that operate for the purposes specified in § 63.6640(f)(4)(ii)	Report	a. The information in § 63.6650(h)(1)	i. annually according to the requirements in § 63.6650(h)(2)-(3).

[78 FR 6719, Jan. 30, 2013]

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Table 8 to Subpart ZZZZ of Part 63—Applicability of General Provisions to Subpart ZZZZ.

As stated in § 63.6665, you must comply with the following applicable general provisions.

General provisions citation	Subject of citation	Applies to subpart	Explanation
§ 63.1	General applicability of the General Provisions	Yes.	
§ 63.2	Definitions	Yes	Additional terms defined in § 63.6675.
§ 63.3	Units and abbreviations	Yes.	
§ 63.4	Prohibited activities and circumvention	Yes.	
§ 63.5	Construction and reconstruction	Yes.	
§ 63.6(a)	Applicability	Yes.	
§ 63.6(b)(1)-(4)	Compliance dates for new and reconstructed sources	Yes.	

General provisions citation	Subject of citation	Applies to subpart	Explanation
§ 63.6(b)(5)	Notification	Yes.	
§ 63.6(b)(6)	[Reserved]		
§ 63.6(b)(7)	Compliance dates for new and reconstructed area sources that become major sources	Yes.	
§ 63.6(c)(1)-(2)	Compliance dates for existing sources	Yes.	
§ 63.6(c)(3)-(4)	[Reserved]		
§ 63.6(c)(5)	Compliance dates for existing area sources that become major sources	Yes.	
§ 63.6(d)	[Reserved]		
§ 63.6(e)	Operation and maintenance	No.	
§ 63.6(f)(1)	Applicability of standards	No.	
§ 63.6(f)(2)	Methods for determining compliance	Yes.	
§ 63.6(f)(3)	Finding of compliance	Yes.	
§ 63.6(g)(1)-(3)	Use of alternate standard	Yes.	
§ 63.6(h)	Opacity and visible emission standards	No	Subpart ZZZZ does not contain opacity or visible emission standards.
§ 63.6(i)	Compliance extension procedures and criteria	Yes.	
§ 63.6(j)	Presidential compliance exemption	Yes.	
§ 63.7(a)(1)-(2)	Performance test dates	Yes	Subpart ZZZZ contains performance test dates at §§ 63.6610, 63.6611, and 63.6612.
§ 63.7(a)(3)	CAA section 114 authority	Yes.	
§ 63.7(b)(1)	Notification of performance test	Yes	Except that § 63.7(b)(1) only applies as specified in § 63.6645.
§ 63.7(b)(2)	Notification of rescheduling	Yes	Except that § 63.7(b)(2) only applies as specified in § 63.6645.
§ 63.7(c)	Quality assurance/test plan	Yes	Except that § 63.7(c) only applies as specified in § 63.6645.
§ 63.7(d)	Testing facilities	Yes.	

General provisions citation	Subject of citation	Applies to subpart	Explanation
§ 63.7(e)(1)	Conditions for conducting performance tests	No.	Subpart ZZZZ specifies conditions for conducting performance tests at § 63.6620.
§ 63.7(e)(2)	Conduct of performance tests and reduction of data	Yes	Subpart ZZZZ specifies test methods at § 63.6620.
§ 63.7(e)(3)	Test run duration	Yes.	
§ 63.7(e)(4)	Administrator may require other testing under section 114 of the CAA	Yes.	
§ 63.7(f)	Alternative test method provisions	Yes.	
§ 63.7(g)	Performance test data analysis, recordkeeping, and reporting	Yes.	
§ 63.7(h)	Waiver of tests	Yes.	
§ 63.8(a)(1)	Applicability of monitoring requirements	Yes	Subpart ZZZZ contains specific requirements for monitoring at § 63.6625.
§ 63.8(a)(2)	Performance specifications	Yes.	
§ 63.8(a)(3)	[Reserved]		
§ 63.8(a)(4)	Monitoring for control devices	No.	
§ 63.8(b)(1)	Monitoring	Yes.	
§ 63.8(b)(2)-(3)	Multiple effluents and multiple monitoring systems	Yes.	
§ 63.8(c)(1)	Monitoring system operation and maintenance	Yes.	
§ 63.8(c)(1)(i)	Routine and predictable SSM	No	
§ 63.8(c)(1)(ii)	SSM not in Startup Shutdown Malfunction Plan	Yes.	
§ 63.8(c)(1)(iii)	Compliance with operation and maintenance requirements	No	
§ 63.8(c)(2)-(3)	Monitoring system installation	Yes.	
§ 63.8(c)(4)	Continuous monitoring system (CMS) requirements	Yes	Except that subpart ZZZZ does not require Continuous Opacity Monitoring System (COMS).
§ 63.8(c)(5)	COMS minimum procedures	No	Subpart ZZZZ does not require COMS.
§ 63.8(c)(6)-(8)	CMS requirements	Yes	Except that subpart ZZZZ does not require COMS.

General provisions citation	Subject of citation	Applies to subpart	Explanation
§ 63.8(d)	**CMS quality control**	**Yes.**	
§ 63.8(e)	**CMS performance evaluation**	**Yes**	**Except for § 63.8(e)(5)(ii), which applies to COMS.**
		Except that § 63.8(e) only applies as specified in § 63.6645.	
§ 63.8(f)(1)-(5)	**Alternative monitoring method**	**Yes**	**Except that § 63.8(f)(4) only applies as specified in § 63.6645.**
§ 63.8(f)(6)	**Alternative to relative accuracy test**	**Yes**	**Except that § 63.8(f)(6) only applies as specified in § 63.6645.**
§ 63.8(g)	**Data reduction**	**Yes**	**Except that provisions for COMS are not applicable. Averaging periods for demonstrating compliance are specified at §§ 63.6635 and 63.6640.**
§ 63.9(a)	**Applicability and State delegation of notification requirements**	**Yes.**	
§ 63.9(b)(1)-(5)	**Initial notifications**	**Yes**	**Except that § 63.9(b)(3) is reserved.**
		Except that § 63.9(b) only applies as specified in § 63.6645.	
§ 63.9(c)	**Request for compliance extension**	**Yes**	**Except that § 63.9(c) only applies as specified in § 63.6645.**
§ 63.9(d)	**Notification of special compliance requirements for new sources**	**Yes**	**Except that § 63.9(d) only applies as specified in § 63.6645.**
§ 63.9(e)	**Notification of performance test**	**Yes**	**Except that § 63.9(e) only applies as specified in § 63.6645.**
§ 63.9(f)	**Notification of visible emission (VE)/opacity test**	**No**	**Subpart ZZZZ does not contain opacity or VE standards.**
§ 63.9(g)(1)	**Notification of performance evaluation**	**Yes**	**Except that § 63.9(g) only applies as specified in § 63.6645.**
§ 63.9(g)(2)	**Notification of use of COMS data**	**No**	**Subpart ZZZZ does not contain opacity or VE standards.**
§ 63.9(g)(3)	**Notification that criterion for alternative to RATA is exceeded**	**Yes**	**If alternative is in use.**

General provisions citation	Subject of citation	Applies to subpart	Explanation
		Except that § 63.9(g) only applies as specified in § 63.6645.	
§ 63.9(h)(1)-(6)	Notification of compliance status	Yes	Except that notifications for sources using a CEMS are due 30 days after completion of performance evaluations. § 63.9(h)(4) is reserved.
			Except that § 63.9(h) only applies as specified in § 63.6645.
§ 63.9(i)	Adjustment of submittal deadlines	Yes.	
§ 63.9(j)	Change in previous information	Yes.	
§ 63.10(a)	Administrative provisions for recordkeeping/reporting	Yes.	
§ 63.10(b)(1)	Record retention	Yes	Except that the most recent 2 years of data do not have to be retained on site.
§ 63.10(b)(2)(i)-(v)	Records related to SSM	No.	
§ 63.10(b)(2)(vi)-(xi)	Records	Yes.	
§ 63.10(b)(2)(xii)	Record when under waiver	Yes.	
§ 63.10(b)(2)(xiii)	Records when using alternative to RATA	Yes	For CO standard if using RATA alternative.
§ 63.10(b)(2)(xiv)	Records of supporting documentation	Yes.	
§ 63.10(b)(3)	Records of applicability determination	Yes.	
§ 63.10(c)	Additional records for sources using CEMS	Yes	Except that § 63.10(c)(2)-(4) and (9) are reserved.
§ 63.10(d)(1)	General reporting requirements	Yes.	
§ 63.10(d)(2)	Report of performance test results	Yes.	
§ 63.10(d)(3)	Reporting opacity or VE observations	No	Subpart ZZZZ does not contain opacity or VE standards.
§ 63.10(d)(4)	Progress reports	Yes.	
§ 63.10(d)(5)	Startup, shutdown, and malfunction reports	No.	

General provisions citation	Subject of citation	Applies to subpart	Explanation
§ 63.10(e)(1) and (2)(i)	Additional CMS Reports	Yes.	
§ 63.10(e)(2)(ii)	COMS-related report	No	Subpart ZZZZ does not require COMS.
§ 63.10(e)(3)	Excess emission and parameter exceedances reports	Yes.	Except that § 63.10(e)(3)(i) (C) is reserved.
§ 63.10(e)(4)	Reporting COMS data	No	Subpart ZZZZ does not require COMS.
§ 63.10(f)	Waiver for recordkeeping/reporting	Yes.	
§ 63.11	Flares	No.	
§ 63.12	State authority and delegations	Yes.	
§ 63.13	Addresses	Yes.	
§ 63.14	Incorporation by reference	Yes.	
§ 63.15	Availability of information	Yes.	

[75 FR 9688, Mar. 3, 2010, as amended at 78 FR 6720, Jan. 30, 2013]

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Appendix A—Protocol for Using an Electrochemical Analyzer to Determine Oxygen and Carbon Monoxide Concentrations From Certain Engines

1.0 SCOPE AND APPLICATION. WHAT IS THIS PROTOCOL?

This protocol is a procedure for using portable electrochemical (EC) cells for measuring carbon monoxide (CO) and oxygen (O_2) concentrations in controlled and uncontrolled emissions from existing stationary 4-stroke lean burn and 4-stroke rich burn reciprocating internal combustion engines as specified in the applicable rule.

1.1 Analytes. What does this protocol determine?

This protocol measures the engine exhaust gas concentrations of carbon monoxide (CO) and oxygen (O_2).

Analyte	CAS No.	Sensitivity
Carbon monoxide (CO)	630-08-0	Minimum detectable limit should be 2 percent of the nominal range or 1 ppm, whichever is less restrictive.
Oxygen (O_2)	*7782-44-7*	

1.2 Applicability. When is this protocol acceptable?

This protocol is applicable to 40 CFR part 63, subpart ZZZZ. Because of inherent cross sensitivities of EC cells, you must not apply this protocol to other emissions sources without specific instruction to that effect.

1.3 Data Quality Objectives. How good must my collected data be?

Refer to Section 13 to verify and document acceptable analyzer performance.

1.4 Range. What is the targeted analytical range for this protocol?

The measurement system and EC cell design(s) conforming to this protocol will determine the analytical range for each gas component. The nominal ranges are defined by choosing up-scale calibration gas concentrations near the maximum anticipated flue gas concentrations for CO and O_2 , or no more than twice the permitted CO level.

1.5 Sensitivity. What minimum detectable limit will this protocol yield for a particular gas component?

The minimum detectable limit depends on the nominal range and resolution of the specific EC cell used, and the signal to noise ratio of the measurement system. The minimum detectable limit should be 2 percent of the nominal range or 1 ppm, whichever is less restrictive.

2.0 SUMMARY OF PROTOCOL

In this protocol, a gas sample is extracted from an engine exhaust system and then conveyed to a portable EC analyzer for measurement of CO and O_2 gas concentrations. This method provides measurement system performance specifications and sampling protocols to ensure reliable data. You may use additions to, or modifications of vendor supplied measurement systems (e.g., heated or unheated sample lines, thermocouples, flow meters, selective gas scrubbers, etc.) to meet the design specifications of this protocol. Do not make changes to the measurement system from the as-verified configuration (Section 3.12).

3.0 DEFINITIONS

3.1 Measurement System. **The total equipment required for the measurement of CO and O_2 concentrations. The measurement system consists of the following major subsystems:**

3.1.1 Data Recorder. **A strip chart recorder, computer or digital recorder for logging measurement data from the analyzer output. You may record measurement data from the digital data display manually or electronically.**

3.1.2 Electrochemical (EC) Cell. **A device, similar to a fuel cell, used to sense the presence of a specific analyte and generate an electrical current output proportional to the analyte concentration.**

3.1.3 Interference Gas Scrubber. **A device used to remove or neutralize chemical compounds that may interfere with the selective operation of an EC cell.**

3.1.4 Moisture Removal System. **Any device used to reduce the concentration of moisture in the sample stream so as to protect the EC cells from the damaging effects of condensation and to minimize errors in measurements caused by the scrubbing of soluble gases.**

3.1.5 Sample Interface. **The portion of the system used for one or more of the following: sample acquisition; sample transport; sample conditioning or protection of the EC cell from any degrading effects of the engine exhaust effluent; removal of particulate matter and condensed moisture.**

3.2 Nominal Range. **The range of analyte concentrations over which each EC cell is operated (normally 25 percent to 150 percent of up-scale calibration gas value). Several nominal ranges can be used for any given cell so long as the calibration and repeatability checks for that range remain within specifications.**

3.3 Calibration Gas. **A vendor certified concentration of a specific analyte in an appropriate balance gas.**

3.4 Zero Calibration Error. **The analyte concentration output exhibited by the EC cell in response to zero-level calibration gas.**

3.5 Up-Scale Calibration Error. **The mean of the difference between the analyte concentration exhibited by the EC cell and the certified concentration of the up-scale calibration gas.**

3.6 Interference Check. **A procedure for quantifying analytical interference from components in the engine exhaust gas other than the targeted analytes.**

3.7 Repeatability Check. **A protocol for demonstrating that an EC cell operated over a given nominal analyte concentration range provides a stable and consistent response and is not significantly affected by repeated exposure to that gas.**

3.8 Sample Flow Rate. **The flow rate of the gas sample as it passes through the EC cell. In some situations, EC cells can experience drift with changes in flow rate. The flow rate must be monitored and documented during all phases of a sampling run.**

3.9 Sampling Run. **A timed three-phase event whereby an EC cell's response rises and plateaus in a sample conditioning phase, remains relatively constant during a measurement data phase, then declines during a refresh phase. The sample conditioning phase exposes the EC cell to the gas sample for a length of time sufficient to reach a constant response. The measurement data phase is the time interval during which gas sample measurements can be made that meet the acceptance criteria of this protocol. The refresh phase then purges the EC cells with CO-free air. The refresh phase replenishes requisite O_2 and moisture in the electrolyte reserve and provides a mechanism to de-gas or desorb any interference gas scrubbers or filters so as to enable a stable CO EC cell response. There are four primary types of sampling runs: pre- sampling calibrations; stack gas sampling; post-sampling calibration checks; and measurement system repeatability checks. Stack gas sampling runs can be chained together for extended evaluations, providing all other procedural specifications are met.**

3.10 Sampling Day. **A time not to exceed twelve hours from the time of the pre-sampling calibration to the post-sampling calibration check. During this time, stack gas sampling runs can be repeated without repeated recalibrations, providing all other sampling specifications have been met.**

3.11 Pre-Sampling Calibration/Post-Sampling Calibration Check. **The protocols executed at the beginning and end of each sampling day to bracket measurement readings with controlled performance checks.**

3.12 Performance-Established Configuration. **The EC cell and sampling system configuration that existed at the time that it initially met the performance requirements of this protocol.**

4.0 INTERFERENCES.

When present in sufficient concentrations, NO and NO_2 are two gas species that have been reported to interfere with CO concentration measurements. In the likelihood of this occurrence, it is the protocol user's responsibility to employ and properly maintain an appropriate CO EC cell filter or scrubber for removal of these gases, as described in Section 6.2.12.

5.0 SAFETY. [RESERVED]

6.0 EQUIPMENT AND SUPPLIES.

6.1 What equipment do I need for the measurement system?

The system must maintain the gas sample at conditions that will prevent moisture condensation in the sample transport lines, both before and as the sample gas contacts the EC cells. The essential components of the measurement system are described below.

6.2 Measurement System Components.

6.2.1 Sample Probe. **A single extraction-point probe constructed of glass, stainless steel or other non-reactive material, and of length sufficient to reach any designated sampling point. The sample probe must be designed to prevent plugging due to condensation or particulate matter.**

6.2.2 Sample Line. **Non-reactive tubing to transport the effluent from the sample probe to the EC cell.**

6.2.3 Calibration Assembly (optional). **A three-way valve assembly or equivalent to introduce calibration gases at ambient pressure at the exit end of the sample probe during calibration checks. The assembly must be designed such that only stack gas or calibration gas flows in the sample line and all gases flow through any gas path filters.**

6.2.4 Particulate Filter (optional). **Filters before the inlet of the EC cell to prevent accumulation of particulate material in the measurement system and extend the useful life of the components. All filters must be fabricated of materials that are non-reactive to the gas mixtures being sampled.**

6.2.5 Sample Pump. **A leak-free pump to provide undiluted sample gas to the system at a flow rate sufficient to minimize the response time of the measurement system. If located upstream of the EC cells, the pump must be constructed of a material that is non-reactive to the gas mixtures being sampled.**

6.2.8 Sample Flow Rate Monitoring. **An adjustable rotameter or equivalent device used to adjust and maintain the sample flow rate through the analyzer as prescribed.**

6.2.9 Sample Gas Manifold (optional). **A manifold to divert a portion of the sample gas stream to the analyzer and the remainder to a by-pass discharge vent. The sample gas manifold may also include provisions for introducing calibration gases directly to the analyzer. The manifold must be constructed of a material that is non-reactive to the gas mixtures being sampled.**

6.2.10 EC cell. **A device containing one or more EC cells to determine the CO and O_2 concentrations in the sample gas stream. The EC cell(s) must meet the applicable performance specifications of Section 13 of this protocol.**

6.2.11 Data Recorder. **A strip chart recorder, computer or digital recorder to make a record of analyzer output data. The data recorder resolution (i.e., readability) must be no greater than 1 ppm for CO; 0.1 percent for O_2 ; and one degree (either °C or °F) for temperature. Alternatively, you may use a digital or analog meter having the same resolution to observe and manually record the analyzer responses.**

6.2.12 Interference Gas Filter or Scrubber. **A device to remove interfering compounds upstream of the CO EC cell. Specific interference gas filters or scrubbers used in the performance-established configuration of the analyzer must continue to be used. Such a filter or scrubber must have a means to determine when the removal agent is exhausted. Periodically replace or replenish it in accordance with the manufacturer's recommendations.**

7.0 REAGENTS AND STANDARDS. WHAT CALIBRATION GASES ARE NEEDED?

7.1 Calibration Gases. **CO calibration gases for the EC cell must be CO in nitrogen or CO in a mixture of nitrogen and O_2. Use CO calibration gases with labeled concentration values certified by the manufacturer to be within ± 5 percent of the label value. Dry ambient air (20.9 percent O_2) is acceptable for calibration of the O_2 cell. If needed, any lower percentage O_2 calibration gas must be a mixture of O_2 in nitrogen.**

7.1.1 Up-Scale CO Calibration Gas Concentration. **Choose one or more up-scale gas concentrations such that the average of the stack gas measurements for each stack gas sampling run are between 25 and 150 percent of those concentrations. Alternatively, choose an up-scale gas that does not exceed twice the concentration of the applicable outlet standard. If a measured gas value exceeds 150 percent of the up-scale CO calibration gas value at any time during the stack gas sampling run, the run must be discarded and repeated.**

7.1.2 Up-Scale O_2 Calibration Gas Concentration.

Select an O_2 gas concentration such that the difference between the gas concentration and the average stack gas measurement or reading for each sample run is less than 15 percent O_2 . When the average exhaust gas O_2 readings are above 6 percent, you may use dry ambient air (20.9 percent O_2) for the up-scale O_2 calibration gas.

7.1.3 Zero Gas. **Use an inert gas that contains less than 0.25 percent of the up-scale CO calibration gas concentration. You may use dry air that is free from ambient CO and other combustion gas products (e.g., CO_2).**

8.0 SAMPLE COLLECTION AND ANALYSIS

8.1 Selection of Sampling Sites.

8.1.1 Control Device Inlet. **Select a sampling site sufficiently downstream of the engine so that the combustion gases should be well mixed. Use a single sampling extraction point near the center of the duct (e.g., within the 10 percent centroidal area), unless instructed otherwise.**

8.1.2 Exhaust Gas Outlet. **Select a sampling site located at least two stack diameters downstream of any disturbance (e.g., turbocharger exhaust, crossover junction or recirculation take-off) and at least one-half stack diameter upstream of the gas discharge to the atmosphere. Use a single sampling extraction point near the center of the duct (e.g., within the 10 percent centroidal area), unless instructed otherwise.**

8.2 Stack Gas Collection and Analysis. **Prior to the first stack gas sampling run, conduct that the pre-sampling calibration in accordance with Section 10.1. Use Figure 1 to record all data. Zero the analyzer with zero gas. Confirm and record that the scrubber media color is correct and not exhausted. Then position the probe at the sampling point and begin the sampling run at the same flow rate used during the up-scale calibration. Record the start time. Record all EC cell output responses and the flow rate during the “sample conditioning phase” once per minute until constant readings are obtained. Then begin the “measurement data phase” and record readings every 15 seconds for at least two minutes (or eight readings), or as otherwise required to achieve two continuous minutes of data that meet the specification given in Section 13.1. Finally, perform the “refresh phase” by introducing dry air, free from**

CO and other combustion gases, until several minute-to-minute readings of consistent value have been obtained. For each run use the "measurement data phase" readings to calculate the average stack gas CO and O_2 concentrations.

8.3 EC Cell Rate. **Maintain the EC cell sample flow rate so that it does not vary by more than ± 10 percent throughout the pre-sampling calibration, stack gas sampling and post-sampling calibration check. Alternatively, the EC cell sample flow rate can be maintained within a tolerance range that does not affect the gas concentration readings by more than ± 3 percent, as instructed by the EC cell manufacturer.**

9.0 QUALITY CONTROL (RESERVED)

10.0 CALIBRATION AND STANDARDIZATION

10.1 Pre-Sampling Calibration. **Conduct the following protocol once for each nominal range to be used on each EC cell before performing a stack gas sampling run on each field sampling day. Repeat the calibration if you replace an EC cell before completing all of the sampling runs. There is no prescribed order for calibration of the EC cells; however, each cell must complete the measurement data phase during calibration. Assemble the measurement system by following the manufacturer's recommended protocols including for preparing and preconditioning the EC cell. Assure the measurement system has no leaks and verify the gas scrubbing agent is not depleted. Use Figure 1 to record all data.**

10.1.1 Zero Calibration. **For both the O_2 and CO cells, introduce zero gas to the measurement system (e.g., at the calibration assembly) and record the concentration reading every minute until readings are constant for at least two consecutive minutes. Include the time and sample flow rate. Repeat the steps in this section at least once to verify the zero calibration for each component gas.**

10.1.2 Zero Calibration Tolerance. **For each zero gas introduction, the zero level output must be less than or equal to ± 3 percent of the up-scale gas value or ± 1 ppm, whichever is less restrictive, for the CO channel and less than or equal to ± 0.3 percent O_2 for the O_2 channel.**

10.1.3 Up-Scale Calibration. **Individually introduce each calibration gas to the measurement system (e.g., at the calibration assembly) and record the start time. Record all EC cell output responses and the flow rate during this "sample conditioning phase" once per minute until readings are constant for at least two minutes. Then begin the "measurement data phase" and record readings every 15 seconds for a total of two minutes, or as otherwise required. Finally, perform the "refresh phase" by introducing dry air, free from CO and other combustion gases, until readings are constant for at least two consecutive minutes. Then repeat the steps in this section at least once to verify the calibration for each component gas. Introduce all gases to flow through the entire sample handling system (i.e., at the exit end of the sampling probe or the calibration assembly).**

10.1.4 Up-Scale Calibration Error. **The mean of the difference of the "measurement data phase" readings from the reported standard gas value must be less than or equal to ± 5 percent or ± 1 ppm for CO or ± 0.5 percent O_2 , whichever is less restrictive, respectively. The maximum allowable deviation from the mean measured value of any single "measurement data phase" reading must be less than or equal to ± 2 percent or ± 1 ppm for CO or ± 0.5 percent O_2 , whichever is less restrictive, respectively.**

10.2 Post-Sampling Calibration Check. **Conduct a stack gas post-sampling calibration check after the stack gas sampling run or set of runs and within 12 hours of the initial calibration. Conduct up-scale and zero calibration checks using the protocol in Section 10.1. Make no changes to the sampling system or EC cell calibration until all post-sampling calibration checks have been recorded. If either the zero or up-scale calibration error exceeds the respective specification in Sections 10.1.2 and 10.1.4 then all measurement data collected since the previous successful calibrations are invalid and re-calibration and re-sampling are required. If the sampling system is disassembled or the EC cell calibration is adjusted, repeat the calibration check before conducting the next analyzer sampling run.**

11.0 ANALYTICAL PROCEDURE

The analytical procedure is fully discussed in Section 8.

12.0 CALCULATIONS AND DATA ANALYSIS

Determine the CO and O_2 concentrations for each stack gas sampling run by calculating the mean gas concentrations of the data recorded during the "measurement data phase".

13.0 PROTOCOL PERFORMANCE

Use the following protocols to verify consistent analyzer performance during each field sampling day.

13.1 Measurement Data Phase Performance Check. **Calculate the mean of the readings from the "measurement data phase". The maximum allowable deviation from the mean for each of the individual readings is ± 2 percent, or ± 1 ppm, whichever is less restrictive. Record the mean value and maximum deviation for each gas monitored. Data must conform to Section 10.1.4. The EC cell flow rate must conform to the specification in Section 8.3.**

***Example: A measurement data phase is invalid if the maximum deviation of any single reading comprising that mean is greater than ± 2* percent *or ± 1 ppm (the default criteria). For example, if the mean = 30 ppm, single readings of below 29 ppm and above 31 ppm are disallowed*).**

13.2 Interference Check. **Before the initial use of the EC cell and interference gas scrubber in the field, and semi-annually thereafter, challenge the interference gas scrubber with NO and NO_2 gas standards that are generally recognized as representative of diesel-fueled engine NO and NO_2 emission values. Record the responses displayed by the CO EC cell and other pertinent data on Figure 1 or a similar form.**

13.2.1 Interference Response. **The combined NO and NO_2 interference response should be less than or equal to ± 5 percent of the up-scale CO calibration gas concentration.**

13.3 Repeatability Check. **Conduct the following check once for each nominal range that is to be used on the CO EC cell within 5 days prior to each field sampling program. If a field sampling program lasts longer than 5 days, repeat this check every 5 days. Immediately repeat the check if the EC cell is replaced or if the EC cell is exposed to gas concentrations greater than 150 percent of the highest up-scale gas concentration.**

13.3.1 Repeatability Check Procedure. **Perform a complete EC cell sampling run (all three phases) by introducing the CO calibration gas to the measurement system and record the response. Follow Section 10.1.3. Use Figure 1 to record all data. Repeat the run three times for a total of four complete runs. During the four repeatability check runs, do not adjust the system except where necessary to achieve the correct calibration gas flow rate at the analyzer.**

13.3.2 Repeatability Check Calculations. **Determine the highest and lowest average "measurement data phase" CO concentrations from the four repeatability check runs and record the results on Figure 1 or a similar form. The absolute value of the difference between the maximum and minimum average values recorded must not vary more than ± 3 percent or ± 1 ppm of the up-scale gas value, whichever is less restrictive.**

14.0 POLLUTION PREVENTION (RESERVED)

15.0 WASTE MANAGEMENT (RESERVED)

16.0 ALTERNATIVE PROCEDURES (RESERVED)

17.0 REFERENCES

(1) “Development of an Electrochemical Cell Emission Analyzer Test Protocol”, Topical Report, Phil Juneau, Emission Monitoring, Inc., July 1997.

(2) “Determination of Nitrogen Oxides, Carbon Monoxide, and Oxygen Emissions from Natural Gas-Fired Engines, Boilers, and Process Heaters Using Portable Analyzers”, EMC Conditional Test Protocol 30 (CTM-30), Gas Research Institute Protocol GRI-96/0008, Revision 7, October 13, 1997.

(3) “ICAC Test Protocol for Periodic Monitoring”, EMC Conditional Test Protocol 34 (CTM-034), The Institute of Clean Air Companies, September 8, 1999.

(4) “Code of Federal Regulations”, Protection of Environment, 40 CFR, Part 60, Appendix A, Methods 1-4; 10.

Table 1: Appendix A—Sampling Run Data.

Facility__________ Engine I.D.__________ Date______				
Run Type:	**(_)**	**(_)**	**(_)**	**(_)**
(X)	**Pre-Sample Calibration**	**Stack Gas Sample**	**Post-Sample Cal. Check**	**Repeatability Check**

Run #	**1**	**1**	**2**	**2**	**3**	**3**	**4**	**4**	**Time**	**Scrub. OK**	**Flow- Rate**
Gas	**O_2**	**CO**	**O_2**	**CO**	**O_2**	**CO**	**O_2**	**CO**			
Sample Cond. Phase											
″											
″											
″											
″											
Measurement Data Phase											
″											
″											
″											
″											

Run #	**1**	**1**	**2**	**2**	**3**	**3**	**4**	**4**	**Time**	**Scrub. OK**	**Flow- Rate**
Gas	**O_2**	**CO**	**O_2**	**CO**	**O_2**	**CO**	**O_2**	**CO**			
″											
″											
″											
″											
″											
″											
Mean											
Refresh Phase											
″											
″											
″											
″											

[78 FR 6721, Jan. 30, 2013]

Modification No. 3: **40 CFR 60, Subpart IIII Updates**
On January 30, 2013, the U.S. EPA had a notice published in the Federal Register indicating U.S. EPA was 40 CFR 60, Subpart IIII to make it consistent with the RICE NESHAP, 40 CFR 63, Subpart ZZZZ. Revisions to 40 CFR 60, Subpart IIII became effective on April 1, 2013. IDEM, OAQ has removed and replaced permit Attachment E with the revised rule.

~~Old Attachment E~~

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

~~Attachment E to a Part 70 Operating Permit~~

~~Source Background and Description~~

~~Source Name: Ohio Valley Resources, LLC~~
~~Source Location: 300-400 East CR 350 North, Rockport, Indiana 47635~~
~~County: Spencer~~
~~SIC Code: 2873~~
~~Permit No.: T 147-32322-00062~~
~~Permit Reviewer: David Matousek~~

~~40 CFR 60, Subpart IIII~~

~~40 CFR 60, Subpart IIII~~ **~~Standards of Performance for Stationary Compression Ignition Internal Combustion Engines~~**

~~Source: 71 FR 39172, July 11, 2006, unless otherwise noted.~~

~~What This Subpart Covers~~

~~§ 60.4200 Am I subject to this subpart?~~

~~(a) The provisions of this subpart are applicable to manufacturers, owners, and operators of stationary compression ignition (CI) internal combustion engines (ICE) and other persons as specified in paragraphs (a)(1) through (4) of this section. For the purposes of this subpart, the date that construction commences is the date the engine is ordered by the owner or operator.~~

~~(1) Manufacturers of stationary CI ICE with a displacement of less than 30 liters per cylinder where the model year is:~~

~~(i) 2007 or later, for engines that are not fire pump engines;~~

~~(ii) The model year listed in Table 3 to this subpart or later model year, for fire pump engines.~~

~~(2) Owners and operators of stationary CI ICE that commence construction after July 11, 2005, where the stationary CI ICE are:~~

~~(i) Manufactured after April 1, 2006, and are not fire pump engines, or~~

~~(ii) Manufactured as a certified National Fire Protection Association (NFPA) fire pump engine after July 1, 2006.~~

~~(3) Owners and operators of any stationary CI ICE that are modified or reconstructed after July 11, 2005 and any person that modifies or reconstructs any stationary CI ICE after July 11, 2005.~~

~~(4) The provisions of § 60.4208 of this subpart are applicable to all owners and operators of stationary CI ICE that commence construction after July 11, 2005.~~

~~(b) The provisions of this subpart are not applicable to stationary CI ICE being tested at a stationary CI ICE test cell/stand.~~

~~(c) If you are an owner or operator of an area source subject to this subpart, you are exempt from the obligation to obtain a permit under 40 CFR part 70 or 40 CFR part 71, provided you are not required to obtain a permit under 40 CFR 70.3(a) or 40 CFR 71.3(a) for a reason other than your status as an area source under this subpart. Notwithstanding the previous sentence, you must continue to comply with the provisions of this subpart applicable to area sources.~~

~~(d) Stationary CI ICE may be eligible for exemption from the requirements of this subpart as described in 40 CFR part 1068, subpart C (or the exemptions described in 40 CFR part 89, subpart J and 40 CFR part 94, subpart J, for engines that would need to be certified to standards in those parts), except that owners and operators, as well as manufacturers, may be eligible to request an exemption for national security.~~

~~(e) Owners and operators of facilities with CI ICE that are acting as temporary replacement units and that are located at a stationary source for less than 1 year and that have been properly certified as meeting the~~

~~standards that would be applicable to such engine under the appropriate nonroad engine provisions, are not required to meet any other provisions under this subpart with regard to such engines.~~

~~[71 FR 39172, July 11, 2006, as amended at 76 FR 37967, June 28, 2011]~~

~~Emission Standards for Manufacturers~~

~~§ 60.4201 What emission standards must I meet for non-emergency engines if I am a stationary CI internal combustion engine manufacturer?~~

~~(a) Stationary CI internal combustion engine manufacturers must certify their 2007 model year and later non-emergency stationary CI ICE with a maximum engine power less than or equal to 2,237 kilowatt (KW) (3,000 horsepower (HP)) and a displacement of less than 10 liters per cylinder to the certification emission standards for new nonroad CI engines in 40 CFR 89.112, 40 CFR 89.113, 40 CFR 1039.101, 40 CFR 1039.102, 40 CFR 1039.104, 40 CFR 1039.105, 40 CFR 1039.107, and 40 CFR 1039.115, as applicable, for all pollutants, for the same model year and maximum engine power.~~

~~(b) Stationary CI internal combustion engine manufacturers must certify their 2007 through 2010 model year non-emergency stationary CI ICE with a maximum engine power greater than 2,237 KW (3,000 HP) and a displacement of less than 10 liters per cylinder to the emission standards in table 1 to this subpart, for all pollutants, for the same maximum engine power.~~

~~(c) Stationary CI internal combustion engine manufacturers must certify their 2011 model year and later non-emergency stationary CI ICE with a maximum engine power greater than 2,237 KW (3,000 HP) and a displacement of less than 10 liters per cylinder to the certification emission standards for new nonroad CI engines in 40 CFR 1039.101, 40 CFR 1039.102, 40 CFR 1039.104, 40 CFR 1039.105, 40 CFR 1039.107, and 40 CFR 1039.115, as applicable, for all pollutants, for the same maximum engine power.~~

~~(d) Stationary CI internal combustion engine manufacturers must certify the following non-emergency stationary CI ICE to the certification emission standards for new marine CI engines in 40 CFR 94.8, as applicable, for all pollutants, for the same displacement and maximum engine power:~~

~~(1) Their 2007 model year through 2012 non-emergency stationary CI ICE with a displacement of greater than or equal to 10 liters per cylinder and less than 30 liters per cylinder;~~

~~(2) Their 2013 model year non-emergency stationary CI ICE with a maximum engine power greater than or equal to 3,700 KW (4,958 HP) and a displacement of greater than or equal to 10 liters per cylinder and less than 15 liters per cylinder; and~~

~~(3) Their 2013 model year non-emergency stationary CI ICE with a displacement of greater than or equal to 15 liters per cylinder and less than 30 liters per cylinder.~~

~~(e) Stationary CI internal combustion engine manufacturers must certify the following non-emergency stationary CI ICE to the certification emission standards and other requirements for new marine CI engines in 40 CFR 1042.101, 40 CFR 1042.107, 40 CFR 1042.110, 40 CFR 1042.115, 40 CFR 1042.120, and 40 CFR 1042.145, as applicable, for all pollutants, for the same displacement and maximum engine power:~~

~~(1) Their 2013 model year non-emergency stationary CI ICE with a maximum engine power less than 3,700 KW (4,958 HP) and a displacement of greater than or equal to 10 liters per cylinder and less than 15 liters per cylinder; and~~

~~(2) Their 2014 model year and later non-emergency stationary CI ICE with a displacement of greater than or equal to 10 liters per cylinder and less than 30 liters per cylinder.~~

~~(f) Notwithstanding the requirements in paragraphs (a) through (c) of this section, stationary non-emergency CI ICE identified in paragraphs (a) and (c) may be certified to the provisions of 40 CFR part 94 or, if Table 1 to 40 CFR 1042.1 identifies 40 CFR part 1042 as being applicable, 40 CFR part 1042, if the engines will be used solely in either or both of the following locations:~~

~~(1) Areas of Alaska not accessible by the Federal Aid Highway System (FAHS); and~~

~~(2) Marine offshore installations.~~

~~(g) Notwithstanding the requirements in paragraphs (a) through (f) of this section, stationary CI internal combustion engine manufacturers are not required to certify reconstructed engines; however manufacturers may elect to do so. The reconstructed engine must be certified to the emission standards specified in paragraphs (a) through (e) of this section that are applicable to the model year, maximum engine power, and displacement of the reconstructed stationary CI ICE.~~

~~[71 FR 39172, July 11, 2006, as amended at 76 FR 37967, June 28, 2011]~~

~~§ 60.4202 What emission standards must I meet for emergency engines if I am a stationary CI internal combustion engine manufacturer?~~

~~(a) Stationary CI internal combustion engine manufacturers must certify their 2007 model year and later emergency stationary CI ICE with a maximum engine power less than or equal to 2,237 KW (3,000 HP) and a displacement of less than 10 liters per cylinder that are not fire pump engines to the emission standards specified in paragraphs (a)(1) through (2) of this section.~~

~~(1) For engines with a maximum engine power less than 37 KW (50 HP):~~

~~(i) The certification emission standards for new nonroad CI engines for the same model year and maximum engine power in 40 CFR 89.112 and 40 CFR 89.113 for all pollutants for model year 2007 engines, and~~

~~(ii) The certification emission standards for new nonroad CI engines in 40 CFR 1039.104, 40 CFR 1039.105, 40 CFR 1039.107, 40 CFR 1039.115, and table 2 to this subpart, for 2008 model year and later engines.~~

~~(2) For engines with a maximum engine power greater than or equal to 37 KW (50 HP), the certification emission standards for new nonroad CI engines for the same model year and maximum engine power in 40 CFR 89.112 and 40 CFR 89.113 for all pollutants beginning in model year 2007.~~

~~(b) Stationary CI internal combustion engine manufacturers must certify their 2007 model year and later emergency stationary CI ICE with a maximum engine power greater than 2,237 KW (3,000 HP) and a displacement of less than 10 liters per cylinder that are not fire pump engines to the emission standards specified in paragraphs (b)(1) through (2) of this section.~~

~~(1) For 2007 through 2010 model years, the emission standards in table 1 to this subpart, for all pollutants, for the same maximum engine power.~~

~~(2) For 2011 model year and later, the certification emission standards for new nonroad CI engines for engines of the same model year and maximum engine power in 40 CFR 89.112 and 40 CFR 89.113 for all pollutants.~~

~~(c) [Reserved]~~

~~(d) Beginning with the model years in table 3 to this subpart, stationary CI internal combustion engine manufacturers must certify their fire pump stationary CI ICE to the emission standards in table 4 to this subpart, for all pollutants, for the same model year and NFPA nameplate power.~~

~~(e) Stationary CI internal combustion engine manufacturers must certify the following emergency stationary CI ICE that are not fire pump engines to the certification emission standards for new marine CI engines in 40 CFR 94.8, as applicable, for all pollutants, for the same displacement and maximum engine power:~~

~~(1) Their 2007 model year through 2012 emergency stationary CI ICE with a displacement of greater than or equal to 10 liters per cylinder and less than 30 liters per cylinder;~~

~~(2) Their 2013 model year and later emergency stationary CI ICE with a maximum engine power greater than or equal to 3,700 KW (4,958 HP) and a displacement of greater than or equal to 10 liters per cylinder and less than 15 liters per cylinder;~~

~~(3) Their 2013 model year emergency stationary CI ICE with a displacement of greater than or equal to 15 liters per cylinder and less than 30 liters per cylinder; and~~

~~(4) Their 2014 model year and later emergency stationary CI ICE with a maximum engine power greater than or equal to 2,000 KW (2,682 HP) and a displacement of greater than or equal to 15 liters per cylinder and less than 30 liters per cylinder.~~

~~(f) Stationary CI internal combustion engine manufacturers must certify the following emergency stationary CI ICE to the certification emission standards and other requirements applicable to Tier 3 new marine CI engines in 40 CFR 1042.101, 40 CFR 1042.107, 40 CFR 1042.115, 40 CFR 1042.120, and 40 CFR 1042.145, for all pollutants, for the same displacement and maximum engine power:~~

~~(1) Their 2013 model year and later emergency stationary CI ICE with a maximum engine power less than 3,700 KW (4,958 HP) and a displacement of greater than or equal to 10 liters per cylinder and less than 15 liters per cylinder; and~~

~~(2) Their 2014 model year and later emergency stationary CI ICE with a maximum engine power less than 2,000 KW (2,682 HP) and a displacement of greater than or equal to 15 liters per cylinder and less than 30 liters per cylinder.~~

~~(g) Notwithstanding the requirements in paragraphs (a) through (d) of this section, stationary emergency CI internal combustion engines identified in paragraphs (a) and (c) may be certified to the provisions of 40 CFR part 94 or, if Table 2 to 40 CFR 1042.101 identifies Tier 3 standards as being applicable, the requirements applicable to Tier 3 engines in 40 CFR part 1042, if the engines will be used solely in either or both of the following locations:~~

~~(1) Areas of Alaska not accessible by the FAHS; and~~

~~(2) Marine offshore installations.~~

~~(h) Notwithstanding the requirements in paragraphs (a) through (f) of this section, stationary CI internal combustion engine manufacturers are not required to certify reconstructed engines; however manufacturers may elect to do so. The reconstructed engine must be certified to the emission standards specified in paragraphs (a) through (f) of this section that are applicable to the model year, maximum engine power and displacement of the reconstructed emergency stationary CI ICE.~~

~~[71 FR 39172, July 11, 2006, as amended at 76 FR 37968, June 28, 2011]~~

~~§ 60.4203 How long must my engines meet the emission standards if I am a manufacturer of stationary CI internal combustion engines?~~

~~Engines manufactured by stationary CI internal combustion engine manufacturers must meet the emission standards as required in §§ 60.4201 and 60.4202 during the certified emissions life of the engines.~~

~~[76 FR 37968, June 28, 2011]~~

~~Emission Standards for Owners and Operators~~

~~§ 60.4204 What emission standards must I meet for non-emergency engines if I am an owner or operator of a stationary CI internal combustion engine?~~

~~(a) Owners and operators of pre-2007 model year non-emergency stationary CI ICE with a displacement of less than 10 liters per cylinder must comply with the emission standards in table 1 to this subpart. Owners and operators of pre-2007 model year non-emergency stationary CI ICE with a displacement of greater than or equal to 10 liters per cylinder and less than 30 liters per cylinder must comply with the emission standards in 40 CFR 94.8(a)(1).~~

~~(b) Owners and operators of 2007 model year and later non-emergency stationary CI ICE with a displacement of less than 30 liters per cylinder must comply with the emission standards for new CI engines in § 60.4201 for their 2007 model year and later stationary CI ICE, as applicable.~~

~~(c) Owners and operators of non-emergency stationary CI engines with a displacement of greater than or equal to 30 liters per cylinder must meet the following requirements:~~

~~(1) For engines installed prior to January 1, 2012, limit the emissions of NO_X in the stationary CI internal combustion engine exhaust to the following:~~

~~(i) 17.0 grams per kilowatt-hour (g/KW-hr) (12.7 grams per horsepower-hr (g/HP-hr)) when maximum engine speed is less than 130 revolutions per minute (rpm);~~

~~(ii) $45 \cdot n^{-0.2}$ g/KW-hr ($34 \cdot n^{-0.2}$ g/HP-hr) when maximum engine speed is 130 or more but less than 2,000 rpm, where n is maximum engine speed; and~~

~~(iii) 9.8 g/KW-hr (7.3 g/HP-hr) when maximum engine speed is 2,000 rpm or more.~~

~~(2) For engines installed on or after January 1, 2012 and before January 1, 2016, limit the emissions of NO_X in the stationary CI internal combustion engine exhaust to the following:~~

~~(i) 14.4 g/KW-hr (10.7 g/HP-hr) when maximum engine speed is less than 130 rpm;~~

~~(ii) $44 \cdot n^{-0.23}$ g/KW-hr ($33 \cdot n^{-0.23}$ g/HP-hr) when maximum engine speed is greater than or equal to 130 but less than 2,000 rpm and where n is maximum engine speed; and~~

~~(iii) 7.7 g/KW-hr (5.7 g/HP-hr) when maximum engine speed is greater than or equal to 2,000 rpm.~~

~~(3) For engines installed on or after January 1, 2016, limit the emissions of NO_X in the stationary CI internal combustion engine exhaust to the following:~~

~~(i) 3.4 g/KW-hr (2.5 g/HP-hr) when maximum engine speed is less than 130 rpm;~~

~~(ii) $9.0 \cdot n^{-0.20}$ g/KW-hr ($6.7 \cdot n^{-0.20}$ g/HP-hr) where n (maximum engine speed) is 130 or more but less than 2,000 rpm; and~~

~~(iii) 2.0 g/KW-hr (1.5 g/HP-hr) where maximum engine speed is greater than or equal to 2,000 rpm.~~

~~(4) Reduce particulate matter (PM) emissions by 60 percent or more, or limit the emissions of PM in the stationary CI internal combustion engine exhaust to 0.15 g/KW-hr (0.11 g/HP-hr).~~

~~(d) Owners and operators of non-emergency stationary CI ICE with a displacement of less than 30 liters per cylinder who conduct performance tests in-use must meet the not-to-exceed (NTE) standards as indicated in § 60.4212.~~

~~(e) Owners and operators of any modified or reconstructed non-emergency stationary CI ICE subject to this subpart must meet the emission standards applicable to the model year, maximum engine power, and displacement of the modified or reconstructed non-emergency stationary CI ICE that are specified in paragraphs (a) through (d) of this section.~~

~~[71 FR 39172, July 11, 2006, as amended at 76 FR 37968, June 28, 2011]~~

~~§ 60.4205 What emission standards must I meet for emergency engines if I am an owner or operator of a stationary CI internal combustion engine?~~

~~(a) Owners and operators of pre-2007 model year emergency stationary CI ICE with a displacement of less than 10 liters per cylinder that are not fire pump engines must comply with the emission standards in Table 1 to this subpart. Owners and operators of pre-2007 model year emergency stationary CI ICE with a displacement of greater than or equal to 10 liters per cylinder and less than 30 liters per cylinder that are not fire pump engines must comply with the emission standards in 40 CFR 94.8(a)(1).~~

~~(b) Owners and operators of 2007 model year and later emergency stationary CI ICE with a displacement of less than 30 liters per cylinder that are not fire pump engines must comply with the emission standards for new nonroad CI engines in § 60.4202, for all pollutants, for the same model year and maximum engine power for their 2007 model year and later emergency stationary CI ICE.~~

~~(c) Owners and operators of fire pump engines with a displacement of less than 30 liters per cylinder must comply with the emission standards in table 4 to this subpart, for all pollutants.~~

~~(d) Owners and operators of emergency stationary CI engines with a displacement of greater than or equal to 30 liters per cylinder must meet the requirements in this section.~~

~~(1) For engines installed prior to January 1, 2012, limit the emissions of~~ NO_X ~~in the stationary CI internal combustion engine exhaust to the following:~~

~~(i) 17.0 g/KW-hr (12.7 g/HP-hr) when maximum engine speed is less than 130 rpm;~~

~~(ii)~~ $45 \cdot n^{-0.2}$ ~~g/KW-hr~~ ~~(~~$34 \cdot n^{-0.2}$ ~~g/HP-hr) when maximum engine speed is 130 or more but less than 2,000 rpm, where n is maximum engine speed; and~~

~~(iii) 9.8 g/kW-hr (7.3 g/HP-hr) when maximum engine speed is 2,000 rpm or more.~~

~~(2) For engines installed on or after January 1, 2012, limit the emissions of~~ NO_X ~~in the stationary CI internal combustion engine exhaust to the following:~~

~~(i) 14.4 g/KW-hr (10.7 g/HP-hr) when maximum engine speed is less than 130 rpm;~~

~~(ii)~~ $44 \cdot n^{-0.23}$ ~~g/KW-hr~~ ~~(~~$33 \cdot n^{-0.23}$ ~~g/HP-hr) when maximum engine speed is greater than or equal to 130 but less than 2,000 rpm and where n is maximum engine speed; and~~

~~(iii) 7.7 g/KW-hr (5.7 g/HP-hr) when maximum engine speed is greater than or equal to 2,000 rpm.~~

~~(3) Limit the emissions of PM in the stationary CI internal combustion engine exhaust to 0.40 g/KW-hr (0.30 g/HP-hr).~~

~~(e) Owners and operators of emergency stationary CI ICE with a displacement of less than 30 liters per cylinder who conduct performance tests in-use must meet the NTE standards as indicated in § 60.4212.~~

~~(f) Owners and operators of any modified or reconstructed emergency stationary CI ICE subject to this subpart must meet the emission standards applicable to the model year, maximum engine power, and displacement of the modified or reconstructed CI ICE that are specified in paragraphs (a) through (e) of this section.~~

~~[71 FR 39172, July 11, 2006, as amended at 76 FR 37969, June 28, 2011]~~

~~§ 60.4206 How long must I meet the emission standards if I am an owner or operator of a stationary CI internal combustion engine?~~

~~Owners and operators of stationary CI ICE must operate and maintain stationary CI ICE that achieve the emission standards as required in §§ 60.4204 and 60.4205 over the entire life of the engine.~~

~~[76 FR 37969, June 28, 2011]~~

~~Fuel Requirements for Owners and Operators~~

~~§ 60.4207 What fuel requirements must I meet if I am an owner or operator of a stationary CI internal combustion engine subject to this subpart?~~

~~(a) Beginning October 1, 2007, owners and operators of stationary CI ICE subject to this subpart that use diesel fuel must use diesel fuel that meets the requirements of 40 CFR 80.510(a).~~

~~(b) Beginning October 1, 2010, owners and operators of stationary CI ICE subject to this subpart with a displacement of less than 30 liters per cylinder that use diesel fuel must purchase diesel fuel that meets the requirements of 40 CFR 80.510(b) for nonroad diesel fuel.~~

~~(c) [Reserved]~~

~~(d) Beginning June 1, 2012, owners and operators of stationary CI ICE subject to this subpart with a displacement of greater than or equal to 30 liters per cylinder are no longer subject to the requirements of paragraph (a) of this section, and must use fuel that meets a maximum per-gallon sulfur content of 1,000 parts per million (ppm).~~

~~(e) Stationary CI ICE that have a national security exemption under § 60.4200(d) are also exempt from the fuel requirements in this section.~~

~~[71 FR 39172, July 11, 2006, as amended at 76 FR 37969, June 28, 2011]~~

~~Other Requirements for Owners and Operators~~

~~§ 60.4208 What is the deadline for importing or installing stationary CI ICE produced in previous model years?~~

~~(a) After December 31, 2008, owners and operators may not install stationary CI ICE (excluding fire pump engines) that do not meet the applicable requirements for 2007 model year engines.~~

~~(b) After December 31, 2009, owners and operators may not install stationary CI ICE with a maximum engine power of less than 19 KW (25 HP) (excluding fire pump engines) that do not meet the applicable requirements for 2008 model year engines.~~

~~(c) After December 31, 2014, owners and operators may not install non-emergency stationary CI ICE with a maximum engine power of greater than or equal to 19 KW (25 HP) and less than 56 KW (75 HP) that do not meet the applicable requirements for 2013 model year non-emergency engines.~~

~~(d) After December 31, 2013, owners and operators may not install non-emergency stationary CI ICE with a maximum engine power of greater than or equal to 56 KW (75 HP) and less than 130 KW (175 HP) that do not meet the applicable requirements for 2012 model year non-emergency engines.~~

~~(e) After December 31, 2012, owners and operators may not install non-emergency stationary CI ICE with a maximum engine power of greater than or equal to 130 KW (175 HP), including those above 560 KW (750 HP), that do not meet the applicable requirements for 2011 model year non-emergency engines.~~

~~(f) After December 31, 2016, owners and operators may not install non-emergency stationary CI ICE with a maximum engine power of greater than or equal to 560 KW (750 HP) that do not meet the applicable requirements for 2015 model year non-emergency engines.~~

~~(g) After December 31, 2018, owners and operators may not install non-emergency stationary CI ICE with a maximum engine power greater than or equal to 600 KW (804 HP) and less than 2,000 KW (2,680 HP) and a displacement of greater than or equal to 10 liters per cylinder and less than 30 liters per cylinder that do not meet the applicable requirements for 2017 model year non-emergency engines.~~

~~(h) In addition to the requirements specified in §§ 60.4201, 60.4202, 60.4204, and 60.4205, it is prohibited to import stationary CI ICE with a displacement of less than 30 liters per cylinder that do not meet the applicable requirements specified in paragraphs (a) through (g) of this section after the dates specified in paragraphs (a) through (g) of this section.~~

~~(i) The requirements of this section do not apply to owners or operators of stationary CI ICE that have been modified, reconstructed, and do not apply to engines that were removed from one existing location and reinstalled at a new location.~~

~~[71 FR 39172, July 11, 2006, as amended at 76 FR 37969, June 28, 2011]~~

~~§ 60.4209 What are the monitoring requirements if I am an owner or operator of a stationary CI internal combustion engine?~~

~~If you are an owner or operator, you must meet the monitoring requirements of this section. In addition, you must also meet the monitoring requirements specified in § 60.4211.~~

~~(a) If you are an owner or operator of an emergency stationary CI internal combustion engine that does not meet the standards applicable to non-emergency engines, you must install a non-resettable hour meter prior to startup of the engine.~~

~~(b) If you are an owner or operator of a stationary CI internal combustion engine equipped with a diesel particulate filter to comply with the emission standards in § 60.4204, the diesel particulate filter must be installed with a backpressure monitor that notifies the owner or operator when the high backpressure limit of the engine is approached.~~

~~[71 FR 39172, July 11, 2006, as amended at 76 FR 37969, June 28, 2011]~~

~~Compliance Requirements~~

~~§ 60.4210 What are my compliance requirements if I am a stationary CI internal combustion engine manufacturer?~~

~~(a) Stationary CI internal combustion engine manufacturers must certify their stationary CI ICE with a displacement of less than 10 liters per cylinder to the emission standards specified in § 60.4201(a) through (c) and § 60.4202(a), (b) and (d) using the certification procedures required in 40 CFR part 89, subpart B, or 40 CFR part 1039, subpart C, as applicable, and must test their engines as specified in those parts. For the purposes of this subpart, engines certified to the standards in table 1 to this subpart shall be subject to the same requirements as engines certified to the standards in 40 CFR part 89. For the purposes of this subpart, engines certified to the standards in table 4 to this subpart shall be subject to the same requirements as engines certified to the standards in 40 CFR part 89, except that engines with NFPA nameplate power of less than 37 KW (50 HP) certified to model year 2011 or later standards shall be subject to the same requirements as engines certified to the standards in 40 CFR part 1039.~~

~~(b) Stationary CI internal combustion engine manufacturers must certify their stationary CI ICE with a displacement of greater than or equal to 10 liters per cylinder and less than 30 liters per cylinder to the emission standards specified in § 60.4201(d) and (e) and § 60.4202(e) and (f) using the certification procedures required in 40 CFR part 94, subpart C, or 40 CFR part 1042, subpart C, as applicable, and must test their engines as specified in 40 CFR part 94 or 1042, as applicable.~~

~~(c) Stationary CI internal combustion engine manufacturers must meet the requirements of 40 CFR 1039.120, 1039.125, 1039.130, and 1039.135, and 40 CFR part 1068 for engines that are certified to the emission standards in 40 CFR part 1039. Stationary CI internal combustion engine manufacturers must meet the corresponding provisions of 40 CFR part 89, 40 CFR part 94 or 40 CFR part 1042 for engines that would be covered by that part if they were nonroad (including marine) engines. Labels on such engines must refer to stationary engines, rather than or in addition to nonroad or marine engines, as appropriate. Stationary CI internal combustion engine manufacturers must label their engines according to paragraphs (c)(1) through (3) of this section.~~

~~(1) Stationary CI internal combustion engines manufactured from January 1, 2006 to March 31, 2006 (January 1, 2006 to June 30, 2006 for fire pump engines), other than those that are part of certified engine families under the nonroad CI engine regulations, must be labeled according to 40 CFR 1039.20.~~

~~(2) Stationary CI internal combustion engines manufactured from April 1, 2006 to December 31, 2006 (or, for fire pump engines, July 1, 2006 to December 31 of the year preceding the year listed in table 3 to this subpart) must be labeled according to paragraphs (c)(2)(i) through (iii) of this section:~~

~~(i) Stationary CI internal combustion engines that are part of certified engine families under the nonroad regulations must meet the labeling requirements for nonroad CI engines, but do not have to meet the labeling requirements in 40 CFR 1039.20.~~

~~(ii) Stationary CI internal combustion engines that meet Tier 1 requirements (or requirements for fire pumps) under this subpart, but do not meet the requirements applicable to nonroad CI engines must be labeled according to 40 CFR 1039.20. The engine manufacturer may add language to the label clarifying that the engine meets Tier 1 requirements (or requirements for fire pumps) of this subpart.~~

~~(iii) Stationary CI internal combustion engines manufactured after April 1, 2006 that do not meet Tier 1 requirements of this subpart, or fire pumps engines manufactured after July 1, 2006 that do not meet the requirements for fire pumps under this subpart, may not be used in the U.S. If any such engines are manufactured in the U.S. after April 1, 2006 (July 1, 2006 for fire pump engines), they must be exported or must be brought into compliance with the appropriate standards prior to initial operation. The export provisions of 40 CFR 1068.230 would apply to engines for export and the manufacturers must label such engines according to 40 CFR 1068.230.~~

~~(3) Stationary CI internal combustion engines manufactured after January 1, 2007 (for fire pump engines, after January 1 of the year listed in table 3 to this subpart, as applicable) must be labeled according to paragraphs (c)(3)(i) through (iii) of this section.~~

~~(i) Stationary CI internal combustion engines that meet the requirements of this subpart and the corresponding requirements for nonroad (including marine) engines of the same model year and HP must be labeled according to the provisions in 40 CFR parts 89, 94, 1039 or 1042, as appropriate.~~

~~(ii) Stationary CI internal combustion engines that meet the requirements of this subpart, but are not certified to the standards applicable to nonroad (including marine) engines of the same model year and HP must be labeled according to the provisions in 40 CFR parts 89, 94, 1039 or 1042, as appropriate, but the words "stationary" must be included instead of "nonroad" or "marine" on the label. In addition, such engines must be labeled according to 40 CFR 1039.20.~~

~~(iii) Stationary CI internal combustion engines that do not meet the requirements of this subpart must be labeled according to 40 CFR 1068.230 and must be exported under the provisions of 40 CFR 1068.230.~~

~~(d) An engine manufacturer certifying an engine family or families to standards under this subpart that are identical to standards applicable under 40 CFR parts 89, 94, 1039 or 1042 for that model year may certify any such family that contains both nonroad (including marine) and stationary engines as a single engine family and/or may include any such family containing stationary engines in the averaging, banking and trading provisions applicable for such engines under those parts.~~

~~(e) Manufacturers of engine families discussed in paragraph (d) of this section may meet the labeling requirements referred to in paragraph (c) of this section for stationary CI ICE by either adding a separate label containing the information required in paragraph (c) of this section or by adding the words "and stationary" after the word "nonroad" or "marine," as appropriate, to the label.~~

~~(f) Starting with the model years shown in table 5 to this subpart, stationary CI internal combustion engine manufacturers must add a permanent label stating that the engine is for stationary emergency use only to each new emergency stationary CI internal combustion engine greater than or equal to 19 KW (25 HP) that meets all the emission standards for emergency engines in § 60.4202 but does not meet all the emission standards for non-emergency engines in § 60.4201. The label must be added according to the labeling requirements specified in 40 CFR 1039.135(b). Engine manufacturers must specify in the owner's manual that operation of emergency engines is limited to emergency operations and required maintenance and testing.~~

~~(g) Manufacturers of fire pump engines may use the test cycle in table 6 to this subpart for testing fire pump engines and may test at the NFPA certified nameplate HP, provided that the engine is labeled as "Fire Pump Applications Only".~~

~~(h) Engine manufacturers, including importers, may introduce into commerce uncertified engines or engines certified to earlier standards that were manufactured before the new or changed standards took effect until inventories are depleted, as long as such engines are part of normal inventory. For example, if the engine manufacturers' normal industry practice is to keep on hand a one-month supply of engines based on its projected sales, and a new tier of standards starts to apply for the 2009 model year, the engine manufacturer may manufacture engines based on the normal inventory requirements late in the 2008 model year, and sell those engines for installation. The engine manufacturer may not circumvent the provisions of §§ 60.4201 or 60.4202 by stockpiling engines that are built before new or changed standards take effect. Stockpiling of such engines beyond normal industry practice is a violation of this subpart.~~

~~(i) The replacement engine provisions of 40 CFR 89.1003(b)(7), 40 CFR 94.1103(b)(3), 40 CFR 94.1103(b)(4) and 40 CFR 1068.240 are applicable to stationary CI engines replacing existing equipment that is less than 15 years old.~~

~~[71 FR 39172, July 11, 2006, as amended at 76 FR 37969, June 28, 2011]~~

~~§ 60.4211 What are my compliance requirements if I am an owner or operator of a stationary CI internal combustion engine?~~

~~(a) If you are an owner or operator and must comply with the emission standards specified in this subpart, you must do all of the following, except as permitted under paragraph (g) of this section:~~

~~(1) Operate and maintain the stationary CI internal combustion engine and control device according to the manufacturer's emission-related written instructions;~~

~~(2) Change only those emission-related settings that are permitted by the manufacturer; and~~

~~(3) Meet the requirements of 40 CFR parts 89, 94 and/or 1068, as they apply to you.~~

~~(b) If you are an owner or operator of a pre-2007 model year stationary CI internal combustion engine and must comply with the emission standards specified in §§ 60.4204(a) or 60.4205(a), or if you are an owner or operator of a CI fire pump engine that is manufactured prior to the model years in table 3 to this subpart and must comply with the emission standards specified in § 60.4205(c), you must demonstrate compliance according to one of the methods specified in paragraphs (b)(1) through (5) of this section.~~

~~(1) Purchasing an engine certified according to 40 CFR part 89 or 40 CFR part 94, as applicable, for the same model year and maximum engine power. The engine must be installed and configured according to the manufacturer's specifications.~~

~~(2) Keeping records of performance test results for each pollutant for a test conducted on a similar engine. The test must have been conducted using the same methods specified in this subpart and these methods must have been followed correctly.~~

~~(3) Keeping records of engine manufacturer data indicating compliance with the standards.~~

~~(4) Keeping records of control device vendor data indicating compliance with the standards.~~

~~(5) Conducting an initial performance test to demonstrate compliance with the emission standards according to the requirements specified in § 60.4212, as applicable.~~

~~(c) If you are an owner or operator of a 2007 model year and later stationary CI internal combustion engine and must comply with the emission standards specified in § 60.4204(b) or § 60.4205(b), or if you are an owner or operator of a CI fire pump engine that is manufactured during or after the model year that applies to your fire pump engine power rating in table 3 to this subpart and must comply with the emission standards specified in § 60.4205(c), you must comply by purchasing an engine certified to the emission standards in § 60.4204(b), or § 60.4205(b) or (c), as applicable, for the same model year and maximum (or in the case of fire pumps, NFPA nameplate) engine power. The engine must be installed and configured according to the manufacturer's emission-related specifications, except as permitted in paragraph (g) of this section.~~

~~(d) If you are an owner or operator and must comply with the emission standards specified in § 60.4204(c) or § 60.4205(d), you must demonstrate compliance according to the requirements specified in paragraphs (d)(1) through (3) of this section.~~

~~(1) Conducting an initial performance test to demonstrate initial compliance with the emission standards as specified in § 60.4213.~~

~~(2) Establishing operating parameters to be monitored continuously to ensure the stationary internal combustion engine continues to meet the emission standards. The owner or operator must petition the Administrator for approval of operating parameters to be monitored continuously. The petition must include the information described in paragraphs (d)(2)(i) through (v) of this section.~~

~~(i) Identification of the specific parameters you propose to monitor continuously;~~

~~(ii) A discussion of the relationship between these parameters and~~ ~~NO_X~~ ~~and PM emissions, identifying how the emissions of these pollutants change with changes in these parameters, and how limitations on these parameters will serve to limit~~ ~~NO_X~~ ~~and PM emissions;~~

~~(iii) A discussion of how you will establish the upper and/or lower values for these parameters which will establish the limits on these parameters in the operating limitations;~~

~~(iv) A discussion identifying the methods and the instruments you will use to monitor these parameters, as well as the relative accuracy and precision of these methods and instruments; and~~

~~(v) A discussion identifying the frequency and methods for recalibrating the instruments you will use for monitoring these parameters.~~

~~(3) For non-emergency engines with a displacement of greater than or equal to 30 liters per cylinder, conducting annual performance tests to demonstrate continuous compliance with the emission standards as specified in § 60.4213.~~

~~(e) If you are an owner or operator of a modified or reconstructed stationary CI internal combustion engine and must comply with the emission standards specified in § 60.4204(e) or § 60.4205(f), you must demonstrate compliance according to one of the methods specified in paragraphs (e)(1) or (2) of this section.~~

~~(1) Purchasing, or otherwise owning or operating, an engine certified to the emission standards in § 60.4204(e) or § 60.4205(f), as applicable.~~

~~(2) Conducting a performance test to demonstrate initial compliance with the emission standards according to the requirements specified in § 60.4212 or § 60.4213, as appropriate. The test must be conducted within 60 days after the engine commences operation after the modification or reconstruction.~~

~~(f) Emergency stationary ICE may be operated for the purpose of maintenance checks and readiness testing, provided that the tests are recommended by Federal, State or local government, the manufacturer, the vendor, or the insurance company associated with the engine. Maintenance checks and readiness testing of such units is limited to 100 hours per year. There is no time limit on the use of emergency stationary ICE in emergency situations. The owner or operator may petition the Administrator for approval of additional hours to be used for maintenance checks and readiness testing, but a petition is not required if the owner or operator maintains records indicating that Federal, State, or local standards require maintenance and testing of emergency ICE beyond 100 hours per year. Emergency stationary ICE may operate up to 50 hours per year in non-emergency situations, but those 50 hours are counted towards the 100 hours per year provided for maintenance and testing. The 50 hours per year for non-emergency situations cannot be used for peak shaving or to generate income for a facility to supply power to an electric grid or otherwise supply non-emergency power as part of a financial arrangement with another entity. For owners and operators of emergency engines, any operation other than emergency operation, maintenance and testing, and operation in non-emergency situations for 50 hours per year, as permitted in this section, is prohibited.~~

~~(g) If you do not install, configure, operate, and maintain your engine and control device according to the manufacturer's emission-related written instructions, or you change emission-related settings in a way that is not permitted by the manufacturer, you must demonstrate compliance as follows:~~

~~(1) If you are an owner or operator of a stationary CI internal combustion engine with maximum engine power less than 100 HP, you must keep a maintenance plan and records of conducted maintenance to demonstrate compliance and must, to the extent practicable, maintain and operate the engine in a manner consistent with good air pollution control practice for minimizing emissions. In addition, if you do not install and configure the engine and control device according to the manufacturer's emission-related written instructions, or you change the emission-related settings in a way that is not permitted by the manufacturer, you must conduct an initial~~

~~performance test to demonstrate compliance with the applicable emission standards within 1 year of such action.~~

~~(2) If you are an owner or operator of a stationary CI internal combustion engine greater than or equal to 100 HP and less than or equal to 500 HP, you must keep a maintenance plan and records of conducted maintenance and must, to the extent practicable, maintain and operate the engine in a manner consistent with good air pollution control practice for minimizing emissions. In addition, you must conduct an initial performance test to demonstrate compliance with the applicable emission standards within 1 year of startup, or within 1 year after an engine and control device is no longer installed, configured, operated, and maintained in accordance with the manufacturer's emission-related written instructions, or within 1 year after you change emission-related settings in a way that is not permitted by the manufacturer.~~

~~(3) If you are an owner or operator of a stationary CI internal combustion engine greater than 500 HP, you must keep a maintenance plan and records of conducted maintenance and must, to the extent practicable, maintain and operate the engine in a manner consistent with good air pollution control practice for minimizing emissions. In addition, you must conduct an initial performance test to demonstrate compliance with the applicable emission standards within 1 year of startup, or within 1 year after an engine and control device is no longer installed, configured, operated, and maintained in accordance with the manufacturer's emission-related written instructions, or within 1 year after you change emission-related settings in a way that is not permitted by the manufacturer. You must conduct subsequent performance testing every 8,760 hours of engine operation or 3 years, whichever comes first, thereafter to demonstrate compliance with the applicable emission standards.~~

~~[71 FR 39172, July 11, 2006, as amended at 76 FR 37970, June 28, 2011]~~

~~Testing Requirements for Owners and Operators~~

~~§ 60.4212 What test methods and other procedures must I use if I am an owner or operator of a stationary CI internal combustion engine with a displacement of less than 30 liters per cylinder?~~

~~Owners and operators of stationary CI ICE with a displacement of less than 30 liters per cylinder who conduct performance tests pursuant to this subpart must do so according to paragraphs (a) through (e) of this section.~~

~~(a) The performance test must be conducted according to the in-use testing procedures in 40 CFR part 1039, subpart F, for stationary CI ICE with a displacement of less than 10 liters per cylinder, and according to 40 CFR part 1042, subpart F, for stationary CI ICE with a displacement of greater than or equal to 10 liters per cylinder and less than 30 liters per cylinder.~~

~~(b) Exhaust emissions from stationary CI ICE that are complying with the emission standards for new CI engines in 40 CFR part 1039 must not exceed the not-to-exceed (NTE) standards for the same model year and maximum engine power as required in 40 CFR 1039.101(e) and 40 CFR 1039.102(g)(1), except as specified in 40 CFR 1039.104(d). This requirement starts when NTE requirements take effect for nonroad diesel engines under 40 CFR part 1039.~~

~~(c) Exhaust emissions from stationary CI ICE that are complying with the emission standards for new CI engines in 40 CFR 89.112 or 40 CFR 94.8, as applicable, must not exceed the NTE numerical requirements, rounded to the same number of decimal places as the applicable standard in 40 CFR 89.112 or 40 CFR 94.8, as applicable, determined from the following equation:~~

$$\text{NTE requirement for each pollutant} = (1.25) \times (\text{STD}) \qquad (\text{Eq. } 1)$$

~~Where:~~

~~STD = The standard specified for that pollutant in 40 CFR 89.112 or 40 CFR 94.8, as applicable.~~

~~Alternatively, stationary CI ICE that are complying with the emission standards for new CI engines in 40 CFR 89.112 or 40 CFR 94.8 may follow the testing procedures specified in § 60.4213 of this subpart, as appropriate.~~

~~(d) Exhaust emissions from stationary CI ICE that are complying with the emission standards for pre-2007 model year engines in § 60.4204(a), § 60.4205(a), or § 60.4205(c) must not exceed the NTE numerical requirements, rounded to the same number of decimal places as the applicable standard in § 60.4204(a), § 60.4205(a), or § 60.4205(c), determined from the equation in paragraph (c) of this section.~~

~~Where:~~

~~STD = The standard specified for that pollutant in § 60.4204(a), § 60.4205(a), or § 60.4205(c).~~

~~Alternatively, stationary CI ICE that are complying with the emission standards for pre-2007 model year engines in § 60.4204(a), § 60.4205(a), or § 60.4205(c) may follow the testing procedures specified in § 60.4213, as appropriate.~~

~~(e) Exhaust emissions from stationary CI ICE that are complying with the emission standards for new CI engines in 40 CFR part 1042 must not exceed the NTE standards for the same model year and maximum engine power as required in 40 CFR 1042.101(c).~~

~~[71 FR 39172, July 11, 2006, as amended at 76 FR 37971, June 28, 2011]~~

~~§ 60.4213 What test methods and other procedures must I use if I am an owner or operator of a stationary CI internal combustion engine with a displacement of greater than or equal to 30 liters per cylinder?~~

~~Owners and operators of stationary CI ICE with a displacement of greater than or equal to 30 liters per cylinder must conduct performance tests according to paragraphs (a) through (f) of this section.~~

~~(a) Each performance test must be conducted according to the requirements in § 60.8 and under the specific conditions that this subpart specifies in table 7. The test must be conducted within 10 percent of 100 percent peak (or the highest achievable) load.~~

~~(b) You may not conduct performance tests during periods of startup, shutdown, or malfunction, as specified in § 60.8(c).~~

~~(c) You must conduct three separate test runs for each performance test required in this section, as specified in § 60.8(f). Each test run must last at least 1 hour.~~

~~(d) To determine compliance with the percent reduction requirement, you must follow the requirements as specified in paragraphs (d)(1) through (3) of this section.~~

~~(1) You must use Equation 2 of this section to determine compliance with the percent reduction requirement:~~

$$\frac{C_i - C_o}{C_i} \times 100 = R \qquad (Eq.\ 2)$$

~~Where:~~

~~C_i = concentration of NO_X or PM at the control device inlet,~~

~~C_o = concentration of NO_X or PM at the control device outlet, and~~

~~R = percent reduction of NO_X or PM emissions.~~

~~(2) You must normalize the NO_X or PM concentrations at the inlet and outlet of the control device to a dry basis and to 15 percent oxygen (O_2) using Equation 3 of this section, or an equivalent percent carbon dioxide (CO_2) using the procedures described in paragraph (d)(3) of this section.~~

$$C_{adj} = C_d \frac{5.9}{20.9 - \% O_2} \qquad (Eq. 3)$$

~~Where:~~

~~C_{adj} = Calculated NO_X or PM concentration adjusted to 15 percent O_2 .~~

~~C_d = Measured concentration of NO_X or PM, uncorrected.~~

~~5.9 = 20.9 percent O_2 −15 percent O_2 , the defined O_2 correction value, percent.~~

~~$\%O_2$ = Measured O_2 concentration, dry basis, percent.~~

~~(3) If pollutant concentrations are to be corrected to 15 percent O_2 and CO_2 concentration is measured in lieu of O_2 concentration measurement, a CO_2 correction factor is needed. Calculate the CO_2 correction factor as described in paragraphs (d)(3)(i) through (iii) of this section.~~

~~(i) Calculate the fuel-specific F_o value for the fuel burned during the test using values obtained from Method 19, Section 5.2, and the following equation:~~

$$F_o = \frac{0.209 F_d}{F_c} \qquad (Eq. 4)$$

~~Where:~~

~~F_o = Fuel factor based on the ratio of O_2 volume to the ultimate CO_2 volume produced by the fuel at zero percent excess air.~~

~~0.209 = Fraction of air that is O_2 , percent/100.~~

~~F_d = Ratio of the volume of dry effluent gas to the gross calorific value of the fuel from Method 19, dsm^3 /J (dscf/10^6 Btu).~~

~~F_c = Ratio of the volume of CO_2 produced to the gross calorific value of the fuel from Method 19, dsm^3 /J (dscf/10^6 Btu).~~

~~(ii) Calculate the CO_2 correction factor for correcting measurement data to 15 percent O_2 , as follows:~~

$$X_{CO_2} = \frac{5.9}{F_o} \qquad (Eq. 5)$$

~~Where:~~

~~X_{CO2} = CO_2 correction factor, percent.~~

~~5.9 = 20.9 percent O_2 −15 percent O_2 , the defined O_2 correction value, percent.~~

~~(iii) Calculate the NO_X and PM gas concentrations adjusted to 15 percent O_2 using CO_2 as follows:~~

$$C_{adj} = C_d \frac{X_{CO_2}}{\%CO_2} \qquad (Eq.\ 6)$$

~~Where:~~

~~C_{adj} = Calculated NO_X or PM concentration adjusted to 15 percent O_2 .~~

~~C_d = Measured concentration of NO_X or PM, uncorrected.~~

~~$\%CO_2$ = Measured CO_2 concentration, dry basis, percent.~~

~~(e) To determine compliance with the NO_X mass per unit output emission limitation, convert the concentration of NO_X in the engine exhaust using Equation 7 of this section:~~

$$ER = \frac{C_d \times 1.912 \times 10^{-3} \times Q \times T}{\text{KW-hour}} \qquad (Eq.\ 7)$$

~~Where:~~

~~ER = Emission rate in grams per KW-hour.~~

~~C_d = Measured NO_X concentration in ppm.~~

~~1.912×10^{-3} = Conversion constant for ppm NO_X to grams per standard cubic meter at 25 degrees Celsius.~~

~~Q = Stack gas volumetric flow rate, in standard cubic meter per hour.~~

~~T = Time of test run, in hours.~~

~~KW-hour = Brake work of the engine, in KW-hour.~~

~~(f) To determine compliance with the PM mass per unit output emission limitation, convert the concentration of PM in the engine exhaust using Equation 8 of this section:~~

$$ER = \frac{C_{adj} \times Q \times T}{\text{KW-hour}} \qquad (Eq.\ 8)$$

~~Where:~~

~~ER = Emission rate in grams per KW-hour.~~

~~C_{adj} = Calculated PM concentration in grams per standard cubic meter.~~

~~Q = Stack gas volumetric flow rate, in standard cubic meter per hour.~~

~~T = Time of test run, in hours.~~

~~KW-hour = Energy output of the engine, in KW.~~

~~[71 FR 39172, July 11, 2006, as amended at 76 FR 37971, June 28, 2011]~~

~~Notification, Reports, and Records for Owners and Operators~~

~~§ 60.4214 What are my notification, reporting, and recordkeeping requirements if I am an owner or operator of a stationary CI internal combustion engine?~~

~~(a) Owners and operators of non-emergency stationary CI ICE that are greater than 2,237 KW (3,000 HP), or have a displacement of greater than or equal to 10 liters per cylinder, or are pre-2007 model year engines that are greater than 130 KW (175 HP) and not certified, must meet the requirements of paragraphs (a)(1) and (2) of this section.~~

~~(1) Submit an initial notification as required in § 60.7(a)(1). The notification must include the information in paragraphs (a)(1)(i) through (v) of this section.~~

~~(i) Name and address of the owner or operator;~~

~~(ii) The address of the affected source;~~

~~(iii) Engine information including make, model, engine family, serial number, model year, maximum engine power, and engine displacement;~~

~~(iv) Emission control equipment; and~~

~~(v) Fuel used.~~

~~(2) Keep records of the information in paragraphs (a)(2)(i) through (iv) of this section.~~

~~(i) All notifications submitted to comply with this subpart and all documentation supporting any notification.~~

~~(ii) Maintenance conducted on the engine.~~

~~(iii) If the stationary CI internal combustion is a certified engine, documentation from the manufacturer that the engine is certified to meet the emission standards.~~

~~(iv) If the stationary CI internal combustion is not a certified engine, documentation that the engine meets the emission standards.~~

~~(b) If the stationary CI internal combustion engine is an emergency stationary internal combustion engine, the owner or operator is not required to submit an initial notification. Starting with the model years in table 5 to this subpart, if the emergency engine does not meet the standards applicable to non-emergency engines in the applicable model year, the owner or operator must keep records of the operation of the engine in emergency and non-emergency service that are recorded through the non-resettable hour meter. The owner must record the time of operation of the engine and the reason the engine was in operation during that time.~~

~~(c) If the stationary CI internal combustion engine is equipped with a diesel particulate filter, the owner or operator must keep records of any corrective action taken after the backpressure monitor has notified the owner or operator that the high backpressure limit of the engine is approached.~~

~~**Special Requirements**~~

~~**§ 60.4215 What requirements must I meet for engines used in Guam, American Samoa, or the Commonwealth of the Northern Mariana Islands?**~~

~~(a) Stationary CI ICE with a displacement of less than 30 liters per cylinder that are used in Guam, American Samoa, or the Commonwealth of the Northern Mariana Islands are required to meet the applicable emission standards in §§ 60.4202 and 60.4205.~~

~~(b) Stationary CI ICE that are used in Guam, American Samoa, or the Commonwealth of the Northern Mariana Islands are not required to meet the fuel requirements in § 60.4207.~~

~~(c) Stationary CI ICE with a displacement of greater than or equal to 30 liters per cylinder that are used in Guam, American Samoa, or the Commonwealth of the Northern Mariana Islands are required to meet the following emission standards:~~

~~(1) For engines installed prior to January 1, 2012, limit the emissions of~~ NO_X ~~in the stationary CI internal combustion engine exhaust to the following:~~

~~(i) 17.0 g/KW-hr (12.7 g/HP-hr) when maximum engine speed is less than 130 rpm;~~

~~(ii)~~ $45 \cdot n^{-0.2}$ ~~g/KW-hr (~~$34 \cdot n^{-0.2}$ ~~g/HP-hr) when maximum engine speed is 130 or more but less than 2,000 rpm, where n is maximum engine speed; and~~

~~(iii) 9.8 g/KW-hr (7.3 g/HP-hr) when maximum engine speed is 2,000 rpm or more.~~

~~(2) For engines installed on or after January 1, 2012, limit the emissions of~~ NO_X ~~in the stationary CI internal combustion engine exhaust to the following:~~

~~(i) 14.4 g/KW-hr (10.7 g/HP-hr) when maximum engine speed is less than 130 rpm;~~

~~(ii)~~ $44 \cdot n^{-0.23}$ ~~g/KW-hr (~~$33 \cdot n^{-0.23}$ ~~g/HP-hr) when maximum engine speed is greater than or equal to 130 but less than 2,000 rpm and where n is maximum engine speed; and~~

~~(iii) 7.7 g/KW-hr (5.7 g/HP-hr) when maximum engine speed is greater than or equal to 2,000 rpm.~~

~~(3) Limit the emissions of PM in the stationary CI internal combustion engine exhaust to 0.40 g/KW-hr (0.30 g/HP-hr).~~

~~[71 FR 39172, July 11, 2006, as amended at 76 FR 37971, June 28, 2011]~~

~~**§ 60.4216 What requirements must I meet for engines used in Alaska?**~~

~~(a) Prior to December 1, 2010, owners and operators of stationary CI ICE with a displacement of less than 30 liters per cylinder located in areas of Alaska not accessible by the FAHS should refer to 40 CFR part 69 to determine the diesel fuel requirements applicable to such engines.~~

~~(b) Except as indicated in paragraph (c) of this section, manufacturers, owners and operators of stationary CI ICE with a displacement of less than 10 liters per cylinder located in areas of Alaska not accessible by the FAHS may meet the requirements of this subpart by manufacturing and installing engines meeting the requirements of 40 CFR parts 94 or 1042, as appropriate, rather than the otherwise applicable requirements of 40 CFR parts 89 and 1039, as indicated in sections §§ 60.4201(f) and 60.4202(g) of this subpart.~~

~~(c) Manufacturers, owners and operators of stationary CI ICE that are located in areas of Alaska not accessible by the FAHS may choose to meet the applicable emission standards for emergency engines in § 60.4202 and § 60.4205, and not those for non-emergency engines in § 60.4201 and § 60.4204, except that for 2014 model year and later non-emergency CI ICE, the owner or operator of any such engine that was not certified as meeting Tier 4 PM standards, must meet the applicable requirements for PM in § 60.4201 and § 60.4204 or install a PM emission control device that achieves PM emission reductions of 85 percent, or 60 percent for engines with a displacement of greater than or equal to 30 liters per cylinder, compared to engine-out emissions.~~

~~(d) The provisions of § 60.4207 do not apply to owners and operators of pre-2014 model year stationary CI ICE subject to this subpart that are located in areas of Alaska not accessible by the FAHS.~~

~~(e) The provisions of § 60.4208(a) do not apply to owners and operators of stationary CI ICE subject to this subpart that are located in areas of Alaska not accessible by the FAHS until after December 31, 2009.~~

~~(f) The provisions of this section and § 60.4207 do not prevent owners and operators of stationary CI ICE subject to this subpart that are located in areas of Alaska not accessible by the FAHS from using fuels mixed with used lubricating oil, in volumes of up to 1.75 percent of the total fuel. The sulfur content of the used lubricating oil must be less than 200 parts per million. The used lubricating oil must meet the on-specification levels and properties for used oil in 40 CFR 279.11.~~

~~[76 FR 37971, June 28, 2011]~~

~~§ 60.4217 What emission standards must I meet if I am an owner or operator of a stationary internal combustion engine using special fuels?~~

~~Owners and operators of stationary CI ICE that do not use diesel fuel may petition the Administrator for approval of alternative emission standards, if they can demonstrate that they use a fuel that is not the fuel on which the manufacturer of the engine certified the engine and that the engine cannot meet the applicable standards required in § 60.4204 or § 60.4205 using such fuels and that use of such fuel is appropriate and reasonably necessary, considering cost, energy, technical feasibility, human health and environmental, and other factors, for the operation of the engine.~~

~~[76 FR 37972, June 28, 2011]~~

~~General Provisions~~

~~§ 60.4218 What parts of the General Provisions apply to me?~~

~~Table 8 to this subpart shows which parts of the General Provisions in §§ 60.1 through 60.19 apply to you.~~

~~DEFINITIONS~~

~~§ 60.4219 What definitions apply to this subpart?~~

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

~~*Certified emissions life* means the period during which the engine is designed to properly function in terms of reliability and fuel consumption, without being remanufactured, specified as a number of hours of operation or calendar years, whichever comes first. The values for certified emissions life for stationary CI ICE with a displacement of less than 10 liters per cylinder are given in 40 CFR 1039.101(g). The values for certified~~

~~emissions life for stationary CI ICE with a displacement of greater than or equal to 10 liters per cylinder and less than 30 liters per cylinder are given in 40 CFR 94.9(a).~~

~~*Combustion turbine* means all equipment, including but not limited to the turbine, the fuel, air, lubrication and exhaust gas systems, control systems (except emissions control equipment), and any ancillary components and sub-components comprising any simple cycle combustion turbine, any regenerative/recuperative cycle combustion turbine, the combustion turbine portion of any cogeneration cycle combustion system, or the combustion turbine portion of any combined cycle steam/electric generating system.~~

~~*Compression ignition* means relating to a type of stationary internal combustion engine that is not a spark ignition engine.~~

~~*Date of manufacture* means one of the following things:~~

~~(1) For freshly manufactured engines and modified engines, date of manufacture means the date the engine is originally produced.~~

~~(2) For reconstructed engines, date of manufacture means the date the engine was originally produced, except as specified in paragraph (3) of this definition.~~

~~(3) Reconstructed engines are assigned a new date of manufacture if the fixed capital cost of the new and refurbished components exceeds 75 percent of the fixed capital cost of a comparable entirely new facility. An engine that is produced from a previously used engine block does not retain the date of manufacture of the engine in which the engine block was previously used if the engine is produced using all new components except for the engine block. In these cases, the date of manufacture is the date of reconstruction or the date the new engine is produced.~~

~~*Diesel fuel* means any liquid obtained from the distillation of petroleum with a boiling point of approximately 150 to 360 degrees Celsius. One commonly used form is number 2 distillate oil.~~

~~*Diesel particulate filter* means an emission control technology that reduces PM emissions by trapping the particles in a flow filter substrate and periodically removes the collected particles by either physical action or by oxidizing (burning off) the particles in a process called regeneration.~~

~~*Emergency stationary internal combustion engine* means any stationary internal combustion engine whose operation is limited to emergency situations and required testing and maintenance. Examples include stationary ICE used to produce power for critical networks or equipment (including power supplied to portions of a facility) when electric power from the local utility (or the normal power source, if the facility runs on its own power production) is interrupted, or stationary ICE used to pump water in the case of fire or flood, etc. Stationary CI ICE used to supply power to an electric grid or that supply power as part of a financial arrangement with another entity are not considered to be emergency engines.~~

~~*Engine manufacturer* means the manufacturer of the engine. See the definition of “manufacturer” in this section.~~

~~*Fire pump engine* means an emergency stationary internal combustion engine certified to NFPA requirements that is used to provide power to pump water for fire suppression or protection.~~

~~*Freshly manufactured engine* means an engine that has not been placed into service. An engine becomes freshly manufactured when it is originally produced.~~

~~*Installed* means the engine is placed and secured at the location where it is intended to be operated.~~

~~*Manufacturer* has the meaning given in section 216(1) of the Act. In general, this term includes any person who manufactures a stationary engine for sale in the United States or otherwise introduces a new stationary engine into commerce in the United States. This includes importers who import stationary engines for sale or resale.~~

~~*Maximum engine power* means maximum engine power as defined in 40 CFR 1039.801.~~

~~*Model year* means the calendar year in which an engine is manufactured (see "date of manufacture"), except as follows:~~

~~(1) Model year means the annual new model production period of the engine manufacturer in which an engine is manufactured (see "date of manufacture"), if the annual new model production period is different than the calendar year and includes January 1 of the calendar year for which the model year is named. It may not begin before January 2 of the previous calendar year and it must end by December 31 of the named calendar year.~~

~~(2) For an engine that is converted to a stationary engine after being placed into service as a nonroad or other non-stationary engine, model year means the calendar year or new model production period in which the engine was manufactured (see "date of manufacture").~~

~~*Other internal combustion engine* means any internal combustion engine, except combustion turbines, which is not a reciprocating internal combustion engine or rotary internal combustion engine.~~

~~*Reciprocating internal combustion engine* means any internal combustion engine which uses reciprocating motion to convert heat energy into mechanical work.~~

~~*Rotary internal combustion engine* means any internal combustion engine which uses rotary motion to convert heat energy into mechanical work.~~

~~*Spark ignition* means relating to a gasoline, natural gas, or liquefied petroleum gas fueled engine or any other type of engine with a spark plug (or other sparking device) and with operating characteristics significantly similar to the theoretical Otto combustion cycle. Spark ignition engines usually use a throttle to regulate intake air flow to control power during normal operation. Dual-fuel engines in which a liquid fuel (typically diesel fuel) is used for CI and gaseous fuel (typically natural gas) is used as the primary fuel at an annual average ratio of less than 2 parts diesel fuel to 100 parts total fuel on an energy equivalent basis are spark ignition engines.~~

~~*Stationary internal combustion engine* means any internal combustion engine, except combustion turbines, that converts heat energy into mechanical work and is not mobile. Stationary ICE differ from mobile ICE in that a stationary internal combustion engine is not a nonroad engine as defined at 40 CFR 1068.30 (excluding paragraph (2)(ii) of that definition), and is not used to propel a motor vehicle, aircraft, or a vehicle used solely for competition. Stationary ICE include reciprocating ICE, rotary ICE, and other ICE, except combustion turbines.~~

~~*Subpart* means 40 CFR part 60, subpart IIII.~~

~~[71 FR 39172, July 11, 2006, as amended at 76 FR 37972, June 28, 2011]~~

~~Table 1 to Subpart IIII of Part 60—Emission Standards for Stationary Pre-2007 Model Year Engines With a Displacement of <10 Liters per Cylinder and 2007-2010 Model Year Engines >2,237 KW (3,000 HP) and With a Displacement of <10 Liters per Cylinder~~

~~[As stated in §§ 60.4201(b), 60.4202(b), 60.4204(a), and 60.4205(a), you must comply with the following emission standards]~~

~~**Maximum engine power**~~	~~**Emission standards for stationary pre-2007 model year engines with a displacement of <10 liters per cylinder and 2007-2010 model year engines >2,237 KW (3,000 HP) and with a displacement of <10 liters per cylinder in g/KW-hr (g/HP-hr)**~~				
	~~**NMHC + NO$_x$**~~	~~**HC**~~	~~**NO$_x$**~~	~~**CO**~~	~~**PM**~~
~~KW<8 (HP<11)~~	~~10.5 (7.8)~~			~~8.0 (6.0)~~	~~1.0 (0.75)~~
~~8≤KW<19 (11≤HP<25)~~	~~9.5 (7.1)~~			~~6.6 (4.9)~~	~~0.80 (0.60)~~
~~19≤KW<37 (25≤HP<50)~~	~~9.5 (7.1)~~			~~5.5 (4.1)~~	~~0.80 (0.60)~~
~~37≤KW<56 (50≤HP<75)~~			~~9.2 (6.9)~~		
~~56≤KW<75 (75≤HP<100)~~			~~9.2 (6.9)~~		
~~75≤KW<130 (100≤HP<175)~~			~~9.2 (6.9)~~		
~~130≤KW<225 (175≤HP<300)~~		~~1.3 (1.0)~~	~~9.2 (6.9)~~	~~11.4 (8.5)~~	~~0.54 (0.40)~~
~~225≤KW<450 (300≤HP<600)~~		~~1.3 (1.0)~~	~~9.2 (6.9)~~	~~11.4 (8.5)~~	~~0.54 (0.40)~~
~~450≤KW≤560 (600≤HP≤750)~~		~~1.3 (1.0)~~	~~9.2 (6.9)~~	~~11.4 (8.5)~~	~~0.54 (0.40)~~
~~KW>560 (HP>750)~~		~~1.3 (1.0)~~	~~9.2 (6.9)~~	~~11.4 (8.5)~~	~~0.54 (0.40)~~

~~Table 2 to Subpart IIII of Part 60—Emission Standards for 2008 Model Year and Later Emergency Stationary CI ICE <37 KW (50 HP) With a Displacement of <10 Liters per Cylinder~~

~~[As stated in § 60.4202(a)(1), you must comply with the following emission standards]~~

~~**Engine power**~~	~~**Emission standards for 2008 model year and later emergency stationary CI ICE <37 KW (50 HP) with a displacement of <10 liters per cylinder in g/KW-hr (g/HP-hr)**~~			
	~~**Model year(s)**~~	~~**NO$_x$+ NMHC**~~	~~**CO**~~	~~**PM**~~
~~KW<8 (HP<11)~~	~~2008+~~	~~7.5 (5.6)~~	~~8.0 (6.0)~~	~~0.40 (0.30)~~
~~8≤KW<19 (11≤HP<25)~~	~~2008+~~	~~7.5 (5.6)~~	~~6.6 (4.9)~~	~~0.40 (0.30)~~
~~19≤KW<37 (25≤HP<50)~~	~~2008+~~	~~7.5 (5.6)~~	~~5.5 (4.1)~~	~~0.30 (0.22)~~

~~Table 3 to Subpart IIII of Part 60—Certification Requirements for Stationary Fire Pump Engines~~

~~As stated in § 60.4202(d), you must certify new stationary fire pump engines beginning with the following model years:~~

~~Engine power~~	~~Starting model year engine manufacturers must certify new stationary fire pump engines according to § 60.4202(d)~~[1]
~~KW<75 (HP<100)~~	~~2011~~
~~75≤KW<130 (100≤HP<175)~~	~~2010~~
~~130≤KW≤560 (175≤HP≤750)~~	~~2009~~
~~KW>560 (HP>750)~~	~~2008~~

[1] ~~Manufacturers of fire pump stationary CI ICE with a maximum engine power greater than or equal to 37 kW (50 HP) and less than 450 KW (600 HP) and a rated speed of greater than 2,650 revolutions per minute (rpm) are not required to certify such engines until three model years following the model year indicated in this Table 3 for engines in the applicable engine power category.~~

~~[71 FR 39172, July 11, 2006, as amended at 76 FR 37972, June 28, 2011]~~

~~Table 4 to Subpart IIII of Part 60—Emission Standards for Stationary Fire Pump Engines~~

~~[As stated in §§ 60.4202(d) and 60.4205(c), you must comply with the following emission standards for stationary fire pump engines]~~

~~Maximum engine power~~	~~Model year(s)~~	~~NMHC + NO_X~~	~~CO~~	~~PM~~
~~KW<8 (HP<11)~~	~~2010 and earlier~~	~~10.5 (7.8)~~	~~8.0 (6.0)~~	~~1.0 (0.75)~~
	~~2011+~~	~~7.5 (5.6)~~		~~0.40 (0.30)~~
~~8≤KW<19 (11≤HP<25)~~	~~2010 and earlier~~	~~9.5 (7.1)~~	~~6.6 (4.9)~~	~~0.80 (0.60)~~
	~~2011+~~	~~7.5 (5.6)~~		~~0.40 (0.30)~~
~~19≤KW<37 (25≤HP<50)~~	~~2010 and earlier~~	~~9.5 (7.1)~~	~~5.5 (4.1)~~	~~0.80 (0.60)~~
	~~2011+~~	~~7.5 (5.6)~~		~~0.30 (0.22)~~
~~37≤KW<56 (50≤HP<75)~~	~~2010 and earlier~~	~~10.5 (7.8)~~	~~5.0 (3.7)~~	~~0.80 (0.60)~~
	~~2011+~~ [1]	~~4.7 (3.5)~~		~~0.40 (0.30)~~
~~56≤KW<75 (75≤HP<100)~~	~~2010 and earlier~~	~~10.5 (7.8)~~	~~5.0 (3.7)~~	~~0.80 (0.60)~~
	~~2011+~~ [1]	~~4.7 (3.5)~~		~~0.40 (0.30)~~
~~75≤KW<130 (100≤HP<175)~~	~~2009 and earlier~~	~~10.5 (7.8)~~	~~5.0 (3.7)~~	~~0.80 (0.60)~~

	~~2010+~~ [2]	~~4.0 (3.0)~~		~~0.30 (0.22)~~
~~130≤KW<225 (175≤HP<300)~~	~~2008 and earlier~~	~~10.5 (7.8)~~	~~3.5 (2.6)~~	~~0.54 (0.40)~~
	~~2009+~~ [3]	~~4.0 (3.0)~~		~~0.20 (0.15)~~
~~225≤KW<450 (300≤HP<600)~~	~~2008 and earlier~~	~~10.5 (7.8)~~	~~3.5 (2.6)~~	~~0.54 (0.40)~~
	~~2009+~~ [3]	~~4.0 (3.0)~~		~~0.20 (0.15)~~
~~450≤KW≤560 (600≤HP≤750)~~	~~2008 and earlier~~	~~10.5 (7.8)~~	~~3.5 (2.6)~~	~~0.54 (0.40)~~
	~~2009+~~	~~4.0 (3.0)~~		~~0.20 (0.15)~~
~~KW>560 (HP>750)~~	~~2007 and earlier~~	~~10.5 (7.8)~~	~~3.5 (2.6)~~	~~0.54 (0.40)~~
	~~2008+~~	~~6.4 (4.8)~~		~~0.20 (0.15)~~

[1] ~~For model years 2011-2013, manufacturers, owners and operators of fire pump stationary CI ICE in this engine power category with a rated speed of greater than 2,650 revolutions per minute (rpm) may comply with the emission limitations for 2010 model year engines.~~

[2] ~~For model years 2010-2012, manufacturers, owners and operators of fire pump stationary CI ICE in this engine power category with a rated speed of greater than 2,650 rpm may comply with the emission limitations for 2009 model year engines.~~

[3] ~~In model years 2009-2011, manufacturers of fire pump stationary CI ICE in this engine power category with a rated speed of greater than 2,650 rpm may comply with the emission limitations for 2008 model year engines.~~

~~Table 5 to Subpart IIII of Part 60—Labeling and Recordkeeping Requirements for New Stationary Emergency Engines~~

~~[You must comply with the labeling requirements in § 60.4210(f) and the recordkeeping requirements in § 60.4214(b) for new emergency stationary CI ICE beginning in the following model years:]~~

~~Engine power~~	**~~Starting model year~~**
~~19≤KW<56 (25≤HP<75)~~	~~2013~~
~~56≤KW<130 (75≤HP<175)~~	~~2012~~
~~KW≥130 (HP≥175)~~	~~2011~~

~~Table 6 to Subpart IIII of Part 60—Optional 3-Mode Test Cycle for Stationary Fire Pump Engines~~

~~[As stated in § 60.4210(g), manufacturers of fire pump engines may use the following test cycle for testing fire pump engines:]~~

~~Mode No.~~	**~~Engine speed~~** [1]	**~~Torque (percent)~~** [2]	**~~Weighting factors~~**
~~1~~	~~Rated~~	~~100~~	~~0.30~~
~~2~~	~~Rated~~	~~75~~	~~0.50~~
~~3~~	~~Rated~~	~~50~~	~~0.20~~

[1] ~~Engine speed: ±2 percent of point.~~

~~[2] Torque: NFPA certified nameplate HP for 100 percent point. All points should be ±2 percent of engine percent load value.~~

~~Table 7 to Subpart IIII of Part 60—Requirements for Performance Tests for Stationary CI ICE With a Displacement of ≥30 Liters per Cylinder~~

~~[As stated in § 60.4213, you must comply with the following requirements for performance tests for stationary CI ICE with a displacement of ≥30 liters per cylinder:]~~

~~**For each**~~	~~**Complying with the requirement to**~~	~~**You must**~~	~~**Using**~~	~~**According to the following requirements**~~
~~1. Stationary CI internal combustion engine with a displacement of ≥30 liters per cylinder~~	~~a. Reduce NO_X emissions by 90 percent or more~~	~~i. Select the sampling port location and the number of traverse points;~~	~~(1) Method 1 or 1A of 40 CFR part 60, appendix A~~	~~(a) Sampling sites must be located at the inlet and outlet of the control device.~~
		~~ii. Measure O_2 at the inlet and outlet of the control device;~~	~~(2) Method 3, 3A, or 3B of 40 CFR part 60, appendix A~~	~~(b) Measurements to determine O_2 concentration must be made at the same time as the measurements for NO_X concentration.~~
		~~iii. If necessary, measure moisture content at the inlet and outlet of the control device; and,~~	~~(3) Method 4 of 40 CFR part 60, appendix A, Method 320 of 40 CFR part 63, appendix A, or ASTM D 6348-03 (incorporated by reference, see § 60.17)~~	~~(c) Measurements to determine moisture content must be made at the same time as the measurements for NO_X concentration.~~
		~~iv. Measure NO_X at the inlet and outlet of the control device~~	~~(4) Method 7E of 40 CFR part 60, appendix A, Method 320 of 40 CFR part 63, appendix A, or ASTM D 6348-03 (incorporated by reference, see § 60.17)~~	~~(d) NO_X concentration must be at 15 percent O_2, dry basis. Results of this test consist of the average of the three 1-hour or longer runs.~~
	~~b. Limit the concentration of NO_X in the stationary CI internal combustion engine exhaust.~~	~~i. Select the sampling port location and the number of traverse points;~~	~~(1) Method 1 or 1A of 40 CFR part 60, appendix A~~	~~(a) If using a control device, the sampling site must be located at the outlet of the control device.~~

~~**For each**~~	~~**Complying with the requirement to**~~	~~**You must**~~	~~**Using**~~	~~**According to the following requirements**~~
		~~ii. Determine the O_2 concentration of the stationary internal combustion engine exhaust at the sampling port location; and,~~	~~(2) Method 3, 3A, or 3B of 40 CFR part 60, appendix A~~	~~(b) Measurements to determine O_2 concentration must be made at the same time as the measurement for NO_X concentration.~~
		~~iii. If necessary, measure moisture content of the stationary internal combustion engine exhaust at the sampling port location; and,~~	~~(3) Method 4 of 40 CFR part 60, appendix A, Method 320 of 40 CFR part 63, appendix A, or ASTM D 6348-03 (incorporated by reference, see § 60.17)~~	~~(c) Measurements to determine moisture content must be made at the same time as the measurement for NO_X concentration.~~
		~~iv. Measure NO_X at the exhaust of the stationary internal combustion engine~~	~~(4) Method 7E of 40 CFR part 60, appendix A, Method 320 of 40 CFR part 63, appendix A, or ASTM D 6348-03 (incorporated by reference, see § 60.17)~~	~~(d) NO_X concentration must be at 15 percent O_2, dry basis. Results of this test consist of the average of the three 1-hour or longer runs.~~
	~~c. Reduce PM emissions by 60 percent or more~~	~~i. Select the sampling port location and the number of traverse points;~~	~~(1) Method 1 or 1A of 40 CFR part 60, appendix A~~	~~(a) Sampling sites must be located at the inlet and outlet of the control device.~~
		~~ii. Measure O_2 at the inlet and outlet of the control device;~~	~~(2) Method 3, 3A, or 3B of 40 CFR part 60, appendix A~~	~~(b) Measurements to determine O_2 concentration must be made at the same time as the measurements for PM concentration.~~
		~~iii. If necessary, measure moisture content at the inlet and outlet of the control device; and~~	~~(3) Method 4 of 40 CFR part 60, appendix A~~	~~(c) Measurements to determine and moisture content must be made at the same time as the measurements for PM concentration.~~
		~~iv. Measure PM at the inlet and outlet of the control device~~	~~(4) Method 5 of 40 CFR part 60, appendix A~~	~~(d) PM concentration must be at 15 percent O_2, dry basis. Results of this test consist of the average of the three 1-hour or longer runs.~~

~~For each~~	~~Complying with the requirement to~~	~~You must~~	~~Using~~	~~According to the following requirements~~
	~~d. Limit the concentration of PM in the stationary CI internal combustion engine exhaust~~	~~i. Select the sampling port location and the number of traverse points;~~	~~(1) Method 1 or 1A of 40 CFR part 60, appendix A~~	~~(a) If using a control device, the sampling site must be located at the outlet of the control device.~~
		~~ii. Determine the O_2concentration of the stationary internal combustion engine exhaust at the sampling port location; and~~	~~(2) Method 3, 3A, or 3B of 40 CFR part 60, appendix A~~	~~(b) Measurements to determine O_2concentration must be made at the same time as the measurements for PM concentration.~~
		~~iii. If necessary, measure moisture content of the stationary internal combustion engine exhaust at the sampling port location; and~~	~~(3) Method 4 of 40 CFR part 60, appendix A~~	~~(c) Measurements to determine moisture content must be made at the same time as the measurements for PM concentration.~~
		~~iv. Measure PM at the exhaust of the stationary internal combustion engine~~	~~(4) Method 5 of 40 CFR part 60, appendix A~~	~~(d) PM concentration must be at 15 percent O_2, dry basis. Results of this test consist of the average of the three 1-hour or longer runs.~~

~~Table 8 to Subpart IIII of Part 60—Applicability of General Provisions to Subpart IIII~~

~~[As stated in § 60.4218, you must comply with the following applicable General Provisions:]~~

~~General Provisions citation~~	~~Subject of citation~~	~~Applies to subpart~~	~~Explanation~~
~~§ 60.1~~	~~General applicability of the General Provisions~~	~~Yes~~	
~~§ 60.2~~	~~Definitions~~	~~Yes~~	~~Additional terms defined in § 60.4219.~~
~~§ 60.3~~	~~Units and abbreviations~~	~~Yes~~	
~~§ 60.4~~	~~Address~~	~~Yes~~	
~~§ 60.5~~	~~Determination of construction or modification~~	~~Yes~~	
~~§ 60.6~~	~~Review of plans~~	~~Yes~~	

~~General Provisions citation~~	~~Subject of citation~~	~~Applies to subpart~~	~~Explanation~~
~~§ 60.7~~	~~Notification and Recordkeeping~~	~~Yes~~	~~Except that § 60.7 only applies as specified in § 60.4214(a).~~
~~§ 60.8~~	~~Performance tests~~	~~Yes~~	~~Except that § 60.8 only applies to stationary CI ICE with a displacement of (≥30 liters per cylinder and engines that are not certified.~~
~~§ 60.9~~	~~Availability of information~~	~~Yes~~	
~~§ 60.10~~	~~State Authority~~	~~Yes~~	
~~§ 60.11~~	~~Compliance with standards and maintenance requirements~~	~~No~~	~~Requirements are specified in subpart IIII.~~
~~§ 60.12~~	~~Circumvention~~	~~Yes~~	
~~§ 60.13~~	~~Monitoring requirements~~	~~Yes~~	~~Except that § 60.13 only applies to stationary CI ICE with a displacement of (≥30 liters per cylinder.~~
~~§ 60.14~~	~~Modification~~	~~Yes~~	
~~§ 60.15~~	~~Reconstruction~~	~~Yes~~	
~~§ 60.16~~	~~Priority list~~	~~Yes~~	
~~§ 60.17~~	~~Incorporations by reference~~	~~Yes~~	
~~§ 60.18~~	~~General control device requirements~~	~~No~~	
~~§ 60.19~~	~~General notification and reporting requirements~~	~~Yes~~	

Revised Attachment E – 40 CFR 60, Subpart IIII

Indiana Department of Environmental Management
Office of Air Quality

Attachment E to a Part 70 Operating Permit

Source Background and Description

Source Name:	**Ohio Valley Resources, LLC**
Source Location:	**300-400 East CR 350 North, Rockport, Indiana 47635**
County:	**Spencer**
SIC Code:	**2873**
Permit No.:	**T 147-32322-00062**
Permit Reviewer:	**David Matousek**

40 CFR 60, Subpart IIII

40 CFR 60, Subpart IIII **Standards of Performance for Stationary Compression Ignition Internal Combustion Engines**

Source: 71 FR 39172, July 11, 2006, unless otherwise noted.

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What This Subpart Covers

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§ 60.4200 Am I subject to this subpart?

(a) The provisions of this subpart are applicable to manufacturers, owners, and operators of stationary compression ignition (CI) internal combustion engines (ICE) and other persons as specified in paragraphs (a)(1) through (4) of this section. For the purposes of this subpart, the date that construction commences is the date the engine is ordered by the owner or operator.

(1) Manufacturers of stationary CI ICE with a displacement of less than 30 liters per cylinder where the model year is:

(i) 2007 or later, for engines that are not fire pump engines;

(ii) The model year listed in Table 3 to this subpart or later model year, for fire pump engines.

(2) Owners and operators of stationary CI ICE that commence construction after July 11, 2005, where the stationary CI ICE are:

(i) Manufactured after April 1, 2006, and are not fire pump engines, or

(ii) Manufactured as a certified National Fire Protection Association (NFPA) fire pump engine after July 1, 2006.

(3) Owners and operators of any stationary CI ICE that are modified or reconstructed after July 11, 2005 and any person that modifies or reconstructs any stationary CI ICE after July 11, 2005.

(4) The provisions of § 60.4208 of this subpart are applicable to all owners and operators of stationary CI ICE that commence construction after July 11, 2005.

(b) The provisions of this subpart are not applicable to stationary CI ICE being tested at a stationary CI ICE test cell/stand.

(c) If you are an owner or operator of an area source subject to this subpart, you are exempt from the obligation to obtain a permit under 40 CFR part 70 or 40 CFR part 71, provided you are not required to obtain a permit under 40 CFR 70.3(a) or 40 CFR 71.3(a) for a reason other than your status as an area source under this subpart. Notwithstanding the previous sentence, you must continue to comply with the provisions of this subpart applicable to area sources.

(d) Stationary CI ICE may be eligible for exemption from the requirements of this subpart as described in 40 CFR part 1068, subpart C (or the exemptions described in 40 CFR part 89, subpart J and 40 CFR part 94, subpart J, for engines that would need to be certified to standards in those parts), except that owners and operators, as well as manufacturers, may be eligible to request an exemption for national security.

(e) Owners and operators of facilities with CI ICE that are acting as temporary replacement units and that are located at a stationary source for less than 1 year and that have been properly certified as meeting the standards that would be applicable to such engine under the appropriate nonroad engine

provisions, are not required to meet any other provisions under this subpart with regard to such engines.

[71 FR 39172, July 11, 2006, as amended at 76 FR 37967, June 28, 2011]

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Emission Standards for Manufacturers

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§ 60.4201 What emission standards must I meet for non-emergency engines if I am a stationary CI internal combustion engine manufacturer?

(a) Stationary CI internal combustion engine manufacturers must certify their 2007 model year and later non-emergency stationary CI ICE with a maximum engine power less than or equal to 2,237 kilowatt (KW) (3,000 horsepower (HP)) and a displacement of less than 10 liters per cylinder to the certification emission standards for new nonroad CI engines in 40 CFR 89.112, 40 CFR 89.113, 40 CFR 1039.101, 40 CFR 1039.102, 40 CFR 1039.104, 40 CFR 1039.105, 40 CFR 1039.107, and 40 CFR 1039.115, as applicable, for all pollutants, for the same model year and maximum engine power.

(b) Stationary CI internal combustion engine manufacturers must certify their 2007 through 2010 model year non-emergency stationary CI ICE with a maximum engine power greater than 2,237 KW (3,000 HP) and a displacement of less than 10 liters per cylinder to the emission standards in table 1 to this subpart, for all pollutants, for the same maximum engine power.

(c) Stationary CI internal combustion engine manufacturers must certify their 2011 model year and later non-emergency stationary CI ICE with a maximum engine power greater than 2,237 KW (3,000 HP) and a displacement of less than 10 liters per cylinder to the certification emission standards for new nonroad CI engines in 40 CFR 1039.101, 40 CFR 1039.102, 40 CFR 1039.104, 40 CFR 1039.105, 40 CFR 1039.107, and 40 CFR 1039.115, as applicable, for all pollutants, for the same maximum engine power.

(d) Stationary CI internal combustion engine manufacturers must certify the following non-emergency stationary CI ICE to the certification emission standards for new marine CI engines in 40 CFR 94.8, as applicable, for all pollutants, for the same displacement and maximum engine power:

(1) Their 2007 model year through 2012 non-emergency stationary CI ICE with a displacement of greater than or equal to 10 liters per cylinder and less than 30 liters per cylinder;

(2) Their 2013 model year non-emergency stationary CI ICE with a maximum engine power greater than or equal to 3,700 KW (4,958 HP) and a displacement of greater than or equal to 10 liters per cylinder and less than 15 liters per cylinder; and

(3) Their 2013 model year non-emergency stationary CI ICE with a displacement of greater than or equal to 15 liters per cylinder and less than 30 liters per cylinder.

(e) Stationary CI internal combustion engine manufacturers must certify the following non-emergency stationary CI ICE to the certification emission standards and other requirements for new marine CI engines in 40 CFR 1042.101, 40 CFR 1042.107, 40 CFR 1042.110, 40 CFR 1042.115, 40 CFR 1042.120, and 40 CFR 1042.145, as applicable, for all pollutants, for the same displacement and maximum engine power:

(1) Their 2013 model year non-emergency stationary CI ICE with a maximum engine power less than 3,700 KW (4,958 HP) and a displacement of greater than or equal to 10 liters per cylinder and less than 15 liters per cylinder; and

(2) Their 2014 model year and later non-emergency stationary CI ICE with a displacement of greater than or equal to 10 liters per cylinder and less than 30 liters per cylinder.

(f) Notwithstanding the requirements in paragraphs (a) through (c) of this section, stationary non-emergency CI ICE identified in paragraphs (a) and (c) may be certified to the provisions of 40 CFR part 94 or, if Table 1 to 40 CFR 1042.1 identifies 40 CFR part 1042 as being applicable, 40 CFR part 1042, if the engines will be used solely in either or both of the following locations:

(1) Areas of Alaska not accessible by the Federal Aid Highway System (FAHS); and

(2) Marine offshore installations.

(g) Notwithstanding the requirements in paragraphs (a) through (f) of this section, stationary CI internal combustion engine manufacturers are not required to certify reconstructed engines; however manufacturers may elect to do so. The reconstructed engine must be certified to the emission standards specified in paragraphs (a) through (e) of this section that are applicable to the model year, maximum engine power, and displacement of the reconstructed stationary CI ICE.

[71 FR 39172, July 11, 2006, as amended at 76 FR 37967, June 28, 2011]

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§ 60.4202 What emission standards must I meet for emergency engines if I am a stationary CI internal combustion engine manufacturer?

(a) Stationary CI internal combustion engine manufacturers must certify their 2007 model year and later emergency stationary CI ICE with a maximum engine power less than or equal to 2,237 KW (3,000 HP) and a displacement of less than 10 liters per cylinder that are not fire pump engines to the emission standards specified in paragraphs (a)(1) through (2) of this section.

(1) For engines with a maximum engine power less than 37 KW (50 HP):

(i) The certification emission standards for new nonroad CI engines for the same model year and maximum engine power in 40 CFR 89.112 and 40 CFR 89.113 for all pollutants for model year 2007 engines, and

(ii) The certification emission standards for new nonroad CI engines in 40 CFR 1039.104, 40 CFR 1039.105, 40 CFR 1039.107, 40 CFR 1039.115, and table 2 to this subpart, for 2008 model year and later engines.

(2) For engines with a maximum engine power greater than or equal to 37 KW (50 HP), the certification emission standards for new nonroad CI engines for the same model year and maximum engine power in 40 CFR 89.112 and 40 CFR 89.113 for all pollutants beginning in model year 2007.

(b) Stationary CI internal combustion engine manufacturers must certify their 2007 model year and later emergency stationary CI ICE with a maximum engine power greater than 2,237 KW (3,000 HP) and a displacement of less than 10 liters per cylinder that are not fire pump engines to the emission standards specified in paragraphs (b)(1) through (2) of this section.

(1) For 2007 through 2010 model years, the emission standards in table 1 to this subpart, for all pollutants, for the same maximum engine power.

(2) For 2011 model year and later, the certification emission standards for new nonroad CI engines for engines of the same model year and maximum engine power in 40 CFR 89.112 and 40 CFR 89.113 for all pollutants.

(c) [Reserved]

(d) Beginning with the model years in table 3 to this subpart, stationary CI internal combustion engine manufacturers must certify their fire pump stationary CI ICE to the emission standards in table 4 to this subpart, for all pollutants, for the same model year and NFPA nameplate power.

(e) Stationary CI internal combustion engine manufacturers must certify the following emergency stationary CI ICE that are not fire pump engines to the certification emission standards for new marine CI engines in 40 CFR 94.8, as applicable, for all pollutants, for the same displacement and maximum engine power:

(1) Their 2007 model year through 2012 emergency stationary CI ICE with a displacement of greater than or equal to 10 liters per cylinder and less than 30 liters per cylinder;

(2) Their 2013 model year and later emergency stationary CI ICE with a maximum engine power greater than or equal to 3,700 KW (4,958 HP) and a displacement of greater than or equal to 10 liters per cylinder and less than 15 liters per cylinder;

(3) Their 2013 model year emergency stationary CI ICE with a displacement of greater than or equal to 15 liters per cylinder and less than 30 liters per cylinder; and

(4) Their 2014 model year and later emergency stationary CI ICE with a maximum engine power greater than or equal to 2,000 KW (2,682 HP) and a displacement of greater than or equal to 15 liters per cylinder and less than 30 liters per cylinder.

(f) Stationary CI internal combustion engine manufacturers must certify the following emergency stationary CI ICE to the certification emission standards and other requirements applicable to Tier 3 new marine CI engines in 40 CFR 1042.101, 40 CFR 1042.107, 40 CFR 1042.115, 40 CFR 1042.120, and 40 CFR 1042.145, for all pollutants, for the same displacement and maximum engine power:

(1) Their 2013 model year and later emergency stationary CI ICE with a maximum engine power less than 3,700 KW (4,958 HP) and a displacement of greater than or equal to 10 liters per cylinder and less than 15 liters per cylinder; and

(2) Their 2014 model year and later emergency stationary CI ICE with a maximum engine power less than 2,000 KW (2,682 HP) and a displacement of greater than or equal to 15 liters per cylinder and less than 30 liters per cylinder.

(g) Notwithstanding the requirements in paragraphs (a) through (d) of this section, stationary emergency CI internal combustion engines identified in paragraphs (a) and (c) may be certified to the provisions of 40 CFR part 94 or, if Table 2 to 40 CFR 1042.101 identifies Tier 3 standards as being applicable, the requirements applicable to Tier 3 engines in 40 CFR part 1042, if the engines will be used solely in either or both of the following locations:

(1) Areas of Alaska not accessible by the FAHS; and

(2) Marine offshore installations.

(h) Notwithstanding the requirements in paragraphs (a) through (f) of this section, stationary CI internal combustion engine manufacturers are not required to certify reconstructed engines; however manufacturers may elect to do so. The reconstructed engine must be certified to the emission standards specified in paragraphs (a) through (f) of this section that are applicable to the model year, maximum engine power and displacement of the reconstructed emergency stationary CI ICE.

[71 FR 39172, July 11, 2006, as amended at 76 FR 37968, June 28, 2011]

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§ 60.4203 How long must my engines meet the emission standards if I am a manufacturer of stationary CI internal combustion engines?

Engines manufactured by stationary CI internal combustion engine manufacturers must meet the emission standards as required in §§ 60.4201 and 60.4202 during the certified emissions life of the engines.

[76 FR 37968, June 28, 2011]

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Emission Standards for Owners and Operators

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§ 60.4204 What emission standards must I meet for non-emergency engines if I am an owner or operator of a stationary CI internal combustion engine?

(a) Owners and operators of pre-2007 model year non-emergency stationary CI ICE with a displacement of less than 10 liters per cylinder must comply with the emission standards in table 1 to this subpart. Owners and operators of pre-2007 model year non-emergency stationary CI ICE with a displacement of greater than or equal to 10 liters per cylinder and less than 30 liters per cylinder must comply with the emission standards in 40 CFR 94.8(a)(1).

(b) Owners and operators of 2007 model year and later non-emergency stationary CI ICE with a displacement of less than 30 liters per cylinder must comply with the emission standards for new CI engines in § 60.4201 for their 2007 model year and later stationary CI ICE, as applicable.

(c) Owners and operators of non-emergency stationary CI engines with a displacement of greater than or equal to 30 liters per cylinder must meet the following requirements:

(1) For engines installed prior to January 1, 2012, limit the emissions of NO_X in the stationary CI internal combustion engine exhaust to the following:

(i) 17.0 grams per kilowatt-hour (g/KW-hr) (12.7 grams per horsepower-hr (g/HP-hr)) when maximum engine speed is less than 130 revolutions per minute (rpm);

(ii) $45 \cdot n^{-0.2}$ g/KW-hr ($34 \cdot n^{-0.2}$ g/HP-hr) when maximum engine speed is 130 or more but less than 2,000 rpm, where n is maximum engine speed; and

(iii) 9.8 g/KW-hr (7.3 g/HP-hr) when maximum engine speed is 2,000 rpm or more.

(2) For engines installed on or after January 1, 2012 and before January 1, 2016, limit the emissions of NO_X in the stationary CI internal combustion engine exhaust to the following:

(i) 14.4 g/KW-hr (10.7 g/HP-hr) when maximum engine speed is less than 130 rpm;

(ii) $44 \cdot n^{-0.23}$ g/KW-hr ($33 \cdot n^{-0.23}$ g/HP-hr) when maximum engine speed is greater than or equal to 130 but less than 2,000 rpm and where n is maximum engine speed; and

(iii) 7.7 g/KW-hr (5.7 g/HP-hr) when maximum engine speed is greater than or equal to 2,000 rpm.

(3) For engines installed on or after January 1, 2016, limit the emissions of NO_X in the stationary CI internal combustion engine exhaust to the following:

(i) 3.4 g/KW-hr (2.5 g/HP-hr) when maximum engine speed is less than 130 rpm;

(ii) $9.0 \cdot n^{-0.20}$ g/KW-hr ($6.7 \cdot n^{-0.20}$ g/HP-hr) where n (maximum engine speed) is 130 or more but less than 2,000 rpm; and

(iii) 2.0 g/KW-hr (1.5 g/HP-hr) where maximum engine speed is greater than or equal to 2,000 rpm.

(4) Reduce particulate matter (PM) emissions by 60 percent or more, or limit the emissions of PM in the stationary CI internal combustion engine exhaust to 0.15 g/KW-hr (0.11 g/HP-hr).

(d) Owners and operators of non-emergency stationary CI ICE with a displacement of less than 30 liters per cylinder who conduct performance tests in-use must meet the not-to-exceed (NTE) standards as indicated in § 60.4212.

(e) Owners and operators of any modified or reconstructed non-emergency stationary CI ICE subject to this subpart must meet the emission standards applicable to the model year, maximum engine power, and displacement of the modified or reconstructed non-emergency stationary CI ICE that are specified in paragraphs (a) through (d) of this section.

[71 FR 39172, July 11, 2006, as amended at 76 FR 37968, June 28, 2011]

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§ 60.4205 What emission standards must I meet for emergency engines if I am an owner or operator of a stationary CI internal combustion engine?

(a) Owners and operators of pre-2007 model year emergency stationary CI ICE with a displacement of less than 10 liters per cylinder that are not fire pump engines must comply with the emission standards in Table 1 to this subpart. Owners and operators of pre-2007 model year emergency stationary CI ICE with a displacement of greater than or equal to 10 liters per cylinder and less than 30 liters per cylinder that are not fire pump engines must comply with the emission standards in 40 CFR 94.8(a)(1).

(b) Owners and operators of 2007 model year and later emergency stationary CI ICE with a displacement of less than 30 liters per cylinder that are not fire pump engines must comply with the emission standards for new nonroad CI engines in § 60.4202, for all pollutants, for the same model year and maximum engine power for their 2007 model year and later emergency stationary CI ICE.

(c) Owners and operators of fire pump engines with a displacement of less than 30 liters per cylinder must comply with the emission standards in table 4 to this subpart, for all pollutants.

(d) Owners and operators of emergency stationary CI engines with a displacement of greater than or equal to 30 liters per cylinder must meet the requirements in this section.

(1) For engines installed prior to January 1, 2012, limit the emissions of NO_X in the stationary CI internal combustion engine exhaust to the following:

(i) 17.0 g/KW-hr (12.7 g/HP-hr) when maximum engine speed is less than 130 rpm;

(ii) $45 \cdot n^{-0.2}$ g/KW-hr ($34 \cdot n^{-0.2}$ g/HP-hr) when maximum engine speed is 130 or more but less than 2,000 rpm, where n is maximum engine speed; and

(iii) 9.8 g/kW-hr (7.3 g/HP-hr) when maximum engine speed is 2,000 rpm or more.

(2) For engines installed on or after January 1, 2012, limit the emissions of NO_X in the stationary CI internal combustion engine exhaust to the following:

(i) 14.4 g/KW-hr (10.7 g/HP-hr) when maximum engine speed is less than 130 rpm;

(ii) $44 \cdot n^{-0.23}$ g/KW-hr ($33 \cdot n^{-0.23}$ g/HP-hr) when maximum engine speed is greater than or equal to 130 but less than 2,000 rpm and where n is maximum engine speed; and

(iii) 7.7 g/KW-hr (5.7 g/HP-hr) when maximum engine speed is greater than or equal to 2,000 rpm.

(3) Limit the emissions of PM in the stationary CI internal combustion engine exhaust to 0.40 g/KW-hr (0.30 g/HP-hr).

(e) Owners and operators of emergency stationary CI ICE with a displacement of less than 30 liters per cylinder who conduct performance tests in-use must meet the NTE standards as indicated in § 60.4212.

(f) Owners and operators of any modified or reconstructed emergency stationary CI ICE subject to this subpart must meet the emission standards applicable to the model year, maximum engine power, and displacement of the modified or reconstructed CI ICE that are specified in paragraphs (a) through (e) of this section.

[71 FR 39172, July 11, 2006, as amended at 76 FR 37969, June 28, 2011]

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§ 60.4206 How long must I meet the emission standards if I am an owner or operator of a stationary CI internal combustion engine?

Owners and operators of stationary CI ICE must operate and maintain stationary CI ICE that achieve the emission standards as required in §§ 60.4204 and 60.4205 over the entire life of the engine.

[76 FR 37969, June 28, 2011]

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Fuel Requirements for Owners and Operators

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§ 60.4207 What fuel requirements must I meet if I am an owner or operator of a stationary CI internal combustion engine subject to this subpart?

(a) Beginning October 1, 2007, owners and operators of stationary CI ICE subject to this subpart that use diesel fuel must use diesel fuel that meets the requirements of 40 CFR 80.510(a).

(b) Beginning October 1, 2010, owners and operators of stationary CI ICE subject to this subpart with a displacement of less than 30 liters per cylinder that use diesel fuel must use diesel fuel that meets the requirements of 40 CFR 80.510(b) for nonroad diesel fuel, except that any existing diesel fuel purchased (or otherwise obtained) prior to October 1, 2010, may be used until depleted.

(c) [Reserved]

(d) Beginning June 1, 2012, owners and operators of stationary CI ICE subject to this subpart with a displacement of greater than or equal to 30 liters per cylinder are no longer subject to the requirements of paragraph (a) of this section, and must use fuel that meets a maximum per-gallon sulfur content of 1,000 parts per million (ppm).

(e) Stationary CI ICE that have a national security exemption under § 60.4200(d) are also exempt from the fuel requirements in this section.

[71 FR 39172, July 11, 2006, as amended at 76 FR 37969, June 28, 2011; 78 FR 6695, Jan. 30, 2013]

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Other Requirements for Owners and Operators

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§ 60.4208 What is the deadline for importing or installing stationary CI ICE produced in previous model years?

(a) After December 31, 2008, owners and operators may not install stationary CI ICE (excluding fire pump engines) that do not meet the applicable requirements for 2007 model year engines.

(b) After December 31, 2009, owners and operators may not install stationary CI ICE with a maximum engine power of less than 19 KW (25 HP) (excluding fire pump engines) that do not meet the applicable requirements for 2008 model year engines.

(c) After December 31, 2014, owners and operators may not install non-emergency stationary CI ICE with a maximum engine power of greater than or equal to 19 KW (25 HP) and less than 56 KW (75 HP) that do not meet the applicable requirements for 2013 model year non-emergency engines.

(d) After December 31, 2013, owners and operators may not install non-emergency stationary CI ICE with a maximum engine power of greater than or equal to 56 KW (75 HP) and less than 130 KW (175 HP) that do not meet the applicable requirements for 2012 model year non-emergency engines.

(e) After December 31, 2012, owners and operators may not install non-emergency stationary CI ICE with a maximum engine power of greater than or equal to 130 KW (175 HP), including those above 560 KW (750 HP), that do not meet the applicable requirements for 2011 model year non-emergency engines.

(f) After December 31, 2016, owners and operators may not install non-emergency stationary CI ICE with a maximum engine power of greater than or equal to 560 KW (750 HP) that do not meet the applicable requirements for 2015 model year non-emergency engines.

(g) After December 31, 2018, owners and operators may not install non-emergency stationary CI ICE with a maximum engine power greater than or equal to 600 KW (804 HP) and less than 2,000 KW (2,680 HP) and a displacement of greater than or equal to 10 liters per cylinder and less than 30 liters per cylinder that do not meet the applicable requirements for 2017 model year non-emergency engines.

(h) In addition to the requirements specified in §§ 60.4201, 60.4202, 60.4204, and 60.4205, it is prohibited to import stationary CI ICE with a displacement of less than 30 liters per cylinder that do not meet the applicable requirements specified in paragraphs (a) through (g) of this section after the dates specified in paragraphs (a) through (g) of this section.

(i) The requirements of this section do not apply to owners or operators of stationary CI ICE that have been modified, reconstructed, and do not apply to engines that were removed from one existing location and reinstalled at a new location.

[71 FR 39172, July 11, 2006, as amended at 76 FR 37969, June 28, 2011]

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§ 60.4209 What are the monitoring requirements if I am an owner or operator of a stationary CI internal combustion engine?

If you are an owner or operator, you must meet the monitoring requirements of this section. In addition, you must also meet the monitoring requirements specified in § 60.4211.

(a) If you are an owner or operator of an emergency stationary CI internal combustion engine that does not meet the standards applicable to non-emergency engines, you must install a non-resettable hour meter prior to startup of the engine.

(b) If you are an owner or operator of a stationary CI internal combustion engine equipped with a diesel particulate filter to comply with the emission standards in § 60.4204, the diesel particulate filter must be installed with a backpressure monitor that notifies the owner or operator when the high backpressure limit of the engine is approached.

[71 FR 39172, July 11, 2006, as amended at 76 FR 37969, June 28, 2011]

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Compliance Requirements

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§ 60.4210 What are my compliance requirements if I am a stationary CI internal combustion engine manufacturer?

(a) Stationary CI internal combustion engine manufacturers must certify their stationary CI ICE with a displacement of less than 10 liters per cylinder to the emission standards specified in § 60.4201(a) through (c) and § 60.4202(a), (b) and (d) using the certification procedures required in 40 CFR part 89, subpart B, or 40 CFR part 1039, subpart C, as applicable, and must test their engines as specified in those parts. For the purposes of this subpart, engines certified to the standards in table 1 to this

subpart shall be subject to the same requirements as engines certified to the standards in 40 CFR part 89. For the purposes of this subpart, engines certified to the standards in table 4 to this subpart shall be subject to the same requirements as engines certified to the standards in 40 CFR part 89, except that engines with NFPA nameplate power of less than 37 KW (50 HP) certified to model year 2011 or later standards shall be subject to the same requirements as engines certified to the standards in 40 CFR part 1039.

(b) Stationary CI internal combustion engine manufacturers must certify their stationary CI ICE with a displacement of greater than or equal to 10 liters per cylinder and less than 30 liters per cylinder to the emission standards specified in § 60.4201(d) and (e) and § 60.4202(e) and (f) using the certification procedures required in 40 CFR part 94, subpart C, or 40 CFR part 1042, subpart C, as applicable, and must test their engines as specified in 40 CFR part 94 or 1042, as applicable.

(c) Stationary CI internal combustion engine manufacturers must meet the requirements of 40 CFR 1039.120, 1039.125, 1039.130, and 1039.135, and 40 CFR part 1068 for engines that are certified to the emission standards in 40 CFR part 1039. Stationary CI internal combustion engine manufacturers must meet the corresponding provisions of 40 CFR part 89, 40 CFR part 94 or 40 CFR part 1042 for engines that would be covered by that part if they were nonroad (including marine) engines. Labels on such engines must refer to stationary engines, rather than or in addition to nonroad or marine engines, as appropriate. Stationary CI internal combustion engine manufacturers must label their engines according to paragraphs (c)(1) through (3) of this section.

(1) Stationary CI internal combustion engines manufactured from January 1, 2006 to March 31, 2006 (January 1, 2006 to June 30, 2006 for fire pump engines), other than those that are part of certified engine families under the nonroad CI engine regulations, must be labeled according to 40 CFR 1039.20.

(2) Stationary CI internal combustion engines manufactured from April 1, 2006 to December 31, 2006 (or, for fire pump engines, July 1, 2006 to December 31 of the year preceding the year listed in table 3 to this subpart) must be labeled according to paragraphs (c)(2)(i) through (iii) of this section:

(i) Stationary CI internal combustion engines that are part of certified engine families under the nonroad regulations must meet the labeling requirements for nonroad CI engines, but do not have to meet the labeling requirements in 40 CFR 1039.20.

(ii) Stationary CI internal combustion engines that meet Tier 1 requirements (or requirements for fire pumps) under this subpart, but do not meet the requirements applicable to nonroad CI engines must be labeled according to 40 CFR 1039.20. The engine manufacturer may add language to the label clarifying that the engine meets Tier 1 requirements (or requirements for fire pumps) of this subpart.

(iii) Stationary CI internal combustion engines manufactured after April 1, 2006 that do not meet Tier 1 requirements of this subpart, or fire pumps engines manufactured after July 1, 2006 that do not meet the requirements for fire pumps under this subpart, may not be used in the U.S. If any such engines are manufactured in the U.S. after April 1, 2006 (July 1, 2006 for fire pump engines), they must be exported or must be brought into compliance with the appropriate standards prior to initial operation. The export provisions of 40 CFR 1068.230 would apply to engines for export and the manufacturers must label such engines according to 40 CFR 1068.230.

(3) Stationary CI internal combustion engines manufactured after January 1, 2007 (for fire pump engines, after January 1 of the year listed in table 3 to this subpart, as applicable) must be labeled according to paragraphs (c)(3)(i) through (iii) of this section.

(i) Stationary CI internal combustion engines that meet the requirements of this subpart and the corresponding requirements for nonroad (including marine) engines of the same model year and HP must be labeled according to the provisions in 40 CFR parts 89, 94, 1039 or 1042, as appropriate.

(ii) Stationary CI internal combustion engines that meet the requirements of this subpart, but are not certified to the standards applicable to nonroad (including marine) engines of the same model year and HP must be labeled according to the provisions in 40 CFR parts 89, 94, 1039 or 1042, as appropriate, but the words "stationary" must be included instead of "nonroad" or "marine" on the label. In addition, such engines must be labeled according to 40 CFR 1039.20.

(iii) Stationary CI internal combustion engines that do not meet the requirements of this subpart must be labeled according to 40 CFR 1068.230 and must be exported under the provisions of 40 CFR 1068.230.

(d) An engine manufacturer certifying an engine family or families to standards under this subpart that are identical to standards applicable under 40 CFR parts 89, 94, 1039 or 1042 for that model year may certify any such family that contains both nonroad (including marine) and stationary engines as a single engine family and/or may include any such family containing stationary engines in the averaging, banking and trading provisions applicable for such engines under those parts.

(e) Manufacturers of engine families discussed in paragraph (d) of this section may meet the labeling requirements referred to in paragraph (c) of this section for stationary CI ICE by either adding a separate label containing the information required in paragraph (c) of this section or by adding the words "and stationary" after the word "nonroad" or "marine," as appropriate, to the label.

(f) Starting with the model years shown in table 5 to this subpart, stationary CI internal combustion engine manufacturers must add a permanent label stating that the engine is for stationary emergency use only to each new emergency stationary CI internal combustion engine greater than or equal to 19 KW (25 HP) that meets all the emission standards for emergency engines in § 60.4202 but does not meet all the emission standards for non-emergency engines in § 60.4201. The label must be added according to the labeling requirements specified in 40 CFR 1039.135(b). Engine manufacturers must specify in the owner's manual that operation of emergency engines is limited to emergency operations and required maintenance and testing.

(g) Manufacturers of fire pump engines may use the test cycle in table 6 to this subpart for testing fire pump engines and may test at the NFPA certified nameplate HP, provided that the engine is labeled as "Fire Pump Applications Only".

(h) Engine manufacturers, including importers, may introduce into commerce uncertified engines or engines certified to earlier standards that were manufactured before the new or changed standards took effect until inventories are depleted, as long as such engines are part of normal inventory. For example, if the engine manufacturers' normal industry practice is to keep on hand a one-month supply of engines based on its projected sales, and a new tier of standards starts to apply for the 2009 model year, the engine manufacturer may manufacture engines based on the normal inventory requirements late in the 2008 model year, and sell those engines for installation. The engine manufacturer may not circumvent the provisions of §§ 60.4201 or 60.4202 by stockpiling engines that are built before new or changed standards take effect. Stockpiling of such engines beyond normal industry practice is a violation of this subpart.

(i) The replacement engine provisions of 40 CFR 89.1003(b)(7), 40 CFR 94.1103(b)(3), 40 CFR 94.1103(b)(4) and 40 CFR 1068.240 are applicable to stationary CI engines replacing existing equipment that is less than 15 years old.

[71 FR 39172, July 11, 2006, as amended at 76 FR 37969, June 28, 2011]

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§ 60.4211 What are my compliance requirements if I am an owner or operator of a stationary CI internal combustion engine?

(a) If you are an owner or operator and must comply with the emission standards specified in this subpart, you must do all of the following, except as permitted under paragraph (g) of this section:

(1) Operate and maintain the stationary CI internal combustion engine and control device according to the manufacturer's emission-related written instructions;

(2) Change only those emission-related settings that are permitted by the manufacturer; and

(3) Meet the requirements of 40 CFR parts 89, 94 and/or 1068, as they apply to you.

(b) If you are an owner or operator of a pre-2007 model year stationary CI internal combustion engine and must comply with the emission standards specified in §§ 60.4204(a) or 60.4205(a), or if you are an owner or operator of a CI fire pump engine that is manufactured prior to the model years in table 3 to this subpart and must comply with the emission standards specified in § 60.4205(c), you must demonstrate compliance according to one of the methods specified in paragraphs (b)(1) through (5) of this section.

(1) Purchasing an engine certified according to 40 CFR part 89 or 40 CFR part 94, as applicable, for the same model year and maximum engine power. The engine must be installed and configured according to the manufacturer's specifications.

(2) Keeping records of performance test results for each pollutant for a test conducted on a similar engine. The test must have been conducted using the same methods specified in this subpart and these methods must have been followed correctly.

(3) Keeping records of engine manufacturer data indicating compliance with the standards.

(4) Keeping records of control device vendor data indicating compliance with the standards.

(5) Conducting an initial performance test to demonstrate compliance with the emission standards according to the requirements specified in § 60.4212, as applicable.

(c) If you are an owner or operator of a 2007 model year and later stationary CI internal combustion engine and must comply with the emission standards specified in § 60.4204(b) or § 60.4205(b), or if you are an owner or operator of a CI fire pump engine that is manufactured during or after the model year that applies to your fire pump engine power rating in table 3 to this subpart and must comply with the emission standards specified in § 60.4205(c), you must comply by purchasing an engine certified to the emission standards in § 60.4204(b), or § 60.4205(b) or (c), as applicable, for the same model year and maximum (or in the case of fire pumps, NFPA nameplate) engine power. The engine must be installed and configured according to the manufacturer's emission-related specifications, except as permitted in paragraph (g) of this section.

(d) If you are an owner or operator and must comply with the emission standards specified in § 60.4204(c) or § 60.4205(d), you must demonstrate compliance according to the requirements specified in paragraphs (d)(1) through (3) of this section.

(1) Conducting an initial performance test to demonstrate initial compliance with the emission standards as specified in § 60.4213.

(2) Establishing operating parameters to be monitored continuously to ensure the stationary internal combustion engine continues to meet the emission standards. The owner or operator must petition the

Administrator for approval of operating parameters to be monitored continuously. The petition must include the information described in paragraphs (d)(2)(i) through (v) of this section.

(i) Identification of the specific parameters you propose to monitor continuously;

(ii) A discussion of the relationship between these parameters and NO_X and PM emissions, identifying how the emissions of these pollutants change with changes in these parameters, and how limitations on these parameters will serve to limit NO_X and PM emissions;

(iii) A discussion of how you will establish the upper and/or lower values for these parameters which will establish the limits on these parameters in the operating limitations;

(iv) A discussion identifying the methods and the instruments you will use to monitor these parameters, as well as the relative accuracy and precision of these methods and instruments; and

(v) A discussion identifying the frequency and methods for recalibrating the instruments you will use for monitoring these parameters.

(3) For non-emergency engines with a displacement of greater than or equal to 30 liters per cylinder, conducting annual performance tests to demonstrate continuous compliance with the emission standards as specified in § 60.4213.

(e) If you are an owner or operator of a modified or reconstructed stationary CI internal combustion engine and must comply with the emission standards specified in § 60.4204(e) or § 60.4205(f), you must demonstrate compliance according to one of the methods specified in paragraphs (e)(1) or (2) of this section.

(1) Purchasing, or otherwise owning or operating, an engine certified to the emission standards in § 60.4204(e) or § 60.4205(f), as applicable.

(2) Conducting a performance test to demonstrate initial compliance with the emission standards according to the requirements specified in § 60.4212 or § 60.4213, as appropriate. The test must be conducted within 60 days after the engine commences operation after the modification or reconstruction.

(f) If you own or operate an emergency stationary ICE, you must operate the emergency stationary ICE according to the requirements in paragraphs (f)(1) through (3) of this section. In order for the engine to be considered an emergency stationary ICE under this subpart, any operation other than emergency operation, maintenance and testing, emergency demand response, and operation in non-emergency situations for 50 hours per year, as described in paragraphs (f)(1) through (3) of this section, is prohibited. If you do not operate the engine according to the requirements in paragraphs (f)(1) through (3) of this section, the engine will not be considered an emergency engine under this subpart and must meet all requirements for non-emergency engines.

(1) There is no time limit on the use of emergency stationary ICE in emergency situations.

(2) You may operate your emergency stationary ICE for any combination of the purposes specified in paragraphs (f)(2)(i) through (iii) of this section for a maximum of 100 hours per calendar year. Any operation for non-emergency situations as allowed by paragraph (f)(3) of this section counts as part of the 100 hours per calendar year allowed by this paragraph (f)(2).

(i) Emergency stationary ICE may be operated for maintenance checks and readiness testing, provided that the tests are recommended by federal, state or local government, the manufacturer, the vendor, the regional transmission organization or equivalent balancing authority and transmission operator, or the

insurance company associated with the engine. The owner or operator may petition the Administrator for approval of additional hours to be used for maintenance checks and readiness testing, but a petition is not required if the owner or operator maintains records indicating that federal, state, or local standards require maintenance and testing of emergency ICE beyond 100 hours per calendar year.

(ii) Emergency stationary ICE may be operated for emergency demand response for periods in which the Reliability Coordinator under the North American Electric Reliability Corporation (NERC) Reliability Standard EOP-002-3, Capacity and Energy Emergencies (incorporated by reference, see § 60.17), or other authorized entity as determined by the Reliability Coordinator, has declared an Energy Emergency Alert Level 2 as defined in the NERC Reliability Standard EOP-002-3.

(iii) Emergency stationary ICE may be operated for periods where there is a deviation of voltage or frequency of 5 percent or greater below standard voltage or frequency.

(3) Emergency stationary ICE may be operated for up to 50 hours per calendar year in non-emergency situations. The 50 hours of operation in non-emergency situations are counted as part of the 100 hours per calendar year for maintenance and testing and emergency demand response provided in paragraph (f)(2) of this section. Except as provided in paragraph (f)(3)(i) of this section, the 50 hours per calendar year for non-emergency situations cannot be used for peak shaving or non-emergency demand response, or to generate income for a facility to an electric grid or otherwise supply power as part of a financial arrangement with another entity.

(i) The 50 hours per year for non-emergency situations can be used to supply power as part of a financial arrangement with another entity if all of the following conditions are met:

(A) The engine is dispatched by the local balancing authority or local transmission and distribution system operator;

(B) The dispatch is intended to mitigate local transmission and/or distribution limitations so as to avert potential voltage collapse or line overloads that could lead to the interruption of power supply in a local area or region.

(C) The dispatch follows reliability, emergency operation or similar protocols that follow specific NERC, regional, state, public utility commission or local standards or guidelines.

(D) The power is provided only to the facility itself or to support the local transmission and distribution system.

(E) The owner or operator identifies and records the entity that dispatches the engine and the specific NERC, regional, state, public utility commission or local standards or guidelines that are being followed for dispatching the engine. The local balancing authority or local transmission and distribution system operator may keep these records on behalf of the engine owner or operator.

(ii) [Reserved]

(g) If you do not install, configure, operate, and maintain your engine and control device according to the manufacturer's emission-related written instructions, or you change emission-related settings in a way that is not permitted by the manufacturer, you must demonstrate compliance as follows:

(1) If you are an owner or operator of a stationary CI internal combustion engine with maximum engine power less than 100 HP, you must keep a maintenance plan and records of conducted maintenance to demonstrate compliance and must, to the extent practicable, maintain and operate the engine in a manner consistent with good air pollution control practice for minimizing emissions. In addition, if you do not install and configure the engine and control device according to the manufacturer's emission-

related written instructions, or you change the emission-related settings in a way that is not permitted by the manufacturer, you must conduct an initial performance test to demonstrate compliance with the applicable emission standards within 1 year of such action.

(2) If you are an owner or operator of a stationary CI internal combustion engine greater than or equal to 100 HP and less than or equal to 500 HP, you must keep a maintenance plan and records of conducted maintenance and must, to the extent practicable, maintain and operate the engine in a manner consistent with good air pollution control practice for minimizing emissions. In addition, you must conduct an initial performance test to demonstrate compliance with the applicable emission standards within 1 year of startup, or within 1 year after an engine and control device is no longer installed, configured, operated, and maintained in accordance with the manufacturer's emission-related written instructions, or within 1 year after you change emission-related settings in a way that is not permitted by the manufacturer.

(3) If you are an owner or operator of a stationary CI internal combustion engine greater than 500 HP, you must keep a maintenance plan and records of conducted maintenance and must, to the extent practicable, maintain and operate the engine in a manner consistent with good air pollution control practice for minimizing emissions. In addition, you must conduct an initial performance test to demonstrate compliance with the applicable emission standards within 1 year of startup, or within 1 year after an engine and control device is no longer installed, configured, operated, and maintained in accordance with the manufacturer's emission-related written instructions, or within 1 year after you change emission-related settings in a way that is not permitted by the manufacturer. You must conduct subsequent performance testing every 8,760 hours of engine operation or 3 years, whichever comes first, thereafter to demonstrate compliance with the applicable emission standards.

[71 FR 39172, July 11, 2006, as amended at 76 FR 37970, June 28, 2011; 78 FR 6695, Jan. 30, 2013]

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Testing Requirements for Owners and Operators

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§ 60.4212 What test methods and other procedures must I use if I am an owner or operator of a stationary CI internal combustion engine with a displacement of less than 30 liters per cylinder?

Owners and operators of stationary CI ICE with a displacement of less than 30 liters per cylinder who conduct performance tests pursuant to this subpart must do so according to paragraphs (a) through (e) of this section.

(a) The performance test must be conducted according to the in-use testing procedures in 40 CFR part 1039, subpart F, for stationary CI ICE with a displacement of less than 10 liters per cylinder, and according to 40 CFR part 1042, subpart F, for stationary CI ICE with a displacement of greater than or equal to 10 liters per cylinder and less than 30 liters per cylinder.

(b) Exhaust emissions from stationary CI ICE that are complying with the emission standards for new CI engines in 40 CFR part 1039 must not exceed the not-to-exceed (NTE) standards for the same model year and maximum engine power as required in 40 CFR 1039.101(e) and 40 CFR 1039.102(g)(1), except as specified in 40 CFR 1039.104(d). This requirement starts when NTE requirements take effect for nonroad diesel engines under 40 CFR part 1039.

(c) Exhaust emissions from stationary CI ICE that are complying with the emission standards for new CI engines in 40 CFR 89.112 or 40 CFR 94.8, as applicable, must not exceed the NTE numerical

requirements, rounded to the same number of decimal places as the applicable standard in 40 CFR 89.112 or 40 CFR 94.8, as applicable, determined from the following equation:

$$\text{NTE requirement for each pollutant} = (1.25) \times (\text{STD}) \qquad (\text{Eq. 1})$$

Where:

STD = The standard specified for that pollutant in 40 CFR 89.112 or 40 CFR 94.8, as applicable.

Alternatively, stationary CI ICE that are complying with the emission standards for new CI engines in 40 CFR 89.112 or 40 CFR 94.8 may follow the testing procedures specified in § 60.4213 of this subpart, as appropriate.

(d) Exhaust emissions from stationary CI ICE that are complying with the emission standards for pre-2007 model year engines in § 60.4204(a), § 60.4205(a), or § 60.4205(c) must not exceed the NTE numerical requirements, rounded to the same number of decimal places as the applicable standard in § 60.4204(a), § 60.4205(a), or § 60.4205(c), determined from the equation in paragraph (c) of this section.

Where:

STD = The standard specified for that pollutant in § 60.4204(a), § 60.4205(a), or § 60.4205(c).

Alternatively, stationary CI ICE that are complying with the emission standards for pre-2007 model year engines in § 60.4204(a), § 60.4205(a), or § 60.4205(c) may follow the testing procedures specified in § 60.4213, as appropriate.

(e) Exhaust emissions from stationary CI ICE that are complying with the emission standards for new CI engines in 40 CFR part 1042 must not exceed the NTE standards for the same model year and maximum engine power as required in 40 CFR 1042.101(c).

[71 FR 39172, July 11, 2006, as amended at 76 FR 37971, June 28, 2011]

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§ 60.4213 What test methods and other procedures must I use if I am an owner or operator of a stationary CI internal combustion engine with a displacement of greater than or equal to 30 liters per cylinder?

Owners and operators of stationary CI ICE with a displacement of greater than or equal to 30 liters per cylinder must conduct performance tests according to paragraphs (a) through (f) of this section.

(a) Each performance test must be conducted according to the requirements in § 60.8 and under the specific conditions that this subpart specifies in table 7. The test must be conducted within 10 percent of 100 percent peak (or the highest achievable) load.

(b) You may not conduct performance tests during periods of startup, shutdown, or malfunction, as specified in § 60.8(c).

(c) You must conduct three separate test runs for each performance test required in this section, as specified in § 60.8(f). Each test run must last at least 1 hour.

(d) To determine compliance with the percent reduction requirement, you must follow the requirements as specified in paragraphs (d)(1) through (3) of this section.

(1) You must use Equation 2 of this section to determine compliance with the percent reduction requirement:

$$\frac{C_i - C_o}{C_i} \times 100 = R \qquad \text{(Eq. 2)}$$

Where:

C_i = concentration of NO_X or PM at the control device inlet,

C_o = concentration of NO_X or PM at the control device outlet, and

R = percent reduction of NO_X or PM emissions.

(2) You must normalize the NO_X or PM concentrations at the inlet and outlet of the control device to a dry basis and to 15 percent oxygen (O_2) using Equation 3 of this section, or an equivalent percent carbon dioxide (CO_2) using the procedures described in paragraph (d)(3) of this section.

$$C_{adj} = C_d \frac{5.9}{20.9 - \%\ O_2} \qquad \text{(Eq. 3)}$$

Where:

C_{adj} = Calculated NO_X or PM concentration adjusted to 15 percent O_2 .

C_d = Measured concentration of NO_X or PM, uncorrected.

5.9 = 20.9 percent O_2 −15 percent O_2 , the defined O_2 correction value, percent.

$\%O_2$ = Measured O_2 concentration, dry basis, percent.

(3) If pollutant concentrations are to be corrected to 15 percent O_2 and CO_2 concentration is measured in lieu of O_2 concentration measurement, a CO_2 correction factor is needed. Calculate the CO_2 correction factor as described in paragraphs (d)(3)(i) through (iii) of this section.

(i) Calculate the fuel-specific F_o value for the fuel burned during the test using values obtained from Method 19, Section 5.2, and the following equation:

$$F_o = \frac{0.209_{F_d}}{F_c} \qquad \text{(Eq. 4)}$$

Where:

F_o = Fuel factor based on the ratio of O_2 volume to the ultimate CO_2 volume produced by the fuel at zero percent excess air.

0.209 = Fraction of air that is O_2 , percent/100.

F_d = Ratio of the volume of dry effluent gas to the gross calorific value of the fuel from Method 19, dsm^3 /J ($dscf/10^6$ Btu).

F_c = Ratio of the volume of CO_2 produced to the gross calorific value of the fuel from Method 19, dsm^3 /J ($dscf/10^6$ Btu).

(ii) Calculate the CO_2 correction factor for correcting measurement data to 15 percent O_2 , as follows:

$$X_{CO_2} = \frac{5.9}{F_o} \qquad (Eq. 5)$$

Where:

X_{CO2} = CO_2 correction factor, percent.

5.9 = 20.9 percent O_2 −15 percent O_2 , the defined O_2 correction value, percent.

(iii) Calculate the NO_X and PM gas concentrations adjusted to 15 percent O_2 using CO_2 as follows:

$$C_{adj} = C_d \frac{X_{CO_2}}{\%CO_2} \qquad (Eq. 6)$$

Where:

C_{adj} = Calculated NO_X or PM concentration adjusted to 15 percent O_2 .

C_d = Measured concentration of NO_X or PM, uncorrected.

$\%CO_2$ = Measured CO_2 concentration, dry basis, percent.

(e) To determine compliance with the NO_X mass per unit output emission limitation, convert the concentration of NO_X in the engine exhaust using Equation 7 of this section:

$$ER = \frac{C_d \times 1.912 \times 10^{-3} \times Q \times T}{\text{KW-hour}} \qquad (Eq. 7)$$

Where:

ER = Emission rate in grams per KW-hour.

C_d = Measured NO_X concentration in ppm.

$1.912x10^{-3}$ = Conversion constant for ppm NO_X to grams per standard cubic meter at 25 degrees Celsius.

Q = Stack gas volumetric flow rate, in standard cubic meter per hour.

T = Time of test run, in hours.

KW-hour = Brake work of the engine, in KW-hour.

(f) To determine compliance with the PM mass per unit output emission limitation, convert the concentration of PM in the engine exhaust using Equation 8 of this section:

$$ER = \frac{C_{adj} \times Q \times T}{\text{KW-hour}} \qquad (Eq. 8)$$

Where:
ER = Emission rate in grams per KW-hour.
C_{adj} = Calculated PM concentration in grams per standard cubic meter.
Q = Stack gas volumetric flow rate, in standard cubic meter per hour.

T = Time of test run, in hours.
KW-hour = Energy output of the engine, in KW.

[71 FR 39172, July 11, 2006, as amended at 76 FR 37971, June 28, 2011]

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Notification, Reports, and Records for Owners and Operators

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§ 60.4214 What are my notification, reporting, and recordkeeping requirements if I am an owner or operator of a stationary CI internal combustion engine?

(a) Owners and operators of non-emergency stationary CI ICE that are greater than 2,237 KW (3,000 HP), or have a displacement of greater than or equal to 10 liters per cylinder, or are pre-2007 model year engines that are greater than 130 KW (175 HP) and not certified, must meet the requirements of paragraphs (a)(1) and (2) of this section.

(1) Submit an initial notification as required in § 60.7(a)(1). The notification must include the information in paragraphs (a)(1)(i) through (v) of this section.

(i) Name and address of the owner or operator;

(ii) The address of the affected source;

(iii) Engine information including make, model, engine family, serial number, model year, maximum engine power, and engine displacement;

(iv) Emission control equipment; and

(v) Fuel used.

(2) Keep records of the information in paragraphs (a)(2)(i) through (iv) of this section.

(i) All notifications submitted to comply with this subpart and all documentation supporting any notification.

(ii) Maintenance conducted on the engine.

(iii) If the stationary CI internal combustion is a certified engine, documentation from the manufacturer that the engine is certified to meet the emission standards.

(iv) If the stationary CI internal combustion is not a certified engine, documentation that the engine meets the emission standards.

(b) If the stationary CI internal combustion engine is an emergency stationary internal combustion engine, the owner or operator is not required to submit an initial notification. Starting with the model years in table 5 to this subpart, if the emergency engine does not meet the standards applicable to non-emergency engines in the applicable model year, the owner or operator must keep records of the operation of the engine in emergency and non-emergency service that are recorded through the non-resettable hour meter. The owner must record the time of operation of the engine and the reason the engine was in operation during that time.

(c) If the stationary CI internal combustion engine is equipped with a diesel particulate filter, the owner or operator must keep records of any corrective action taken after the backpressure monitor has notified the owner or operator that the high backpressure limit of the engine is approached.

(d) If you own or operate an emergency stationary CI ICE with a maximum engine power more than 100 HP that operates or is contractually obligated to be available for more than 15 hours per calendar year for the purposes specified in § 60.4211(f)(2)(ii) and (iii) or that operates for the purposes specified in § 60.4211(f)(3)(i), you must submit an annual report according to the requirements in paragraphs (d)(1) through (3) of this section.

(1) The report must contain the following information:

(i) Company name and address where the engine is located.

(ii) Date of the report and beginning and ending dates of the reporting period.

(iii) Engine site rating and model year.

(iv) Latitude and longitude of the engine in decimal degrees reported to the fifth decimal place.

(v) Hours operated for the purposes specified in § 60.4211(f)(2)(ii) and (iii), including the date, start time, and end time for engine operation for the purposes specified in § 60.4211(f)(2)(ii) and (iii).

(vi) Number of hours the engine is contractually obligated to be available for the purposes specified in § 60.4211(f)(2)(ii) and (iii).

(vii) Hours spent for operation for the purposes specified in § 60.4211(f)(3)(i), including the date, start time, and end time for engine operation for the purposes specified in § 60.4211(f)(3)(i). The report must also identify the entity that dispatched the engine and the situation that necessitated the dispatch of the engine.

(2) The first annual report must cover the calendar year 2015 and must be submitted no later than March 31, 2016. Subsequent annual reports for each calendar year must be submitted no later than March 31 of the following calendar year.

(3) The annual report must be submitted electronically using the subpart specific reporting form in the Compliance and Emissions Data Reporting Interface (CEDRI) that is accessed through EPA's Central Data Exchange (CDX) (*www.epa.gov/cdx*). However, if the reporting form specific to this subpart is not available in CEDRI at the time that the report is due, the written report must be submitted to the Administrator at the appropriate address listed in § 60.4.

[71 FR 39172, July 11, 2006, as amended at 78 FR 6696, Jan. 30, 2013]

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Special Requirements

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§ 60.4215 What requirements must I meet for engines used in Guam, American Samoa, or the Commonwealth of the Northern Mariana Islands?

(a) Stationary CI ICE with a displacement of less than 30 liters per cylinder that are used in Guam, American Samoa, or the Commonwealth of the Northern Mariana Islands are required to meet the applicable emission standards in §§ 60.4202 and 60.4205.

(b) Stationary CI ICE that are used in Guam, American Samoa, or the Commonwealth of the Northern Mariana Islands are not required to meet the fuel requirements in § 60.4207.

(c) Stationary CI ICE with a displacement of greater than or equal to 30 liters per cylinder that are used in Guam, American Samoa, or the Commonwealth of the Northern Mariana Islands are required to meet the following emission standards:

(1) For engines installed prior to January 1, 2012, limit the emissions of NO_X in the stationary CI internal combustion engine exhaust to the following:

(i) 17.0 g/KW-hr (12.7 g/HP-hr) when maximum engine speed is less than 130 rpm;

(ii) $45 \cdot n^{-0.2}$ g/KW-hr ($34 \cdot n^{-0.2}$ g/HP-hr) when maximum engine speed is 130 or more but less than 2,000 rpm, where n is maximum engine speed; and

(iii) 9.8 g/KW-hr (7.3 g/HP-hr) when maximum engine speed is 2,000 rpm or more.

(2) For engines installed on or after January 1, 2012, limit the emissions of NO_X in the stationary CI internal combustion engine exhaust to the following:

(i) 14.4 g/KW-hr (10.7 g/HP-hr) when maximum engine speed is less than 130 rpm;

(ii) $44 \cdot n^{-0.23}$ g/KW-hr ($33 \cdot n^{-0.23}$ g/HP-hr) when maximum engine speed is greater than or equal to 130 but less than 2,000 rpm and where n is maximum engine speed; and

(iii) 7.7 g/KW-hr (5.7 g/HP-hr) when maximum engine speed is greater than or equal to 2,000 rpm.

(3) Limit the emissions of PM in the stationary CI internal combustion engine exhaust to 0.40 g/KW-hr (0.30 g/HP-hr).

[71 FR 39172, July 11, 2006, as amended at 76 FR 37971, June 28, 2011]

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§ 60.4216 What requirements must I meet for engines used in Alaska?

(a) Prior to December 1, 2010, owners and operators of stationary CI ICE with a displacement of less than 30 liters per cylinder located in areas of Alaska not accessible by the FAHS should refer to 40 CFR part 69 to determine the diesel fuel requirements applicable to such engines.

(b) Except as indicated in paragraph (c) of this section, manufacturers, owners and operators of stationary CI ICE with a displacement of less than 10 liters per cylinder located in areas of Alaska not accessible by the FAHS may meet the requirements of this subpart by manufacturing and installing engines meeting the requirements of 40 CFR parts 94 or 1042, as appropriate, rather than the otherwise applicable requirements of 40 CFR parts 89 and 1039, as indicated in sections §§ 60.4201(f) and 60.4202(g) of this subpart.

(c) Manufacturers, owners and operators of stationary CI ICE that are located in areas of Alaska not accessible by the FAHS may choose to meet the applicable emission standards for emergency engines in § 60.4202 and § 60.4205, and not those for non-emergency engines in § 60.4201 and § 60.4204, except that for 2014 model year and later non-emergency CI ICE, the owner or operator of any such engine that was not certified as meeting Tier 4 PM standards, must meet the applicable requirements for PM in § 60.4201 and § 60.4204 or install a PM emission control device that achieves PM emission reductions of 85 percent, or 60 percent for engines with a displacement of greater than or equal to 30 liters per cylinder, compared to engine-out emissions.

(d) The provisions of § 60.4207 do not apply to owners and operators of pre-2014 model year stationary CI ICE subject to this subpart that are located in areas of Alaska not accessible by the FAHS.

(e) The provisions of § 60.4208(a) do not apply to owners and operators of stationary CI ICE subject to this subpart that are located in areas of Alaska not accessible by the FAHS until after December 31, 2009.

(f) The provisions of this section and § 60.4207 do not prevent owners and operators of stationary CI ICE subject to this subpart that are located in areas of Alaska not accessible by the FAHS from using fuels mixed with used lubricating oil, in volumes of up to 1.75 percent of the total fuel. The sulfur content of the used lubricating oil must be less than 200 parts per million. The used lubricating oil must meet the on-specification levels and properties for used oil in 40 CFR 279.11.

[76 FR 37971, June 28, 2011]

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§ 60.4217 What emission standards must I meet if I am an owner or operator of a stationary internal combustion engine using special fuels?

Owners and operators of stationary CI ICE that do not use diesel fuel may petition the Administrator for approval of alternative emission standards, if they can demonstrate that they use a fuel that is not the fuel on which the manufacturer of the engine certified the engine and that the engine cannot meet the applicable standards required in § 60.4204 or § 60.4205 using such fuels and that use of such fuel is appropriate and reasonably necessary, considering cost, energy, technical feasibility, human health and environmental, and other factors, for the operation of the engine.

[76 FR 37972, June 28, 2011]

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General Provisions

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§ 60.4218 What parts of the General Provisions apply to me?

Table 8 to this subpart shows which parts of the General Provisions in §§ 60.1 through 60.19 apply to you.

DEFINITIONS

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§ 60.4219 What definitions apply to this subpart?

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

Certified emissions life **means the period during which the engine is designed to properly function in terms of reliability and fuel consumption, without being remanufactured, specified as a number of hours of operation or calendar years, whichever comes first. The values for certified emissions life for stationary CI ICE with a displacement of less than 10 liters per cylinder are given in 40 CFR 1039.101(g). The values for certified emissions life for stationary CI ICE with a displacement of greater than or equal to 10 liters per cylinder and less than 30 liters per cylinder are given in 40 CFR 94.9(a).**

Combustion turbine **means all equipment, including but not limited to the turbine, the fuel, air, lubrication and exhaust gas systems, control systems (except emissions control equipment), and any ancillary components and sub-components comprising any simple cycle combustion turbine, any regenerative/recuperative cycle combustion turbine, the combustion turbine portion of any cogeneration cycle combustion system, or the combustion turbine portion of any combined cycle steam/electric generating system.**

Compression ignition **means relating to a type of stationary internal combustion engine that is not a spark ignition engine.**

Date of manufacture **means one of the following things:**

(1) For freshly manufactured engines and modified engines, date of manufacture means the date the engine is originally produced.

(2) For reconstructed engines, date of manufacture means the date the engine was originally produced, except as specified in paragraph (3) of this definition.

(3) Reconstructed engines are assigned a new date of manufacture if the fixed capital cost of the new and refurbished components exceeds 75 percent of the fixed capital cost of a comparable entirely new facility. An engine that is produced from a previously used engine block does not retain the date of manufacture of the engine in which the engine block was previously used if the engine is produced using all new components except for the engine block. In these cases, the date of manufacture is the date of reconstruction or the date the new engine is produced.

Diesel fuel **means any liquid obtained from the distillation of petroleum with a boiling point of approximately 150 to 360 degrees Celsius. One commonly used form is number 2 distillate oil.**

Diesel particulate filter **means an emission control technology that reduces PM emissions by trapping the particles in a flow filter substrate and periodically removes the collected particles by either physical action or by oxidizing (burning off) the particles in a process called regeneration.**

Emergency stationary internal combustion engine **means any stationary reciprocating internal combustion engine that meets all of the criteria in paragraphs (1) through (3) of this definition. All emergency stationary ICE must comply with the requirements specified in § 60.4211(f) in order to be considered emergency stationary ICE. If the engine does not comply with the requirements specified in § 60.4211(f), then it is not considered to be an emergency stationary ICE under this subpart.**

(1) The stationary ICE is operated to provide electrical power or mechanical work during an emergency situation. Examples include stationary ICE used to produce power for critical networks or equipment (including power supplied to portions of a facility) when electric power from the local utility (or the

normal power source, if the facility runs on its own power production) is interrupted, or stationary ICE used to pump water in the case of fire or flood, etc.

(2) The stationary ICE is operated under limited circumstances for situations not included in paragraph (1) of this definition, as specified in § 60.4211(f).

(3) The stationary ICE operates as part of a financial arrangement with another entity in situations not included in paragraph (1) of this definition only as allowed in § 60.4211(f)(2)(ii) or (iii) and § 60.4211(f)(3)(i).

Engine manufacturer **means the manufacturer of the engine. See the definition of "manufacturer" in this section.**

Fire pump engine **means an emergency stationary internal combustion engine certified to NFPA requirements that is used to provide power to pump water for fire suppression or protection.**

Freshly manufactured engine **means an engine that has not been placed into service. An engine becomes freshly manufactured when it is originally produced.**

Installed **means the engine is placed and secured at the location where it is intended to be operated.**

Manufacturer **has the meaning given in section 216(1) of the Act. In general, this term includes any person who manufactures a stationary engine for sale in the United States or otherwise introduces a new stationary engine into commerce in the United States. This includes importers who import stationary engines for sale or resale.**

Maximum engine power **means maximum engine power as defined in 40 CFR 1039.801.**

Model year **means the calendar year in which an engine is manufactured (see "date of manufacture"), except as follows:**

(1) Model year means the annual new model production period of the engine manufacturer in which an engine is manufactured (see "date of manufacture"), if the annual new model production period is different than the calendar year and includes January 1 of the calendar year for which the model year is named. It may not begin before January 2 of the previous calendar year and it must end by December 31 of the named calendar year.

(2) For an engine that is converted to a stationary engine after being placed into service as a nonroad or other non-stationary engine, model year means the calendar year or new model production period in which the engine was manufactured (see "date of manufacture").

Other internal combustion engine **means any internal combustion engine, except combustion turbines, which is not a reciprocating internal combustion engine or rotary internal combustion engine.**

Reciprocating internal combustion engine **means any internal combustion engine which uses reciprocating motion to convert heat energy into mechanical work.**

Rotary internal combustion engine **means any internal combustion engine which uses rotary motion to convert heat energy into mechanical work.**

Spark ignition **means relating to a gasoline, natural gas, or liquefied petroleum gas fueled engine or any other type of engine with a spark plug (or other sparking device) and with operating characteristics significantly similar to the theoretical Otto combustion cycle. Spark ignition engines usually use a throttle to regulate intake air flow to control power during normal operation. Dual-fuel engines in which**

a liquid fuel (typically diesel fuel) is used for CI and gaseous fuel (typically natural gas) is used as the primary fuel at an annual average ratio of less than 2 parts diesel fuel to 100 parts total fuel on an energy equivalent basis are spark ignition engines.

Stationary internal combustion engine **means any internal combustion engine, except combustion turbines, that converts heat energy into mechanical work and is not mobile. Stationary ICE differ from mobile ICE in that a stationary internal combustion engine is not a nonroad engine as defined at 40 CFR 1068.30 (excluding paragraph (2)(ii) of that definition), and is not used to propel a motor vehicle, aircraft, or a vehicle used solely for competition. Stationary ICE include reciprocating ICE, rotary ICE, and other ICE, except combustion turbines.**

Subpart **means 40 CFR part 60, subpart IIII.**

[71 FR 39172, July 11, 2006, as amended at 76 FR 37972, June 28, 2011; 78 FR 6696, Jan. 30, 2013]

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Table 1 to Subpart IIII of Part 60—Emission Standards for Stationary Pre-2007 Model Year Engines With a Displacement of <10 Liters per Cylinder and 2007-2010 Model Year Engines >2,237 KW (3,000 HP) and With a Displacement of <10 Liters per Cylinder

[As stated in §§ 60.4201(b), 60.4202(b), 60.4204(a), and 60.4205(a), you must comply with the following emission standards]

Maximum engine power	Emission standards for stationary pre-2007 model year engines with a displacement of <10 liters per cylinder and 2007-2010 model year engines >2,237 KW (3,000 HP) and with a displacement of <10 liters per cylinder in g/KW-hr (g/HP-hr)				
	NMHC + NO_X	HC	NO_X	CO	PM
KW<8 (HP<11)	10.5 (7.8)			8.0 (6.0)	1.0 (0.75)
8≤KW<19 (11≤HP<25)	9.5 (7.1)			6.6 (4.9)	0.80 (0.60)
19≤KW<37 (25≤HP<50)	9.5 (7.1)			5.5 (4.1)	0.80 (0.60)
37≤KW<56 (50≤HP<75)			9.2 (6.9)		
56≤KW<75 (75≤HP<100)			9.2 (6.9)		
75≤KW<130 (100≤HP<175)			9.2 (6.9)		
130≤KW<225 (175≤HP<300)		1.3 (1.0)	9.2 (6.9)	11.4 (8.5)	0.54 (0.40)
225≤KW<450 (300≤HP<600)		1.3 (1.0)	9.2 (6.9)	11.4 (8.5)	0.54 (0.40)
450≤KW≤560 (600≤HP≤750)		1.3 (1.0)	9.2 (6.9)	11.4 (8.5)	0.54 (0.40)
KW>560 (HP>750)		1.3 (1.0)	9.2 (6.9)	11.4 (8.5)	0.54 (0.40)

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Table 2 to Subpart IIII of Part 60—Emission Standards for 2008 Model Year and Later Emergency Stationary CI ICE <37 KW (50 HP) With a Displacement of <10 Liters per Cylinder

[As stated in § 60.4202(a)(1), you must comply with the following emission standards]

	Emission standards for 2008 model year and later emergency stationary CI ICE <37 KW (50 HP) with a displacement of <10 liters per cylinder in g/KW-hr (g/HP-hr)			
Engine power	Model year(s)	NO_X+ NMHC	CO	PM
KW<8 (HP<11)	2008+	7.5 (5.6)	8.0 (6.0)	0.40 (0.30)
8≤KW<19 (11≤HP<25)	2008+	7.5 (5.6)	6.6 (4.9)	0.40 (0.30)
19≤KW<37 (25≤HP<50)	2008+	7.5 (5.6)	5.5 (4.1)	0.30 (0.22)

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Table 3 to Subpart IIII of Part 60—Certification Requirements for Stationary Fire Pump Engines

As stated in § 60.4202(d), you must certify new stationary fire pump engines beginning with the following model years:

Engine power	Starting model year engine manufacturers must certify new stationary fire pump engines according to § 60.4202(d)[1]
KW<75 (HP<100)	2011
75≤KW<130 (100≤HP<175)	2010
130≤KW≤560 (175≤HP≤750)	2009
KW>560 (HP>750)	2008

[1] Manufacturers of fire pump stationary CI ICE with a maximum engine power greater than or equal to 37 kW (50 HP) and less than 450 KW (600 HP) and a rated speed of greater than 2,650 revolutions per minute (rpm) are not required to certify such engines until three model years following the model year indicated in this Table 3 for engines in the applicable engine power category.

[71 FR 39172, July 11, 2006, as amended at 76 FR 37972, June 28, 2011]

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Table 4 to Subpart IIII of Part 60—Emission Standards for Stationary Fire Pump Engines

[As stated in §§ 60.4202(d) and 60.4205(c), you must comply with the following emission standards for stationary fire pump engines]

Maximum engine power	Model year(s)	NMHC + NO_X	CO	PM
KW<8 (HP<11)	2010 and earlier	10.5 (7.8)	8.0 (6.0)	1.0 (0.75)
	2011+	7.5 (5.6)		0.40 (0.30)
8≤KW<19 (11≤HP<25)	2010 and earlier	9.5 (7.1)	6.6 (4.9)	0.80 (0.60)
	2011+	7.5 (5.6)		0.40 (0.30)
19≤KW<37 (25≤HP<50)	2010 and earlier	9.5 (7.1)	5.5 (4.1)	0.80 (0.60)
	2011+	7.5 (5.6)		0.30 (0.22)
37≤KW<56 (50≤HP<75)	2010 and earlier	10.5 (7.8)	5.0 (3.7)	0.80 (0.60)
	2011+ [1]	4.7 (3.5)		0.40 (0.30)
56≤KW<75 (75≤HP<100)	2010 and earlier	10.5 (7.8)	5.0 (3.7)	0.80 (0.60)
	2011+ [1]	4.7 (3.5)		0.40 (0.30)
75≤KW<130 (100≤HP<175)	2009 and earlier	10.5 (7.8)	5.0 (3.7)	0.80 (0.60)
	2010+ [2]	4.0 (3.0)		0.30 (0.22)
130≤KW<225 (175≤HP<300)	2008 and earlier	10.5 (7.8)	3.5 (2.6)	0.54 (0.40)
	2009+ [3]	4.0 (3.0)		0.20 (0.15)
225≤KW<450 (300≤HP<600)	2008 and earlier	10.5 (7.8)	3.5 (2.6)	0.54 (0.40)
	2009+ [3]	4.0 (3.0)		0.20 (0.15)
450≤KW≤560 (600≤HP≤750)	2008 and earlier	10.5 (7.8)	3.5 (2.6)	0.54 (0.40)
	2009+	4.0 (3.0)		0.20 (0.15)
KW>560 (HP>750)	2007 and earlier	10.5 (7.8)	3.5 (2.6)	0.54 (0.40)
	2008+	6.4 (4.8)		0.20 (0.15)

[1] For model years 2011-2013, manufacturers, owners and operators of fire pump stationary CI ICE in this engine power category with a rated speed of greater than 2,650 revolutions per minute (rpm) may comply with the emission limitations for 2010 model year engines.

[2] For model years 2010-2012, manufacturers, owners and operators of fire pump stationary CI ICE in this engine power category with a rated speed of greater than 2,650 rpm may comply with the emission limitations for 2009 model year engines.

[3] In model years 2009-2011, manufacturers of fire pump stationary CI ICE in this engine power category with a rated speed of greater than 2,650 rpm may comply with the emission limitations for 2008 model year engines.

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Table 5 to Subpart IIII of Part 60—Labeling and Recordkeeping Requirements for New Stationary Emergency Engines

[You must comply with the labeling requirements in § 60.4210(f) and the recordkeeping requirements in § 60.4214(b) for new emergency stationary CI ICE beginning in the following model years:]

Engine power	Starting model year
19≤KW<56 (25≤HP<75)	2013
56≤KW<130 (75≤HP<175)	2012
KW≥130 (HP≥175)	2011

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Table 6 to Subpart IIII of Part 60—Optional 3-Mode Test Cycle for Stationary Fire Pump Engines

[As stated in § 60.4210(g), manufacturers of fire pump engines may use the following test cycle for testing fire pump engines:]

Mode No.	Engine speed [1]	Torque (percent) [2]	Weighting factors
1	Rated	100	0.30
2	Rated	75	0.50
3	Rated	50	0.20

[1] Engine speed: ±2 percent of point.

[2] Torque: NFPA certified nameplate HP for 100 percent point. All points should be ±2 percent of engine percent load value.

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Table 7 to Subpart IIII of Part 60—Requirements for Performance Tests for Stationary CI ICE With a Displacement of ≥30 Liters per Cylinder

[As stated in § 60.4213, you must comply with the following requirements for performance tests for stationary CI ICE with a displacement of ≥30 liters per cylinder:]

For each	Complying with the requirement to	You must	Using	According to the following requirements
1. Stationary CI internal combustion engine with a displacement of ≥30 liters per cylinder	a. Reduce NO_X emissions by 90 percent or more	i. Select the sampling port location and the number of traverse points;	(1) Method 1 or 1A of 40 CFR part 60, appendix A	(a) Sampling sites must be located at the inlet and outlet of the control device.

For each	Complying with the requirement to	You must	Using	According to the following requirements
		ii. Measure O_2 at the inlet and outlet of the control device;	**(2) Method 3, 3A, or 3B of 40 CFR part 60, appendix A**	**(b) Measurements to determine O_2 concentration must be made at the same time as the measurements for NO_X concentration.**
		iii. If necessary, measure moisture content at the inlet and outlet of the control device; and,	**(3) Method 4 of 40 CFR part 60, appendix A, Method 320 of 40 CFR part 63, appendix A, or ASTM D 6348-03 (incorporated by reference, see § 60.17)**	**(c) Measurements to determine moisture content must be made at the same time as the measurements for NO_X concentration.**
		iv. Measure NO_X at the inlet and outlet of the control device	**(4) Method 7E of 40 CFR part 60, appendix A, Method 320 of 40 CFR part 63, appendix A, or ASTM D 6348-03 (incorporated by reference, see § 60.17)**	**(d) NO_X concentration must be at 15 percent O_2, dry basis. Results of this test consist of the average of the three 1-hour or longer runs.**
	b. Limit the concentration of NO_X in the stationary CI internal combustion engine exhaust.	**i. Select the sampling port location and the number of traverse points;**	**(1) Method 1 or 1A of 40 CFR part 60, appendix A**	**(a) If using a control device, the sampling site must be located at the outlet of the control device.**
		ii. Determine the O_2 concentration of the stationary internal combustion engine exhaust at the sampling port location; and,	**(2) Method 3, 3A, or 3B of 40 CFR part 60, appendix A**	**(b) Measurements to determine O_2 concentration must be made at the same time as the measurement for NO_X concentration.**
		iii. If necessary, measure moisture content of the stationary internal combustion engine exhaust at the sampling port location; and,	**(3) Method 4 of 40 CFR part 60, appendix A, Method 320 of 40 CFR part 63, appendix A, or ASTM D 6348-03 (incorporated by reference, see § 60.17)**	**(c) Measurements to determine moisture content must be made at the same time as the measurement for NO_X concentration.**

For each	Complying with the requirement to	You must	Using	According to the following requirements
		iv. Measure NO_X at the exhaust of the stationary internal combustion engine	**(4) Method 7E of 40 CFR part 60, appendix A, Method 320 of 40 CFR part 63, appendix A, or ASTM D 6348-03 (incorporated by reference, see § 60.17)**	**(d) NO_X concentration must be at 15 percent O_2, dry basis. Results of this test consist of the average of the three 1-hour or longer runs.**
	c. Reduce PM emissions by 60 percent or more	**i. Select the sampling port location and the number of traverse points;**	**(1) Method 1 or 1A of 40 CFR part 60, appendix A**	**(a) Sampling sites must be located at the inlet and outlet of the control device.**
		ii. Measure O_2 at the inlet and outlet of the control device;	**(2) Method 3, 3A, or 3B of 40 CFR part 60, appendix A**	**(b) Measurements to determine O_2 concentration must be made at the same time as the measurements for PM concentration.**
		iii. If necessary, measure moisture content at the inlet and outlet of the control device; and	**(3) Method 4 of 40 CFR part 60, appendix A**	**(c) Measurements to determine and moisture content must be made at the same time as the measurements for PM concentration.**
		iv. Measure PM at the inlet and outlet of the control device	**(4) Method 5 of 40 CFR part 60, appendix A**	**(d) PM concentration must be at 15 percent O_2, dry basis. Results of this test consist of the average of the three 1-hour or longer runs.**
	d. Limit the concentration of PM in the stationary CI internal combustion engine exhaust	**i. Select the sampling port location and the number of traverse points;**	**(1) Method 1 or 1A of 40 CFR part 60, appendix A**	**(a) If using a control device, the sampling site must be located at the outlet of the control device.**
		ii. Determine the O_2 concentration of the stationary internal combustion engine exhaust at the sampling port location; and	**(2) Method 3, 3A, or 3B of 40 CFR part 60, appendix A**	**(b) Measurements to determine O_2 concentration must be made at the same time as the measurements for PM concentration.**

For each	Complying with the requirement to	You must	Using	According to the following requirements
		iii. If necessary, measure moisture content of the stationary internal combustion engine exhaust at the sampling port location; and	(3) Method 4 of 40 CFR part 60, appendix A	(c) Measurements to determine moisture content must be made at the same time as the measurements for PM concentration.
		iv. Measure PM at the exhaust of the stationary internal combustion engine	(4) Method 5 of 40 CFR part 60, appendix A	(d) PM concentration must be at 15 percent O_2, dry basis. Results of this test consist of the average of the three 1-hour or longer runs.

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Table 8 to Subpart IIII of Part 60—Applicability of General Provisions to Subpart IIII

[As stated in § 60.4218, you must comply with the following applicable General Provisions:]

General Provisions citation	Subject of citation	Applies to subpart	Explanation
§ 60.1	General applicability of the General Provisions	Yes	
§ 60.2	Definitions	Yes	Additional terms defined in § 60.4219.
§ 60.3	Units and abbreviations	Yes	
§ 60.4	Address	Yes	
§ 60.5	Determination of construction or modification	Yes	
§ 60.6	Review of plans	Yes	
§ 60.7	Notification and Recordkeeping	Yes	Except that § 60.7 only applies as specified in § 60.4214(a).
§ 60.8	Performance tests	Yes	Except that § 60.8 only applies to stationary CI ICE with a displacement of (≥30 liters per cylinder and engines that are not certified.
§ 60.9	Availability of information	Yes	
§ 60.10	State Authority	Yes	
§ 60.11	Compliance with standards and maintenance requirements	No	Requirements are specified in subpart IIII.
§ 60.12	Circumvention	Yes	

General Provisions citation	Subject of citation	Applies to subpart	Explanation
§ 60.13	Monitoring requirements	Yes	Except that § 60.13 only applies to stationary CI ICE with a displacement of (≥30 liters per cylinder.
§ 60.14	Modification	Yes	
§ 60.15	Reconstruction	Yes	
§ 60.16	Priority list	Yes	
§ 60.17	Incorporations by reference	Yes	
§ 60.18	General control device requirements	No	
§ 60.19	General notification and reporting requirements	Yes	

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Modification No. 4: **40 CFR 63, Subpart DDDDD Updates**

On January 31, 2013, the U.S. EPA had a notice published in the Federal Register indicating U.S. EPA was taking final action on its reconsideration of certain issues in the emission standards for the control of hazardous air pollutants (HAPs) from new and existing industrial, commercial, and institutional boilers and process heaters at major sources of HAPs. Revisions to 40 CFR 63, Subpart DDDDD became effective on April 1, 2013. IDEM, OAQ has removed and replaced permit Attachment H with the revised rule.

~~Old Attachment H~~

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

~~Attachment H to a Part 70 Operating Permit~~

~~Source Background and Description~~

~~Source Name: Ohio Valley Resources, LLC~~
~~Source Location: 300-400 East CR 350 North, Rockport, Indiana 47635~~
~~County: Spencer~~
~~SIC Code: 2873~~
~~Permit No.: T 147-32322-00062~~
~~Permit Reviewer: David Matousek~~

~~40 CFR 63, Subpart DDDDD~~

~~Subpart DDDDD — National Emission Standards for Hazardous Air Pollutants for Major Sources: Industrial, Commercial, and Institutional Boilers and Process Heaters~~

~~SOURCE: 76 FR 15664, Mar. 21, 2011, unless otherwise noted.~~

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~~What This Subpart Covers~~

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~~§ 63.7480 What is the purpose of this subpart?~~

~~This subpart establishes national emission limitations and work practice standards for hazardous air pollutants (HAP) emitted from industrial, commercial, and institutional boilers and process heaters located at major sources of HAP. This subpart also establishes requirements to demonstrate initial and continuous compliance with the emission limitations and work practice standards.~~

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~~§ 63.7485 Am I subject to this subpart?~~

~~Link to an amendment published at 78 FR 7162, January 31, 2013.~~

~~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, except as specified in § 63.7491. For purposes of this subpart, a major source of HAP is as defined in § 63.2, except that for oil and natural gas production facilities, a major source of HAP is as defined in § 63.761 (subpart HH of this part, National Emission Standards for Hazardous Air Pollutants from Oil and Natural Gas Production Facilities).~~

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~~§ 63.7490 What is the affected source of this subpart?~~

~~Link to an amendment published at 78 FR 7162, January 31, 2013.~~

~~(a) This subpart applies to new, reconstructed, and existing affected sources as described in paragraphs (a)(1) and (2) of this section.~~

~~(1) The affected source of this subpart is the collection at a major source of all existing industrial, commercial, and institutional boilers and process heaters within a subcategory 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, as defined in § 63.7575, located at a major source.~~

~~(b) A boiler or process heater is new if you commence construction of the boiler or process heater after June 4, 2010, 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 June 4, 2010, 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.~~

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~~§ 63.7491 Are any boilers or process heaters not subject to this subpart?~~

~~Link to an amendment published at 78 FR 7162, January 31, 2013.~~

~~The types of boilers and process heaters listed in paragraphs (a) through (m) of this section are not subject to this subpart.~~

~~(a) An electric utility steam generating unit.~~

~~(b) A recovery boiler or furnace covered by subpart MM of this part.~~

~~(c) A boiler or process heater that is used specifically for research and development. This does not include units that provide heat or steam to a process at a research and development facility.~~

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

~~(e) A refining kettle covered by subpart X of this part.~~

~~(f) An ethylene cracking furnace covered by subpart YY of this part.~~

~~(g) Blast furnace stoves as described in EPA-453/R-01-005 (incorporated by reference, see § 63.14).~~

~~(h) Any boiler or process heater that is part of the affected source subject to another subpart of this part (i.e., another National Emission Standards for Hazardous Air Pollutants in 40 CFR part 63).~~

~~(i) Any boiler or process heater that is used as a control device to comply with another subpart of this part, provided that at least 50 percent of the heat input to the boiler is provided by the gas stream that is regulated under another subpart.~~

~~(j) Temporary boilers as defined in this subpart.~~

~~(k) Blast furnace gas fuel-fired boilers and process heaters as defined in this subpart.~~

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

~~(m) A boiler required to have a permit under section 3005 of the Solid Waste Disposal Act or covered by subpart EEE of this part (e.g., hazardous waste boilers).~~

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~~§ 63.7495 When do I have to comply with this subpart?~~

~~Link to an amendment published at 78 FR 7162, January 31, 2013.~~

~~(a) If you have a new or reconstructed boiler or process heater, you must comply with this subpart by May 20, 2011 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 March 21, 2014.~~

~~(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 source must be in compliance with this subpart upon startup.~~

~~(2) Any existing boiler or process heater at the existing source must be in compliance with this subpart within 3 years after the source 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.~~

~~(e) If you own or operate an industrial, commercial, or institutional boiler or process heater and would be subject to this subpart except for the exemption in § 63.7491(l) for commercial and industrial solid waste incineration units covered by part 60, subpart CCCC or subpart DDDD, and you cease combusting solid waste, you must be in compliance with this subpart on the effective date of the switch from waste to fuel.~~

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~~Emission Limitations and Work Practice Standards~~

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~~§ 63.7499 What are the subcategories of boilers and process heaters?~~

~~Link to an amendment published at 78 FR 7163, January 31, 2013.~~

~~The subcategories of boilers and process heaters, as defined in § 63.7575 are:~~

~~(a) Pulverized coal/solid fossil fuel units.~~

~~(b) Stokers designed to burn coal/solid fossil fuel.~~

~~(c) Fluidized bed units designed to burn coal/solid fossil fuel.~~

~~(d) Stokers designed to burn biomass/bio-based solid.~~

~~(e) Fluidized bed units designed to burn biomass/bio-based solid.~~

~~(f) Suspension burners/Dutch Ovens designed to burn biomass/bio-based solid.~~

~~(g) Fuel Cells designed to burn biomass/bio-based solid.~~

~~(h) Hybrid suspension/grate burners designed to burn biomass/bio-based solid.~~

~~(i) Units designed to burn solid fuel.~~

~~(j) Units designed to burn liquid fuel.~~

~~(k) Units designed to burn liquid fuel in non-continental States or territories.~~

~~(l) Units designed to burn natural gas, refinery gas or other gas 1 fuels.~~

~~(m) Units designed to burn gas 2 (other) gases.~~

~~(n) Metal process furnaces.~~

~~(o) Limited-use boilers and process heaters.~~

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~~§ 63.7500 What emission limitations, work practice standards, and operating limits must I meet?~~

~~Link to an amendment published at 78 FR 7163, January 31, 2013.~~

~~(a) You must meet the requirements in paragraphs (a)(1) through (3) of this section, except as provided in paragraphs (b) and (c) of this section. You must meet these requirements at all times.~~

~~(1) You must meet each emission limit and work practice standard in Tables 1 through 3, and 12 to this subpart that applies to your boiler or process heater, for each boiler or process heater at your source, except as provided under § 63.7522. If your affected source is a new or reconstructed affected source that commenced construction or reconstruction after June 4, 2010, and before May 20, 2011, you may comply with the emission limits in Table 1 or 12 to this subpart until March 21, 2014. On and after March 21, 2014, you must comply with the emission limits in Table 1 to this subpart.~~

~~(2) You must meet each operating limit in Table 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 Table 4 to this subpart, or you wish to establish and monitor an alternative operating limit and alternative monitoring parameters, you must apply to the EPA Administrator for approval of alternative monitoring under § 63.8(f).~~

~~(3) At all times, you must operate and maintain any affected source, including associated air pollution control equipment and monitoring equipment, in a manner consistent with safety and good air pollution control practices for minimizing emissions. Determination of whether such operation and maintenance procedures are being used will be based on information available to the Administrator that may include, but is not limited to, monitoring results, review of operation and maintenance procedures, review of operation and maintenance records, and inspection of the source.~~

~~(b) As provided in § 63.6(g), EPA may approve use of an alternative to the work practice standards in this section.~~

~~(c) Limited-use boilers and process heaters must complete a biennial tune-up as specified in § 63.7540. They are not subject to the emission limits in Tables 1 and 2 to this subpart, the annual tune-up requirement in Table 3 to this subpart, or the operating limits in Table 4 to this subpart. Major sources that have limited-use boilers and process heaters must complete an energy assessment as specified in Table 3 to this subpart if the source has other existing boilers subject to this subpart that are not limited-use boilers.~~

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~~§ 63.7501 How can I assert an affirmative defense if I exceed an emission limitations during a malfunction?~~

~~Link to an amendment published at 78 FR 7163, January 31, 2013.~~

~~In response to an action to enforce the emission limitations and operating limits set forth in § 63.7500 you may assert an affirmative defense to a claim for civil penalties for exceeding such standards that are caused by malfunction, as defined at § 63.2. Appropriate penalties may be assessed, however, if you fail to meet your burden of proving all of the requirements in the affirmative defense. The affirmative defense shall not be available for claims for injunctive relief.~~

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

~~(1) The excess emissions:~~

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

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

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

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

~~(2) Repairs were made as expeditiously as possible when the applicable emission limitations were being exceeded. Off-shift and overtime labor were used, to the extent practicable to make these repairs; and~~

~~(3) The frequency, amount and duration of the excess emissions (including any bypass) were minimized to the maximum extent practicable during periods of such emissions; and~~

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

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

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

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

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

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

~~(b) *Notification.* The owner or operator of the facility experiencing an exceedance of its emission limitat(s) during a malfunction shall notify the Administrator by telephone or facsimile (fax) transmission as soon as possible, but no later than 2 business days after the initial occurrence of the malfunction, if it wishes to avail itself of an affirmative defense to civil penalties for that malfunction. The owner or operator seeking to assert an affirmative defense shall also submit a written report to the Administrator within 45 days of the initial ocurrence of the exceedance of the standard in § 63.7500 to demonstrate, with all necessary supporting documentation, that it has met the requirements set forth in paragraph (a) of this section. The owner or operator may seek an extension of this deadline for up to 30 additional days by submitting a written request to the Administrator before the expiration of the 45 day period. Until a request for an extension has been approved by the Administrator, the owner or operator is subject to the requirement to submit such report within 45 days of the initial occurrence of the exceedance.~~

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~~General Compliance Requirements~~

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~~§ 63.7505 What are my general requirements for complying with this subpart?~~

~~Link to an amendment published at 78 FR 7164, January 31, 2013.~~

~~(a) You must be in compliance with the emission limits and operating limits in this subpart. These limits apply to you at all times.~~

~~(b) [Reserved]~~

~~(c) You must demonstrate compliance with all applicable emission limits using performance testing, fuel analysis, or continuous monitoring systems (CMS), including a continuous emission monitoring system (CEMS) or continuous opacity monitoring system (COMS), where applicable. You may demonstrate compliance with the applicable emission limit for hydrogen chloride or mercury using fuel analysis if the emission rate calculated according to § 63.7530(c) is less than the applicable emission limit. Otherwise, you must demonstrate compliance for hydrogen chloride or mercury using performance testing, if subject to an applicable emission limit listed in Table 1, 2, or 12 to this subpart.~~

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

~~(1) For each CMS required in this section (including CEMS, COMS, or continuous parameter monitoring system), you must develop, and submit to the delegated authority for approval upon request, a site-specific monitoring plan that addresses paragraphs (d)(1)(i) through (iii) of this section. You must submit this site-specific monitoring plan, if requested, at least 60 days before your initial performance evaluation of your CMS. This requirement to develop and submit a site specific monitoring plan does not apply to affected sources with existing monitoring plans that apply to CEMS and COMS prepared under appendix B to part 60 of this chapter and that meet the requirements of § 63.7525.~~

~~(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)(ii), (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) (as applicable in Table 10 to this subpart), (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.~~

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~~Testing, Fuel Analyses, and Initial Compliance Requirements~~

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~~§ 63.7510 What are my initial compliance requirements and by what date must I conduct them?~~

~~Link to an amendment published at 78 FR 7164, January 31, 2013.~~

~~(a) For affected sources that elect to demonstrate compliance with any of the applicable emission limits in Tables 1 or 2 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 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. For purposes of this subpart, units that use a supplemental fuel only for startup, unit shutdown, and transient flame stability purposes still qualify as affected sources that burn a single type of fuel, and the supplemental fuel is not subject to the fuel analysis requirements under § 63.7521 and Table 6 to this subpart.~~

~~(b) For affected sources that elect to demonstrate compliance with the applicable emission limits in Tables 1 or 2 of this subpart for hydrogen chloride or mercury 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) If your boiler or process heater is subject to a carbon monoxide limit, your initial compliance demonstration for carbon monoxide is to conduct a performance test for carbon monoxide according to Table 5 to this subpart. Your initial compliance demonstration for carbon monoxide also includes conducting a performance evaluation of your continuous oxygen monitor according to § 63.7525(a).~~

~~(d) If your boiler or process heater subject to a PM limit has a heat input capacity greater than 250 MMBtu per hour and combusts coal, biomass, or residual oil, your initial compliance demonstration for PM is to conduct a performance evaluation of your continuous emission monitoring system for PM according to § 63.7525(b). Boilers and process heaters that use a continuous emission monitoring system for PM are exempt from the performance testing and operating limit requirements specified in paragraph (a) of this section.~~

~~(e) For existing affected sources, you must demonstrate initial compliance, as specified in paragraphs (a) through (d) of this section, 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.~~

~~(f) If your new or reconstructed affected source commenced construction or reconstruction after June 4, 2010, you must demonstrate initial compliance with the emission limits no later than November 16, 2011 or within 180 days after startup of the source, whichever is later. If you are demonstrating compliance with an emission limit in Table 12 to this subpart that is less stringent than (that is, higher than) the applicable emission limit in Table 1 to this subpart, you must demonstrate compliance with the applicable emission limit in Table 1 no later than September 17, 2014.~~

~~(g) For affected sources that ceased burning solid waste consistent with § 63.7495(e) and for which your initial compliance date has passed, you must demonstrate compliance within 60 days of the effective date of the waste-to-fuel switch. If you have not conducted your compliance demonstration for this subpart within the previous 12 months, you must complete all compliance demonstrations for this subpart before you commence or recommence combustion of solid waste.~~

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~~§ 63.7515 When must I conduct subsequent performance tests, fuel analyses, or tune-ups?~~

~~Link to an amendment published at 78 FR 7165, January 31, 2013.~~

~~(a) You must conduct all applicable performance tests according to § 63.7520 on an annual basis, except those for dioxin/furan emissions, unless you follow the requirements listed in paragraphs (b) through (e) of this section. Annual performance tests must be completed no more than 13 months after the previous performance test, unless you follow the requirements listed in paragraphs (b) through (e) of this section. Annual performance testing for dioxin/furan emissions is not required after the initial compliance demonstration.~~

~~(b) You can conduct performance tests less often for a given pollutant if your performance tests for the pollutant for at least 2 consecutive years show that your emissions are at or below 75 percent of the emission limit, and if there are no changes in the operation of the affected source or air pollution control equipment that could increase emissions. 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 37 months after the previous performance test. If you elect to demonstrate compliance using emission averaging under § 63.7522, you must continue to conduct performance tests annually.~~

~~(c) If your boiler or process heater continues to meet the emission limit for the pollutant, you may choose to conduct performance tests for the pollutant every third year if your emissions are at or below 75 percent of the emission limit, and if there are no changes in the operation of the affected source or air pollution control equipment that could increase emissions, but each such performance test must be conducted no more than 37 months after the previous performance test. If you elect to demonstrate compliance using emission averaging under § 63.7522, you must continue to conduct performance tests annually. The requirement to test at maximum chloride input level is waived unless the stack test is conducted for HCl. The requirement to test at maximum Hg input level is waived unless the stack test is conducted for Hg.~~

~~(d) If a performance test shows emissions exceeded 75 percent of the emission limit for a pollutant, you must conduct annual performance tests for that pollutant until all performance tests over a consecutive 2-year period show compliance.~~

~~(e) If you are required to meet an applicable tune-up work practice standard, you must conduct an annual or biennial performance tune-up according to § 63.7540(a)(10) and (a)(11), respectively. Each annual tune-up specified in § 63.7540(a)(10) must be no more than 13 months after the previous tune-up. Each biennial tune-up specified in § 63.7540(a)(11) must be conducted no more than 25 months after the previous tune-up.~~

~~(f) If you demonstrate compliance with the mercury or hydrogen chloride based on fuel analysis, you must conduct a monthly fuel analysis according to § 63.7521 for each type of fuel burned that is subject to an emission limit in Table 1, 2, or 12 of this subpart. 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. If 12 consecutive monthly fuel analyses demonstrate compliance, you may request decreased fuel analysis frequency by applying to the EPA Administrator for approval of alternative monitoring under § 63.8(f).~~

~~(g) You must report the results of performance tests and the associated initial fuel analyses within 90 days after the completion of the performance tests. This report must 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 must include all applicable information required in § 63.7550.~~

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~~§ 63.7520 What stack tests and procedures must I use?~~

~~Link to an amendment published at 78 FR 7166, January 31, 2013.~~

~~(a) You must conduct all performance tests according to § 63.7(c), (d), (f), and (h). You must also develop a site-specific stack test plan according to the requirements in § 63.7(c). You shall conduct all performance tests under such conditions as the Administrator specifies to you based on representative performance of the affected source for the period being tested. Upon request, you shall make available to the Administrator such records as may be necessary to determine the conditions of the performance tests.~~

~~(b) You must conduct each performance test according to the requirements in Table 5 to this subpart.~~

~~(c) 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 representative operating load conditions while burning the type of fuel or mixture of fuels that has the highest content of chlorine and mercury, and you must demonstrate initial compliance and establish your operating limits based on these performance tests. These requirements could result in the need to conduct more than one performance test. Following each performance test and until the next performance test, you must comply with the operating limit for operating load conditions specified in Table 4 to this subpart.~~

~~(d) 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 comply with the minimum applicable sampling times or volumes specified in Tables 1, 2, and 12 to this subpart.~~

~~(e) To determine compliance with the emission limits, you must use the F-Factor methodology and equations in sections 12.2 and 12.3 of EPA Method 19 at 40 CFR part 60, appendix A-7 of this chapter to convert the measured particulate matter concentrations, the measured hydrogen chloride 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.~~

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~~§ 63.7521 What fuel analyses, fuel specification, and procedures must I use?~~

~~Link to an amendment published at 78 FR 7167, January 31, 2013.~~

~~(a) For solid, liquid, and gas 2 (other) fuels, you must conduct fuel analyses for chloride and mercury according to the procedures in paragraphs (b) through (e) of this section and Table 6 to this subpart, as applicable. You are not required to conduct fuel analyses for fuels used for only startup, unit shutdown, and transient flame stability purposes. You are required to conduct fuel analyses only for fuels and units that are subject to emission limits for mercury and hydrogen chloride in Tables 1, 2, or 12 to this subpart. Gaseous and liquid fuels are exempt from requirements in paragraphs (c) and (d) of this section and Table 6 of this subpart.~~

~~(b) You must develop and submit a site-specific fuel monitoring 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 conduct an initial compliance demonstration.~~

~~(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 from Table 6, with the expected minimum detection levels, to be used for the measurement of 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 you are proposing to use. Methods in Table 6 shall be used until the requested alternative is approved.~~

~~(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. You must collect all the material (fines and coarse) in the full cross-section. You must transfer the sample to a clean plastic bag.~~

~~(ii) Each composite sample will consist of a minimum of three samples collected at approximately equal 1-hour intervals during the testing period.~~

~~(2) If sampling from a fuel pile or truck, you must collect fuel samples according to paragraphs (c)(2)(i) through (iii) of this section.~~

~~(i) For each composite sample, you must select a minimum of five sampling locations uniformly spaced over the surface of the pile.~~

~~(ii) At each sampling site, you must dig into the pile to a depth of 18 inches. You must 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) You must transfer all samples to a clean plastic bag for further processing.~~

~~(d) You must prepare each composite sample according to the procedures in paragraphs (d)(1) through (7) of this section.~~

~~(1) You must thoroughly mix and pour the entire composite sample over a clean plastic sheet.~~

~~(2) You must break sample pieces larger than 3 inches into smaller sizes.~~

~~(3) You must make a pie shape with the entire composite sample and subdivide it into four equal parts.~~

~~(4) You must separate one of the quarter samples as the first subset.~~

~~(5) If this subset is too large for grinding, you must repeat the procedure in paragraph (d)(3) of this section with the quarter sample and obtain a one-quarter subset from this sample.~~

~~(6) You must grind the sample in a mill.~~

~~(7) You must 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) You must determine the concentration of pollutants in the fuel (mercury and/or chlorine) 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.~~

~~(f) To demonstrate that a gaseous fuel other than natural gas or refinery gas qualifies as an other gas 1 fuel, as defined in § 63.7575, you must conduct a fuel specification analyses for hydrogen sulfide and mercury according to the procedures in paragraphs (g) through (i) of this section and Table 6 to this subpart, as applicable. You are not required to conduct the fuel specification analyses in paragraphs (g) through (i) of this section for gaseous fuels other than natural gas or refinery gas that are complying with the limits for units designed to burn gas 2 (other) fuels.~~

~~(g) You must develop and submit a site-specific fuel analysis plan for other gas 1 fuels to the EPA Administrator for review and approval according to the following procedures and requirements in paragraphs (g)(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 conduct an initial compliance demonstration.~~

~~(2) You must include the information contained in paragraphs (g)(2)(i) through (vi) of this section in your fuel analysis plan.~~

~~(i) The identification of all gaseous fuel types other than natural gas or refinery gas 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 specification analysis.~~

~~(iii) For each fuel type, a detailed description of the sample location and specific procedures to be used for collecting and preparing the samples if your procedures are different from the sampling methods contained in Table 6. 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. If multiple boilers or process heaters are fueled by a common fuel stream it is permissible to conduct a single gas specification at the common point of gas distribution.~~

~~(iv) For each fuel type, the analytical methods from Table 6, with the expected minimum detection levels, to be used for the measurement of hydrogen sulfide and 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 you are proposing to use. Methods in Table 6 shall be used until the requested alternative is approved.~~

~~(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.~~

~~(h) You must obtain a single fuel sample for each other gas 1 fuel type according to the sampling procedures listed in Table 6 for fuel specification of gaseous fuels.~~

~~(i) You must determine the concentration in the fuel of mercury, in units of microgram per cubic meter, and of hydrogen sulfide, in units of parts per million, by volume, dry basis, of each sample for each gas 1 fuel type according to the procedures in Table 6 to this subpart.~~

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~~§ 63.7522 Can I use emissions averaging to comply with this subpart?~~

~~Link to an amendment published at 78 FR 7168, January 31, 2013.~~

~~(a) As an alternative to meeting the requirements of § 63.7500 for particulate matter, hydrogen chloride, or mercury on a boiler or process heater-specific basis, if you have more than one existing boiler or process heater in any subcategory located at your facility, you may demonstrate compliance by emissions averaging, if your averaged emissions are not more than 90 percent of the applicable emission limit, according to the procedures in this section. You may not include new boilers or process heaters in an emissions average.~~

~~(b) For a group of two or more existing boilers or process heaters in the same subcategory that each vent to a separate stack, you may average particulate matter, hydrogen chloride, or mercury emissions among existing units to demonstrate compliance with the limits in Table 2 to this subpart if you satisfy the requirements in paragraphs (c), (d), (e), (f), and (g) of this section.~~

~~(c) For each existing boiler or process heater 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 May 20, 2011 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 May 20, 2011.~~

~~(d) The averaged emissions rate from the existing boilers and process heaters participating in the emissions averaging option must be in compliance with the limits in Table 2 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 using the maximum rated heat input capacity or maximum steam generation capacity of each unit and the results of the initial performance tests or fuel analysis.~~

~~(1) You must use Equation 1 of this section to demonstrate that the particulate matter, hydrogen chloride, or mercury emissions from all existing units participating in the emissions averaging option for that pollutant do not exceed the emission limits in Table 2 to this subpart.~~

$$AveWeightedEmissions = 1.1 \times \sum_{i=1}^{n} (Er \times Hm) \div \sum_{i=1}^{n} Hm \qquad (Eq.\ 1)$$

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~~Where:~~

~~AveWeightedEmissions = Average weighted emissions for particulate matter, hydrogen chloride, or mercury, in units of pounds per million Btu of heat input.~~

~~Er = Emission rate (as determined during the initial compliance demonstration) of particulate matter, hydrogen chloride, or mercury from unit, i, in units of pounds per million Btu of heat input. Determine the emission rate for particulate matter, hydrogen chloride, or mercury by performance testing according to Table 5 to this subpart, or by fuel analysis for hydrogen chloride or mercury using the applicable equation in § 63.7530(c).~~

~~Hm = Maximum rated heat input capacity of unit, i, in units of million Btu per hour.~~

~~n = Number of units participating in the emissions averaging option.~~

~~1.1 = Required discount factor.~~

~~(2) If you are not capable of determining the maximum rated heat input capacity of one or more boilers that generate steam, you may use Equation 2 of this section as an alternative to using Equation 1 of this section to demonstrate that the particulate matter, hydrogen chloride, or mercury emissions from all existing units participating in the emissions averaging option do not exceed the emission limits for that pollutant in Table 2 to this subpart.~~

$$AveWeightedEmissions = 1.1 \times \sum_{i=1}^{n} (Er \times Sm \times Cfi) \div \sum_{i=1}^{n} (Sm \times Cfi) \qquad \text{(Eq. 2)}$$

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~~Where:~~

~~AveWeightedEmissions = Average weighted emission level for PM, hydrogen chloride, or mercury, in units of pounds per million Btu of heat input.~~

~~Er = Emission rate (as determined during the most recent compliance demonstration) of particulate matter, hydrogen chloride, or mercury from unit, i, in units of pounds per million Btu of heat input. Determine the emission rate for particulate matter, hydrogen chloride, or mercury by performance testing according to Table 5 to this subpart, or by fuel analysis for hydrogen chloride or mercury using the applicable equation in § 63.7530(c).~~

~~Sm = Maximum steam generation capacity by unit, i, in units of pounds.~~

~~Cfi = Conversion factor, calculated from the most recent compliance test, in units of million Btu of heat input per pounds of steam generated for unit, i.~~

~~1.1 = Required discount factor.~~

~~(f) After the initial compliance demonstration described in paragraph (e) of this section, you must demonstrate 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 average weighted emission rate for that month using the actual heat input for each existing unit participating in the emissions averaging option.~~

$$AveWeightedEmissions = 1.1 \times \sum_{i=1}^{n} (Er \times Hb) \div \sum_{i=1}^{n} Hb \qquad \text{(Eq. 3)}$$

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~~Where:~~

~~AveWeightedEmissions = Average weighted emission level for particulate matter, hydrogen chloride, or mercury, in units of pounds per million Btu of heat input, for that calendar month.~~

~~Er = Emission rate (as determined during the most recent compliance demonstration) of particulate matter, hydrogen chloride, or mercury from unit, i, in units of pounds per million Btu of heat input. Determine the emission rate for particulate matter, hydrogen chloride, or mercury by performance testing according to Table 5 to this subpart, or by fuel analysis for hydrogen chloride or mercury using the applicable equation in § 63.7530(c).~~

~~Hb = The heat input for that calendar month to unit, i, in units of million Btu.~~

~~n = Number of units participating in the emissions averaging option.~~

~~1.1 = Required discount factor.~~

~~(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 average weighted emission rate using the actual steam generation from the boilers participating in the emissions averaging option.~~

$$AveWeightedEmissions = 1.1 \times \sum_{i=1}^{n} (Er \times Sa \times Cfi) \div \sum_{i=1}^{n} (Sa \times Cfi) \qquad (\text{Eq. } 4)$$

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~~Where:~~

~~AveWeightedEmissions = average weighted emission level for PM, hydrogen chloride, or mercury, in units of pounds per million Btu of heat input for that calendar month.~~

~~Er = Emission rate (as determined during the most recent compliance demonstration of particulate matter, hydrogen chloride, or mercury from unit, i, in units of pounds per million Btu of heat input. Determine the emission rate for particulate matter, hydrogen chloride, or mercury by performance testing according to Table 5 to this subpart, or by fuel analysis for hydrogen chloride or mercury using the applicable equation in § 63.7530(c).~~

~~Sa = Actual steam generation for that calendar month by boiler, i, in units of pounds.~~

~~Cfi = Conversion factor, as calculated during the most recent compliance test, in units of million Btu of heat input per pounds of steam generated for boiler, i.~~

~~1.1 = Required discount factor.~~

~~(3) Until 12 monthly weighted average emission rates have been accumulated, calculate and report only the average weighted emission rate determined under paragraph (f)(1) or (2) of this section for each calendar month. After 12 monthly weighted average emission rates have been accumulated, for each subsequent calendar month, use Equation 5 of this section to calculate the 12-month rolling average of the monthly weighted average emission rates for the current calendar month and the previous 11 calendar months.~~

$$Eavg = \sum_{i=1}^{n} ERi \div 12 \qquad (\text{Eq. } 5)$$

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~~Where:~~

~~Eavg = 12-month rolling average emission rate, (pounds per million Btu heat input)~~

~~ERi = Monthly weighted average, for calendar month "i" (pounds per million Btu heat input), as calculated by paragraph (f)(1) or (2) of this section.~~

~~(g) You must develop, and submit to the applicable delegated authority for review and approval, an implementation plan for emission averaging according to the following procedures and requirements in paragraphs (g)(1) through (4) of this section.~~

~~(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 boilers and process heaters in the averaging group, including for each either the applicable HAP emission level or the control technology installed as of May 20, 2011 and the date on which you are requesting emission averaging to commence;~~

~~(ii) The process parameter (heat input or steam generated) that will be monitored for each averaging group;~~

~~(iii) The specific control technology or pollution prevention measure to be used for each emission boiler or process heater in the averaging group and the date of its installation or application. If the pollution prevention measure reduces or eliminates emissions from multiple boilers or process heaters, the owner or operator must identify each boiler or process heater;~~

~~(iv) The test plan for the measurement of particulate matter, hydrogen chloride, or mercury emissions in accordance with the requirements in § 63.7520;~~

~~(v) The operating parameters to be monitored for each control system or device consistent with § 63.7500 and Table 4, 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 delegated 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 load conditions. Following each compliance demonstration and until the next compliance demonstration, you must comply with the operating limit for operating load conditions specified in Table 4 to this subpart.~~

~~(3) The delegated 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 delegated 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 unit in the same subcategory.~~

~~(h) For a group of two or more existing affected units, each of which vents through a single common stack, you may average particulate matter, hydrogen chloride, or mercury emissions to demonstrate compliance with the limits for that pollutant in Table 2 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 units in the same subcategory, 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 unit for purposes of this subpart and comply with the requirements of this subpart as if the group were a single unit.~~

~~(j) For all other groups of units subject to the common stack requirements of paragraph (h) of this section, including situations where the exhaust of affected units are each individually controlled and then sent to a common stack, 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 vent to the common stack. The emission limits that the group must comply with are determined by the use of Equation 6 of this section.~~

$$En = \sum_{i=1}^{n} (ELi \times Hi) \div \sum_{i=1}^{n} Hi \quad (\text{Eq. } 6)$$

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~~Where:~~

~~En = HAP emission limit, pounds per million British thermal units (lb/MMBtu), parts per million (ppm), or nanograms per dry standard cubic meter (ng/dscm).~~

~~ELi = Appropriate emission limit from Table 2 to this subpart for unit i, in units of lb/MMBtu, ppm or ng/dscm.~~

~~Hi = Heat input from unit i, MMBtu.~~

~~(2) Conduct performance tests according to procedures specified in § 63.7520 in the common stack. If affected units and non-affected units vent to the common stack, the non-affected units must be shut down or vented to a different stack during the performance test unless the facility determines to demonstrate compliance with the non-affected units venting to the stack; and~~

~~(3) Meet the applicable operating limit specified in § 63.7540 and Table 8 to this subpart for each emissions control system (except that, if each unit 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) The common stack of a group of two or more existing boilers or process heaters in the same subcategory 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.~~

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~~§ 63.7525 What are my monitoring, installation, operation, and maintenance requirements?~~

~~Link to an amendment published at 78 FR 7171, January 31, 2013.~~

~~(a) If your boiler or process heater is subject to a carbon monoxide emission limit in Table 1, 2, or 12 to this subpart, you must install, operate, and maintain a continuous oxygen monitor according to the procedures in paragraphs (a)(1) through (6) of this section by the compliance date specified in § 63.7495. The oxygen level shall be monitored at the outlet of the boiler or process heater.~~

~~(1) Each CEMS for oxygen (O_2 CEMS) must be installed, operated, and maintained according to the applicable procedures under Performance Specification 3 at 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 O_2 CEMS according to the requirements in § 63.8(e) and according to Performance Specification 3 at 40 CFR part 60, appendix B.~~

~~(3) Each O_2 CEMS must complete a minimum of one cycle of operation (sampling, analyzing, and data recording) for each successive 15-minute period.~~

~~(4) The O_2 CEMS data must be reduced as specified in § 63.8(g)(2).~~

~~(5) You must calculate and record 12-hour block average concentrations for each operating day.~~

~~(6) For purposes of calculating data averages, you must use all the data collected during all periods in assessing compliance, excluding data collected during periods when the monitoring system malfunctions or is out of control, during associated repairs, and during required quality assurance or control activities (including, as applicable, calibration checks and required zero and span adjustments). Monitoring failures that are caused in part by poor maintenance or careless operation are not malfunctions. Any period for which the monitoring system malfunctions or is out of control and data are not available for a required calculation constitutes a deviation from the monitoring requirements. Periods when data are unavailable because of required quality assurance or control activities (including, as applicable, calibration checks and required zero and span adjustments) do not constitute monitoring deviations.~~

~~(b) If your boiler or process heater has a heat input capacity of greater than 250 MMBtu per hour and combusts coal, biomass, or residual oil, you must install, certify, maintain, and operate a CEMS measuring PM emissions discharged to the atmosphere and record the output of the system as specified in paragraphs (b)(1) through (5) of this section.~~

~~(1) Each CEMS shall be installed, certified, operated, and maintained according to the requirements in § 63.7540(a)(9).~~

~~(2) For a new unit, the initial performance evaluation shall be completed no later than November 16, 2011 or 180 days after the date of initial startup, whichever is later. For an existing unit, the initial performance evaluation shall be completed no later than September 17, 2014.~~

~~(3) Compliance with the applicable emissions limit shall be determined based on the 30-day rolling average of the hourly arithmetic average emissions concentrations using the continuous monitoring system outlet data. The 30-day rolling arithmetic average emission concentration shall be calculated using EPA Reference Method 19 at 40 CFR part 60, appendix A-7.~~

~~(4) Collect CEMS hourly averages for all operating hours on a 30-day rolling average basis. Collect at least four CMS data values representing the four 15-minute periods in an hour, or at least two 15-minute data values during an hour when CMS calibration, quality assurance, or maintenance activities are being performed.~~

~~(5) The 1-hour arithmetic averages required shall be expressed in lb/MMBtu and shall be used to calculate the boiler operating day daily arithmetic average emissions.~~

~~(c) If you have an applicable opacity operating limit in this rule, and are not otherwise required to install and operate a PM CEMS or a bag leak detection system, you must install, operate, certify and maintain each COMS according to the procedures in paragraphs (c)(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 Performance Specification 1 at appendix B to part 60 of this chapter.~~

~~(2) You must conduct a performance evaluation of each COMS according to the requirements in § 63.8(e) and according to Performance Specification 1 at appendix B to part 60 of this chapter.~~

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

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

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

~~(6) You must operate and maintain each COMS according to the requirements in the monitoring plan and the requirements of § 63.8(e). You must identify periods the COMS is out of control including any periods that the COMS fails to pass a daily calibration drift assessment, a quarterly performance audit, or an annual zero alignment audit. Any 6-minute period for which the monitoring system is out of control and data are not available for a required calculation constitutes a deviation from the monitoring requirements.~~

~~(7) You must determine and record all the 6-minute averages (and daily block averages as applicable) collected for periods during which the COMS is not out of control.~~

~~(d) If you have an operating limit that requires the use of a CMS, you must install, operate, and maintain each continuous parameter monitoring system according to the procedures in paragraphs (d)(1) through (5) of this section by the compliance date specified in § 63.7495.~~

~~(1) The continuous parameter monitoring system 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 15-minute period for which the monitoring system is out-of-control and data are not available for a required calculation constitutes a deviation from the monitoring requirements.~~

~~(4) You must determine the 4-hour block average of all recorded readings, except as provided in paragraph (d)(3) of this section.~~

~~(5) You must record the results of each inspection, calibration, and validation check.~~

~~(e) If you have an operating limit that requires the use of a flow monitoring system, you must meet the requirements in paragraphs (d) and (e)(1) through (4) of this section.~~

~~(1) You must install the flow sensor and other necessary equipment in a position that provides a representative flow.~~

~~(2) You must use a flow sensor with a measurement sensitivity of no greater than 2 percent of the expected flow rate.~~

~~(3) You must minimize the effects of swirling flow or abnormal velocity distributions due to upstream and downstream disturbances.~~

~~(4) You must conduct a flow monitoring system performance evaluation in accordance with your monitoring plan at the time of each performance test but no less frequently than annually. (f) If you have an operating limit that requires the use of a pressure monitoring system, you must meet the requirements in paragraphs (d) and (f)(1) through (6) of this section.~~

~~(1) Install the pressure sensor(s) in a position that provides a representative measurement of the pressure (~~ ~~*e.g.*~~ ~~, PM scrubber pressure drop).~~

~~(2) Minimize or eliminate pulsating pressure, vibration, and internal and external corrosion.~~

~~(3) Use a pressure sensor with a minimum tolerance of 1.27 centimeters of water or a minimum tolerance of 1 percent of the pressure monitoring system operating range, whichever is less.~~

~~(4) Perform checks at least once each process operating day to ensure pressure measurements are not obstructed (~~ ~~*e.g.*~~ ~~, check for pressure tap pluggage daily).~~

~~(5) Conduct a performance evaluation of the pressure monitoring system in accordance with your monitoring plan at the time of each performance test but no less frequently than annually.~~

~~(6) If at any time the measured pressure exceeds the manufacturer's specified maximum operating pressure range, conduct a performance evaluation of the pressure monitoring system in accordance with your monitoring plan and confirm that the pressure monitoring system continues to meet the performance requirements in you monitoring plan. Alternatively, install and verify the operation of a new pressure sensor.~~

~~(g) If you have an operating limit that requires a pH monitoring system, you must meet the requirements in paragraphs (d) and (g)(1) through (4) of this section.~~

~~(1) Install 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) Conduct a performance evaluation of the pH monitoring system in accordance with your monitoring plan at least once each process operating day.~~

~~(4) Conduct a performance evaluation (including a two-point calibration with one of the two buffer solutions having a pH within 1 of the pH of the operating limit) of the pH monitoring system in accordance with your monitoring plan at the time of each performance test but no less frequently than quarterly.~~

~~(h) If you have an operating limit that requires a secondary electric power monitoring system for an electrostatic precipitator (ESP) operated with a wet scrubber, you must meet the requirements in paragraphs (h)(1) and (2) of this section.~~

~~(1) Install sensors to measure (secondary) voltage and current to the precipitator collection plates.~~

~~(2) Conduct a performance evaluation of the electric power monitoring system in accordance with your monitoring plan at the time of each performance test but no less frequently than annually.~~

~~(i) If you have an operating limit that requires the use of a monitoring system to measure sorbent injection rate (e.g., weigh belt, weigh hopper, or hopper flow measurement device), you must meet the requirements in paragraphs (d) and (i)(1) through (2) of this section.~~

~~(1) Install the system in a position(s) that provides a representative measurement of the total sorbent injection rate.~~

~~(2) Conduct a performance evaluation of the sorbent injection rate monitoring system in accordance with your monitoring plan at the time of each performance test but no less frequently than annually.~~

~~(j) If you are not required to use a PM CEMS and 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 the bag leak detection system as specified in paragraphs (j)(1) through (7) of this section.~~

~~(1) You must install a bag leak detection sensor(s) in a position(s) that will be representative of the relative or absolute particulate matter loadings for each exhaust stack, roof vent, or compartment (*e.g.,* for a positive pressure fabric filter) of the fabric filter.~~

~~(2) Conduct a performance evaluation of the bag leak detection system in accordance with your monitoring plan and consistent with the guidance provided in EPA-454/R-98-015 (incorporated by reference, *see* § 63.14).~~

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

~~(4) Use a bag leak detection system equipped with a device to record continuously the output signal from the sensor.~~

~~(5) Use a bag leak detection system equipped with a system that will alert when an increase in relative particulate matter emissions over a preset level is detected. The alarm must be located where it can be easily heard or seen by plant operating personnel.~~

~~(7) Where multiple bag leak detectors are required, the system's instrumentation and alarm may be shared among detectors.~~

~~(k) For each unit that meets the definition of limited-use boiler or process heater, you must monitor and record the operating hours per year for that unit.~~

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~~§ 63.7530 How do I demonstrate initial compliance with the emission limitations, fuel specifications and work practice standards?~~

~~Link to an amendment published at 78 FR 7174, January 31, 2013.~~

~~(a) You must demonstrate initial compliance with each emission limit that applies to you by conducting initial performance tests and fuel analyses and establishing operating limits, as applicable, according to § 63.7520, paragraphs (b) and (c) of this section, and Tables 5 and 7 to this subpart. If applicable, you must also install, and operate, maintain all applicable CMS (including CEMS, COMS, and continuous parameter monitoring systems) according to § 63.7525.~~

~~(b) If you demonstrate compliance through performance testing, you must establish each site-specific operating limit in Table 4 to this subpart that applies to you according to the requirements in § 63.7520, Table 7 to this subpart, and paragraph (b)(3) 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 (b)(1) and (2) of this section, as applicable. As specified in § 63.7510(a), if your affected source burns a single type of fuel (excluding supplemental fuels used for unit startup, shutdown, or transient flame stabilization), you are not required to perform the initial fuel analysis for each type of fuel burned in your boiler or process heater. However, if you switch fuel(s) and cannot show that the new fuel(s) do (does) not increase the chlorine or mercury input into the unit through the results of fuel analysis, then you must repeat the performance test to demonstrate compliance while burning the new fuel(s).~~

~~(1) You must establish the maximum chlorine fuel input (Clinput) during the initial fuel analysis according to the procedures in paragraphs (b)(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 fuel analysis for hydrogen chloride, you must determine the fraction of the total heat input for each fuel type burned (Qi) based on the fuel mixture that has the highest content of chlorine, and the average chlorine concentration of each fuel type burned (Ci).~~

~~(iii) You must establish a maximum chlorine input level using Equation 7 of this section.~~

$$Clinput = \sum_{i=1}^{n} (Ci \times Qi) \quad \text{(Eq. 7)}$$

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~~Where:~~

~~Clinput = Maximum amount of chlorine entering the boiler or process heater through fuels burned in units of pounds per million Btu.~~

~~Ci = Arithmetic average concentration of chlorine in fuel type, i, analyzed according to § 63.7521, in units of pounds per million Btu.~~

~~Qi = 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 Qi.~~

~~n = Number of different fuel types burned in your boiler or process heater for the mixture that has the highest content of chlorine.~~

~~(2) You must establish the maximum mercury fuel input level (Mercuryinput) during the initial fuel analysis using the procedures in paragraphs (b)(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 mercury.~~

~~(ii) During the compliance demonstration for mercury, you must determine the fraction of total heat input for each fuel burned (Qi) based on the fuel mixture that has the highest content of mercury, and the average mercury concentration of each fuel type burned (HGi).~~

~~(iii) You must establish a maximum mercury input level using Equation 8 of this section.~~

$$Mercuryinput = \sum_{i=1}^{n} (HGi \times Qi) \qquad \text{(Eq. 8)}$$

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~~Where:~~

~~Mercuryinput = Maximum amount of mercury entering the boiler or process heater through fuels burned in units of pounds per million Btu.~~

~~HGi = Arithmetic average concentration of mercury in fuel type, i, analyzed according to § 63.7521, in units of pounds per million Btu.~~

~~Qi = 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 Qi.~~

~~n = Number of different fuel types burned in your boiler or process heater for the mixture that has the highest content of mercury.~~

~~(3) You must establish parameter operating limits according to paragraphs (b)(3)(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, hydrogen chloride, 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 hydrogen chloride 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 operated with a wet scrubber, you must establish the minimum voltage and secondary amperage (or total power input), as defined in § 63.7575, as your operating limits during the three-run performance test. (These operating limits do not apply to electrostatic precipitators that are operated as dry controls without a wet scrubber.)~~

~~(iii) For a dry scrubber, you must establish the minimum sorbent injection rate for each sorbent, as defined in § 63.7575, as your operating limit during the three-run performance test.~~

~~(iv) For activated carbon injection, you must establish the minimum activated carbon injection rate, as defined in § 63.7575, as your operating limit during the three-run performance test.~~

~~(v) The operating limit for boilers or process heaters with fabric filters that demonstrate continuous compliance through bag leak detection systems is that a bag leak detection system be installed according to the~~

~~requirements in § 63.7525, 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.~~

~~(c) 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 (c)(1) through (4) 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 9 of this section.~~

$$P90 = mean + (SD \times t) \qquad \text{(Eq. 9)}$$

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~~Where:~~

~~P90 = 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 hydrogen chloride, the hydrogen chloride emission rate that you calculate for your boiler or process heater using Equation 10 of this section must not exceed the applicable emission limit for hydrogen chloride.~~

$$HCl = \sum_{i=1}^{n} (Ci90 \times Qi \times 1.028) \qquad \text{(Eq. 10)}$$

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~~Where:~~

~~HCl = Hydrogen chloride emission rate from the boiler or process heater in units of pounds per million Btu.~~

~~Ci90 = 90th percentile confidence level concentration of chlorine in fuel type, i, in units of pounds per million Btu as calculated according to Equation 9 of this section.~~

~~Qi = 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 Qi.~~

~~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 hydrogen chloride to chlorine.~~

~~(4) 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 not exceed the applicable emission limit for mercury.~~

$$Mercury = \sum_{i=1}^{n} (Hgi90 \times Qi) \qquad \text{(Eq. 11)}$$

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~~Where:~~

~~Mercury = Mercury emission rate from the boiler or process heater in units of pounds per million Btu.~~

~~Hgi90 = 90th percentile confidence level concentration of mercury in fuel, i, in units of pounds per million Btu as calculated according to Equation 9 of this section.~~

~~Qi = 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 Qi.~~

~~n = Number of different fuel types burned in your boiler or process heater for the mixture that has the highest mercury content.~~

~~(d) If you own or operate an existing unit with a heat input capacity of less than 10 million Btu per hour, you must submit a signed statement in the Notification of Compliance Status report that indicates that you conducted a tune-up of the unit.~~

~~(e) You must include with the Notification of Compliance Status a signed certification that the energy assessment was completed according to Table 3 to this subpart and is an accurate depiction of your facility.~~

~~(f) You must submit the Notification of Compliance Status containing the results of the initial compliance demonstration according to the requirements in § 63.7545(e).~~

~~(g) If you elect to demonstrate that a gaseous fuel meets the specifications of an other gas 1 fuel as defined in § 63.7575, you must conduct an initial fuel specification analyses according to § 63.7521(f) through (i). If the mercury and hydrogen sulfide constituents in the gaseous fuels will never exceed the specifications included in the definition, you will include a signed certification with the Notification of Compliance Status that the initial fuel specification test meets the gas specifications outlined in the definition of other gas 1 fuels. If your gas constituents could vary above the specifications, you will conduct monthly testing according to the procedures in § 63.7521(f) through (i) and § 63.7540(c) and maintain records of the results of the testing as outlined in § 63.7555(g).~~

~~(h) If you own or operate a unit subject emission limits in Tables 1, 2, or 12 of this subpart, you must minimize the unit's startup and shutdown periods following the manufacturer's recommended procedures, if available. If manufacturer's recommended procedures are not available, you must follow recommended procedures for a unit of similar design for which manufacturer's recommended procedures are available. You must submit a signed statement in the Notification of Compliance Status report that indicates that you conducted startups and shutdowns according to the manufacturer's recommended procedures or procedures specified for a unit of similar design if manufacturer's recommended procedures are not available.~~

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~~§ 63.7533 Can I use emission credits earned from implementation of energy conservation measures to comply with this subpart?~~

~~Link to an amendment published at 78 FR 7178, January 31, 2013.~~

~~(a) If you elect to comply with the alternative equivalent steam output-based emission limits, instead of the heat input-based limits, listed in Tables 1 and 2 of this subpart and you want to take credit for implementing energy conservation measures identified in an energy assessment, you may demonstrate compliance using emission reduction credits according to the procedures in this section. Owners or operators using this compliance approach must establish an emissions benchmark, calculate and document the emission credits, develop an Implementation Plan, comply with the general reporting requirements, and apply the emission credit according to the procedures in paragraphs (b) through (f) of this section.~~

~~(b) For each existing affected boiler for which you intend to apply emissions credits, establish a benchmark from which emission reduction credits may be generated by determining the actual annual fuel heat input to the affected boiler before initiation of an energy conservation activity to reduce energy demand (~~ ~~*i.e.,*~~ ~~fuel usage) according to paragraphs (b)(1) through (4) of this section. The benchmark shall be expressed in trillion Btu per year heat input.~~

~~(1) The benchmark from which emission credits may be generated shall be determined by using the most representative, accurate, and reliable process available for the source. The benchmark shall be established for a one-year period before the date that an energy demand reduction occurs, unless it can be demonstrated that a different time period is more representative of historical operations.~~

~~(2) Determine the starting point from which to measure progress. Inventory all fuel purchased and generated on-site (off-gases, residues) in physical units (MMBtu, million cubic feet, etc.).~~

~~(3) Document all uses of energy from the affected boiler. Use the most recent data available.~~

~~(4) Collect non-energy related facility and operational data to normalize, if necessary, the benchmark to current operations, such as building size, operating hours, etc. Use actual, not estimated, use data, if possible and data that are current and timely.~~

~~(c) Emissions credits can be generated if the energy conservation measures were implemented after January 14, 2011 and if sufficient information is available to determine the appropriate value of credits.~~

~~(1) The following emission points cannot be used to generate emissions averaging credits:~~

~~(i) Energy conservation measures implemented on or before January 14, 2011, unless the level of energy demand reduction is increased after January 14, 2011, in which case credit will be allowed only for change in demand reduction achieved after January 14, 2011.~~

~~(ii) Emission credits on shut-down boilers. Boilers that are shut down cannot be used to generate credits.~~

~~(2) For all points included in calculating emissions credits, the owner or operator shall:~~

~~(i) Calculate annual credits for all energy demand points. Use Equation 12 to calculate credits. Energy conservation measures that meet the criteria of paragraph (c)(1) of this section shall not be included, except as specified in paragraph (c)(1)(i) of this section.~~

~~(3) Credits are generated by the difference between the benchmark that is established for each affected boiler, and the actual energy demand reductions from energy conservation measures implemented after January 14, 2011. Credits shall be calculated using Equation 12 of this section as follows:~~

~~(i) The overall equation for calculating credits is:~~

$$Credits = \sum_{i=1}^{n} EIS_{iactual} \div EI_{baseline} \quad \text{(Eq. 12)}$$

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~~Where:~~

~~Credits = Energy Input Savings for all energy conservation measures implemented for an affected boiler, million Btu per year.~~

~~$EIS_{iactual}$ = Energy Input Savings for each energy conservation measure implemented for an affected boiler, million Btu per year.~~

~~$EI_{baseline}$ = Energy Input for the affected boiler, million Btu.~~

~~n = Number of energy conservation measures included in the emissions credit for the affected boiler.~~

~~(d) The owner or operator shall develop and submit for approval an Implementation Plan containing all of the information required in this paragraph for all boilers to be included in an emissions credit approach. The Implementation Plan shall identify all existing affected boilers to be included in applying the emissions credits. The Implementation Plan shall include a description of the energy conservation measures implemented and the energy savings generated from each measure and an explanation of the criteria used for determining that savings. You must submit the implementation plan for emission credits to the applicable delegated authority for review and approval no later than 180 days before the date on which the facility intends to demonstrate compliance using the emission credit approach.~~

~~(e) The emissions rate from each existing boiler participating in the emissions credit option must be in compliance with the limits in Table 2 to this subpart at all times following the compliance date specified in § 63.7495.~~

~~(f) You must demonstrate initial compliance according to paragraph (f)(1) or (2) of this section.~~

~~(1) You must use Equation 13 of this section to demonstrate that the emissions from the affected boiler participating in the emissions credit compliance approach do not exceed the emission limits in Table 2 to this subpart.~~

$$E_{adj} = E_m \times (1 - EC) \quad \text{(Eq. 13)}$$

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~~Where:~~

~~E_{adj} = Emission level adjusted applying the emission credits earned, lb per million Btu steam output for the affected boiler.~~

~~E_m = Emissions measured during the performance test, lb per million Btu steam output for the affected boiler.~~

~~EC = Emission credits from equation 12 for the affected boiler.~~

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~~Continuous Compliance Requirements~~

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~~§ 63.7535 How do I monitor and collect data to demonstrate continuous compliance?~~

~~Link to an amendment published at 78 FR 7179, January 31, 2013.~~

~~(a) You must monitor and collect data according to this section and the site-specific monitoring plan required by § 63.7505(d).~~

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

~~(c) You may not use data recorded during monitoring system malfunctions or out-of-control periods, repairs associated with monitoring system malfunctions or out-of-control periods, or required monitoring system quality assurance or control activities in data averages and calculations used to report emissions 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.~~

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

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~~§ 63.7540 How do I demonstrate continuous compliance with the emission limitations, fuel specifications and work practice standards?~~

~~Link to an amendment published at 78 FR 7179, January 31, 2013.~~

~~(a) You must demonstrate continuous compliance with each emission limit, operating limit, and work practice standard in Tables 1 through 3 to this subpart that applies to you according to the methods specified in Table 8 to this subpart and paragraphs (a)(1) through (11) of this section.~~

~~(1) Following the date on which the initial compliance demonstration is completed or is required to be completed under §§ 63.7 and 63.7510, whichever date comes first, operation above the established maximum or below the established minimum operating limits shall constitute a deviation of established operating limits listed in Table 4 of this subpart except during performance tests conducted to determine compliance with the emission limits or to establish new operating limits. Operating limits must be confirmed or reestablished during performance tests.~~

~~(2) As specified in § 63.7550(c), 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 hydrogen chloride and mercury than the applicable emission limit for each pollutant (if you demonstrate compliance through fuel analysis), or result in lower fuel input of chlorine and mercury than the maximum values calculated during the last performance test (if you demonstrate compliance through performance testing).~~

~~(3) If you demonstrate compliance with an applicable hydrogen chloride emission limit through fuel analysis and you plan to burn a new type of fuel, you must recalculate the hydrogen chloride 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 hydrogen chloride emission rate from your boiler or process heater under these new conditions using Equation 10 of § 63.7530. The recalculated hydrogen chloride emission rate must be less than the applicable emission limit.~~

~~(4) If you demonstrate compliance with an applicable hydrogen chloride 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 7 of § 63.7530. If the results of recalculating the maximum chlorine input using Equation 7 of § 63.7530 are greater 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 hydrogen chloride 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(b).~~

~~(5) 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)(5)(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.~~

~~(6) 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 8 of § 63.7530. If the results of recalculating the maximum mercury input using Equation 8 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(b).~~

~~(7) 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.~~

~~(8) [Reserved]~~

~~(9) The owner or operator of an affected source using a CEMS measuring PM emissions to meet requirements of this subpart shall install, certify, operate, and maintain the PM CEMS as specified in paragraphs (a)(9)(i) through (a)(9)(iv) of this section.~~

~~(i) The owner or operator shall conduct a performance evaluation of the PM CEMS according to the applicable requirements of § 60.13, and Performance Specification 11 at 40 CFR part 60, appendix B of this chapter.~~

~~(ii) During each PM correlation testing run of the CEMS required by Performance Specification 11 at 40 CFR part 60, appendix B of this chapter, PM and oxygen (or carbon dioxide) data shall be collected concurrently (or within a 30-to 60-minute period) by both the CEMS and conducting performance tests using Method 5 or 5B at 40 CFR part 60, appendix A-3 or Method 17 at 40 CFR part 60, appendix A-6 of this chapter.~~

~~(iii) Quarterly accuracy determinations and daily calibration drift tests shall be performed in accordance with Procedure 2 at 40 CFR part 60, appendix F of this chapter. Relative Response Audits must be performed annually and Response Correlation Audits must be performed every 3 years.~~

~~(iv) After December 31, 2011, within 60 days after the date of completing each CEMS relative accuracy test audit or performance test conducted to demonstrate compliance with this subpart, you must submit the relative accuracy test audit data and performance test data to EPA by successfully submitting the data electronically into EPA's Central Data Exchange by using the Electronic Reporting Tool (see~~ ~~*http://www.epa.gov/ttn/chief/ert/ert tool.html/*~~ ~~).~~

~~(10) If your boiler or process heater is in either the natural gas, refinery gas, other gas 1, or Metal Process Furnace subcategories and has a heat input capacity of 10 million Btu per hour or greater, you must conduct a tune-up of the boiler or process heater annually to demonstrate continuous compliance as specified in paragraphs (a)(10)(i) through (a)(10)(vi) of this section. This requirement does not apply to limited-use boilers and process heaters, as defined in § 63.7575.~~

~~(i) As applicable, inspect the burner, and clean or replace any components of the burner as necessary (you may delay the burner inspection until the next scheduled unit shutdown, but you must inspect each burner at least once every 36 months);~~

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

~~(iii) Inspect the system controlling the air-to-fuel ratio, as applicable, and ensure that it is correctly calibrated and functioning properly;~~

~~(iv) Optimize total emissions of carbon monoxide. This optimization should be consistent with the manufacturer's specifications, if available;~~

~~(v) Measure the concentrations in the effluent stream of carbon monoxide in parts per million, by volume, and oxygen in volume percent, before and after the adjustments are made (measurements may be either on a dry or wet basis, as long as it is the same basis before and after the adjustments are made); and~~

~~(vi) Maintain on-site and submit, if requested by the Administrator, an annual report containing the information in paragraphs (a)(10)(vi)(A) through (C) of this section,~~

~~(A) The concentrations of carbon monoxide in the effluent stream in parts per million by volume, and oxygen in volume percent, measured before and after the adjustments of the boiler;~~

~~(B) A description of any corrective actions taken as a part of the combustion adjustment; and~~

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

~~(11) If your boiler or process heater has a heat input capacity of less than 10 million Btu per hour, or meets the definition of limited-use boiler or process heater in § 63.7575, you must conduct a biennial tune-up of the boiler or process heater as specified in paragraphs (a)(10)(i) through (a)(10)(vi) of this section to demonstrate continuous compliance.~~

~~(12) If the unit is not operating on the required date for a tune-up, the tune-up must be conducted within one week of startup.~~

~~(b) You must report each instance in which you did not meet each emission limit and operating limit in Tables 1 through 4 to this subpart that apply to you. These instances are deviations from the emission limits in this subpart. These deviations must be reported according to the requirements in § 63.7550.~~

~~(c) If you elected to demonstrate that the unit meets the specifications for hydrogen sulfide and mercury for the other gas 1 subcategory and you cannot submit a signed certification under § 63.7545(g) because the constituents could exceed the specifications, you must conduct monthly fuel specification testing of the gaseous fuels, according to the procedures in § 63.7521(f) through (i).~~

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~~§ 63.7541 How do I demonstrate continuous compliance under the emissions averaging provision?~~

~~Link to an amendment published at 78 FR 7182, January 31, 2013.~~

~~(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 units 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) and (ii) of this section.~~

~~(i) For each existing unit 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 units participating in the emissions averaging option where each unit in the group is equipped with a dry control system and vented to a common stack that does not receive emissions from non-affected units, maintain opacity at or below the applicable limit at the common stack.~~

~~(3) For each existing unit 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.~~

~~(4) For each existing unit 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 unit participating in the emissions averaging option venting to a common stack configuration containing affected units from other subcategories, maintain the appropriate operating limit for each unit as specified in Table 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 is a deviation.~~

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~~Notification, Reports, and Records~~

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~~§ 63.7545 What notifications must I submit and when?~~

~~Link to an amendment published at 78 FR 7183, January 31, 2013.~~

~~(a) You must submit to the delegated authority 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 May 20, 2011, you must submit an Initial Notification not later than 120 days after May 20, 2011.~~

~~(c) As specified in § 63.9(b)(4) and (b)(5), if you startup your new or reconstructed affected source on or after May 20, 2011, 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 60 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 the initial compliance demonstration for each affected source, 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 all performance test and/or other initial compliance demonstrations for the affected source according to § 63.10(d)(2). The Notification of Compliance Status report must contain all the information specified in paragraphs (e)(1) through (8), as applicable.~~

~~(1) A description of the affected unit(s) including identification of which subcategory the unit is in, the design heat input capacity of the unit, a description of the add-on controls used on the unit, description of the fuel(s) burned, including whether the fuel(s) were determined by you or EPA through a petition process to be a non-waste under § 241.3, whether the fuel(s) were processed from discarded non-hazardous secondary materials within the meaning of § 241.3, and justification for the selection of fuel(s) burned during the compliance demonstration.~~

~~(2) Summary of the results of all performance tests and fuel analyses, and calculations conducted to demonstrate initial compliance including all established operating limits.~~

~~(3) A summary of the maximum carbon monoxide emission levels recorded during the performance test to show that you have met any applicable emission standard in Table 1, 2, or 12 to this subpart.~~

~~(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 and identification of whether you plan to demonstrate compliance by using emission credits through energy conservation:~~

~~(i) If you plan to demonstrate compliance by emission averaging, report the emission level that was being achieved or the control technology employed on May 20, 2011.~~

~~(6) A signed certification that you have met all applicable emission limits and work practice standards.~~

~~(7) If you had a deviation from any emission limit, work practice standard, or operating limit, 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.~~

~~(8) In addition to the information required in § 63.9(h)(2), your notification of compliance status must include the following certification(s) of compliance, as applicable, and signed by a responsible official:~~

~~(i) “This facility complies with the requirements in § 63.7540(a)(10) to conduct an annual or biennial tune-up, as applicable, of each unit.”~~

~~(ii) “This facility has had an energy assessment performed according to § 63.7530(e).”~~

~~(iii) Except for units that qualify for a statutory exemption as provided in section 129(g)(1) of the Clean Air Act, include the following: “No secondary materials that are solid waste were combusted in any affected unit.”~~

~~(f) If you operate a unit designed to burn natural gas, refinery gas, or other gas 1 fuels that is subject to this subpart, and you intend to use a fuel other than natural gas, refinery gas, or other gas 1 fuel to fire the affected unit during a period of natural gas curtailment or supply interruption, as defined in § 63.7575, you must submit a notification of alternative fuel use within 48 hours of the declaration of each period of natural gas curtailment or supply interruption, as defined in § 63.7575. The notification must include the information specified in paragraphs (f)(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.~~

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

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

~~(2) The currently applicable subcategory under this subpart.~~

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

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

~~(h) If you intend to switch fuels, and this fuel switch may result in the applicability of a different subcategory, you must provide 30 days prior notice of the date upon which you will switch fuels. The notification must identify:~~

~~(1) The name of the owner or operator of the affected source, the location of the source, the boiler(s) that will switch fuels, and the date of the notice.~~

~~(2) The currently applicable subcategory under this subpart.~~

~~(3) The date on which you became subject to the currently applicable standards.~~

~~(4) The date upon which you will commence the fuel switch.~~

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~~§ 63.7550 What reports must I submit and when?~~

~~Link to an amendment published at 78 FR 7183, January 31, 2013.~~

~~(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. For units that are subject only to a requirement to conduct an annual or biennial tune-up according to § 63.7540(a)(10) or (a)(11), respectively, and not subject to emission limits or operating limits, you may submit only an annual or biennial compliance report, as applicable, as specified in paragraphs (b)(1) through (5) of this section, instead of a semi-annual compliance report.~~

~~(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 (or 1 or 2 year, as applicable, if submitting an annual or biennial compliance report) 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. The first annual or biennial compliance report must be postmarked no later than January 31.~~

~~(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. Annual and biennial compliance reports must cover the applicable one or two year periods from January 1 to 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. Annual and biennial compliance reports must be postmarked no later than January 31.~~

~~(5) For each affected source that is subject to permitting regulations pursuant to part 70 or part 71 of this chapter, and if the delegated authority has established dates for submitting semiannual reports pursuant to § 70.6(a)(3)(iii)(A) or § 71.6(a)(3)(iii)(A), you may submit the first and subsequent compliance reports according to the dates the delegated 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 (13) 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 (or annual or biennial) reporting period, including, but not limited to, a description of the fuel, whether the fuel has received a non-waste determination by EPA or your basis for concluding that the fuel is not a waste, and the total fuel usage amount with units of measure.~~

~~(5) A summary of the results of the annual performance tests for affected sources subject to an emission limit, a summary of any fuel analyses associated with performance tests, and documentation of any operating limits that were reestablished during this test, if applicable. If you are conducting performance tests once every 3 years consistent with § 63.7515(b) or (c), the date of the last 2 performance tests, a comparison of the emission level you achieved in the last 2 performance tests to the 75 percent emission limit threshold required in § 63.7515(b) or (c), and a statement as to whether there have been any operational changes since the last performance test that could increase emissions.~~

~~(6) A signed statement indicating that you burned no new types of fuel in an affected source subject to an emission limit. Or, if you did burn a new type of fuel and are subject to a hydrogen chloride emission limit, 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 hydrogen chloride emission rate using Equation 10 of § 63.7530 that demonstrates that your source is still meeting the emission limit for hydrogen chloride emissions (for boilers or process heaters that demonstrate compliance through fuel analysis). If you burned a new type of fuel and are subject to a mercury emission limit, you must submit the calculation of mercury input, using Equation 8 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 in an affected source subject to an emission limit and you cannot demonstrate compliance with the maximum chlorine input operating limit using Equation 7 of § 63.7530 or the maximum mercury input operating limit using Equation 8 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) A summary of any monthly fuel analyses conducted to demonstrate compliance according to §§ 63.7521 and 63.7530 for affected sources subject to emission limits, and any fuel specification analyses conducted according to § 63.7521(f) and § 63.7530(g).~~

~~(9) If there are no deviations from any emission limits or operating limits in this subpart that apply to you, a statement that there were no deviations from the emission limits or operating limits during the reporting period.~~

~~(10) If there were no deviations from the monitoring requirements including no periods during which the CMSs, including CEMS, COMS, and continuous parameter monitoring systems, were out of control as specified in § 63.8(c)(7), a statement that there were no deviations and no periods during which the CMS were out of control during the reporting period.~~

~~(11) If a malfunction occurred during the reporting period, the report must include the number, duration, and a brief description for each type of malfunction which occurred during the reporting period and which caused or may have caused any applicable emission limitation to be exceeded. The report must also include a description of actions taken by you during a malfunction of a boiler, process heater, or associated air pollution control~~

~~device or CMS to minimize emissions in accordance with § 63.7500(a)(3), including actions taken to correct the malfunction.~~

~~(12) Include the date of the most recent tune-up for each unit subject to only the requirement to conduct an annual or biennial tune-up according to § 63.7540(a)(10) or (a)(11), respectively. Include the date of the most recent burner inspection if it was not done annually or biennially and was delayed until the next scheduled unit shutdown.~~

~~(13) If you plan to demonstrate compliance by emission averaging, certify the emission level achieved or the control technology employed is no less stringent that the level or control technology contained in the notification of compliance status in § 63.7545(e)(5)(i).~~

~~(d) For each deviation from an emission limit or operating limit in this subpart that occurs at an affected source where you are not using a CMS to comply with that emission limit or operating limit, the compliance report must additionally contain the information required in paragraphs (d)(1) through (4) of this section.~~

~~(1) The total operating time of each affected source during the reporting period.~~

~~(2) A description of the deviation and which emission limit or operating limit 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 limits.~~

~~(e) For each deviation from an emission limit, operating limit, and monitoring requirement in this subpart occurring at an affected source where you are using a CMS to comply with that emission limit or operating limit, you must include the information required in paragraphs (e)(1) through (12) of this section. This includes any deviations from your site-specific monitoring plan as required in § 63.7505(d).~~

~~(1) The date and time that each deviation 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.~~

~~(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) An analysis of the total duration of the deviations during the reporting period into those that are due to control equipment problems, process problems, other known causes, and other unknown causes.~~

~~(7) A summary of the total duration of CMS's 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.~~

~~(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 part 70 or part 71 of this chapter must report all deviations as defined in this subpart in the semiannual monitoring report required by § 70.6(a)(3)(iii)(A) or § 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 § 70.6(a)(3)(iii)(A) or § 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 delegated authority.~~

~~(g) [Reserved]~~

~~(h) As of January 1, 2012 and within 60 days after the date of completing each performance test, as defined in § 63.2, conducted to demonstrate compliance with this subpart, you must submit relative accuracy test audit (*i.e.* , reference method) data and performance test (*i.e.* , compliance test) data, except opacity data, electronically to EPA's Central Data Exchange (CDX) by using the Electronic Reporting Tool (ERT) (see *http://www.epa.gov/ttn/chief/ert/ert tool.html/*) or other compatible electronic spreadsheet. Only data collected using test methods compatible with ERT are subject to this requirement to be submitted electronically into EPA's WebFIRE database.~~

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~~§ 63.7555 What records must I keep?~~

~~Link to an amendment published at 78 FR 7185, January 31, 2013.~~

~~(a) You must keep records according to paragraphs (a)(1) and (2) 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) Records of performance tests, fuel analyses, or other compliance demonstrations and performance evaluations as required in § 63.10(b)(2)(viii).~~

~~(b) For each CEMS, COMS, and continuous monitoring system you must keep records according to paragraphs (b)(1) through (5) of this section.~~

~~(1) Records described in § 63.10(b)(2)(vii) 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.~~

~~(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, pH, and operating load, to show continuous compliance with each emission limit and operating limit that applies to you.~~

~~(d) For each boiler or process heater subject to an emission limit in Table 1, 2 or 12 to this subpart, you must also keep the applicable records in paragraphs (d)(1) through (8) 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) If you combust non-hazardous secondary materials that have been determined not to be solid waste pursuant to § 41.3(b)(1), you must keep a record which documents how the secondary material meets each of the legitimacy criteria. If you combust a fuel that has been processed from a discarded non-hazardous secondary material pursuant to § 241.3(b)(4), you must keep records as to how the operations that produced the fuel satisfies the definition of processing in § 241.2. If the fuel received a non-waste determination pursuant to the petition process submitted under § 241.3(c), you must keep a record that documents how the fuel satisfies the requirements of the petition process.~~

~~(3) You must keep records of monthly hours of operation by each boiler or process heater that meets the definition of limited-use boiler or process heater.~~

~~(4) A copy of all calculations and supporting documentation of maximum chlorine fuel input, using Equation 7 of § 63.7530, that were done to demonstrate continuous compliance with the hydrogen chloride 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 hydrogen chloride emission rates, using Equation 10 of § 63.7530, that were done to demonstrate compliance with the hydrogen chloride emission limit. Supporting documentation should include results of any fuel analyses and basis for the estimates of maximum chlorine fuel input or hydrogen chloride 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 hydrogen chloride emission rate, for each boiler and process heater.~~

~~(5) A copy of all calculations and supporting documentation of maximum mercury fuel input, using Equation 8 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.~~

~~(6) If, consistent with § 63.7515(b) and (c), you choose to stack test less frequently than annually, you must keep annual records that document that your emissions in the previous stack test(s) were less than 75 percent of the applicable emission limit, and document that there was no change in source operations including fuel composition and operation of air pollution control equipment that would cause emissions of the relevant pollutant to increase within the past year.~~

~~(7) Records of the occurrence and duration of each malfunction of the boiler or process heater, or of the associated air pollution control and monitoring equipment.~~

~~(8) Records of actions taken during periods of malfunction to minimize emissions in accordance with the general duty to minimize emissions in § 63.7500(a)(3), including corrective actions to restore the malfunctioning boiler or process heater, air pollution control, or monitoring equipment to its normal or usual manner of operation.~~

~~(e) If you elect to average emissions consistent with § 63.7522, you must additionally keep a copy of the emission averaging implementation plan required in § 63.7522(g), all calculations required under § 63.7522, including monthly records of heat input or steam generation, as applicable, and monitoring records consistent with § 63.7541.~~

~~(f) If you elect to use emission credits from energy conservation measures to demonstrate compliance according to § 63.7533, you must keep a copy of the Implementation Plan required in § 63.7533(d) and copies of all data and calculations used to establish credits according to § 63.7533(b), (c), and (f).~~

~~(g) If you elected to demonstrate that the unit meets the specifications for hydrogen sulfide and mercury for the other gas 1 subcategory and you cannot submit a signed certification under § 63.7545(g) because the constituents could exceed the specifications, you must maintain monthly records of the calculations and results of the fuel specifications for mercury and hydrogen sulfide in Table 6.~~

~~(h) If you operate a unit designed to burn natural gas, refinery gas, or other gas 1 fuel that is subject to this subpart, and you use an alternative fuel other than natural gas, refinery gas, or other gas 1 fuel, you must keep records of the total hours per calendar year that alternative fuel is burned.~~

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~~§ 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, or they must be accessible from on site (for example, through a computer network), 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.~~

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~~Other Requirements and Information~~

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~~§ 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.~~

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~~§ 63.7570 Who implements and enforces this subpart?~~

~~Link to an amendment published at 78 FR 7186, January 31, 2013.~~

~~(a) This subpart can be implemented and enforced by 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 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, 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, and alternative analytical methods requested under § 63.7521(b)(2).~~

~~(4) Approval of major change to monitoring under § 63.8(f) and as defined in § 63.90, and approval of alternative operating parameters under § 63.7500(a)(2) and § 63.7522(g)(2).~~

~~(5) Approval of major change to recordkeeping and reporting under § 63.10(e) and as defined in § 63.90.~~

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~~§ 63.7575 What definitions apply to this subpart?~~

~~Link to an amendment published at 78 FR 7187, January 31, 2013.~~

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

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

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

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

~~*Benchmarking* means a process of comparison against standard or average.~~

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

~~*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 annual gas volume 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. Controlled flame combustion refers to a steady-~~

~~state, or near steady-state, process wherein fuel and/or oxidizer feed rates are controlled. A device combusting solid waste, as defined in § 241.3, is not a boiler unless the device is exempt from the definition of a solid waste incineration unit as provided in section 129(g)(1) of the Clean Air Act. Waste heat boilers are excluded from this definition.~~

~~*Boiler system* means the boiler and associated components, such as, the feed water system, the combustion air system, the fuel system (including burners), blowdown system, combustion control system, and energy consuming systems.~~

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

~~*Coal* means all solid fuels classifiable as anthracite, bituminous, sub-bituminous, or lignite by ASTM D388 (incorporated by reference, see § 63.14), coal refuse, and petroleum coke. For the purposes of this subpart, this definition of "coal" includes synthetic fuels derived from coal for creating useful heat, including but not limited to, solvent-refined coal, coal-oil mixtures, and coal-water mixtures. 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 steam and/or hot water.~~

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

~~*Cost-effective energy conservation measure* means a measure that is implemented to improve the energy efficiency of the boiler or facility that has a payback (return of investment) period of 2 years or less.~~

~~*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; or~~

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

~~(2) A deviation is not always a violation. 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.~~

~~*Dioxins/furans* means tetra- through octa-chlorinated dibenzo-p-dioxins and dibenzofurans.~~

~~*Distillate oil* means fuel oils, including recycled oils, that comply with the specifications for fuel oil numbers 1 and 2, as defined by ASTM D396 (incorporated by reference, see § 63.14).~~

~~*Dry scrubber* means an add-on air pollution control system that injects dry alkaline sorbent (dry injection) or sprays an alkaline sorbent (spray dryer) to react with and neutralize acid gas in the exhaust stream forming a~~

~~dry powder material. Sorbent injection systems in fluidized bed boilers and process heaters are included in this definition. A dry scrubber is a dry control system.~~

~~*Dutch oven* means a unit having a refractory-walled cell connected to a conventional boiler setting. Fuel materials are introduced through an opening in the roof of the Dutch oven and burn in a pile on its floor.~~

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

~~*Emission credit* means emission reductions above those required by this subpart. Emission credits generated may be used to comply with the emissions limits. Credits may come from pollution prevention projects that result in reduced fuel use by affected units. Shutdowns cannot be used to generate credits.~~

~~*Energy assessment* means the following only as this term is used in Table 3 to this subpart.~~

~~(1) Energy assessment for facilities with affected boilers and process heaters using less than 0.3 trillion Btu per year heat input will be one day in length maximum. The boiler system and energy use system accounting for at least 50 percent of the energy output will be evaluated to identify energy savings opportunities, within the limit of performing a one-day energy assessment.~~

~~(2) The Energy assessment for facilities with affected boilers and process heaters using 0.3 to 1.0 trillion Btu per year will be 3 days in length maximum. The boiler system and any energy use system accounting for at least 33 percent of the energy output will be evaluated to identify energy savings opportunities, within the limit of performing a 3-day energy assessment.~~

~~(3) In the Energy assessment for facilities with affected boilers and process heaters using greater than 1.0 trillion Btu per year, the boiler system and any energy use system accounting for at least 20 percent of the energy output will be evaluated to identify energy savings opportunities.~~

~~*Energy management practices* means the set of practices and procedures designed to manage energy use that are demonstrated by the facility's energy policies, a facility energy manager and other staffing responsibilities, energy performance measurement and tracking methods, an energy saving goal, action plans, operating procedures, internal reporting requirements, and periodic review intervals used at the facility.~~

~~*Energy use system* includes, but is not limited to, process heating; compressed air systems; machine drive (motors, pumps, fans); process cooling; facility heating, ventilation, and air-conditioning systems; hot heater systems; building envelop; and lighting.~~

~~*Equivalent* means the following only as this term is used in Table 6 to this subpart:~~

~~(1) An equivalent sample collection procedure means a published voluntary consensus standard or practice (VCS) or EPA method that includes collection of a minimum of three composite fuel samples, with each composite consisting of a minimum of three increments collected at approximately equal intervals over the test period.~~

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

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

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

~~(5) An equivalent procedure for determining fuel moisture content means a published VCS or EPA method to obtain moisture content. If the sample analysis plan calls for determining 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, hydrogen chloride, hydrogen sulfide) 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 this subpart for the same purpose.~~

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

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

~~*Fluidized bed boiler* means a boiler utilizing a fluidized bed combustion process.~~

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

~~*Fuel cell* means a boiler type in which the fuel is dropped onto suspended fixed grates and is fired in a pile. The refractory-lined fuel cell uses combustion air preheating and positioning of secondary and tertiary air injection ports to improve boiler efficiency.~~

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

~~*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.~~

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

~~*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 degrees Fahrenheit (99 degrees Celsius). *Hot water heater* also means a tankless unit that provides on demand hot water.~~

~~*Hybrid suspension grate boiler* means a boiler designed with air distributors to spread the fuel material over the entire width and depth of the boiler combustion zone. The drying and much of the combustion of the fuel takes place in suspension, and the combustion is completed on the grate or floor of the boiler.~~

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

~~*Limited-use boiler or process heater* means any boiler or process heater that burns any amount of solid, liquid, or gaseous fuels, has a rated capacity of greater than 10 MMBtu per hour heat input, and has a federally enforceable limit of no more than 876 hours per year of operation.~~

~~*Liquid fuel subcategory* includes any boiler or process heater of any design that burns more than 10 percent liquid fuel and less than 10 percent solid fuel, based on the total annual heat input to the unit.~~

~~*Liquid fuel* includes, but is not limited to, distillate oil, residual oil, on-spec used oil, and biodiesel.~~

~~*Load fraction* means the actual heat input of the boiler or process heater divided by the average operating load determined according to Table 7 to this subpart.~~

~~*Metal process furnaces* include natural gas-fired annealing furnaces, preheat furnaces, reheat furnaces, aging furnaces, heat treat furnaces, and homogenizing furnaces.~~

~~*Million Btu (MMBtu)* means one million British thermal units.~~

~~*Minimum activated carbon injection rate* means load fraction (percent) multiplied by the lowest hourly average activated carbon injection rate measured according to Table 7 to this subpart during the most recent performance test demonstrating compliance with the applicable emission limits.~~

~~*Minimum pressure drop* means the lowest hourly 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 the lowest hourly average sorbent liquid pH measured at the inlet to 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 liquid flow rate* means the lowest hourly average liquid flow rate (*e.g.,* to the PM scrubber or to the acid gas scrubber) measured according to Table 7 to this subpart during the most recent performance test demonstrating compliance with the applicable emission limit.~~

~~*Minimum scrubber pressure drop* means the lowest hourly average scrubber pressure drop measured according to Table 7 to this subpart during the most recent performance test demonstrating compliance with the applicable emission limit.~~

~~*Minimum sorbent injection rate* means load fraction (percent) multiplied by the lowest hourly average sorbent injection rate for each sorbent measured according to Table 7 to this subpart during the most recent performance test demonstrating compliance with the applicable emission limits.~~

~~*Minimum total secondary electric power* means the lowest hourly average total secondary electric power determined from the values of secondary voltage and secondary current to the electrostatic precipitator measured according to Table 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 in ASTM D1835 (incorporated by reference, *see* § 63.14); 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 mega joules (MJ) per dry standard cubic meter (910 and 1,150 Btu per dry standard cubic foot); or~~

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

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

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

~~*Other gas 1 fuel* means a gaseous fuel that is not natural gas or refinery gas and does not exceed the maximum concentration of 40 micrograms/cubic meters of mercury and 4 parts per million, by volume, of hydrogen sulfide.~~

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

~~*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. The act of entering into a contractual agreement with a supplier of natural gas established for curtailment purposes does not constitute a reason that is under the control of a facility for the purposes of this definition. An increase in the cost or unit price of natural gas does not constitute a period of natural gas curtailment or supply interruption.~~

~~*Process heater* means an enclosed device using controlled flame, and the unit's primary purpose is to transfer heat indirectly to a process material (liquid, gas, or solid) or to a heat transfer material for use in a process unit, instead of generating steam. Process heaters are devices in which the combustion gases do not come into direct contact with process materials. A device combusting solid waste, as defined in § 241.3, is not a process heater unless the device is exempt from the definition of a solid waste incineration unit as provided in section 129(g)(1) of the Clean Air Act. Process heaters do not include units used for comfort heat or space heat, food preparation for on-site consumption, or autoclaves.~~

~~*Pulverized coal boiler* means a boiler in which pulverized coal or other solid fossil fuel is introduced into an air stream that carries the coal to the combustion chamber of the boiler where it is fired in suspension.~~

~~*Qualified energy assessor* means:~~

~~(1) someone who has demonstrated capabilities to evaluate a set of the typical energy savings opportunities available in opportunity areas for steam generation and major energy using systems, including, but not limited to:~~

~~(i) Boiler combustion management.~~

~~(ii) Boiler thermal energy recovery, including~~

~~(A) Conventional feed water economizer,~~

~~(B) Conventional combustion air preheater, and~~

~~(C) Condensing economizer.~~

~~(iii) Boiler blowdown thermal energy recovery.~~

~~(iv) Primary energy resource selection, including~~

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

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

~~(v) Insulation issues.~~

~~(vi) Steam trap and steam leak management.~~

~~(vi) Condensate recovery.~~

~~(viii) Steam end-use management.~~

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

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

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

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

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

~~(v) Boiler-steam turbine cogeneration systems.~~

~~(vi) Industry specific steam end-use systems.~~

~~*Refinery gas* means any gas that is generated at a petroleum refinery and is combusted. Refinery gas includes natural gas when the natural gas is combined and combusted in any proportion with a gas generated at a refinery. Refinery gas includes gases generated from other facilities when that gas is combined and combusted in any proportion with gas generated at a refinery.~~

~~*Residual oil* means crude oil, and all fuel oil numbers 4, 5 and 6, as defined in ASTM D396-10 (incorporated by reference, see § 63.14(b)).~~

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

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

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

~~*Steam output* means (1) for a boiler that produces steam for process or heating only (no power generation), the energy content in terms of MMBtu of the boiler steam output, and (2) for a boiler that cogenerates process steam and electricity (also known as combined heat and power (CHP)), the total energy output, which is the sum of the energy content of the steam exiting the turbine and sent to process in MMBtu and the energy of the electricity generated converted to MMBtu at a rate of 10,000 Btu per kilowatt-hour generated (10 MMBtu per megawatt-hour).~~

~~*Stoker* means a unit consisting of a mechanically operated fuel feeding mechanism, a stationary or moving grate to support the burning of fuel and admit under-grate air to the fuel, an overfire air system to complete combustion, and an ash discharge system. This definition of stoker includes air swept stokers. There are two general types of stokers: Underfeed and overfeed. Overfeed stokers include mass feed and spreader stokers.~~

~~*Suspension boiler* means a unit designed to feed the fuel by means of fuel distributors. The distributors inject air at the point where the fuel is introduced into the boiler in order to spread the fuel material over the boiler width. The drying (and much of the combustion) occurs while the material is suspended in air. The combustion of the fuel material is completed on a grate or floor below. Suspension boilers almost universally are designed to have high heat release rates to dry quickly the wet fuel as it is blown into the boilers.~~

~~*Temporary boiler* means any gaseous or liquid fuel boiler that is designed to, and is capable of, being carried or moved from one location to another by means of, for example, wheels, skids, carrying handles, dollies, trailers, or platforms. A boiler is not a temporary boiler if any one of the following conditions exists:~~

~~(1) The equipment is attached to a foundation.~~

~~(2) The boiler or a replacement remains at a location for more than 12 consecutive months. Any temporary boiler that replaces a temporary boiler at a location and performs the same or similar function will be included in calculating the consecutive time period.~~

~~(3) The equipment is located at a seasonal facility and operates during the full annual operating period of the seasonal facility, remains at the facility for at least 2 years, and operates at that facility for at least 3 months each year.~~

~~(4) The equipment is moved from one location to another in an attempt to circumvent the residence time requirements of this definition.~~

~~*Tune-up* means adjustments made to a boiler in accordance with procedures supplied by the manufacturer (or an approved specialist) to optimize the combustion efficiency.~~

~~*Unit designed to burn biomass/bio-based solid subcategory* includes any boiler or process heater that burns at least 10 percent biomass or bio-based solids on an annual heat input basis in combination with solid fossil fuels, liquid fuels, or gaseous fuels.~~

~~*Unit designed to burn coal/solid fossil fuel subcategory* includes any boiler or process heater that burns any coal or other solid fossil fuel alone or at least 10 percent coal or other solid fossil fuel on an annual heat input basis in combination with liquid fuels, gaseous fuels, or less than 10 percent biomass and bio-based solids on an annual heat input basis.~~

~~*Unit designed to burn gas 1 subcategory* includes any boiler or process heater that burns only natural gas, refinery gas, and/or other gas 1 fuels; with the exception of liquid fuels burned for periodic testing not to exceed a combined total of 48 hours during any calendar year, or during periods of gas curtailment and gas supply emergencies.~~

~~*Unit designed to burn gas 2 (other) subcategory* includes any boiler or process heater that is not in the unit designed to burn gas 1 subcategory and burns any gaseous fuels either alone or in combination with less than~~

~~10 percent coal/solid fossil fuel, less than 10 percent biomass/bio-based solid fuel, and less than 10 percent liquid fuels on an annual heat input basis.~~

~~*Unit designed to burn liquid subcategory* includes any boiler or process heater that burns any liquid fuel, but less than 10 percent coal/solid fossil fuel and less than 10 percent biomass/bio-based solid fuel on an annual heat input basis, either alone or in combination with gaseous fuels. Gaseous fuel boilers and process heaters that burn liquid fuel for periodic testing of liquid fuel, maintenance, or operator training, not to exceed a combined total of 48 hours during any calendar year or during periods of maintenance, operator training, or testing of liquid fuel, not to exceed a combined total of 48 hours during any calendar year are not included in this definition. Gaseous fuel boilers and process heaters that burn liquid fuel during periods of gas curtailment or gas supply emergencies of any duration are also not included in this definition.~~

~~*Unit designed to burn liquid fuel that is a non-continental unit* means an industrial, commercial, or institutional boiler or process heater designed to burn liquid fuel located in the State of Hawaii, the Virgin Islands, Guam, American Samoa, the Commonwealth of Puerto Rico, or the Northern Mariana Islands.~~

~~*Unit designed to burn solid fuel subcategory* means any boiler or process heater that burns any solid fuel alone or at least 10 percent solid fuel on an annual heat input basis in combination with liquid fuels or gaseous fuels.~~

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

~~*Waste heat boiler* means a device that recovers normally unused energy and converts it to usable heat. Waste heat boilers are also referred to as heat recovery steam generators.~~

~~*Waste heat process heater* means an enclosed device that recovers normally unused energy and converts it to usable heat. Waste heat process heaters are also referred to as recuperative process heaters.~~

~~*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 or to absorb and neutralize acid gases, such as hydrogen chloride. A wet scrubber creates an aqueous stream or slurry as a byproduct of the emissions control process.~~

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

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~~Tables to Subpart DDDDD of Part 63~~

~~Link to an amendment published at 78 FR 7193, January 31, 2013.~~

~~Link to an amendment published at 78 FR 7195, January 31, 2013.~~

~~Link to an amendment published at 78 FR 7198, January 31, 2013.~~

~~Link to an amendment published at 78 FR 7199, January 31, 2013.~~

~~Link to an amendment published at 78 FR 7200, January 31, 2013.~~

~~Link to an amendment published at 78 FR 7201, January 31, 2013.~~

~~Link to an amendment published at 78 FR 7203, January 31, 2013.~~

~~Link to an amendment published at 78 FR 7204, January 31, 2013.~~

~~Link to an amendment published at 78 FR 7205, January 31, 2013.~~

~~Link to an amendment published at 78 FR 7205, January 31, 2013.~~

~~Link to an amendment published at 78 FR 7206, January 31, 2013.~~

~~Link to an amendment published at 78 FR 7208, January 31, 2013.~~

~~Link to an amendment published at 78 FR 7210, January 31, 2013.~~

~~As stated in § 63.7500, you must comply with the following applicable emission limits:~~

~~Table 1 to Subpart DDDDD of Part 63—Emission Limits for New or Reconstructed Boilers and Process Heaters~~ [a]

~~[Units with heat input capacity of 10 million Btu per hour or greater]~~

~~If your boiler or process heater is in this subcategory . . .~~	~~For the following pollutants . . .~~	~~The emissions must not exceed the following emission limits, except during periods of startup and shutdown . . .~~	~~Or the emissions must not exceed the following output-based limits (lb per MMBtu of steam output) . . .~~	~~Using this specified sampling volume or test run duration . . .~~
~~1. Units in all subcategories designed to burn solid fuel~~	~~a. Particulate Matter~~	~~0.0011 lb per MMBtu of heat input (30-day rolling average for units 250 MMBtu/hr or greater, 3-run average for units less than 250 MMBtu/hr)~~	~~0.0011; (30-day rolling average for units 250 MMBtu/hr or greater, 3-run average for units less than 250 MMBtu/hr)~~	~~Collect a minimum of 3 dscm per run.~~

~~If your boiler or process heater is in this subcategory . . .~~	~~For the following pollutants . . .~~	~~The emissions must not exceed the following emission limits, except during periods of startup and shutdown . . .~~	~~Or the emissions must not exceed the following output-based limits (lb per MMBtu of steam output) . . .~~	~~Using this specified sampling volume or test run duration . . .~~
—	~~b. Hydrogen Chloride~~	~~0.0022 lb per MMBtu of heat input~~	~~0.0021~~	~~For M26A, collect a minimum of 1 dscm per run; for M26 collect a minimum of 60 liters per run.~~
—	~~c. Mercury~~	~~3.5E-06 lb per MMBtu of heat input~~	~~3.4E-06~~	~~For M29, collect a minimum of 1 dscm per run; for M30A or M30B, collect a minimum sample as specified in the method; for ASTM D6784~~ [b] ~~collect a minimum of 2 dscm.~~
~~2. Units designed to burn pulverized coal/solid fossil fuel~~	~~a. Carbon monoxide (CO)~~	~~12 ppm by volume on a dry basis corrected to 3 percent oxygen~~	~~0.01~~	~~1 hr minimum sampling time, use a span value of 30 ppmv.~~
—	~~b. Dioxins/Furans~~	~~0.003 ng/dscm (TEQ) corrected to 7 percent oxygen~~	~~2.8E-12 (TEQ)~~	~~Collect a minimum of 4 dscm per run.~~
~~3. Stokers designed to burn coal/solid fossil fuel~~	~~a. CO~~	~~6 ppm by volume on a dry basis corrected to 3 percent oxygen~~	~~0.005~~	~~1 hr minimum sampling time, use a span value of 20 ppmv.~~
—	~~b. Dioxins/Furans~~	~~0.003 ng/dscm (TEQ) corrected to 7 percent oxygen~~	~~2.8E-12 (TEQ)~~	~~Collect a minimum of 4 dscm per run.~~
~~4. Fluidized bed units designed to burn coal/solid fossil fuel~~	~~a. CO~~	~~18 ppm by volume on a dry basis corrected to 3 percent oxygen~~	~~0.02~~	~~1 hr minimum sampling time, use a span value of 40 ppmv.~~
—	~~b. Dioxins/Furans~~	~~0.002 ng/dscm (TEQ) corrected to 7 percent oxygen~~	~~1.8E-12 (TEQ)~~	~~Collect a minimum of 4 dscm per run.~~
~~5. Stokers designed to burn biomass/bio-based solids~~	~~a. CO~~	~~160 ppm by volume on a dry basis corrected to 3 percent oxygen~~	~~0.13~~	~~1 hr minimum sampling time, use a span value of 400 ppmv.~~
—	~~b. Dioxins/Furans~~	~~0.005 ng/dscm (TEQ) corrected to 7 percent oxygen~~	~~4.4E-12 (TEQ)~~	~~Collect a minimum of 4 dscm per run.~~
~~6. Fluidized bed units designed to burn biomass/bio-based solids~~	~~a. CO~~	~~260 ppm by volume on a dry basis corrected to 3 percent oxygen~~	~~0.18~~	~~1 hr minimum sampling time, use a span value of 500 ppmv.~~
—	~~b. Dioxins/Furans~~	~~0.02 ng/dscm (TEQ) corrected to 7 percent oxygen~~	~~1.8E-11 (TEQ)~~	~~Collect a minimum of 4 dscm per run.~~

~~If your boiler or process heater is in this subcategory . . .~~	~~For the following pollutants . . .~~	~~The emissions must not exceed the following emission limits, except during periods of startup and shutdown . . .~~	~~Or the emissions must not exceed the following output-based limits (lb per MMBtu of steam output) . . .~~	~~Using this specified sampling volume or test run duration . . .~~
~~7. Suspension burners/Dutch Ovens designed to burn biomass/bio-based solids~~	~~a. CO~~	~~470 ppm by volume on a dry basis corrected to 3 percent oxygen~~	~~0.45~~	~~1 hr minimum sampling time, use a span value of 1000 ppmv.~~
—	~~b. Dioxins/Furans~~	~~0.2 ng/dscm (TEQ) corrected to 7 percent oxygen~~	~~1.8E-10 (TEQ)~~	~~Collect a minimum of 4 dscm per run.~~
~~8. Fuel cells designed to burn biomass/bio-based solids~~	~~a. CO~~	~~470 ppm by volume on a dry basis corrected to 3 percent oxygen~~	~~0.23~~	~~1 hr minimum sampling time, use a span value of 1000 ppmv.~~
—	~~b. Dioxins/Furans~~	~~0.003 ng/dscm (TEQ) corrected to 7 percent oxygen~~	~~2.86E-12 (TEQ)~~	~~Collect a minimum of 4 dscm per run.~~
~~9. Hybrid suspension/grate units designed to burn biomass/bio-based solids~~	~~a. CO~~	~~1,500 ppm by volume on a dry basis corrected to 3 percent oxygen~~	~~0.84~~	~~1 hr minimum sampling time, use a span value of 3000 ppmv.~~
—	~~b. Dioxins/Furans~~	~~0.2 ng/dscm (TEQ) corrected to 7 percent oxygen~~	~~1.8E-10 (TEQ)~~	~~Collect a minimum of 4 dscm per run.~~
~~10. Units designed to burn liquid fuel~~	~~a. Particulate Matter~~	~~0.0013 lb per MMBtu of heat input (30-day rolling average for residual oil-fired units 250 MMBtu/hr or greater, 3-run average for other units)~~	~~0.001; (30-day rolling average for residual oil-fired units 250 MMBtu/hr or greater, 3-run average for other units)~~	~~Collect a minimum of 3 dscm per run.~~
—	~~b. Hydrogen Chloride~~	~~0.00033 lb per MMBtu of heat input~~	~~0.0003~~	~~For M26A: Collect a minimum of 1 dscm per run; for M26, collect a minimum of 60 liters per run.~~
—	~~c. Mercury~~	~~2.1E-07 lb per MMBtu of heat input~~	~~0.2E-06~~	~~Collect enough volume to meet an in-stack detection limit data quality objective of 0.10 ug/dscm.~~
—	~~d. CO~~	~~3 ppm by volume on a dry basis corrected to 3 percent oxygen~~	~~0.0026~~	~~1 hr minimum sampling time, use a span value of 3 ppmv.~~

~~**If your boiler or process heater is in this subcategory . . .**~~	~~**For the following pollutants . . .**~~	~~**The emissions must not exceed the following emission limits, except during periods of startup and shutdown . . .**~~	~~**Or the emissions must not exceed the following output-based limits (lb per MMBtu of steam output) . . .**~~	~~**Using this specified sampling volume or test run duration . . .**~~
~~—~~	~~e. Dioxins/Furans~~	~~0.002 ng/dscm (TEQ) corrected to 7 percent oxygen~~	~~4.6E-12 (TEQ)~~	~~Collect a minimum of 4 dscm per run.~~
~~11. Units designed to burn liquid fuel located in non-continental States and territories~~	~~a. Particulate Matter~~	~~0.0013 lb per MMBtu of heat input (30-day rolling average for residual oil-fired units 250 MMBtu/hr or greater, 3-run average for other units)~~	~~0.001; (30-day rolling average for residual oil-fired units 250 MMBtu/hr or greater, 3-run average for other units)~~	~~Collect a minimum of 3 dscm per run.~~
~~—~~	~~b. Hydrogen Chloride~~	~~0.00033 lb per MMBtu of heat input~~	~~0.0003~~	~~For M26A: Collect a minimum of 1 dscm per run; for M26, collect a minimum of 60 liters per run.~~
~~—~~	~~c. Mercury~~	~~7.8E-07 lb per MMBtu of heat input~~	~~8.0E-07~~	~~For M29, collect a minimum of 3 dscm per run; for M30B, collect a minimum sample as specified in the method; for ASTM D6784~~ [b]~~collect a minimum of 3 dscm.~~
~~—~~	~~d. CO~~	~~51 ppm by volume on a dry basis corrected to 3 percent oxygen~~	~~0.043~~	~~1 hr minimum sampling time, use a span value of 100 ppmv.~~
~~—~~	~~e. Dioxins/Furans~~	~~0.002 ng/dscm (TEQ) corrected to 7 percent oxygen~~	~~4.6E-12(TEQ)~~	~~Collect a minimum of 3 dscm per run.~~
~~12. Units designed to burn gas 2 (other) gases~~	~~a. Particulate Matter~~	~~0.0067 lb per MMBtu of heat input (30-day rolling average for units 250 MMBtu/hr or greater, 3-run average for units less than 250 MMBtu/hr)~~	~~.004; (30-day rolling average for units 250 MMBtu/hr or greater, 3-run average for units less than 250 MMBtu/hr)~~	~~Collect a minimum of 1 dscm per run.~~
~~—~~	~~b. Hydrogen Chloride~~	~~0.0017 lb per MMBtu of heat input~~	~~.003~~	~~For M26A, Collect a minimum of 1 dscm per run; for M26, collect a minimum of 60 liters per run.~~

~~**If your boiler or process heater is in this subcategory . . .**~~	~~**For the following pollutants . . .**~~	~~**The emissions must not exceed the following emission limits, except during periods of startup and shutdown . . .**~~	~~**Or the emissions must not exceed the following output-based limits (lb per MMBtu of steam output) . . .**~~	~~**Using this specified sampling volume or test run duration . . .**~~
~~—~~	~~c. Mercury~~	~~7.9E-06 lb per MMBtu of heat input~~	~~2.0E-07~~	~~For M29, collect a minimum of 1 dscm per run; for M30A or M30B, collect a minimum sample as specified in the method; for ASTM D6784~~ [b] ~~collect a minimum of 2 dscm.~~
~~—~~	~~d. CO~~	~~3 ppm by volume on a dry basis corrected to 3 percent oxygen~~	~~0.002~~	~~1 hr minimum sampling time, use a span value of 10 ppmv.~~
~~—~~	~~e. Dioxins/Furans~~	~~0.08 ng/dscm (TEQ) corrected to 7 percent oxygen~~	~~4.1E-12 (TEQ)~~	~~Collect a minimum of 4 dscm per run~~

[a] ~~If your affected source is a new or reconstructed affected source that commenced construction or reconstruction after June 4, 2010, and before May 20, 2011, you may comply with the emission limits in Table 12 to this subpart until March 21, 2014. On and after March 21, 2014, you must comply with the emission limits in Table 1 to this subpart.~~

[b] ~~Incorporated by reference, see § 63.14.~~

~~As stated in § 63.7500, you must comply with the following applicable emission limits:~~

~~Table 2 to Subpart DDDDD of Part 63—Emission Limits for Existing Boilers and Process Heaters~~

~~[Units with heat input capacity of 10 million Btu per hour or greater]~~

~~**If your boiler or process heater is in this subcategory . . .**~~	~~**For the following pollutants . . .**~~	~~**The emissions must not exceed the following emission limits, except during periods of startup and shutdown . . .**~~	~~**The emissions must not exceed the following output-based limits (lb per MMBtu of steam output) . . .**~~	~~**Using this specified sampling volume or test run duration . . .**~~
~~1. Units in all subcategories designed to burn solid fuel~~	~~a. Particulate Matter~~	~~0.039 lb per MMBtu of heat input (30-day rolling average for units 250 MMBtu/hr or greater, 3-run average for units less than 250 MMBtu/hr)~~	~~0.038; (30-day rolling average for units 250 MMBtu/hr or greater, 3-run average for units less than 250 MMBtu/hr)~~	~~Collect a minimum of 1 dscm per run.~~

~~If your boiler or process heater is in this subcategory . . .~~	~~For the following pollutants . . .~~	~~The emissions must not exceed the following emission limits, except during periods of startup and shutdown . . .~~	~~The emissions must not exceed the following output-based limits (lb per MMBtu of steam output) . . .~~	~~Using this specified sampling volume or test run duration . . .~~
—	~~b. Hydrogen Chloride~~	~~0.035 lb per MMBtu of heat input~~	~~0.04~~	~~For M26A, collect a minimum of 1 dscm per run; for M26, collect a minimum of 60 liters per run.~~
—	~~c. Mercury~~	~~4.6E-06 lb per MMBtu of heat input~~	~~4.5E-06~~	~~For M29, collect a minimum of 1 dscm per run; for M30A or M30B, collect a minimum sample as specified in the method; for ASTM D6784 [a] collect a minimum of 2 dscm.~~
~~2. Pulverized coal units designed to burn pulverized coal/solid fossil fuel~~	~~a. CO~~	~~160 ppm by volume on a dry basis corrected to 3 percent oxygen~~	~~0.14~~	~~1 hr minimum sampling time, use a span value of 300 ppmv.~~
—	~~b. Dioxins/Furans~~	~~0.004 ng/dscm (TEQ) corrected to 7 percent oxygen~~	~~3.7E-12 (TEQ)~~	~~Collect a minimum of 4 dscm per run.~~
~~3. Stokers designed to burn coal/solid fossil fuel~~	~~a. CO~~	~~270 ppm by volume on a dry basis corrected to 3 percent oxygen~~	~~0.25~~	~~1 hr minimum sampling time, use a span value of 500 ppmv.~~
—	~~b. Dioxins/Furans~~	~~0.003 ng/dscm (TEQ) corrected to 7 percent oxygen~~	~~2.8E-12 (TEQ)~~	~~Collect a minimum of 4 dscm per run.~~
~~4. Fluidized bed units designed to burn coal/solid fossil fuel~~	~~a. CO~~	~~82 ppm by volume on a dry basis corrected to 3 percent oxygen~~	~~0.08~~	~~1 hr minimum sampling time, use a span value of 200 ppmv~~
—	~~b. Dioxins/Furans~~	~~0.002 ng/dscm (TEQ) corrected to 7 percent oxygen~~	~~1.8E-12 (TEQ)~~	~~Collect a minimum of 4 dscm per run.~~
~~5. Stokers designed to burn biomass/bio-based solid~~	~~a. CO~~	~~490 ppm by volume on a dry basis corrected to 3 percent oxygen~~	~~0.35~~	~~1 hr minimum sampling time, use a span value of 1000 ppmv.~~
—	~~b. Dioxins/Furans~~	~~0.005 ng/dscm (TEQ) corrected to 7 percent oxygen~~	~~4.4E-12 (TEQ)~~	~~Collect a minimum of 4 dscm per run.~~
~~6. Fluidized bed units designed to burn biomass/bio-based solid~~	~~a. CO~~	~~430 ppm by volume on a dry basis corrected to 3 percent oxygen~~	~~0.28~~	~~1 hr minimum sampling time, use a span value of 850 ppmv.~~
—	~~b. Dioxins/Furans~~	~~0.02 ng/dscm (TEQ) corrected to 7 percent oxygen~~	~~1.8E-11(TEQ)~~	~~Collect a minimum of 4 dscm per run.~~

~~If your boiler or process heater is in this subcategory . . .~~	~~For the following pollutants . . .~~	~~The emissions must not exceed the following emission limits, except during periods of startup and shutdown . . .~~	~~The emissions must not exceed the following output-based limits (lb per MMBtu of steam output) . . .~~	~~Using this specified sampling volume or test run duration . . .~~
~~7. Suspension burners/Dutch Ovens designed to burn biomass/bio-based solid~~	~~a. CO~~	~~470 ppm by volume on a dry basis corrected to 3 percent oxygen~~	~~0.45~~	~~1 hr minimum sampling time, use a span value of 1000 ppmv.~~
—	~~b. Dioxins/Furans~~	~~0.2 ng/dscm (TEQ) corrected to 7 percent oxygen~~	~~1.8E-10 (TEQ)~~	~~Collect a minimum of 4 dscm per run.~~
~~8. Fuel cells designed to burn biomass/bio-based solid~~	~~a. CO~~	~~690 ppm by volume on a dry basis corrected to 3 percent oxygen~~	~~0.34~~	~~1 hr minimum sampling time, use a span value of 1300 ppmv.~~
—	~~b. Dioxins/Furans~~	~~4 ng/dscm (TEQ) corrected to 7 percent oxygen~~	~~3.5E-09 (TEQ)~~	~~Collect a minimum of 4 dscm per run.~~
~~9. Hybrid suspension/grate units designed to burn biomass/bio-based solid~~	~~a. CO~~	~~3,500 ppm by volume on a dry basis corrected to 3 percent oxygen~~	~~2.0~~	~~1 hr minimum sampling time, use a span value of 7000 ppmv.~~
—	~~b. Dioxins/Furans~~	~~0.2 ng/dscm (TEQ) corrected to 7 percent oxygen~~	~~1.8E-10 (TEQ)~~	~~Collect a minimum of 4 dscm per run.~~
~~10. Units designed to burn liquid fuel~~	~~a. Particulate Matter~~	~~0.0075 lb per MMBtu of heat input (30-day rolling average for residual oil-fired units 250 MMBtu/hr or greater, 3-run average for other units)~~	~~0.0073; (30-day rolling average for residual oil-fired units 250 MMBtu/hr or greater, 3-run average for other units)~~	~~Collect a minimum of 1 dscm per run.~~
—	~~b. Hydrogen Chloride~~	~~0.00033 lb per MMBtu of heat input~~	~~0.0003~~	~~For M26A, collect a minimum of 1 dscm per run; for M26, collect a minimum of 200 liters per run.~~
—	~~c. Mercury~~	~~3.5E-06 lb per MMBtu of heat input~~	~~3.3E-06~~	~~For M29, collect a minimum of 1 dscm per run; for M30A or M30B collect a minimum sample as specified in the method, for ASTM D6784~~ [a] ~~collect a minimum of 2 dscm.~~
—	~~d. CO~~	~~10 ppm by volume on a dry basis corrected to 3 percent oxygen~~	~~0.0083~~	~~1 hr minimum sampling time, use a span value of 20 ppmv.~~

~~If your boiler or process heater is in this subcategory . . .~~	~~For the following pollutants . . .~~	~~The emissions must not exceed the following emission limits, except during periods of startup and shutdown . . .~~	~~The emissions must not exceed the following output-based limits (lb per MMBtu of steam output) . . .~~	~~Using this specified sampling volume or test run duration . . .~~
~~—~~	~~e. Dioxins/Furans~~	~~4 ng/dscm (TEQ) corrected to 7 percent oxygen~~	~~9.2E-09 (TEQ)~~	~~Collect a minimum of 1 dscm per run.~~
~~11. Units designed to burn liquid fuel located in non-continental States and territories~~	~~a. Particulate Matter~~	~~0.0075 lb per MMBtu of heat input (30-day rolling average for residual oil-fired units 250 MMBtu/hr or greater, 3-run average for other units)~~	~~0.0073; (30-day rolling average for residual oil-fired units 250 MMBtu/hr or greater, 3-run average for other units)~~	~~Collect a minimum of 1 dscm per run.~~
~~—~~	~~b. Hydrogen Chloride~~	~~0.00033 lb per MMBtu of heat input~~	~~0.0003~~	~~For M26A, collect a minimum of 1 dscm per run; for M26, collect a minimum of 200 liters per run.~~
~~—~~	~~c. Mercury~~	~~7.8E-07 lb per MMBtu of heat input~~	~~8.0E-07~~	~~For M29, collect a minimum of 1 dscm per run; for M30A or M30B, collect a minimum sample as specified in the method; for ASTM D6784~~ [a] ~~collect a minimum of 2 dscm.~~
~~—~~	~~d. CO~~	~~160 ppm by volume on a dry basis corrected to 3 percent oxygen~~	~~0.13~~	~~1 hr minimum sampling time, use a span value of 300 ppmv.~~
~~—~~	~~e. Dioxins/Furans~~	~~4 ng/dscm (TEQ) corrected to 7 percent oxygen~~	~~9.2E-09 (TEQ)~~	~~Collect a minimum of 1 dscm per run.~~
~~12. Units designed to burn gas 2 (other) gases~~	~~a. Particulate Matter~~	~~0.043 lb per MMBtu of heat input (30-day rolling average for units 250 MMBtu/hr or greater, 3-run average for units less than 250 MMBtu/hr)~~	~~0.026; (30-day rolling average for units 250 MMBtu/hr or greater, 3-run average for units less than 250 MMBtu/hr)~~	~~Collect a minimum of 1 dscm per run.~~
~~—~~	~~b. Hydrogen Chloride~~	~~0.0017 lb per MMBtu of heat input~~	~~0.001~~	~~For M26A, collect a minimum of 1 dscm per run; for M26, collect a minimum of 60 liters per run.~~

~~If your boiler or process heater is in this subcategory . . .~~	~~For the following pollutants . . .~~	~~The emissions must not exceed the following emission limits, except during periods of startup and shutdown . . .~~	~~The emissions must not exceed the following output-based limits (lb per MMBtu of steam output) . . .~~	~~Using this specified sampling volume or test run duration . . .~~
—	~~c. Mercury~~	~~1.3E-05 lb per MMBtu of heat input~~	~~7.8E-06~~	~~For M29, collect a minimum of 1 dscm per run; for M30A or M30B, collect a minimum sample as specified in the method; for ASTM D6784 [a] collect a minimum of 2 dscm.~~
—	~~d. CO~~	~~9 ppm by volume on a dry basis corrected to 3 percent oxygen~~	~~0.005~~	~~1 hr minimum sampling time, use a span value of 20 ppmv.~~
—	~~e. Dioxins/Furans~~	~~0.08 ng/dscm (TEQ) corrected to 7 percent oxygen~~	~~3.9E-11 (TEQ)~~	~~Collect a minimum of 4 dscm per run.~~

~~[a] Incorporated by reference, see § 63.14.~~

~~As stated in § 63.7500, you must comply with the following applicable work practice standards:~~

~~Table 3 to Subpart DDDDD of Part 63—Work Practice Standards~~

~~If your unit is . . .~~	~~You must meet the following . . .~~
~~1. A new or existing boiler or process heater with heat input capacity of less than 10 million Btu per hour or a limited use boiler or process heater~~	~~Conduct a tune-up of the boiler or process heater biennially as specified in § 63.7540.~~
~~2. A new or existing boiler or process heater in either the Gas 1 or Metal Process Furnace subcategory with heat input capacity of 10 million Btu per hour or greater~~	~~Conduct a tune-up of the boiler or process heater annually as specified in § 63.7540.~~
~~3. An existing boiler or process heater located at a major source facility~~	~~Must have a one-time energy assessment performed on the major source facility by qualified energy assessor. An energy assessment completed on or after January 1, 2008, that meets or is amended to meet the energy assessment requirements in this table, satisfies the energy assessment requirement. The energy assessment must include:~~
—	~~a. A visual inspection of the boiler or process heater system.~~
—	~~b. An evaluation of operating characteristics of the facility, specifications of energy using systems, operating and maintenance procedures, and unusual operating constraints,~~
—	~~c. An inventory of major energy consuming systems,~~
—	~~d. A review of available architectural and engineering plans, facility operation and maintenance procedures and logs, and fuel usage,~~
—	~~e. A review of the facility's energy management practices and provide recommendations for improvements consistent with the definition of energy management practices,~~

~~**If your unit is . . .**~~	~~**You must meet the following . . .**~~
—	~~f. A list of major energy conservation measures,~~
—	~~g. A list of the energy savings potential of the energy conservation measures identified, and~~
—	~~h. A comprehensive report detailing the ways to improve efficiency, the cost of specific improvements, benefits, and the time frame for recouping those investments.~~
~~4. An existing or new unit subject to emission limits in Tables 1, 2, or 12 of this subpart.~~	~~Minimize the unit's startup and shutdown periods following the manufacturer's recommended procedures. If manufacturer's recommended procedures are not available, you must follow recommended procedures for a unit of similar design for which manufacturer's recommended procedures are available.~~

~~As stated in § 63.7500, you must comply with the applicable operating limits:~~

~~Table 4 to Subpart DDDDD of Part 63—Operating Limits for Boilers and Process Heaters~~

~~**If you demonstrate compliance using . . .**~~	~~**You must meet these operating limits . . .**~~
~~1. Wet PM scrubber control~~	~~Maintain the 12-hour block average pressure drop and the 12-hour block average liquid flow rate at or above the lowest 1-hour average pressure drop and the lowest 1-hour average liquid flow rate, respectively, measured during the most recent performance test demonstrating compliance with the PM emission limitation according to § 63.7530(b) and Table 7 to this subpart.~~
~~2. Wet acid gas (HCl) scrubber control~~	~~Maintain the 12-hour block average effluent pH at or above the lowest 1-hour average pH and the 12-hour block average liquid flow rate at or above the lowest 1-hour average liquid flow rate measured during the most recent performance test demonstrating compliance with the HCl emission limitation according to § 63.7530(b) and Table 7 to this subpart.~~
~~3. Fabric filter control on units not required to install and operate a PM CEMS~~	~~a. Maintain opacity to less than or equal to 10 percent opacity (daily block average); or~~ ~~b. Install and operate a bag leak detection system according to § 63.7525 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.~~
~~4. Electrostatic precipitator control on units not required to install and operate a PM CEMS~~	~~a. This option is for boilers and process heaters that operate dry control systems (*i.e.*,an ESP without a wet scrubber). Existing and new boilers and process heaters must maintain opacity to less than or equal to 10 percent opacity (daily block average); or~~
—	~~b. This option is only for boilers and process heaters not subject to PM CEMS or continuous compliance with an opacity limit (i.e., COMS). Maintain the minimum total secondary electric power input of the electrostatic precipitator at or above the operating limits established during the performance test according to § 63.7530(b) and Table 7 to this subpart.~~
~~5. Dry scrubber or carbon injection control~~	~~Maintain the minimum sorbent or carbon injection rate as defined in § 63.7575 of this subpart.~~
~~6. Any other add-on air pollution control type on units not required to install and operate a PM CEMS~~	~~This option is for boilers and process heaters that operate dry control systems. Existing and new boilers and process heaters must maintain opacity to less than or equal to 10 percent opacity (daily block average).~~
~~7. Fuel analysis~~	~~Maintain the fuel type or fuel mixture such that the applicable emission rates calculated according to § 63.7530(c)(1), (2) and/or (3) is less than the applicable emission limits.~~

~~**If you demonstrate compliance using . . .**~~	~~**You must meet these operating limits . . .**~~
~~8. Performance testing~~	~~For boilers and process heaters that demonstrate compliance with a performance test, maintain the operating load of each unit such that is does not exceed 110 percent of the average operating load recorded during the most recent performance test.~~
~~9. Continuous Oxygen Monitoring System~~	~~For boilers and process heaters subject to a carbon monoxide emission limit that demonstrate compliance with an O_2CEMS as specified in § 63.7525(a), maintain the oxygen level of the stack gas such that it is not below the lowest hourly average oxygen concentration measured during the most recent CO performance test.~~

~~As stated in § 63.7520, you must comply with the following requirements for performance testing for existing, new or reconstructed affected sources:~~

~~Table 5 to Subpart DDDDD of Part 63—Performance Testing Requirements~~

~~**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~~ ~~b. Determine velocity and volumetric flow-rate of the stack gas.~~	~~Method 1 at 40 CFR part 60, appendix A-1 of this chapter.~~ ~~Method 2, 2F, or 2G at 40 CFR part 60, appendix A-1 or A-2 to part 60 of this chapter.~~
—	~~c. Determine oxygen or carbon dioxide concentration of the stack gas~~	~~Method 3A or 3B at 40 CFR part 60, appendix A-2 to part 60 of this chapter, or ANSI/ASME PTC 19.10-1981.[a]~~
—	~~d. Measure the moisture content of the stack gas~~	~~Method 4 at 40 CFR part 60, appendix A-3 of this chapter.~~
—	~~e. Measure the particulate matter emission concentration~~	~~Method 5 or 17 (positive pressure fabric filters must use Method 5D) at 40 CFR part 60, appendix A-3 or A-6 of this chapter.~~
—	~~f. Convert emissions concentration to lb per MMBtu emission rates~~	~~Method 19 F-factor methodology at 40 CFR part 60, appendix A-7 of this chapter.~~
~~2. Hydrogen chloride~~	~~a. Select sampling ports location and the number of traverse points~~	~~Method 1 at 40 CFR part 60, appendix A-1 of this chapter.~~
—	~~b. Determine velocity and volumetric flow-rate of the stack gas~~	~~Method 2, 2F, or 2G at 40 CFR part 60, appendix A-2 of this chapter.~~
—	~~c. Determine oxygen or carbon dioxide concentration of the stack gas~~	~~Method 3A or 3B at 40 CFR part 60, appendix A-2 of this chapter, or ANSI/ASME PTC 19.10-1981.[a]~~
—	~~d. Measure the moisture content of the stack gas~~	~~Method 4 at 40 CFR part 60, appendix A-3 of this chapter.~~
—	~~e. Measure the hydrogen chloride emission concentration~~	~~Method 26 or 26A (M26 or M26A) at 40 CFR part 60, appendix A-8 of this chapter.~~

~~To conduct a performance test for the following pollutant...~~	~~You must...~~	~~Using...~~
—	~~f. Convert emissions concentration to lb per MMBtu emission rates~~	~~Method 19 F-factor methodology at 40 CFR part 60, appendix A-7 of this chapter.~~
~~3. Mercury~~	~~a. Select sampling ports location and the number of traverse points~~	~~Method 1 at 40 CFR part 60, appendix A-1 of this chapter.~~
—	~~b. Determine velocity and volumetric flow-rate of the stack gas~~	~~Method 2, 2F, or 2G at 40 CFR part 60, appendix A-1 or A-2 of this chapter.~~
—	~~c. Determine oxygen or carbon dioxide concentration of the stack gas~~	~~Method 3A or 3B at 40 CFR part 60, appendix A-1 of this chapter, or ANSI/ASME PTC 19.10-1981.~~[a]
—	~~d. Measure the moisture content of the stack gas~~	~~Method 4 at 40 CFR part 60, appendix A-3 of this chapter.~~
—	~~e. Measure the mercury emission concentration~~	~~Method 29, 30A, or 30B (M29, M30A, or M30B) at 40 CFR part 60, appendix A-8 of this chapter or Method 101A at 40 CFR part 60, appendix B of this chapter, or ASTM Method D6784.~~[a]
—	~~f. Convert emissions concentration to lb per MMBtu emission rates~~	~~Method 19 F-factor methodology at 40 CFR part 60, appendix A-7 of this chapter.~~
~~4. CO~~	~~a. Select the sampling ports location and the number of traverse points~~	~~Method 1 at 40 CFR part 60, appendix A-1 of this chapter.~~
—	~~b. Determine oxygen concentration of the stack gas~~	~~Method 3A or 3B at 40 CFR part 60, appendix A-3 of this chapter, or ASTM D6522-00 (Reapproved 2005), or ANSI/ASME PTC 19.10-1981.~~[a]
—	~~c. Measure the moisture content of the stack gas~~	~~Method 4 at 40 CFR part 60, appendix A-3 of this chapter.~~
—	~~d. Measure the CO emission concentration~~	~~Method 10 at 40 CFR part 60, appendix A-4 of this chapter. Use a span value of 2 times the concentration of the applicable emission limit.~~
~~5. Dioxins/Furans~~	~~a. Select the sampling ports location and the number of traverse points~~	~~Method 1 at 40 CFR part 60, appendix A-1 of this chapter.~~
—	~~b. Determine oxygen concentration of the stack gas~~	~~Method 3A or 3B at 40 CFR part 60, appendix A-3 of this chapter, or ASTM D6522-00 (Reapproved 2005),~~[a]~~or ANSI/ASME PTC 19.10-1981.~~[a]
—	~~c. Measure the moisture content of the stack gas~~	~~Method 4 at 40 CFR part 60, appendix A-3 of this chapter.~~
—	~~d. Measure the dioxins/furans emission concentration~~	~~Method 23 at 40 CFR part 60, appendix A-7 of this chapter.~~
—	~~e. Multiply the measured dioxins/furans emission concentration by the appropriate toxic equivalency factor~~	~~Table 11 of this subpart.~~

[a] ~~Incorporated by reference, see § 63.14.~~

~~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 (as defined in § 63.7575) may be used in lieu of the prescribed methods at the discretion of the source owner or operator:~~

~~Table 6 to Subpart DDDDD of Part 63—Fuel Analysis Requirements~~

~~To conduct a fuel analysis for the following pollutant . . .~~	~~You must . . .~~	~~Using . . .~~
~~1. Mercury~~	~~a. Collect fuel samples~~	~~Procedure in § 63.7521(c) or ASTM D2234/D2234M [a](for coal) or ASTM D6323 [a](for biomass), or equivalent.~~
~~—~~	~~b. Composite fuel samples~~	~~Procedure in § 63.7521(d) or equivalent.~~
~~—~~	~~c. Prepare composited fuel samples~~	~~EPA SW-846-3050B [a](for solid samples), EPA SW-846-3020A [a](for liquid samples), ASTM D2013/D2013M [a](for coal), ASTM D5198 [a](for biomass), or equivalent.~~
~~—~~	~~d. Determine heat content of the fuel type~~	~~ASTM D5865 [a](for coal) or ASTM E711 [a](for biomass), or equivalent.~~
~~—~~	~~e. Determine moisture content of the fuel type~~	~~ASTM D3173 [a]or ASTM E871,[a]or equivalent.~~
~~—~~	~~f. Measure mercury concentration in fuel sample~~	~~ASTM D6722 [a](for coal), EPA SW-846-7471B [a](for solid samples), or EPA SW-846-7470A [a](for liquid samples), or equivalent.~~
~~—~~	~~g. Convert concentration into units of pounds of pollutant per MMBtu of heat content~~	
~~2. Hydrogen Chloride~~	~~a. Collect fuel samples~~	~~Procedure in § 63.7521(c) or ASTM D2234/D2234M [a](for coal) or ASTM D6323 [a](for biomass), or equivalent.~~
~~—~~	~~b. Composite fuel samples~~	~~Procedure in § 63.7521(d) or equivalent.~~
~~—~~	~~c. Prepare composited fuel samples~~	~~EPA SW-846-3050B [a](for solid samples), EPA SW-846-3020A [a](for liquid samples), ASTM D2013/D2013M [a](for coal), or ASTM D5198 [a](for biomass), or equivalent.~~
~~—~~	~~d. Determine heat content of the fuel type~~	~~ASTM D5865 [a](for coal) or ASTM E711 [a](for biomass), or equivalent.~~
~~—~~	~~e. Determine moisture content of the fuel type~~	~~ASTM D3173 [a]or ASTM E871,[a]or equivalent.~~
~~—~~	~~f. Measure chlorine concentration in fuel sample~~	~~EPA SW-846-9250,[a]ASTM D6721 [a](for coal), or ASTM E776 [a](for biomass), or equivalent.~~
~~—~~	~~g. Convert concentrations into units of pounds of pollutant per MMBtu of heat content~~	
~~3. Mercury Fuel Specification for other gas 1 fuels~~	~~a. Measure mercury concentration in the fuel sample~~ ~~b. Convert concentration to unit of micrograms/cubic meter~~	~~ASTM D5954,[a]~~ ~~ASTM D6350,[a]ISO 6978-1:2003(E),[a]or ISO 6978-2:2003(E) [a], or equivalent.~~

~~To conduct a fuel analysis for the following pollutant . . .~~	~~You must . . .~~	~~Using . . .~~
~~4. Hydrogen Sulfide Fuel Specification for other gas 1 fuels~~	~~a. Measure total hydrogen sulfide~~ ~~b. Convert to ppm~~	~~ASTM D4084a or equivalent.~~

~~[a] Incorporated by reference, see § 63.14.~~

~~As stated in § 63.7520, you must comply with the following requirements for establishing operating limits:~~

~~Table 7 to Subpart DDDDD of Part 63—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 or mercury~~	~~a. Wet scrubber operating parameters~~	~~i. Establish a site-specific minimum pressure drop and minimum flow rate operating limit according to § 63.7530(b)~~	~~(1) Data from the pressure drop and liquid flow rate monitors and the particulate matter or mercury 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 lowest hourly average pressure drop and liquid flow rate by computing the hourly averages using all of the 15-minute readings taken during each performance test.~~
—	~~b. Electrostatic precipitator operating parameters (option only for units that operate wet scrubbers)~~	~~i. Establish a site-specific minimum total secondary electric power input according to § 63.7530(b)~~	~~(1) Data from the voltage and secondary amperage monitors during the particulate matter or mercury performance test~~	~~(a) You must collect secondary voltage and secondary amperage for each ESP cell and calculate total secondary electric power input data every 15 minutes during the entire period of the performance tests;~~
—				~~(b) Determine the average total secondary electric power input by computing the hourly averages using all of the 15-minute readings taken during each performance test.~~
~~2. Hydrogen Chloride~~	~~a. Wet scrubber operating parameters~~	~~i. Establish site-specific minimum pressure drop, effluent pH, and flow rate operating limits according to § 63.7530(b)~~	~~(1) Data from the pressure drop, pH, and liquid flow-rate monitors and the hydrogen chloride performance test~~	~~(a) You must collect pH 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 hourly average pH and liquid flow rate by computing the hourly averages using all of the 15-minute readings taken during each performance test.~~
—	~~b. Dry scrubber operating parameters~~	~~i. Establish a site-specific minimum sorbent injection rate operating limit according to § 63.7530(b). If different acid gas sorbents are used during the hydrogen chloride performance test, the average value for each sorbent becomes the site-specific operating limit for that sorbent~~	~~(1) Data from the sorbent injection rate monitors and hydrogen chloride or mercury performance test~~	~~(a) You must collect sorbent injection rate data every 15 minutes during the entire period of the performance tests;~~ ~~(b) Determine the hourly average sorbent injection rate by computing the hourly averages using all of the 15-minute readings taken during each performance test.~~
—				~~(c) Determine the lowest hourly average of the three test run averages established during the performance test as your operating limit. When your unit operates at lower loads, multiply your sorbent injection rate by the load fraction (e.g., for 50 percent load, multiply the injection rate operating limit by 0.5) to determine the required injection rate.~~
~~3. Mercury and dioxins/furans~~	~~a. Activated carbon injection~~	~~i. Establish a site-specific minimum activated carbon injection rate operating limit according to § 63.7530(b)~~	~~(1) Data from the activated carbon rate monitors and mercury and dioxins/furans performance tests~~	~~(a) You must collect activated carbon injection rate data every 15 minutes during the entire period of the performance tests;~~
				~~(b) Determine the hourly average activated carbon injection rate by computing the hourly averages using all of the 15-minute readings taken during each performance test.~~

~~If you have an applicable emission limit for . . .~~	~~And your operating limits are based on . . .~~	~~You must . . .~~	~~Using . . .~~	~~According to the following requirements~~
—				~~(c) Determine the lowest hourly average established during the performance test as your operating limit. When your unit operates at lower loads, multiply your activated carbon injection rate by the load fraction (e.g., actual heat input divided by heat input during performance test, for 50 percent load, multiply the injection rate operating limit by 0.5) to determine the required injection rate.~~
~~4. Carbon monoxide~~	~~a. Oxygen~~	~~i. Establish a unit-specific limit for minimum oxygen level according to § 63.7520~~	~~(1) Data from the oxygen monitor specified in § 63.7525(a)~~	~~(a) You must collect oxygen data every 15 minutes during the entire period of the performance tests;~~
—				~~(b) Determine the hourly average oxygen concentration by computing the hourly averages using all of the 15-minute readings taken during each performance test.~~
—				~~(c) Determine the lowest hourly average established during the performance test as your minimum operating limit.~~
~~5. Any pollutant for which compliance is demonstrated by a performance test~~	~~a. Boiler or process heater operating load~~	~~i. Establish a unit specific limit for maximum operating load according to § 63.7520(c)~~	~~(1) Data from the operating load monitors or from steam generation monitors~~	~~(a) You must collect operating load or steam generation data every 15 minutes during the entire period of the performance test.~~
—				~~(b) Determine the average operating load by computing the hourly averages using all of the 15-minute readings taken during each performance test.~~
—				~~(c) Determine the average of the three test run averages during the performance test, and multiply this by 1.1 (110 percent) as your operating limit.~~

~~As stated in § 63.7540, you must show continuous compliance with the emission limitations for affected sources according to the following:~~

~~Table 8 to Subpart DDDDD of Part 63—Demonstrating Continuous Compliance~~

~~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(c) and § 63.7535; and~~
—	~~b. Reducing the opacity monitoring data to 6-minute averages; and~~
—	~~c. Maintaining opacity to less than or equal to 10 percent (daily block average).~~
~~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~~
—	~~b. Reducing the data to 12-hour block averages; and~~
—	~~c. Maintaining the 12-hour average pressure drop and liquid flow-rate at or above the operating limits established during the performance test according to § 63.7530(b).~~
~~4. Wet Scrubber pH~~	~~a. Collecting the pH monitoring system data according to §§ 63.7525 and 63.7535; and~~
—	~~b. Reducing the data to 12-hour block averages; and~~
—	~~c. Maintaining the 12-hour average pH at or above the operating limit established during the performance test according to § 63.7530(b).~~
~~5. Dry Scrubber Sorbent or Carbon Injection Rate~~	~~a. Collecting the sorbent or carbon injection rate monitoring system data for the dry scrubber according to §§ 63.7525 and 63.7535; and~~
—	~~b. Reducing the data to 12-hour block averages; and~~
—	~~c. Maintaining the 12-hour average sorbent or carbon injection rate at or above the minimum sorbent or carbon injection rate as defined in § 63.7575.~~
~~6. Electrostatic Precipitator Total Secondary Electric Power Input~~	~~a. Collecting the total secondary electric power input monitoring system data for the electrostatic precipitator according to §§ 63.7525 and 63.7535; and~~
—	~~b. Reducing the data to 12-hour block averages; and~~
—	~~c. Maintaining the 12-hour average total secondary electric power input at or above the operating limits established during the performance test according to § 63.7530(b).~~
~~7. Fuel Pollutant Content~~	~~a. Only burning the fuel types and fuel mixtures used to demonstrate compliance with the applicable emission limit according to § 63.7530(b) or (c) as applicable; and~~
—	~~b. Keeping monthly records of fuel use according to § 63.7540(a).~~
~~8. Oxygen content~~	~~a. Continuously monitor the oxygen content in the combustion exhaust according to § 63.7525(a).~~
—	~~b. Reducing the data to 12-hour block averages; and~~
—	~~c. Maintain the 12-hour block average oxygen content in the exhaust at or above the lowest hourly average oxygen level measured during the most recent carbon monoxide performance test.~~
~~9. Boiler or process heater operating load~~	~~a. Collecting operating load data or steam generation data every 15 minutes.~~

~~If you must meet the following operating limits or work practice standards . . .~~	~~You must demonstrate continuous compliance by . . .~~
~~—~~	~~b. Reducing the data to 12-hour block averages; and~~
~~—~~	~~c. Maintaining the 12-hour average operating load at or below the operating limit established during the performance test according to § 63.7520(c).~~

~~As stated in § 63.7550, you must comply with the following requirements for reports:~~

~~Table 9 to Subpart DDDDD of Part 63—Reporting Requirements~~

~~You must submit a(n)~~	~~The report must contain . . .~~	~~You must submit the report . . .~~
~~1. Compliance report~~	~~a. Information required in § 63.7550(c)(1) through (12); and~~	~~Semiannually, annually, or biennially 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 3 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) where you are not using a CMS to comply with that emission limit or operating limit, or a deviation from a work practice standard during the reporting period, the report must contain the information in § 63.7550(d); and~~	
~~—~~	~~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), or otherwise not operating, the report must contain the information in § 63.7550(e)~~	

~~As stated in § 63.7565, you must comply with the applicable General Provisions according to the following:~~

~~Table 10 to Subpart DDDDD of Part 63—Applicability of General Provisions to Subpart DDDDD~~

~~Citation~~	~~Subject~~	~~Applies to subpart DDDDD~~
~~§ 63.1~~	~~Applicability~~	~~Yes.~~
~~§ 63.2~~	~~Definitions~~	~~Yes. Additional terms defined in § 63.7575~~
~~§ 63.3~~	~~Units and Abbreviations~~	~~Yes.~~
~~§ 63.4~~	~~Prohibited Activities and Circumvention~~	~~Yes.~~
~~§ 63.5~~	~~Preconstruction Review and Notification Requirements~~	~~Yes.~~
~~§ 63.6(a), (b)(1)-(b)(5), (b)(7), (c)~~	~~Compliance with Standards and Maintenance Requirements~~	~~Yes.~~
~~§ 63.6(e)(1)(i)~~	~~General duty to minimize emissions.~~	~~No. See § 63.7500(a)(3) for the general duty requirement.~~
~~§ 63.6(e)(1)(ii)~~	~~Requirement to correct malfunctions as soon as practicable.~~	~~No.~~
~~§ 63.6(e)(3)~~	~~Startup, shutdown, and malfunction plan requirements.~~	~~No.~~
~~§ 63.6(f)(1)~~	~~Startup, shutdown, and malfunction exemptions for compliance with non-opacity emission standards.~~	~~No.~~
~~§ 63.6(f)(2) and (3)~~	~~Compliance with non-opacity emission standards.~~	~~Yes.~~
~~§ 63.6(g)~~	~~Use of alternative standards~~	~~Yes.~~
~~§ 63.6(h)(1)~~	~~Startup, shutdown, and malfunction exemptions to opacity standards.~~	~~No. See § 63.7500(a).~~
~~§ 63.6(h)(2) to (h)(9)~~	~~Determining compliance with opacity emission standards~~	~~Yes.~~
~~§ 63.6(i)~~	~~Extension of compliance.~~	~~Yes.~~
~~§ 63.6(j)~~	~~Presidential exemption.~~	~~Yes.~~
~~§ 63.7(a), (b), (c), and (d)~~	~~Performance Testing Requirements~~	~~Yes.~~
~~§ 63.7(e)(1)~~	~~Conditions for conducting performance tests.~~	~~No. Subpart DDDDD specifies conditions for conducting performance tests at § 63.7520(a).~~
~~§ 63.7(e)(2)-(e)(9), (f), (g), and (h)~~	~~Performance Testing Requirements~~	~~Yes.~~
~~§ 63.8(a) and (b)~~	~~Applicability and Conduct of Monitoring~~	~~Yes.~~
~~§ 63.8(c)(1)~~	~~Operation and maintenance of CMS~~	~~Yes.~~

~~**Citation**~~	~~**Subject**~~	~~**Applies to subpart DDDDD**~~
~~§ 63.8(c)(1)(i)~~	~~General duty to minimize emissions and CMS operation~~	~~No. See § 63.7500(a)(3).~~
~~§ 63.8(c)(1)(ii)~~	~~Operation and maintenance of CMS~~	~~Yes.~~
~~§ 63.8(c)(1)(iii)~~	~~Startup, shutdown, and malfunction plans for CMS~~	~~No.~~
~~§ 63.8(c)(2) to (c)(9)~~	~~Operation and maintenance of CMS~~	~~Yes.~~
~~§ 63.8(d)(1) and (2)~~	~~Monitoring Requirements, Quality Control Program~~	~~Yes.~~
~~§ 63.8(d)(3)~~	~~Written procedures for CMS~~	~~Yes, except for the last sentence, which refers to a startup, shutdown, and malfunction plan. Startup, shutdown, and malfunction plans are not required.~~
~~§ 63.8(e)~~	~~Performance evaluation of a CMS~~	~~Yes.~~
~~§ 63.8(f)~~	~~Use of an alternative monitoring method.~~	~~Yes.~~
~~63.8(g)~~	~~Reduction of monitoring data.~~	~~Yes.~~
~~§ 63.9~~	~~Notification Requirements~~	~~Yes.~~
~~§ 63.10(a), (b)(1)~~	~~Recordkeeping and Reporting Requirements~~	~~Yes.~~
~~§ 63.10(b)(2)(i)~~	~~Recordkeeping of occurrence and duration of startups or shutdowns~~	~~Yes.~~
~~§ 63.10(b)(2)(ii)~~	~~Recordkeeping of malfunctions~~	~~No. See § 63.7555(d)(7) for recordkeeping of occurrence and duration and § 63.7555(d)(8) for actions taken during malfunctions.~~
~~§ 63.10(b)(2)(iii)~~	~~Maintenance records~~	~~Yes.~~
~~§ 63.10(b)(2)(iv) and (v)~~	~~Actions taken to minimize emissions during startup, shutdown, or malfunction~~	~~No.~~
~~§ 63.10(b)(2)(vi)~~	~~Recordkeeping for CMS malfunctions~~	~~Yes.~~
~~§ 63.10(b)(2)(vii) to (xiv)~~	~~Other CMS requirements~~	~~Yes.~~
~~§ 63.10(b)(3)~~	~~Recordkeeping requirements for applicability determinations~~	~~No.~~
~~§ 63.10(c)(1) to (9)~~	~~Recordkeeping for sources with CMS~~	~~Yes.~~
~~§ 63.10(c)(10) and (11)~~	~~Recording nature and cause of malfunctions, and corrective actions~~	~~No. See § 63.7555(d)(7) for recordkeeping of occurrence and duration and § 63.7555(d)(8) for actions taken during malfunctions.~~
~~§ 63.10(c)(12) and (13)~~	~~Recordkeeping for sources with CMS~~	~~Yes.~~

~~Citation~~	~~Subject~~	~~Applies to subpart DDDDD~~
~~§ 63.10(c)(15)~~	~~Use of startup, shutdown, and malfunction plan~~	~~No.~~
~~§ 63.10(d)(1) and (2)~~	~~General reporting requirements~~	~~Yes.~~
~~§ 63.10(d)(3)~~	~~Reporting opacity or visible emission observation results~~	~~No.~~
~~§ 63.10(d)(4)~~	~~Progress reports under an extension of compliance~~	~~Yes.~~
~~§ 63.10(d)(5)~~	~~Startup, shutdown, and malfunction reports~~	~~No. See § 63.7550(c)(11) for malfunction reporting requirements.~~
~~§ 63.10(e) and (f)~~		~~Yes.~~
~~§ 63.11~~	~~Control Device Requirements~~	~~No.~~
~~§ 63.12~~	~~State Authority and Delegation~~	~~Yes.~~
~~§ 63.13-63.16~~	~~Addresses, Incorporation by Reference, Availability of Information, Performance Track Provisions~~	~~Yes.~~
~~§ 63.1(a)(5),(a)(7)-(a)(9), (b)(2), (c)(3)-(4), (d), 63.6(b)(6), (c)(3), (c)(4), (d), (e)(2), (e)(3)(ii), (h)(3), (h)(5)(iv), 63.8(a)(3), 63.9(b)(3), (h)(4), 63.10(c)(2)-(4), (c)(9).~~	~~Reserved~~	~~No.~~

~~Table 11 to Subpart DDDDD of Part 63—Toxic Equivalency Factors for Dioxins/Furans~~

~~Dioxin/furan congener~~	~~Toxic equivalency factor~~
~~2,3,7,8-tetrachlorinated dibenzo-p-dioxin~~	~~1~~
~~1,2,3,7,8-pentachlorinated dibenzo-p-dioxin~~	~~1~~
~~1,2,3,4,7,8-hexachlorinated dibenzo-p-dioxin~~	~~0.1~~
~~1,2,3,7,8,9-hexachlorinated dibenzo-p-dioxin~~	~~0.1~~
~~1,2,3,6,7,8-hexachlorinated dibenzo-p-dioxin~~	~~0.1~~
~~1,2,3,4,6,7,8-heptachlorinated dibenzo-p-dioxin~~	~~0.01~~
~~octachlorinated dibenzo-p-dioxin~~	~~0.0003~~
~~2,3,7,8-tetrachlorinated dibenzofuran~~	~~0.1~~
~~2,3,4,7,8-pentachlorinated dibenzofuran~~	~~0.3~~
~~1,2,3,7,8-pentachlorinated dibenzofuran~~	~~0.03~~
~~1,2,3,4,7,8-hexachlorinated dibenzofuran~~	~~0.1~~
~~1,2,3,6,7,8-hexachlorinated dibenzofuran~~	~~0.1~~
~~1,2,3,7,8,9-hexachlorinated dibenzofuran~~	~~0.1~~
~~2,3,4,6,7,8-hexachlorinated dibenzofuran~~	~~0.1~~
~~1,2,3,4,6,7,8-heptachlorinated dibenzofuran~~	~~0.01~~
~~1,2,3,4,7,8,9-heptachlorinated dibenzofuran~~	~~0.01~~
~~octachlorinated dibenzofuran~~	~~0.0003~~

~~Table 12 to Subpart DDDDD of Part 63—Alternative Emission Limits for New or Reconstructed Boilers and Process Heaters That Commenced Construction or Reconstruction After June 4, 2010, and Before May 20, 2011~~

~~If your boiler or process heater is in this subcategory~~	~~For the following pollutants~~	~~The emissions must not exceed the following emission limits, except during periods of startup and shutdown~~	~~Using this specified sampling volume or test run duration~~
~~1. Units in all subcategories designed to burn solid fuel~~	~~a. Mercury~~	~~3.5E-06 lb per MMBtu of heat input~~	~~For M29, collect a minimum of 2 dscm per run; for M30A or M30B, collect a minimum sample as specified in the method; for ASTM D6784~~ [a] ~~collect a minimum of 2 dscm.~~
~~2. Units in all subcategories designed to burn solid fuel that combust at least 10 percent biomass/bio-based solids on an annual heat input basis and less than 10 percent coal/solid fossil fuels on an annual heat input basis~~	~~a. Particulate Matter~~	~~0.008 lb per MMBtu of heat input (30-day rolling average for units 250 MMBtu/hr or greater, 3-run average for units less than 250 MMBtu/hr)~~	~~Collect a minimum of 1 dscm per run.~~
—	~~b. Hydrogen Chloride~~	~~0.004 lb per MMBtu of heat input~~	~~For M26A, collect a minimum of 1 dscm per run; for M26, collect a minimum of 60 liters per run.~~
~~3. Units in all subcategories designed to burn solid fuel that combust at least 10 percent coal/solid fossil fuels on an annual heat input basis and less than 10 percent biomass/bio-based solids on an annual heat input basis~~	~~a. Particulate Matter~~	~~0.0011 lb per MMBtu of heat input (30-day rolling average for units 250 MMBtu/hr or greater, 3-run average for units less than 250 MMBtu/hr)~~	~~Collect a minimum of 3 dscm per run.~~
—	~~b. Hydrogen Chloride~~	~~0.0022 lb per MMBtu of heat input~~	~~For M26A, collect a minimum of 1 dscm per run; for M26, collect a minimum of 60 liters per run.~~
~~4. Units designed to burn pulverized coal/solid fossil fuel~~	~~a. CO~~	~~90 ppm by volume on a dry basis corrected to 3 percent oxygen~~	~~1 hr minimum sampling time.~~
—	~~b. Dioxins/Furans~~	~~0.003 ng/dscm (TEQ) corrected to 7 percent oxygen~~	~~Collect a minimum of 4 dscm per run.~~
~~5. Stokers designed to burn coal/solid fossil fuel~~	~~a. CO~~	~~7 ppm by volume on a dry basis corrected to 3 percent oxygen~~	~~1 hr minimum sampling time.~~
—	~~b. Dioxins/Furans~~	~~0.003 ng/dscm (TEQ) corrected to 7 percent oxygen~~	~~Collect a minimum of 4 dscm per run.~~
~~6. Fluidized bed units designed to burn coal/solid fossil fuel~~	~~a. CO~~	~~30 ppm by volume on a dry basis corrected to 3~~	~~1 hr minimum sampling time.~~

~~If your boiler or process heater is in this subcategory~~	~~For the following pollutants~~	~~The emissions must not exceed the following emission limits, except during periods of startup and shutdown~~	~~Using this specified sampling volume or test run duration~~
		~~percent oxygen~~	
—	~~b. Dioxins/Furans~~	~~0.002 ng/dscm (TEQ) corrected to 7 percent oxygen~~	~~Collect a minimum of 4 dscm per run.~~
~~7. Stokers designed to burn biomass/bio-based solids~~	~~a. CO~~	~~560 ppm by volume on a dry basis corrected to 3 percent oxygen~~	~~1 hr minimum sampling time.~~
—	~~b. Dioxins/Furans~~	~~0.005 ng/dscm (TEQ) corrected to 7 percent oxygen~~	~~Collect a minimum of 4 dscm per run.~~
~~8. Fluidized bed units designed to burn biomass/bio-based solids~~	~~a. CO~~	~~260 ppm by volume on a dry basis corrected to 3 percent oxygen~~	~~1 hr minimum sampling time.~~
—	~~b. Dioxins/Furans~~	~~0.02 ng/dscm (TEQ) corrected to 7 percent oxygen~~	~~Collect a minimum of 4 dscm per run.~~
~~9. Suspension burners/Dutch Ovens designed to burn biomass/bio-based solids~~	~~a. CO~~	~~1,010 ppm by volume on a dry basis corrected to 3 percent oxygen~~	~~1 hr minimum sampling time.~~
—	~~b. Dioxins/Furans~~	~~0.2 ng/dscm (TEQ) corrected to 7 percent oxygen~~	~~Collect a minimum of 4 dscm per run.~~
~~10. Fuel cells designed to burn biomass/bio-based solids~~	~~a. CO~~	~~470 ppm by volume on a dry basis corrected to 3 percent oxygen~~	~~1 hr minimum sampling time.~~
—	~~b. Dioxins/Furans~~	~~0.003 ng/dscm (TEQ) corrected to 7 percent oxygen~~	~~Collect a minimum of 4 dscm per run.~~
~~11. Hybrid suspension/grate units designed to burn biomass/bio-based solids~~	~~a. CO~~	~~1,500 ppm by volume on a dry basis corrected to 3 percent oxygen~~	~~1 hr minimum sampling time.~~
—	~~b. Dioxins/Furans~~	~~0.2 ng/dscm (TEQ) corrected to 7 percent oxygen~~	~~Collect a minimum of 4 dscm per run.~~
~~12. Units designed to burn liquid fuel~~	~~a. Particulate Matter~~	~~0.002 lb per MMBtu of heat input (30-day rolling average for units 250 MMBtu/hr or greater, 3-run average for units less than 250 MMBtu/hr)~~	~~Collect a minimum of 2 dscm per run.~~
—	~~b. Hydrogen Chloride~~	~~0.0032 lb per MMBtu of heat input~~	~~For M26A, collect a minimum of 1 dscm per run; for M26, collect a minimum of 60 liters per run.~~
—	~~c. Mercury~~	~~3.0E-07 lb per MMBtu of~~	~~For M29, collect a minimum of~~

~~If your boiler or process heater is in this subcategory~~	~~For the following pollutants~~	~~The emissions must not exceed the following emission limits, except during periods of startup and shutdown~~	~~Using this specified sampling volume or test run duration~~
		~~heat input~~	~~2 dscm per run; for M30A or M30B, collect a minimum sample as specified in the method; for ASTM D6784~~ [a] ~~collect a minimum of 2 dscm.~~
—	~~d. CO~~	~~3 ppm by volume on a dry basis corrected to 3 percent oxygen~~	~~1 hr minimum sampling time.~~
—	~~e. Dioxins/Furans~~	~~0.002 ng/dscm (TEQ) corrected to 7 percent oxygen~~	~~Collect a minimum of 4 dscm per run.~~
~~13. Units designed to burn liquid fuel located in non-continental States and territories~~	~~a. Particulate Matter~~	~~0.002 lb per MMBtu of heat input (30-day rolling average for units 250 MMBtu/hr or greater, 3-run average for units less than 250 MMBtu/hr)~~	~~Collect a minimum of 2 dscm per run.~~
—	~~b. Hydrogen Chloride~~	~~0.0032 lb per MMBtu of heat input~~	~~For M26A, collect a minimum of 1 dscm per run; for M26, collect a minimum of 60 liters per run.~~
—	~~c. Mercury~~	~~7.8E-07 lb per MMBtu of heat input~~	~~For M29, collect a minimum of 1 dscm per run; for M30A or M30B, collect a minimum sample as specified in the method; for ASTM D6784~~ [a] ~~collect a minimum of 2 dscm.~~
—	~~d. CO~~	~~51 ppm by volume on a dry basis corrected to 3 percent oxygen~~	~~1 hr minimum sampling time.~~
—	~~e. Dioxins/Furans~~	~~0.002 ng/dscm (TEQ) corrected to 7 percent oxygen~~	~~Collect a minimum of 4 dscm per run.~~
~~14. Units designed to burn gas 2 (other) gases~~	~~a. Particulate Matter~~	~~0.0067 lb per MMBtu of heat input (30-day rolling average for units 250 MMBtu/hr or greater, 3-run average for units less than 250 MMBtu/hr)~~	~~Collect a minimum of 1 dscm per run.~~
—	~~b. Hydrogen Chloride~~	~~0.0017 lb per MMBtu of heat input~~	~~For M26A, collect a minimum of 1 dscm per run; for M26, collect a minimum of 60 liters per run.~~

~~If your boiler or process heater is in this subcategory~~	~~For the following pollutants~~	~~The emissions must not exceed the following emission limits, except during periods of startup and shutdown~~	~~Using this specified sampling volume or test run duration~~
—	~~c. Mercury~~	~~7.9E-06 lb per MMBtu of heat input~~	~~For M29, collect a minimum of 1 dscm per run; for M30A or M30B, collect a minimum sample as specified in the method; for ASTM D6784 [a] collect a minimum of 2 dscm.~~
—	~~d. CO~~	~~3 ppm by volume on a dry basis corrected to 3 percent oxygen~~	~~1 hr minimum sampling time.~~
—	~~e. Dioxins/Furans~~	~~0.08 ng/dscm (TEQ) corrected to 7 percent oxygen~~	~~Collect a minimum of 4 dscm per run.~~

[a] ~~Incorporated by reference, see § 63.14.~~

Revised Attachment H – 40 CFR 63, Subpart DDDDD

Indiana Department of Environmental Management
Office of Air Quality

Attachment H to a Part 70 Operating Permit

Source Background and Description

Source Name:	**Ohio Valley Resources, LLC**
Source Location:	**300-400 East CR 350 North, Rockport, Indiana 47635**
County:	**Spencer**
SIC Code:	**2873**
Permit No.:	**T 147-32322-00062**
Permit Reviewer:	**David Matousek**

40 CFR 63, Subpart DDDDD

Subpart DDDDD — National Emission Standards for Hazardous Air Pollutants for Major Sources: Industrial, Commercial, and Institutional Boilers and Process Heaters

Source: 76 FR 15664, Mar. 21, 2011, unless otherwise noted.

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What This Subpart Covers

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§ 63.7480 What is the purpose of this subpart?

This subpart establishes national emission limitations and work practice standards for hazardous air pollutants (HAP) emitted from industrial, commercial, and institutional boilers and process heaters located at major sources of HAP. This subpart also establishes requirements to demonstrate initial and continuous compliance with the emission limitations and work practice standards.

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§ 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, except as specified in § 63.7491. For purposes of this subpart, a major source of HAP is as defined in § 63.2, except that for oil and natural gas production facilities, a major source of HAP is as defined in § 63.7575.

[78 FR 7162, Jan. 31, 2013]

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§ 63.7490 What is the affected source of this subpart?

(a) This subpart applies to new, reconstructed, and existing affected sources as described in paragraphs (a)(1) and (2) of this section.

(1) The affected source of this subpart is the collection at a major source of all existing industrial, commercial, and institutional boilers and process heaters within a subcategory 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, as defined in § 63.7575, located at a major source.

(b) A boiler or process heater is new if you commence construction of the boiler or process heater after June 4, 2010, 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 June 4, 2010, 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.

(e) An existing electric utility steam generating unit (EGU) that meets the applicability requirements of this subpart after the effective date of this final rule due to a change (e.g., fuel switch) is considered to be an existing source under this subpart.

[76 FR 15664, Mar. 21, 2011, as amended at 78 FR 7162, Jan. 31, 2013]

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§ 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 (n) of this section are not subject to this subpart.

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

(b) A recovery boiler or furnace covered by subpart MM of this part.

(c) A boiler or process heater that is used specifically for research and development, including test steam boilers used to provide steam for testing the propulsion systems on military vessels. This does not include units that provide heat or steam to a process at a research and development facility.

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

(e) A refining kettle covered by subpart X of this part.

(f) An ethylene cracking furnace covered by subpart YY of this part.

(g) Blast furnace stoves as described in EPA-453/R-01-005 (incorporated by reference, see § 63.14).

(h) Any boiler or process heater that is part of the affected source subject to another subpart of this part, such as boilers and process heaters used as control devices to comply with subparts JJJ, OOO, PPP, and U of this part.

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

(j) Temporary boilers as defined in this subpart.

(k) Blast furnace gas fuel-fired boilers and process heaters as defined in this subpart.

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

(m) A unit that burns hazardous waste covered by Subpart EEE of this part. A unit that is exempt from Subpart EEE as specified in § 63.1200(b) is not covered by Subpart EEE.

[76 FR 15664, Mar. 21, 2011, as amended at 78 FR 7162, Jan. 31, 2013]

EDITORIAL NOTE: At 78 FR 7162, Jan. 31, 2013, § 63.7491 was amended by revising paragraph (n). However, there is no paragraph (n) to revise.

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§ 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 January 31, 2013, 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 January 31, 2016, except as provided in § 63.6(i).

(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 source must be in compliance with this subpart upon startup.

(2) Any existing boiler or process heater at the existing source must be in compliance with this subpart within 3 years after the source 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.

(e) If you own or operate an industrial, commercial, or institutional boiler or process heater and would be subject to this subpart except for the exemption in § 63.7491(l) for commercial and industrial solid waste incineration units covered by part 60, subpart CCCC or subpart DDDD, and you cease combusting solid waste, you must be in compliance with this subpart on the effective date of the switch from waste to fuel.

(f) If you own or operate an existing EGU that becomes subject to this subpart after January 31, 2013, you must be in compliance with the applicable existing source provisions of this subpart on the effective date such unit becomes subject to this subpart.

(g) If you own or operate an existing industrial, commercial, or institutional boiler or process heater and would be subject to this subpart except for a exemption in § 63.7491(i) that becomes subject to this subpart after January 31, 2013, you must be in compliance with the applicable existing source provisions of this subpart within 3 years after such unit becomes subject to this subpart.

[76 FR 15664, Mar. 21, 2011, as amended at 78 FR 7162, Jan. 31, 2013]
EDITORIAL NOTE: At 78 FR 7162, Jan. 31, 2013, § 63.7495 was amended by adding paragraph (e). However, there is already a paragraph (e).

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Emission Limitations and Work Practice Standards

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§ 63.7499 What are the subcategories of boilers and process heaters?

The subcategories of boilers and process heaters, as defined in § 63.7575 are:

(a) Pulverized coal/solid fossil fuel units.

(b) Stokers designed to burn coal/solid fossil fuel.

(c) Fluidized bed units designed to burn coal/solid fossil fuel.

(d) Stokers/sloped grate/other units designed to burn kiln dried biomass/bio-based solid.

(e) Fluidized bed units designed to burn biomass/bio-based solid.

(f) Suspension burners designed to burn biomass/bio-based solid.

(g) Fuel cells designed to burn biomass/bio-based solid.

(h) Hybrid suspension/grate burners designed to burn wet biomass/bio-based solid.

(i) Stokers/sloped grate/other units designed to burn wet biomass/bio-based solid.

(j) Dutch ovens/pile burners designed to burn biomass/bio-based solid.

(k) Units designed to burn liquid fuel that are non-continental units.

(l) Units designed to burn gas 1 fuels.

(m) Units designed to burn gas 2 (other) gases.

(n) Metal process furnaces.

(o) Limited-use boilers and process heaters.

(p) Units designed to burn solid fuel.

(q) Units designed to burn liquid fuel.

(r) Units designed to burn coal/solid fossil fuel.

(s) Fluidized bed units with an integrated fluidized bed heat exchanger designed to burn coal/solid fossil fuel.

(t) Units designed to burn heavy liquid fuel.

(u) Units designed to burn light liquid fuel.

[76 FR 15664, Mar. 21, 2011, as amended at 78 FR 7162, Jan. 31, 2013]

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§ 63.7500 What emission limitations, work practice standards, and operating limits must I meet?

(a) You must meet the requirements in paragraphs (a)(1) through (3) of this section, except as provided in paragraphs (b), through (e) of this section. You must meet these requirements at all times the affected unit is operating, except as provided in paragraph (f) of this section.

(1) You must meet each emission limit and work practice standard in Tables 1 through 3, and 11 through 13 to this subpart that applies to your boiler or process heater, for each boiler or process heater at your source, except as provided under § 63.7522. The output-based emission limits, in units of pounds per million Btu of steam output, in Tables 1 or 2 to this subpart are an alternative applicable only to boilers and process heaters that generate steam. The output-based emission limits, in units of pounds per megawatt-hour, in Tables 1 or 2 to this subpart are an alternative applicable only to boilers that generate electricity. If you operate a new boiler or process heater, you can choose to comply with alternative limits as discussed in paragraphs (a)(1)(i) through (a)(1)(iii) of this section, but on or after January 31, 2016, you must comply with the emission limits in Table 1 to this subpart.

(i) If your boiler or process heater commenced construction or reconstruction after June 4, 2010 and before May 20, 2011, you may comply with the emission limits in Table 1 or 11 to this subpart until January 31, 2016.

(ii) If your boiler or process heater commenced construction or reconstruction after May 20, 2011 and before December 23, 2011, you may comply with the emission limits in Table 1 or 12 to this subpart until January 31, 2016.

(iii) If your boiler or process heater commenced construction or reconstruction after December 23, 2011 and before January 31, 2013, you may comply with the emission limits in Table 1 or 13 to this subpart until January 31, 2016.

(2) You must meet each operating limit in Table 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 Table 4 to this subpart, or you wish to establish and monitor an alternative operating limit or an alternative monitoring parameter, you must apply to the EPA Administrator for approval of alternative monitoring under § 63.8(f).

(3) At all times, you must operate and maintain any affected source (as defined in § 63.7490), including associated air pollution control equipment and monitoring equipment, in a manner consistent with safety and good air pollution control practices for minimizing emissions. Determination of whether such operation and maintenance procedures are being used will be based on information available to the Administrator that may include, but is not limited to, monitoring results, review of operation and maintenance procedures, review of operation and maintenance records, and inspection of the source.

(b) As provided in § 63.6(g), EPA may approve use of an alternative to the work practice standards in this section.

(c) Limited-use boilers and process heaters must complete a tune-up every 5 years as specified in § 63.7540. They are not subject to the emission limits in Tables 1 and 2 or 11 through 13 to this subpart, the annual tune-up, or the energy assessment requirements in Table 3 to this subpart, or the operating limits in Table 4 to this subpart.

(d) Boilers and process heaters with a heat input capacity of less than or equal to 5 million Btu per hour in the units designed to burn gas 2 (other) fuels subcategory or units designed to burn light liquid fuels subcategory must complete a tune-up every 5 years as specified in § 63.7540.

(e) Boilers and process heaters in the units designed to burn gas 1 fuels subcategory with a heat input capacity of less than or equal to 5 million Btu per hour must complete a tune-up every 5 years as specified in § 63.7540. Boilers and process heaters in the units designed to burn gas 1 fuels subcategory with a heat input capacity greater than 5 million Btu per hour and less than 10 million Btu per hour must complete a tune-up every 2 years as specified in § 63.7540. Boilers and process heaters in the units designed to burn gas 1 fuels subcategory are not subject to the emission limits in Tables 1 and 2 or 11 through 13 to this subpart, or the operating limits in Table 4 to this subpart.

(f) These standards apply at all times the affected unit is operating, except during periods of startup and shutdown during which time you must comply only with Table 3 to this subpart.

[76 FR 15664, Mar. 21, 2011, as amended at 78 FR 7162, Jan. 31, 2013]

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§ 63.7501 Affirmative Defense for Violation of Emission Standards During Malfunction.

In response to an action to enforce the standards set forth in § 63.7500 you may assert an affirmative defense to a claim for civil penalties for violations of such standards that are caused by malfunction, as defined at § 63.2. Appropriate penalties may be assessed if you fail to meet your burden of proving all of the requirements in the affirmative defense. The affirmative defense shall not be available for claims for injunctive relief.

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

(1) The violation:

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

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

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

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

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

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

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

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

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

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

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

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

(b) *Report.* The owner or operator seeking to assert an affirmative defense shall submit a written report to the Administrator with all necessary supporting documentation, that it has met the requirements set forth in § 63.7500 of this section. This affirmative defense report shall be included in the first periodic compliance, deviation report or excess emission report otherwise required after the initial occurrence of the violation of the relevant standard (which may be the end of any applicable averaging period). If such compliance, deviation report or excess emission report is due less than 45 days after the initial occurrence of the violation, the affirmative defense report may be included in the second compliance, deviation report or excess emission report due after the initial occurrence of the violation of the relevant standard.

[78 FR 7163, Jan. 31, 2013]

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General Compliance Requirements

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§ 63.7505 What are my general requirements for complying with this subpart?

(a) You must be in compliance with the emission limits, work practice standards, and operating limits in this subpart. These limits apply to you at all times the affected unit is operating except for the periods noted in § 63.7500(f).

(b) [Reserved]

(c) You must demonstrate compliance with all applicable emission limits using performance stack testing, fuel analysis, or continuous monitoring systems (CMS), including a continuous emission monitoring system (CEMS), continuous opacity monitoring system (COMS), continuous parameter monitoring system (CPMS), or particulate matter continuous parameter monitoring system (PM CPMS), where applicable. You may demonstrate compliance with the applicable emission limit for hydrogen chloride (HCl), mercury, or total selected metals (TSM) using fuel analysis if the emission rate calculated according to § 63.7530(c) is less than the applicable emission limit. (For gaseous fuels, you may not use fuel analyses to comply with the TSM alternative standard or the HCl standard.) Otherwise, you must demonstrate compliance for HCl, mercury, or TSM using performance testing, if subject to an applicable emission limit listed in Tables 1, 2, or 11 through 13 to this subpart.

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

(1) For each CMS required in this section (including CEMS, COMS, or CPMS), you must develop, and submit to the Administrator for approval upon request, a site-specific monitoring plan that addresses design, data collection, and the quality assurance and quality control elements outlined in § 63.8(d) and the elements described in paragraphs (d)(1)(i) through (iii) of this section. You must submit this site-specific monitoring plan, if requested, at least 60 days before your initial performance evaluation of your CMS. This requirement to develop and submit a site specific monitoring plan does not apply to affected sources with existing CEMS or COMS operated according to the performance specifications under appendix B to part 60 of this chapter and that meet the requirements of § 63.7525. Using the process described in § 63.8(f)(4), you may request approval of alternative monitoring system quality assurance and quality control procedures in place of those specified in this paragraph and, if approved, include the alternatives in your site-specific monitoring plan.

(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, accuracy audits, analytical drift).

(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)(ii), (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) (as applicable in Table 10 to this subpart), (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.

[76 FR 15664, Mar. 21, 2011, as amended at 78 FR 7164, Jan. 31, 2013]

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Testing, Fuel Analyses, and Initial Compliance Requirements

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§ 63.7510 What are my initial compliance requirements and by what date must I conduct them?

(a) For each boiler or process heater that is required or that you elect to demonstrate compliance with any of the applicable emission limits in Tables 1 or 2 or 11 through 13 of this subpart through performance testing, your initial compliance requirements include all the following:

(1) Conduct performance tests according to § 63.7520 and Table 5 to this subpart.

(2) 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, except as specified in paragraphs (a)(2)(i) through (iii) of this section.

(i) For each boiler or process heater that burns a single type of fuel, you are not required 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. For purposes of this subpart, units that use a supplemental fuel only for startup, unit shutdown, and transient flame stability purposes still qualify as units that burn a single type of fuel, and the supplemental fuel is not subject to the fuel analysis requirements under § 63.7521 and Table 6 to this subpart.

(ii) When natural gas, refinery gas, or other gas 1 fuels are co-fired with other fuels, you are not required to conduct a fuel analysis of those fuels according to § 63.7521 and Table 6 to this subpart. If gaseous fuels other than natural gas, refinery gas, or other gas 1 fuels are co-fired with other fuels and those gaseous fuels are subject to another subpart of this part, part 60, part 61, or part 65, you are not required to conduct a fuel analysis of those fuels according to § 63.7521 and Table 6 to this subpart.

(iii) You are not required to conduct a chlorine fuel analysis for any gaseous fuels. You must conduct a fuel analysis for mercury on gaseous fuels unless the fuel is exempted in paragraphs (a)(2)(i) and (ii) of this section.

(3) Establish operating limits according to § 63.7530 and Table 7 to this subpart.

(4) Conduct CMS performance evaluations according to § 63.7525.

(b) For each boiler or process heater that you elect to demonstrate compliance with the applicable emission limits in Tables 1 or 2 or 11 through 13 to this subpart 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. The fuels described in paragraph (a)(2)(i) and (ii) of this section are exempt from these fuel analysis and operating limit requirements. The fuels described in paragraph (a)(2)(ii) of this section are exempt from the chloride fuel analysis and operating limit requirements. Boilers and process heaters that use a CEMS for mercury or HCl are exempt from the performance testing and operating limit requirements specified in paragraph (a) of this section for the HAP for which CEMS are used.

(c) If your boiler or process heater is subject to a carbon monoxide (CO) limit, your initial compliance demonstration for CO is to conduct a performance test for CO according to Table 5 to this subpart or conduct a performance evaluation of your continuous CO monitor, if applicable, according to § 63.7525(a). Boilers and process heaters that use a CO CEMS to comply with the applicable alternative CO CEMS emission standard listed in Tables 12, or 11 through 13 to this subpart, as specified in § 63.7525(a), are exempt from the initial CO performance testing and oxygen concentration operating limit requirements specified in paragraph (a) of this section.

(d) If your boiler or process heater is subject to a PM limit, your initial compliance demonstration for PM is to conduct a performance test in accordance with § 63.7520 and Table 5 to this subpart.

(e) For existing affected sources (as defined in § 63.7490), you must complete the initial compliance demonstration, as specified in paragraphs (a) through (d) of this section, 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, except as specified in paragraph (j) of this section. You must complete an initial tune-up by following the procedures described in § 63.7540(a)(10)(i) through (vi) no later than the compliance date specified in § 63.7495, except as specified in paragraph (j) of this section. You must complete the one-time energy assessment specified in Table 3 to this subpart no later than the compliance date specified in § 63.7495, except as specified in paragraph (j) of this section.

(f) For new or reconstructed affected sources (as defined in § 63.7490), you must complete the initial compliance demonstration with the emission limits no later than July 30, 2013 or within 180 days after startup of the source, whichever is later. If you are demonstrating compliance with an emission limit in Tables 11 through 13 to this subpart that is less stringent (that is, higher) than the applicable emission limit in Table 1 to this subpart, you must demonstrate compliance with the applicable emission limit in Table 1 no later than July 29, 2016.

(g) For new or reconstructed affected sources (as defined in § 63.7490), you must demonstrate initial compliance with the applicable work practice standards in Table 3 to this subpart within the applicable annual, biennial, or 5-year schedule as specified in § 63.7540(a) following the initial compliance date specified in § 63.7495(a). Thereafter, you are required to complete the applicable annual, biennial, or 5-year tune-up as specified in § 63.7540(a).

(h) For affected sources (as defined in § 63.7490) that ceased burning solid waste consistent with § 63.7495(e) and for which the initial compliance date has passed, you must demonstrate compliance within 60 days of the effective date of the waste-to-fuel switch. If you have not conducted your compliance demonstration for this subpart within the previous 12 months, you must complete all compliance demonstrations for this subpart before you commence or recommence combustion of solid waste.

(i) For an existing EGU that becomes subject after January 31, 2013, you must demonstrate compliance within 180 days after becoming an affected source.

(j) For existing affected sources (as defined in § 63.7490) that have not operated between the effective date of the rule and the compliance date that is specified for your source in § 63.7495, you must complete the initial compliance demonstration, if subject to the emission limits in Table 2 to this

subpart, as specified in paragraphs (a) through (d) of this section, no later than 180 days after the re-start of the affected source and according to the applicable provisions in § 63.7(a)(2) as cited in Table 10 to this subpart. You must complete an initial tune-up by following the procedures described in § 63.7540(a)(10)(i) through (vi) no later than 30 days after the re-start of the affected source and, if applicable, complete the one-time energy assessment specified in Table 3 to this subpart, no later than the compliance date specified in § 63.7495.

[78 FR 7164, Jan. 31, 2013]

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§ 63.7515 When must I conduct subsequent performance tests, fuel analyses, or tune-ups?

(a) You must conduct all applicable performance tests according to § 63.7520 on an annual basis, except as specified in paragraphs (b) through (e), (g), and (h) of this section. Annual performance tests must be completed no more than 13 months after the previous performance test, except as specified in paragraphs (b) through (e), (g), and (h) of this section.

(b) If your performance tests for a given pollutant for at least 2 consecutive years show that your emissions are at or below 75 percent of the emission limit (or, in limited instances as specified in Tables 1 and 2 or 11 through 13 to this subpart, at or below the emission limit) for the pollutant, and if there are no changes in the operation of the individual boiler or process heater or air pollution control equipment that could increase emissions, you may choose to conduct performance tests for the pollutant every third year. Each such performance test must be conducted no more than 37 months after the previous performance test. If you elect to demonstrate compliance using emission averaging under § 63.7522, you must continue to conduct performance tests annually. The requirement to test at maximum chloride input level is waived unless the stack test is conducted for HCl. The requirement to test at maximum mercury input level is waived unless the stack test is conducted for mercury. The requirement to test at maximum TSM input level is waived unless the stack test is conducted for TSM.

(c) If a performance test shows emissions exceeded the emission limit or 75 percent of the emission limit (as specified in Tables 1 and 2 or 11 through 13 to this subpart) for a pollutant, you must conduct annual performance tests for that pollutant until all performance tests over a consecutive 2-year period meet the required level (at or below 75 percent of the emission limit, as specified in Tables 1 and 2 or 11 through 13 to this subpart).

(d) If you are required to meet an applicable tune-up work practice standard, you must conduct an annual, biennial, or 5-year performance tune-up according to § 63.7540(a)(10), (11), or (12), respectively. Each annual tune-up specified in § 63.7540(a)(10) must be no more than 13 months after the previous tune-up. Each biennial tune-up specified in § 63.7540(a)(11) must be conducted no more than 25 months after the previous tune-up. Each 5-year tune-up specified in § 63.7540(a)(12) must be conducted no more than 61 months after the previous tune-up. For a new or reconstructed affected source (as defined in § 63.7490), the first annual, biennial, or 5-year tune-up must be no later than 13 months, 25 months, or 61 months, respectively, after the initial startup of the new or reconstructed affected source.

(e) If you demonstrate compliance with the mercury, HCl, or TSM based on fuel analysis, you must conduct a monthly fuel analysis according to § 63.7521 for each type of fuel burned that is subject to an emission limit in Tables 1, 2, or 11 through 13 to this subpart. You may comply with this monthly requirement by completing the fuel analysis any time within the calendar month as long as the analysis is separated from the previous analysis by at least 14 calendar days. 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. If each of 12 consecutive monthly fuel analyses demonstrates 75 percent or less of the compliance level, you may decrease the fuel analysis frequency to quarterly for that fuel. If any quarterly sample exceeds 75 percent of the compliance level or you begin burning a new type of fuel, you must return to monthly

monitoring for that fuel, until 12 months of fuel analyses are again less than 75 percent of the compliance level.

(f) You must report the results of performance tests and the associated fuel analyses within 60 days after the completion of the performance tests. This report must also verify that the operating limits for each boiler or process heater have not changed or provide documentation of revised operating limits established according to § 63.7530 and Table 7 to this subpart, as applicable. The reports for all subsequent performance tests must include all applicable information required in § 63.7550.

(g) For affected sources (as defined in § 63.7490) that have not operated since the previous compliance demonstration and more than one year has passed since the previous compliance demonstration, you must complete the subsequent compliance demonstration, if subject to the emission limits in Tables 1, 2, or 11 through 13 to this subpart, no later than 180 days after the re-start of the affected source and according to the applicable provisions in § 63.7(a)(2) as cited in Table 10 to this subpart. You must complete a subsequent tune-up by following the procedures described in § 63.7540(a)(10)(i) through (vi) and the schedule described in § 63.7540(a)(13) for units that are not operating at the time of their scheduled tune-up.

(h) If your affected boiler or process heater is in the unit designed to burn light liquid subcategory and you combust ultra low sulfur liquid fuel, you do not need to conduct further performance tests if the pollutants measured during the initial compliance performance tests meet the emission limits in Tables 1 or 2 of this subpart providing you demonstrate ongoing compliance with the emissions limits by monitoring and recording the type of fuel combusted on a monthly basis. If you intend to use a fuel other than ultra low sulfur liquid fuel, natural gas, refinery gas, or other gas 1 fuel, you must conduct new performance tests within 60 days of burning the new fuel type.

(i) If you operate a CO CEMS that meets the Performance Specifications outlined in § 63.7525(a)(3) of this subpart to demonstrate compliance with the applicable alternative CO CEMS emission standard listed in Tables 1, 2, or 11 through 13 to this subpart, you are not required to conduct CO performance tests and are not subject to the oxygen concentration operating limit requirement specified in § 63.7510(a).

[78 FR 7165, Jan. 31, 2013]

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§ 63.7520 What stack 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 stack test plan according to the requirements in § 63.7(c). You shall conduct all performance tests under such conditions as the Administrator specifies to you based on the representative performance of each boiler or process heater for the period being tested. Upon request, you shall make available to the Administrator such records as may be necessary to determine the conditions of the performance tests.

(b) You must conduct each performance test according to the requirements in Table 5 to this subpart.

(c) 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 representative operating load conditions while burning the type of fuel or mixture of fuels that has the highest content of chlorine and mercury, and TSM if you are opting to comply with the TSM alternative standard and you must demonstrate initial compliance and establish your operating limits based on these performance tests. These requirements could result in the need to conduct more than one performance test. Following each performance test and until the next performance test, you must comply with the operating limit for operating load conditions specified in Table 4 to this subpart.

(d) You must conduct a minimum of three separate test runs for each performance test required in this section, as specified in § 63.7(e)(3). Each test run must comply with the minimum applicable sampling times or volumes specified in Tables 1 and 2 or 11 through 13 to this subpart.

(e) To determine compliance with the emission limits, you must use the F-Factor methodology and equations in sections 12.2 and 12.3 of EPA Method 19 at 40 CFR part 60, appendix A-7 of this chapter to convert the measured particulate matter (PM) concentrations, the measured HCl concentrations, the measured mercury concentrations, and the measured TSM concentrations that result from the performance test to pounds per million Btu heat input emission rates.

(f) Except for a 30-day rolling average based on CEMS (or sorbent trap monitoring system) data, if measurement results for any pollutant are reported as below the method detection level (e.g., laboratory analytical results for one or more sample components are below the method defined analytical detection level), you must use the method detection level as the measured emissions level for that pollutant in calculating compliance. The measured result for a multiple component analysis (e.g., analytical values for multiple Method 29 fractions both for individual HAP metals and for total HAP metals) may include a combination of method detection level data and analytical data reported above the method detection level.

[76 FR 15664, Mar. 21, 2011, as amended at 78 FR 7166, Jan. 31, 2013]

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§ 63.7521 What fuel analyses, fuel specification, and procedures must I use?

(a) For solid and liquid fuels, you must conduct fuel analyses for chloride and mercury according to the procedures in paragraphs (b) through (e) of this section and Table 6 to this subpart, as applicable. For solid fuels and liquid fuels, you must also conduct fuel analyses for TSM if you are opting to comply with the TSM alternative standard. For gas 2 (other) fuels, you must conduct fuel analyses for mercury according to the procedures in paragraphs (b) through (e) of this section and Table 6 to this subpart, as applicable. (For gaseous fuels, you may not use fuel analyses to comply with the TSM alternative standard or the HCl standard.) For purposes of complying with this section, a fuel gas system that consists of multiple gaseous fuels collected and mixed with each other is considered a single fuel type and sampling and analysis is only required on the combined fuel gas system that will feed the boiler or process heater. Sampling and analysis of the individual gaseous streams prior to combining is not required. You are not required to conduct fuel analyses for fuels used for only startup, unit shutdown, and transient flame stability purposes. You are required to conduct fuel analyses only for fuels and units that are subject to emission limits for mercury, HCl, or TSM in Tables 1 and 2 or 11 through 13 to this subpart. Gaseous and liquid fuels are exempt from the sampling requirements in paragraphs (c) and (d) of this section and Table 6 to this subpart.

(b) You must develop a site-specific fuel monitoring plan according to the following procedures and requirements in paragraphs (b)(1) and (2) of this section, if you are required to conduct fuel analyses as specified in § 63.7510.

(1) If you intend to use an alternative analytical method other than those required by Table 6 to this subpart, you must submit the fuel analysis plan to the Administrator for review and approval no later than 60 days before the date that you intend to conduct the initial compliance demonstration described in § 63.7510.

(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 anticipated fuel type, the notification of whether you or a fuel supplier will be conducting the fuel analysis.

(iii) For each anticipated 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 anticipated fuel type, the analytical methods from Table 6, with the expected minimum detection levels, to be used for the measurement of 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 you are proposing to use. Methods in Table 6 shall be used until the requested alternative is approved.

(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, or the methods listed in Table 6 to this subpart, or use an automated sampling mechanism that provides representative composite fuel samples for each fuel type that includes both coarse and fine material.

(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. You must collect all the material (fines and coarse) in the full cross-section. You must transfer the sample to a clean plastic bag.

(ii) Each composite sample will consist of a minimum of three samples collected at approximately equal one-hour intervals during the testing period for sampling during performance stack testing. For monthly sampling, each composite sample shall be collected at approximately equal 10-day intervals during the month.

(2) If sampling from a fuel pile or truck, you must collect fuel samples according to paragraphs (c)(2)(i) through (iii) of this section.

(i) For each composite sample, you must select a minimum of five sampling locations uniformly spaced over the surface of the pile.

(ii) At each sampling site, you must dig into the pile to a uniform depth of approximately 18 inches. You must insert a clean shovel into the hole and withdraw a sample, making sure that large pieces do not fall off during sampling; use the same shovel to collect all samples.

(iii) You must transfer all samples to a clean plastic bag for further processing.

(d) You must prepare each composite sample according to the procedures in paragraphs (d)(1) through (7) of this section.

(1) You must thoroughly mix and pour the entire composite sample over a clean plastic sheet.

(2) You must break large sample pieces (e.g., larger than 3 inches) into smaller sizes.

(3) You must make a pie shape with the entire composite sample and subdivide it into four equal parts.

(4) You must separate one of the quarter samples as the first subset.

(5) If this subset is too large for grinding, you must repeat the procedure in paragraph (d)(3) of this section with the quarter sample and obtain a one-quarter subset from this sample.

(6) You must grind the sample in a mill.

(7) You must 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) You must determine the concentration of pollutants in the fuel (mercury and/or chlorine and/or TSM) 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, for use in Equations 7, 8, and 9 of this subpart.

(f) To demonstrate that a gaseous fuel other than natural gas or refinery gas qualifies as an other gas 1 fuel, as defined in § 63.7575, you must conduct a fuel specification analyses for mercury according to the procedures in paragraphs (g) through (i) of this section and Table 6 to this subpart, as applicable, except as specified in paragraph (f)(1) through (4) of this section.

(1) You are not required to conduct the fuel specification analyses in paragraphs (g) through (i) of this section for natural gas or refinery gas.

(2) You are not required to conduct the fuel specification analyses in paragraphs (g) through (i) of this section for gaseous fuels that are subject to another subpart of this part, part 60, part 61, or part 65.

(3) You are not required to conduct the fuel specification analyses in paragraphs (g) through (i) of this section on gaseous fuels for units that are complying with the limits for units designed to burn gas 2 (other) fuels.

(4) You are not required to conduct the fuel specification analyses in paragraphs (g) through (i) of this section for gas streams directly derived from natural gas at natural gas production sites or natural gas plants.

(g) You must develop and submit a site-specific fuel analysis plan for other gas 1 fuels to the EPA Administrator for review and approval according to the following procedures and requirements in paragraphs (g)(1) and (2) of this section.

(1) If you intend to use an alternative analytical method other than those required by Table 6 to this subpart, you must submit the fuel analysis plan to the Administrator for review and approval no later than 60 days before the date that you intend to conduct the initial compliance demonstration described in § 63.7510.

(2) You must include the information contained in paragraphs (g)(2)(i) through (vi) of this section in your fuel analysis plan.

(i) The identification of all gaseous fuel types other than those exempted from fuel specification analysis under (f)(1) through (3) of this section anticipated to be burned in each boiler or process heater.

(ii) For each anticipated fuel type, the notification of whether you or a fuel supplier will be conducting the fuel specification analysis.

(iii) For each anticipated fuel type, a detailed description of the sample location and specific procedures to be used for collecting and preparing the samples if your procedures are different from the sampling methods contained in Table 6 to this subpart. 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. If multiple boilers or process heaters are fueled by a common fuel stream it is permissible to conduct a single gas specification at the common point of gas distribution.

(iv) For each anticipated fuel type, the analytical methods from Table 6 to this subpart, with the expected minimum detection levels, to be used for the measurement of 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 you are proposing to use. Methods in Table 6 to this subpart shall be used until the requested alternative is approved.

(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.

(h) You must obtain a single fuel sample for each fuel type according to the sampling procedures listed in Table 6 for fuel specification of gaseous fuels.

(i) You must determine the concentration in the fuel of mercury, in units of microgram per cubic meter, dry basis, of each sample for each other gas 1 fuel type according to the procedures in Table 6 to this subpart.

[78 FR 7167, Jan. 31, 2013]

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§ 63.7522 Can I use emissions averaging to comply with this subpart?

(a) As an alternative to meeting the requirements of § 63.7500 for PM (or TSM), HCl, or mercury on a boiler or process heater-specific basis, if you have more than one existing boiler or process heater in any subcategories located at your facility, you may demonstrate compliance by emissions averaging, if your averaged emissions are not more than 90 percent of the applicable emission limit, according to the procedures in this section. You may not include new boilers or process heaters in an emissions average.

(b) For a group of two or more existing boilers or process heaters in the same subcategory that each vent to a separate stack, you may average PM (or TSM), HCl, or mercury emissions among existing units to demonstrate compliance with the limits in Table 2 to this subpart as specified in paragraph (b)(1) through (3) of this section, if you satisfy the requirements in paragraphs (c) through (g) of this section.

(1) You may average units using a CEMS or PM CPMS for demonstrating compliance.

(2) For mercury and HCl, averaging is allowed as follows:

(i) You may average among units in any of the solid fuel subcategories.

(ii) You may average among units in any of the liquid fuel subcategories.

(iii) You may average among units in a subcategory of units designed to burn gas 2 (other) fuels.

(iv) You may not average across the units designed to burn liquid, units designed to burn solid fuel, and units designed to burn gas 2 (other) subcategories.

(3) For PM (or TSM), averaging is only allowed between units within each of the following subcategories and you may not average across subcategories:

(i) Units designed to burn coal/solid fossil fuel.

(ii) Stokers/sloped grate/other units designed to burn kiln dried biomass/bio-based solids.

(iii) Stokers/sloped grate/other units designed to burn wet biomass/bio-based solids.

(iv) Fluidized bed units designed to burn biomass/bio-based solid.

(v) Suspension burners designed to burn biomass/bio-based solid.

(vi) Dutch ovens/pile burners designed to burn biomass/bio-based solid.

(vii) Fuel Cells designed to burn biomass/bio-based solid.

(viii) Hybrid suspension/grate burners designed to burn wet biomass/bio-based solid.

(ix) Units designed to burn heavy liquid fuel.

(x) Units designed to burn light liquid fuel.

(xi) Units designed to burn liquid fuel that are non-continental units.

(xii) Units designed to burn gas 2 (other) gases.

(c) For each existing boiler or process heater 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 January 31, 2013 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 January 31, 2013.

(d) The averaged emissions rate from the existing boilers and process heaters participating in the emissions averaging option must not exceed 90 percent of the limits in Table 2 to this subpart at all times the affected units are operating following the compliance date specified in § 63.7495.

(e) You must demonstrate initial compliance according to paragraph (e)(1) or (2) of this section using the maximum rated heat input capacity or maximum steam generation capacity of each unit and the results of the initial performance tests or fuel analysis.

(1) You must use Equation 1a or 1b or 1c of this section to demonstrate that the PM (or TSM), HCl, or mercury emissions from all existing units participating in the emissions averaging option for that pollutant do not exceed the emission limits in Table 2 to this subpart. Use Equation 1a if you are complying with the emission limits on a heat input basis, use Equation 1b if you are complying with the emission limits on a steam generation (output) basis, and use Equation 1c if you are complying with the emission limits on a electric generation (output) basis.

$$AveWeightedEmissions = 1.1 \times \sum_{i=1}^{n} \left(Er \times Hm\right) \div \sum_{i=1}^{n} Hm \qquad \text{(Eq.1a)}$$

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Where:

AveWeightedEmissions = Average weighted emissions for PM (or TSM), HCl, or mercury, in units of pounds per million Btu of heat input.

Er = Emission rate (as determined during the initial compliance demonstration) of PM (or TSM), HCl, or mercury from unit, i, in units of pounds per million Btu of heat input. Determine the emission rate for PM (or TSM), HCl, or mercury by performance testing according to Table 5 to this subpart, or by fuel analysis for HCl or mercury or TSM using the applicable equation in § 63.7530(c).

Hm = Maximum rated heat input capacity of unit, i, in units of million Btu per hour.

n = Number of units participating in the emissions averaging option.

1.1 = Required discount factor.

$$AveWeightedEmissions = 1.1 \times \sum_{i=1}^{n} \left(Er \times So\right) \div \sum_{i=1}^{n} So \qquad \text{(Eq.1b)}$$

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Where:

AveWeightedEmissions = Average weighted emissions for PM (or TSM), HCl, or mercury, in units of pounds per million Btu of steam output.

Er = Emission rate (as determined during the initial compliance demonstration) of PM (or TSM), HCl, or mercury from unit, i, in units of pounds per million Btu of steam output. Determine the emission rate for PM (or TSM), HCl, or mercury by performance testing according to Table 5 to this subpart, or by fuel analysis for HCl or mercury or TSM using the applicable equation in § 63.7530(c). If you are taking credit for energy conservation measures from a unit according to § 63.7533, use the adjusted emission level for that unit, Eadj, determined according to § 63.7533 for that unit.

So = Maximum steam output capacity of unit, i, in units of million Btu per hour, as defined in § 63.7575.

n = Number of units participating in the emissions averaging option.

1.1 = Required discount factor.

$$AveWeightedEmissions = 1.1 \times \sum_{i=1}^{n} \left(Er \times Eo\right) \div \sum_{i=1}^{n} Eo \qquad \text{(Eq.1c)}$$

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Where:

AveWeightedEmissions = Average weighted emissions for PM (or TSM), HCl, or mercury, in units of pounds per megawatt hour.

Er = Emission rate (as determined during the initial compliance demonstration) of PM (or TSM), HCl, or mercury from unit, i, in units of pounds per megawatt hour. Determine the emission rate for PM (or TSM), HCl, or mercury by performance testing according to Table 5 to this subpart, or

by fuel analysis for HCl or mercury or TSM using the applicable equation in § 63.7530(c). If you are taking credit for energy conservation measures from a unit according to § 63.7533, use the adjusted emission level for that unit, Eadj, determined according to § 63.7533 for that unit.

Eo = Maximum electric generating output capacity of unit, i, in units of megawatt hour, as defined in § 63.7575.

n = Number of units participating in the emissions averaging option.

1.1 = Required discount factor.

(2) If you are not capable of determining the maximum rated heat input capacity of one or more boilers that generate steam, you may use Equation 2 of this section as an alternative to using Equation 1a of this section to demonstrate that the PM (or TSM), HCl, or mercury emissions from all existing units participating in the emissions averaging option do not exceed the emission limits for that pollutant in Table 2 to this subpart that are in pounds per million Btu of heat input.

$$AveWeightedEmissions = 1.1 \times \sum_{i=1}^{n} (Er \times Sm \times Cfi) \div \sum_{i=1}^{n} (Sm \times Cfi) \quad \text{(Eq. 2)}$$

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Where:

AveWeightedEmissions = 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 determined during the most recent compliance demonstration) of PM (or TSM), HCl, or mercury from unit, i, in units of pounds per million Btu of heat input. Determine the emission rate for PM (or TSM), HCl, or mercury by performance testing according to Table 5 to this subpart, or by fuel analysis for HCl or mercury or TSM using the applicable equation in § 63.7530(c).

Sm = Maximum steam generation capacity by unit, i, in units of pounds per hour.

Cfi = Conversion factor, calculated from the most recent compliance test, in units of million Btu of heat input per pounds of steam generated for unit, i.

1.1 = Required discount factor.

(f) After the initial compliance demonstration described in paragraph (e) of this section, you must demonstrate 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. If the affected source elects to collect monthly data for up the 11 months preceding the first monthly period, these additional data points can be used to compute the 12-month rolling average in paragraph (f)(3) of this section.

(1) For each calendar month, you must use Equation 3a or 3b or 3c of this section to calculate the average weighted emission rate for that month. Use Equation 3a and the actual heat input for the month for each existing unit participating in the emissions averaging option if you are complying with emission limits on a heat input basis. Use Equation 3b and the actual steam generation for the month if you are complying with the emission limits on a steam generation (output) basis. Use Equation 3c and the actual steam generation for the month if you are complying with the emission limits on a electrical generation (output) basis.

$$AveWeightedEmissions = 1.1 \times \sum_{i=1}^{n} \left(Er \times Hb \right) \div \sum_{i=1}^{n} Hb \qquad \text{(Eq. 3a)}$$

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Where:

AveWeightedEmissions = Average weighted emission level for PM (or TSM), HCl, or mercury, in units of pounds per million Btu of heat input, for that calendar month.

Er = Emission rate (as determined during the most recent compliance demonstration) of PM (or TSM), HCl, or mercury from unit, i, in units of pounds per million Btu of heat input. Determine the emission rate for PM (or TSM), HCl, or mercury by performance testing according to Table 5 to this subpart, or by fuel analysis for HCl or mercury or TSM according to Table 6 to this subpart.

Hb = The heat input for that calendar month to unit, i, in units of million Btu.

n = Number of units participating in the emissions averaging option.

1.1 = Required discount factor.

$$AveWeightedEmissions = 1.1 \times \sum_{i=1}^{n} \left(Er \times So \right) \div \sum_{i=1}^{n} So \qquad \text{(Eq. 3b)}$$

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Where:

AveWeightedEmissions = Average weighted emission level for PM (or TSM), HCl, or mercury, in units of pounds per million Btu of steam output, for that calendar month.

Er = Emission rate (as determined during the most recent compliance demonstration) of PM (or TSM), HCl, or mercury from unit, i, in units of pounds per million Btu of steam output. Determine the emission rate for PM (or TSM), HCl, or mercury by performance testing according to Table 5 to this subpart, or by fuel analysis for HCl or mercury or TSM according to Table 6 to this subpart. If you are taking credit for energy conservation measures from a unit according to § 63.7533, use the adjusted emission level for that unit, E_{adj} , determined according to § 63.7533 for that unit.

So = The steam output for that calendar month from unit, i, in units of million Btu, as defined in § 63.7575.

n = Number of units participating in the emissions averaging option.

1.1 = Required discount factor.

$$AveWeightedEmissions = 1.1 \times \sum_{i=1}^{n} \left(Er \times Eo \right) \div \sum_{i=1}^{n} Eo \qquad \text{(Eq. 3c)}$$

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Where:

AveWeightedEmissions = Average weighted emission level for PM (or TSM), HCl, or mercury, in units of pounds per megawatt hour, for that calendar month.

Er = Emission rate (as determined during the most recent compliance demonstration) of PM (or TSM), HCl, or mercury from unit, i, in units of pounds per megawatt hour. Determine the emission

rate for PM (or TSM), HCl, or mercury by performance testing according to Table 5 to this subpart, or by fuel analysis for HCl or mercury or TSM according to Table 6 to this subpart. If you are taking credit for energy conservation measures from a unit according to § 63.7533, use the adjusted emission level for that unit, E_{adj} , determined according to § 63.7533 for that unit.

Eo = The electric generating output for that calendar month from unit, i, in units of megawatt hour, as defined in § 63.7575.

n = Number of units participating in the emissions averaging option.

1.1 = Required discount factor.

(2) If you are not capable of monitoring heat input, you may use Equation 4 of this section as an alternative to using Equation 3a of this section to calculate the average weighted emission rate using the actual steam generation from the boilers participating in the emissions averaging option.

$$AveWeightedEmissions = 1.1 \times \sum_{i=1}^{n}\left(Er \times Sa \times Cfi\right) \div \sum_{i=1}^{n}\left(Sa \times Cfi\right) \quad \text{(Eq. 4)}$$

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Where:

AveWeightedEmissions = average weighted emission level for PM (or TSM), HCl, or mercury, in units of pounds per million Btu of heat input for that calendar month.

Er = Emission rate (as determined during the most recent compliance demonstration of PM (or TSM), HCl, or mercury from unit, i, in units of pounds per million Btu of heat input. Determine the emission rate for PM (or TSM), HCl, or mercury by performance testing according to Table 5 to this subpart, or by fuel analysis for HCl or mercury or TSM according to Table 6 to this subpart.

Sa = Actual steam generation for that calendar month by boiler, i, in units of pounds.

Cfi = Conversion factor, as calculated during the most recent compliance test, in units of million Btu of heat input per pounds of steam generated for boiler, i.

1.1 = Required discount factor.

(3) Until 12 monthly weighted average emission rates have been accumulated, calculate and report only the average weighted emission rate determined under paragraph (f)(1) or (2) of this section for each calendar month. After 12 monthly weighted average emission rates have been accumulated, for each subsequent calendar month, use Equation 5 of this section to calculate the 12-month rolling average of the monthly weighted average emission rates for the current calendar month and the previous 11 calendar months.

$$Eavg = \sum_{i=1}^{n} ERi \div 12 \quad \text{(Eq. 5)}$$

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Where:

Eavg = 12-month rolling average emission rate, (pounds per million Btu heat input)

ERi = Monthly weighted average, for calendar month “i” (pounds per million Btu heat input), as calculated by paragraph (f)(1) or (2) of this section.

(g) You must develop, and submit upon request to the applicable Administrator for review and approval, an implementation plan for emission averaging according to the following procedures and requirements in paragraphs (g)(1) through (4) of this section.

(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 boilers and process heaters in the averaging group, including for each either the applicable HAP emission level or the control technology installed as of January 31, 2013 and the date on which you are requesting emission averaging to commence;

(ii) The process parameter (heat input or steam generated) that will be monitored for each averaging group;

(iii) The specific control technology or pollution prevention measure to be used for each emission boiler or process heater in the averaging group and the date of its installation or application. If the pollution prevention measure reduces or eliminates emissions from multiple boilers or process heaters, the owner or operator must identify each boiler or process heater;

(iv) The test plan for the measurement of PM (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 consistent with § 63.7500 and Table 4, 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 Administrator, 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 load conditions. Following each compliance demonstration and until the next compliance demonstration, you must comply with the operating limit for operating load conditions specified in Table 4 to this subpart.

(3) The Administrator 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 Administrator 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 unit in the same subcategories.

(h) For a group of two or more existing affected units, each of which vents through a single common stack, you may average PM (or TSM), HCl, or mercury emissions to demonstrate compliance with the limits for that pollutant in Table 2 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 units in the same subcategories, 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 unit for purposes of this subpart and comply with the requirements of this subpart as if the group were a single unit.

(j) For all other groups of units subject to the common stack requirements of paragraph (h) of this section, including situations where the exhaust of affected units are each individually controlled and then sent to a common stack, 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 vent to the common stack. The emission limits that the group must comply with are determined by the use of Equation 6 of this section.

$$En = \sum_{i=1}^{n} (ELi \times Hi) \div \sum_{i=1}^{n} Hi \qquad \text{(Eq. 6)}$$

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Where:

En = HAP emission limit, pounds per million British thermal units (lb/MMBtu), parts per million (ppm), or nanograms per dry standard cubic meter (ng/dscm).

ELi = Appropriate emission limit from Table 2 to this subpart for unit i, in units of lb/MMBtu, ppm or ng/dscm.

Hi = Heat input from unit i, MMBtu.

(2) Conduct performance tests according to procedures specified in § 63.7520 in the common stack. If affected units and non-affected units vent to the common stack, the non-affected units must be shut down or vented to a different stack during the performance test unless the facility determines to demonstrate compliance with the non-affected units venting to the stack; and

(3) Meet the applicable operating limit specified in § 63.7540 and Table 8 to this subpart for each emissions control system (except that, if each unit 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) The common stack of a group of two or more existing boilers or process heaters in the same subcategories 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.

[76 FR 15664, Mar. 21, 2011, as amended at 78 FR 7168, Jan. 31, 2013]

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§ 63.7525 What are my monitoring, installation, operation, and maintenance requirements?

(a) If your boiler or process heater is subject to a CO emission limit in Tables 1, 2, or 11 through 13 to this subpart, you must install, operate, and maintain an oxygen analyzer system, as defined in § 63.7575, or install, certify, operate and maintain continuous emission monitoring systems for CO and oxygen according to the procedures in paragraphs (a)(1) through (7) of this section.

(1) Install the CO CEMS and oxygen analyzer by the compliance date specified in § 63.7495. The CO and oxygen levels shall be monitored at the same location at the outlet of the boiler or process heater.

(2) To demonstrate compliance with the applicable alternative CO CEMS emission standard listed in Tables 1, 2, or 11 through 13 to this subpart, you must install, certify, operate, and maintain a CO CEMS and an oxygen analyzer according to the applicable procedures under Performance Specification 4, 4A, or 4B at 40 CFR part 60, appendix B, the site-specific monitoring plan developed according to § 63.7505(d), and the requirements in § 63.7540(a)(8) and paragraph (a) of this section. Any boiler or process heater that has a CO CEMS that is compliant with Performance Specification 4, 4A, or 4B at 40 CFR part 60, appendix B, a site-specific monitoring plan developed according to § 63.7505(d), and the requirements in § 63.7540(a)(8) and paragraph (a) of this section must use the CO CEMS to comply with the applicable alternative CO CEMS emission standard listed in Tables 1, 2, or 11 through 13 to this subpart.

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

(ii) During each relative accuracy test run of the CO CEMS, you must be collect emission data for CO concurrently (or within a 30- to 60-minute period) by both the CO CEMS and by Method 10, 10A, or 10B at 40 CFR part 60, appendix A-4. The relative accuracy testing must be at representative operating conditions.

(iii) You must follow the quality assurance procedures (e.g., quarterly accuracy determinations and daily calibration drift tests) of Procedure 1 of appendix F to part 60. The measurement span value of the CO CEMS must be two times the applicable CO emission limit, expressed as a concentration.

(iv) Any CO CEMS that does not comply with § 63.7525(a) cannot be used to meet any requirement in this subpart to demonstrate compliance with a CO emission limit listed in Tables 1, 2, or 11 through 13 to this subpart.

(v) For a new unit, complete the initial performance evaluation no later than July 30, 2013, or 180 days after the date of initial startup, whichever is later. For an existing unit, complete the initial performance evaluation no later than July 29, 2016.

(3) Complete a minimum of one cycle of CO and oxygen CEMS operation (sampling, analyzing, and data recording) for each successive 15-minute period. Collect CO and oxygen data concurrently. Collect at least four CO and oxygen CEMS data values representing the four 15-minute periods in an hour, or at

least two 15-minute data values during an hour when CEMS calibration, quality assurance, or maintenance activities are being performed.

(4) Reduce the CO CEMS data as specified in § 63.8(g)(2).

(5) Calculate one-hour arithmetic averages, corrected to 3 percent oxygen from each hour of CO CEMS data in parts per million CO concentration. The one-hour arithmetic averages required shall be used to calculate the 30-day or 10-day rolling average emissions. Use Equation 19-19 in section 12.4.1 of Method 19 of 40 CFR part 60, appendix A-7 for calculating the average CO concentration from the hourly values.

(6) For purposes of collecting CO data, operate the CO CEMS as specified in § 63.7535(b). You must use all the data collected during all periods in calculating data averages and assessing compliance, except that you must exclude certain data as specified in § 63.7535(c). Periods when CO data are unavailable may constitute monitoring deviations as specified in § 63.7535(d).

(7) Operate an oxygen trim system with the oxygen level set no lower than the lowest hourly average oxygen concentration measured during the most recent CO performance test as the operating limit for oxygen according to Table 7 to this subpart.

(b) If your boiler or process heater is in the unit designed to burn coal/solid fossil fuel subcategory or the unit designed to burn heavy liquid subcategory and has an average annual heat input rate greater than 250 MMBtu per hour from solid fossil fuel and/or heavy liquid, and you demonstrate compliance with the PM limit instead of the alternative TSM limit, you must install, certify, maintain, and operate a PM CPMS monitoring emissions discharged to the atmosphere and record the output of the system as specified in paragraphs (b)(1) through (4) of this section. As an alternative to use of a PM CPMS to demonstrate compliance with the PM limit, you may choose to use a PM CEMS. If you choose to use a PM CEMS to demonstrate compliance with the PM limit instead of the alternative TSM limit, you must install, certify, maintain, and operate a PM CEMS monitoring emissions discharged to the atmosphere and record the output of the system as specified in paragraph (b)(5) through (8) of this section. For other boilers or process heaters, you may elect to use a PM CPMS or PM CEMS operated in accordance with this section in lieu of using other CMS for monitoring PM compliance (e.g., bag leak detectors, ESP secondary power, PM scrubber pressure). Owners of boilers and process heaters who elect to comply with the alternative TSM limit are not required to install a PM CPMS.

(1) Install, certify, operate, and maintain your PM CPMS according to the procedures in your approved site-specific monitoring plan developed in accordance with § 63.7505(d), the requirements in § 63.7540(a)(9), and paragraphs (b)(1)(i) through (iii) of this section.

(i) The operating principle of the PM CPMS must be based on in-stack or extractive light scatter, light scintillation, beta attenuation, or mass accumulation detection of PM in the exhaust gas or representative exhaust gas sample. The reportable measurement output from the PM CPMS must be expressed as milliamps.

(ii) The PM CPMS must have a cycle time (i.e., period required to complete sampling, measurement, and reporting for each measurement) no longer than 60 minutes.

(iii) The PM CPMS must be capable of detecting and responding to PM concentrations of no greater than 0.5 milligram per actual cubic meter.

(2) For a new unit, complete the initial performance evaluation no later than July 30, 2013, or 180 days after the date of initial startup, whichever is later. For an existing unit, complete the initial performance evaluation no later than July 29, 2016.

(3) Collect PM CPMS hourly average output data for all boiler or process heater operating hours except as indicated in § 63.7535(a) through (d). Express the PM CPMS output as milliamps.

(4) Calculate the arithmetic 30-day rolling average of all of the hourly average PM CPMS output data collected during all boiler or process heater operating hours (milliamps).

(5) Install, certify, operate, and maintain your PM CEMS according to the procedures in your approved site-specific monitoring plan developed in accordance with § 63.7505(d), the requirements in § 63.7540(a)(9), and paragraphs (b)(5)(i) through (iv) of this section.

(i) You shall conduct a performance evaluation of the PM CEMS according to the applicable requirements of § 60.8(e), and Performance Specification 11 at 40 CFR part 60, appendix B of this chapter.

(ii) During each PM correlation testing run of the CEMS required by Performance Specification 11 at 40 CFR part 60, appendix B of this chapter, you shall collect PM and oxygen (or carbon dioxide) data concurrently (or within a 30-to 60-minute period) by both the CEMS and conducting performance tests using Method 5 at 40 CFR part 60, appendix A-3 or Method 17 at 40 CFR part 60, appendix A-6 of this chapter.

(iii) You shall perform quarterly accuracy determinations and daily calibration drift tests in accordance with Procedure 2 at 40 CFR part 60, appendix F of this chapter. You must perform Relative Response Audits annually and perform Response Correlation Audits every 3 years.

(iv) Within 60 days after the date of completing each CEMS relative accuracy test audit or performance test conducted to demonstrate compliance with this subpart, you must submit the relative accuracy test audit data and performance test data to the EPA by successfully submitting the data electronically into the EPA's Central Data Exchange by using the Electronic Reporting Tool (see *http://www.epa.gov/ttn/chief/ert/erttool.html/*).

(6) For a new unit, complete the initial performance evaluation no later than July 30, 2013, or 180 days after the date of initial startup, whichever is later. For an existing unit, complete the initial performance evaluation no later than July 29, 2016.

(7) Collect PM CEMS hourly average output data for all boiler or process heater operating hours except as indicated in § 63.7535(a) through (d).

(8) Calculate the arithmetic 30-day rolling average of all of the hourly average PM CEMS output data collected during all boiler or process heater operating hours.

(c) If you have an applicable opacity operating limit in this rule, and are not otherwise required or elect to install and operate a PM CPMS, PM CEMS, or a bag leak detection system, you must install, operate, certify and maintain each COMS according to the procedures in paragraphs (c)(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 Performance Specification 1 at appendix B to part 60 of this chapter.

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

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

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

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

(6) You must operate and maintain each COMS according to the requirements in the monitoring plan and the requirements of § 63.8(e). You must identify periods the COMS is out of control including any periods that the COMS fails to pass a daily calibration drift assessment, a quarterly performance audit, or an annual zero alignment audit. Any 6-minute period for which the monitoring system is out of control and data are not available for a required calculation constitutes a deviation from the monitoring requirements.

(7) You must determine and record all the 6-minute averages (and daily block averages as applicable) collected for periods during which the COMS is not out of control.

(d) If you have an operating limit that requires the use of a CMS other than a PM CPMS or COMS, you must install, operate, and maintain each CMS according to the procedures in paragraphs (d)(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 every 15-minutes. You must have a minimum of four successive cycles of operation, one representing each of the four 15-minute periods in an hour, to have a valid hour of data.

(2) You must operate the monitoring system as specified in § 63.7535(b), and comply with the data calculation requirements specified in § 63.7535(c).

(3) Any 15-minute period for which the monitoring system is out-of-control and data are not available for a required calculation constitutes a deviation from the monitoring requirements. Other situations that constitute a monitoring deviation are specified in § 63.7535(d).

(4) You must determine the 30-day rolling average of all recorded readings, except as provided in § 63.7535(c).

(5) You must record the results of each inspection, calibration, and validation check.

(e) If you have an operating limit that requires the use of a flow monitoring system, you must meet the requirements in paragraphs (d) and (e)(1) through (4) of this section.

(1) You must install the flow sensor and other necessary equipment in a position that provides a representative flow.

(2) You must use a flow sensor with a measurement sensitivity of no greater than 2 percent of the design flow rate.

(3) You must minimize, consistent with good engineering practices, the effects of swirling flow or abnormal velocity distributions due to upstream and downstream disturbances.

(4) You must conduct a flow monitoring system performance evaluation in accordance with your monitoring plan at the time of each performance test but no less frequently than annually.

(f) If you have an operating limit that requires the use of a pressure monitoring system, you must meet the requirements in paragraphs (d) and (f)(1) through (6) of this section.

(1) Install the pressure sensor(s) in a position that provides a representative measurement of the pressure (*e.g.* , PM scrubber pressure drop).

(2) Minimize or eliminate pulsating pressure, vibration, and internal and external corrosion consistent with good engineering practices.

(3) Use a pressure sensor with a minimum tolerance of 1.27 centimeters of water or a minimum tolerance of 1 percent of the pressure monitoring system operating range, whichever is less.

(4) Perform checks at least once each process operating day to ensure pressure measurements are not obstructed (*e.g.* , check for pressure tap pluggage daily).

(5) Conduct a performance evaluation of the pressure monitoring system in accordance with your monitoring plan at the time of each performance test but no less frequently than annually.

(6) If at any time the measured pressure exceeds the manufacturer's specified maximum operating pressure range, conduct a performance evaluation of the pressure monitoring system in accordance with your monitoring plan and confirm that the pressure monitoring system continues to meet the performance requirements in you monitoring plan. Alternatively, install and verify the operation of a new pressure sensor.

(g) If you have an operating limit that requires a pH monitoring system, you must meet the requirements in paragraphs (d) and (g)(1) through (4) of this section.

(1) Install 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) Conduct a performance evaluation of the pH monitoring system in accordance with your monitoring plan at least once each process operating day.

(4) Conduct a performance evaluation (including a two-point calibration with one of the two buffer solutions having a pH within 1 of the pH of the operating limit) of the pH monitoring system in accordance with your monitoring plan at the time of each performance test but no less frequently than quarterly.

(h) If you have an operating limit that requires a secondary electric power monitoring system for an electrostatic precipitator (ESP) operated with a wet scrubber, you must meet the requirements in paragraphs (h)(1) and (2) of this section.

(1) Install sensors to measure (secondary) voltage and current to the precipitator collection plates.

(2) Conduct a performance evaluation of the electric power monitoring system in accordance with your monitoring plan at the time of each performance test but no less frequently than annually.

(i) If you have an operating limit that requires the use of a monitoring system to measure sorbent injection rate (e.g., weigh belt, weigh hopper, or hopper flow measurement device), you must meet the requirements in paragraphs (d) and (i)(1) through (2) of this section.

(1) Install the system in a position(s) that provides a representative measurement of the total sorbent injection rate.

(2) Conduct a performance evaluation of the sorbent injection rate monitoring system in accordance with your monitoring plan at the time of each performance test but no less frequently than annually.

(j) If you are not required to use a PM CPMS and 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 the bag leak detection system as specified in paragraphs (j)(1) through (6) of this section.

(1) You must install a bag leak detection sensor(s) in a position(s) that will be representative of the relative or absolute PM loadings for each exhaust stack, roof vent, or compartment (e.g., for a positive pressure fabric filter) of the fabric filter.

(2) Conduct a performance evaluation of the bag leak detection system in accordance with your monitoring plan and consistent with the guidance provided in EPA-454/R-98-015 (incorporated by reference, see § 63.14).

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

(4) Use a bag leak detection system equipped with a device to record continuously the output signal from the sensor.

(5) Use a bag leak detection system equipped with a system that will alert plant operating personnel when an increase in relative PM emissions over a preset level is detected. The alert must easily recognizable (e.g., heard or seen) by plant operating personnel.

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

(k) For each unit that meets the definition of limited-use boiler or process heater, you must keep fuel use records for the days the boiler or process heater was operating.

(l) For each unit for which you decide to demonstrate compliance with the mercury or HCl emissions limits in Tables 1 or 2 or 11 through 13 of this subpart by use of a CEMS for mercury or HCl, you must install, certify, maintain, and operate a CEMS measuring emissions discharged to the atmosphere and record the output of the system as specified in paragraphs (l)(1) through (8) of this section. For HCl, this option for an affected unit takes effect on the date a final performance specification for a HCl CEMS is published in the FEDERAL REGISTER or the date of approval of a site-specific monitoring plan.

(1) Notify the Administrator one month before starting use of the CEMS, and notify the Administrator one month before stopping use of the CEMS.

(2) Each CEMS shall be installed, certified, operated, and maintained according to the requirements in § 63.7540(a)(14) for a mercury CEMS and § 63.7540(a)(15) for a HCl CEMS.

(3) For a new unit, you must complete the initial performance evaluation of the CEMS by the latest of the dates specified in paragraph (l)(3)(i) through (iii) of this section.

(i) No later than July 30, 2013.

(ii) No later 180 days after the date of initial startup.

(iii) No later 180 days after notifying the Administrator before starting to use the CEMS in place of performance testing or fuel analysis to demonstrate compliance.

(4) For an existing unit, you must complete the initial performance evaluation by the latter of the two dates specified in paragraph (l)(4)(i) and (ii) of this section.

(i) No later than July 29, 2016.

(ii) No later 180 days after notifying the Administrator before starting to use the CEMS in place of performance testing or fuel analysis to demonstrate compliance.

(5) Compliance with the applicable emissions limit shall be determined based on the 30-day rolling average of the hourly arithmetic average emissions rates using the continuous monitoring system outlet data. The 30-day rolling arithmetic average emission rate (lb/MMBtu) shall be calculated using the equations in EPA Reference Method 19 at 40 CFR part 60, appendix A-7, but substituting the mercury or HCl concentration for the pollutant concentrations normally used in Method 19.

(6) Collect CEMS hourly averages for all operating hours on a 30-day rolling average basis. Collect at least four CMS data values representing the four 15-minute periods in an hour, or at least two 15-minute data values during an hour when CMS calibration, quality assurance, or maintenance activities are being performed.

(7) The one-hour arithmetic averages required shall be expressed in lb/MMBtu and shall be used to calculate the boiler 30-day and 10-day rolling average emissions.

(8) You are allowed to substitute the use of the PM, mercury or HCl CEMS for the applicable fuel analysis, annual performance test, and operating limits specified in Table 4 to this subpart to demonstrate compliance with the PM, mercury or HCl emissions limit, and if you are using an acid gas wet scrubber or dry sorbent injection control technology to comply with the HCl emission limit, you are allowed to substitute the use of a sulfur dioxide (SO_2) CEMS for the applicable fuel analysis, annual performance test, and operating limits specified in Table 4 to this subpart to demonstrate compliance with HCl emissions limit.

(m) If your unit is subject to a HCl emission limit in Tables 1, 2, or 11 through 13 of this subpart and you have an acid gas wet scrubber or dry sorbent injection control technology and you use an SO_2 CEMS, you must install the monitor at the outlet of the boiler or process heater, downstream of all emission control devices, and you must install, certify, operate, and maintain the CEMS according to part 75 of this chapter.

(1) The SO_2 CEMS must be installed by the compliance date specified in § 63.7495.

(2) For on-going quality assurance (QA), the SO_2 CEMS must meet the applicable daily, quarterly, and semiannual or annual requirements in sections 2.1 through 2.3 of appendix B to part 75 of this chapter, with the following addition: You must perform the linearity checks required in section 2.2 of appendix B to part 75 of this chapter if the SO_2 CEMS has a span value of 30 ppm or less.

(3) For a new unit, the initial performance evaluation shall be completed no later than July 30, 2013, or 180 days after the date of initial startup, whichever is later. For an existing unit, the initial performance evaluation shall be completed no later than July 29, 2016.

(4) For purposes of collecting SO_2 data, you must operate the SO_2 CEMS as specified in § 63.7535(b). You must use all the data collected during all periods in calculating data averages and assessing compliance, except that you must exclude certain data as specified in § 63.7535(c). Periods when SO_2 data are unavailable may constitute monitoring deviations as specified in § 63.7535(d).

(5) Collect CEMS hourly averages for all operating hours on a 30-day rolling average basis.

(6) Use only unadjusted, quality-assured SO_2 concentration values in the emissions calculations; do not apply bias adjustment factors to the part 75 SO_2 data and do not use part 75 substitute data values.

[76 FR 15664, Mar. 21, 2011, as amended at 78 FR 7171, Jan. 31, 2013]

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§ 63.7530 How do I demonstrate initial compliance with the emission limitations, fuel specifications and work practice standards?

(a) You must demonstrate initial compliance with each emission limit that applies to you by conducting initial performance tests and fuel analyses and establishing operating limits, as applicable, according to § 63.7520, paragraphs (b) and (c) of this section, and Tables 5 and 7 to this subpart. The requirement to conduct a fuel analysis is not applicable for units that burn a single type of fuel, as specified by § 63.7510(a)(2)(i). If applicable, you must also install, operate, and maintain all applicable CMS (including CEMS, COMS, and CPMS) according to § 63.7525.

(b) If you demonstrate compliance through performance testing, you must establish each site-specific operating limit in Table 4 to this subpart that applies to you according to the requirements in § 63.7520, Table 7 to this subpart, and paragraph (b)(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 (b)(1) through (3) of this section, as applicable, and as specified in § 63.7510(a)(2). (Note that § 63.7510(a)(2) exempts certain fuels from the fuel analysis requirements.) However, if you switch fuel(s) and cannot show that the new fuel(s) does (do) not increase the chlorine, mercury, or TSM input into the unit through the results of fuel analysis, then you must repeat the performance test to demonstrate compliance while burning the new fuel(s).

(1) You must establish the maximum chlorine fuel input (Clinput) during the initial fuel analysis according to the procedures in paragraphs (b)(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 fuel analysis for hydrogen chloride, you must determine the fraction of the total heat input for each fuel type burned (Qi) based on the fuel mixture that has the highest content of chlorine, and the average chlorine concentration of each fuel type burned (Ci).

(iii) You must establish a maximum chlorine input level using Equation 7 of this section.

$$Clinput = \sum_{i=1}^{n} (Ci \times Qi) \quad \text{(Eq. 7)}$$

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Where:

Clinput = Maximum amount of chlorine entering the boiler or process heater through fuels burned in units of pounds per million Btu.

Ci = Arithmetic average concentration of chlorine in fuel type, i, analyzed according to § 63.7521, in units of pounds per million Btu.

Qi = 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 Qi.

n = Number of different fuel types burned in your boiler or process heater for the mixture that has the highest content of chlorine.

(2) You must establish the maximum mercury fuel input level (Mercuryinput) during the initial fuel analysis using the procedures in paragraphs (b)(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 mercury.

(ii) During the compliance demonstration for mercury, you must determine the fraction of total heat input for each fuel burned (Qi) based on the fuel mixture that has the highest content of mercury, and the average mercury concentration of each fuel type burned (HGi).

(iii) You must establish a maximum mercury input level using Equation 8 of this section.

$$Mercuryinput = \sum_{i=1}^{n} (HGi \times Qi) \qquad \text{(Eq. 8)}$$

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Where:

Mercuryinput = Maximum amount of mercury entering the boiler or process heater through fuels burned in units of pounds per million Btu.

HGi = Arithmetic average concentration of mercury in fuel type, i, analyzed according to § 63.7521, in units of pounds per million Btu.

Qi = 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 Qi.

n = Number of different fuel types burned in your boiler or process heater for the mixture that has the highest content of mercury.

(3) If you opt to comply with the alternative TSM limit, you must establish the maximum TSM fuel input (TSMinput) for solid or liquid fuels during the initial fuel analysis according to the procedures in paragraphs (b)(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 TSM.

(ii) During the fuel analysis for TSM, you must determine the fraction of the total heat input for each fuel type burned (Qi) based on the fuel mixture that has the highest content of TSM, and the average TSM concentration of each fuel type burned (TSMi).

(iii) You must establish a maximum TSM input level using Equation 9 of this section.

$$TSMinput = \sum_{i=1}^{n} (TSMi \times Qi) \qquad \text{(Eq. 9)}$$

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Where:

TSMinput = Maximum amount of TSM entering the boiler or process heater through fuels burned in units of pounds per million Btu.

TSMi = Arithmetic average concentration of TSM in fuel type, i, analyzed according to § 63.7521, in units of pounds per million Btu.

Qi = Fraction of total heat input from 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 testing, it is not necessary to determine the value of this term. Insert a value of "1" for Qi.

n = Number of different fuel types burned in your boiler or process heater for the mixture that has the highest content of TSM.

(4) You must establish parameter operating limits according to paragraphs (b)(4)(i) through (ix) of this section. As indicated in Table 4 to this subpart, you are not required to establish and comply with the operating parameter limits when you are using a CEMS to monitor and demonstrate compliance with the applicable emission limit for that control device parameter.

(i) For a wet acid gas scrubber, you must establish the minimum scrubber effluent pH and liquid flow rate as defined in § 63.7575, as your operating limits during the performance test during which you demonstrate compliance with your applicable limit. If you use a wet scrubber and you conduct separate performance tests for HCl and mercury emissions, you must establish one set of minimum scrubber effluent pH, liquid flow rate, 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 flow rate operating limit at the higher of the minimum values established during the performance tests.

(ii) For any particulate control device (e.g., ESP, particulate wet scrubber, fabric filter) for which you use a PM CPMS, you must establish your PM CPMS operating limit and determine compliance with it according to paragraphs (b)(4)(ii)(A) through (F) of this section.

(A) Determine your operating limit as the average PM CPMS output value recorded during the most recent performance test run demonstrating compliance with the filterable PM emission limit or at the PM CPMS output value corresponding to 75 percent of the emission limit if your PM performance test demonstrates compliance below 75 percent of the emission limit. You must verify an existing or establish a new operating limit after each repeated performance test. You must repeat the performance test annually and reassess and adjust the site-specific operating limit in accordance with the results of the performance test.

(***1*** **) Your PM CPMS must provide a 4-20 milliamp output and the establishment of its relationship to manual reference method measurements must be determined in units of milliamps.**

(***2*** **) Your PM CPMS operating range must be capable of reading PM concentrations from zero to a level equivalent to at least two times your allowable emission limit. If your PM CPMS is an auto-ranging instrument capable of multiple scales, the primary range of the instrument must be capable of reading PM concentration from zero to a level equivalent to two times your allowable emission limit.**

(***3*** **) During the initial performance test or any such subsequent performance test that demonstrates compliance with the PM limit, record and average all milliamp output values from the PM CPMS for the periods corresponding to the compliance test runs (e.g., average all your PM CPMS output values for three corresponding 2-hour Method 5I test runs).**

(B) If the average of your three PM performance test runs are below 75 percent of your PM emission limit, you must calculate an operating limit by establishing a relationship of PM CPMS signal to PM concentration using the PM CPMS instrument zero, the average PM CPMS values corresponding to the three compliance test runs, and the average PM concentration from the Method 5 or performance test with the procedures in paragraphs (b)(4)(ii)(B)(*1*) through (*4*) of this section.

(*1*) Determine your instrument zero output with one of the following procedures:

(*i*) Zero point data for *in-situ* instruments should be obtained by removing the instrument from the stack and monitoring ambient air on a test bench.

(*ii*) Zero point data for *extractive* instruments should be obtained by removing the extractive probe from the stack and drawing in clean ambient air.

(*iii*) The zero point may also be established by performing manual reference method measurements when the flue gas is free of PM emissions or contains very low PM concentrations (e.g., when your process is not operating, but the fans are operating or your source is combusting only natural gas) and plotting these with the compliance data to find the zero intercept.

(*iv*) If none of the steps in paragraphs (b)(4)(ii)(B)(*1*)(*i*) through (*iii*) of this section are possible, you must use a zero output value provided by the manufacturer.

(*2*) Determine your PM CPMS instrument average in milliamps, and the average of your corresponding three PM compliance test runs, using equation 10.

$$\bar{X} = \frac{1}{n}\sum_{i=1}^{n} X_1, \bar{Y} = \frac{1}{n}\sum_{i=1}^{n} Y_1 \qquad \text{(Eq. 10)}$$

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Where:

X_1 = the PM CPMS data points for the three runs constituting the performance test,

Y_1 = the PM concentration value for the three runs constituting the performance test, and

n = the number of data points.

(*3*) With your instrument zero expressed in milliamps, your three run average PM CPMS milliamp value, and your three run average PM concentration from your three compliance tests, determine a relationship of lb/MMBtu per milliamp with equation 11.

$$R = \frac{Y_1}{(X_1 - z)} \qquad \text{(Eq. 11)}$$

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Where:

R = the relative lb/MMBtu per milliamp for your PM CPMS,

Y_1 = the three run average lb/MMBtu PM concentration,

X_1 = the three run average milliamp output from you PM CPMS, and

z = the milliamp equivalent of your instrument zero determined from (B)(i).

(*4*) Determine your source specific 30-day rolling average operating limit using the lb/MMBtu per milliamp value from Equation 11 in equation 12, below. This sets your operating limit at the PM CPMS output value corresponding to 75 percent of your emission limit.

$$O_l = z + \frac{0.75(L)}{R} \qquad \text{(Eq. 12)}$$

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Where:

O_l = the operating limit for your PM CPMS on a 30-day rolling average, in milliamps.

L = your source emission limit expressed in lb/MMBtu,

z = your instrument zero in milliamps, determined from (B)(i), and

R = the relative lb/MMBtu per milliamp for your PM CPMS, from Equation 11.

(C) If the average of your three PM compliance test runs is at or above 75 percent of your PM emission limit you must determine your 30-day rolling average operating limit by averaging the PM CPMS milliamp output corresponding to your three PM performance test runs that demonstrate compliance with the emission limit using equation 13 and you must submit all compliance test and PM CPMS data according to the reporting requirements in paragraph (b)(4)(ii)(F) of this section.

$$O_h = \frac{1}{n}\sum_{i=1}^{n} X_1 \qquad \text{(Eq. 13)}$$

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Where:

X_1 = the PM CPMS data points for all runs i,

n = the number of data points, and

O_h = your site specific operating limit, in milliamps.

(D) To determine continuous compliance, you must record the PM CPMS output data for all periods when the process is operating and the PM CPMS is not out-of-control. You must demonstrate continuous compliance by using all quality-assured hourly average data collected by the PM CPMS for all operating hours to calculate the arithmetic average operating parameter in units of the operating limit (milliamps) on a 30-day rolling average basis, updated at the end of each new operating hour. Use Equation 14 to determine the 30-day rolling average.

$$30-\text{day} = \frac{\sum_{i=1}^{n} Hpvi}{n} \qquad \text{(Eq. 14)}$$

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Where:

30-day = 30-day average.

Hpvi = is the hourly parameter value for hour i

n = is the number of valid hourly parameter values collected over the previous 720 operating hours.

(E) Use EPA Method 5 of appendix A to part 60 of this chapter to determine PM emissions. For each performance test, conduct three separate runs under the conditions that exist when the affected source is operating at the highest load or capacity level reasonably expected to occur. Conduct each test run to collect a minimum sample volume specified in Tables 1, 2, or 11 through 13 to this subpart, as applicable, for determining compliance with a new source limit or an existing source limit. Calculate the average of the results from three runs to determine compliance. You need not determine the PM collected in the impingers ("back half") of the Method 5 particulate sampling train to demonstrate compliance with the PM standards of this subpart. This shall not preclude the permitting authority from requiring a determination of the "back half" for other purposes.

(F) For PM performance test reports used to set a PM CPMS operating limit, the electronic submission of the test report must also include the make and model of the PM CPMS instrument, serial number of the instrument, analytical principle of the instrument (e.g. beta attenuation), span of the instruments primary analytical range, milliamp value equivalent to the instrument zero output, technique by which this zero value was determined, and the average milliamp signals corresponding to each PM compliance test run.
(iii) For a particulate wet scrubber, you must establish the minimum pressure drop and liquid flow rate as defined in § 63.7575, as your operating limits during the three-run performance test during which you demonstrate compliance with your applicable limit. If you use a wet scrubber and you conduct separate performance tests for PM and TSM emissions, you must establish one set of minimum scrubber liquid flow rate 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 flow rate and pressure drop operating limits at the higher of the minimum values established during the performance tests.

(iii) For an electrostatic precipitator (ESP) operated with a wet scrubber, you must establish the minimum total secondary electric power input, as defined in § 63.7575, as your operating limit during the three-run performance test during which you demonstrate compliance with your applicable limit. (These operating limits do not apply to ESP that are operated as dry controls without a wet scrubber.)

(iv) For a dry scrubber, you must establish the minimum sorbent injection rate for each sorbent, as defined in § 63.7575, as your operating limit during the three-run performance test during which you demonstrate compliance with your applicable limit.

(v) For activated carbon injection, you must establish the minimum activated carbon injection rate, as defined in § 63.7575, as your operating limit during the three-run performance test during which you demonstrate compliance with your applicable limit.

(vi) The operating limit for boilers or process heaters with fabric filters that demonstrate continuous compliance through bag leak detection systems is that a bag leak detection system be installed according to the requirements in § 63.7525, and that each fabric filter must be operated such that the bag leak detection system alert is not activated more than 5 percent of the operating time during a 6-month period.

(vii) For a minimum oxygen level, if you conduct multiple performance tests, you must set the minimum oxygen level at the lower of the minimum values established during the performance tests.

(viii) The operating limit for boilers or process heaters that demonstrate continuous compliance with the HCl emission limit using a SO_2 CEMS is to install and operate the SO_2 according to the requirements in

§ 63.7525(m) establish a maximum SO_2 emission rate equal to the highest hourly average SO_2 measurement during the most recent three-run performance test for HCl.

(c) 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 (c)(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 t-statistic test described in Equation 15 of this section.

$$P90 = mean + (SD \times t) \qquad \text{(Eq. 15)}$$

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Where:

P90 = 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 mean of pollutant concentration in the fuel samples analyzed according to § 63.7521, in units of pounds per million Btu. SD is calculated as the sample standard deviation divided by the square root of the number of samples.

t = t distribution critical value for 90th percentile ($t_{0.1}$) probability for the appropriate degrees of freedom (number of samples minus one) as obtained from a t-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 16 of this section must not exceed the applicable emission limit for HCl.

$$HCl = \sum_{i=1}^{n} (Ci90 \times Qi \times 1.028) \qquad \text{(Eq. 16)}$$

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Where:

HCl = HCl emission rate from the boiler or process heater in units of pounds per million Btu.

Ci90 = 90th percentile confidence level concentration of chlorine in fuel type, i, in units of pounds per million Btu as calculated according to Equation 11 of this section.

Qi = 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 Qi.

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 mercury, the mercury emission rate that you calculate for your boiler or process heater using Equation 17 of this section must not exceed the applicable emission limit for mercury.

$$Mercury = \sum_{i=1}^{n} \left(Hgi90 \times Qi \right) \qquad \text{(Eq. 17)}$$

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Where:

Mercury = Mercury emission rate from the boiler or process heater in units of pounds per million Btu.

Hgi90 = 90th percentile confidence level concentration of mercury in fuel, i, in units of pounds per million Btu as calculated according to Equation 11 of this section.

Qi = 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 Qi.

n = Number of different fuel types burned in your boiler or process heater for the mixture that has the highest mercury content.

(5) To demonstrate compliance with the applicable emission limit for TSM for solid or liquid fuels, the TSM emission rate that you calculate for your boiler or process heater from solid fuels using Equation 18 of this section must not exceed the applicable emission limit for TSM.

$$Metals = \sum_{i=1}^{n} \left(TSM90i \times Qi \right) \qquad \text{(Eq. 18)}$$

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Where:

Metals = TSM emission rate from the boiler or process heater in units of pounds per million Btu.

TSMi90 = 90th percentile confidence level concentration of TSM in fuel, i, in units of pounds per million Btu as calculated according to Equation 11 of this section.

Qi = Fraction of total heat input from fuel type, i, based on the fuel mixture that has the highest TSM 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 Qi.

n = Number of different fuel types burned in your boiler or process heater for the mixture that has the highest TSM content.

(d) If you own or operate an existing unit with a heat input capacity of less than 10 million Btu per hour or a unit in the unit designed to burn gas 1 subcategory, you must submit a signed statement in the Notification of Compliance Status report that indicates that you conducted a tune-up of the unit.

(e) You must include with the Notification of Compliance Status a signed certification that the energy assessment was completed according to Table 3 to this subpart and is an accurate depiction of your facility at the time of the assessment.

(f) You must submit the Notification of Compliance Status containing the results of the initial compliance demonstration according to the requirements in § 63.7545(e).

(g) If you elect to demonstrate that a gaseous fuel meets the specifications of another gas 1 fuel as defined in § 63.7575, you must conduct an initial fuel specification analyses according to § 63.7521(f) through (i) and according to the frequency listed in § 63.7540(c) and maintain records of the results of the testing as outlined in § 63.7555(g). For samples where the initial mercury specification has not been exceeded, you will include a signed certification with the Notification of Compliance Status that the initial fuel specification test meets the gas specification outlined in the definition of other gas 1 fuels.

(h) If you own or operate a unit subject to emission limits in Tables 1 or 2 or 11 through 13 to this subpart, you must meet the work practice standard according to Table 3 of this subpart. During startup and shutdown, you must only follow the work practice standards according to item 5 of Table 3 of this subpart.

(i) If you opt to comply with the alternative SO_2 CEMS operating limit in Tables 4 and 8 to this subpart, you may do so only if your affected boiler or process heater:

(1) Has a system using wet scrubber or dry sorbent injection and SO_2 CEMS installed on the unit; and

(2) At all times, you operate the wet scrubber or dry sorbent injection for acid gas control on the unit consistent with § 63.7500(a)(3); and

(3) You establish a unit-specific maximum SO_2 operating limit by collecting the minimum hourly SO_2 emission rate on the SO_2 CEMS during the paired 3-run test for HCl. The maximum SO_2 operating limit is equal to the highest hourly average SO_2 concentration measured during the most recent HCl performance test.

[76 FR 15664, Mar. 21, 2013, as amended at 78 FR 7174, Jan. 31, 2013]

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§ 63.7533 Can I use efficiency credits earned from implementation of energy conservation measures to comply with this subpart?

(a) If you elect to comply with the alternative equivalent output-based emission limits, instead of the heat input-based limits listed in Table 2 to this subpart, and you want to take credit for implementing energy conservation measures identified in an energy assessment, you may demonstrate compliance using efficiency credits according to the procedures in this section. You may use this compliance approach for an existing affected boiler for demonstrating initial compliance according to § 63.7522(e) and for demonstrating monthly compliance according to § 63.7522(f). Owners or operators using this compliance approach must establish an emissions benchmark, calculate and document the efficiency credits, develop an Implementation Plan, comply with the general reporting requirements, and apply the efficiency credit according to the procedures in paragraphs (b) through (f) of this section. You cannot use this compliance approach for a new or reconstructed affected boiler. Additional guidance from the Department of Energy on efficiency credits is available at: *http://www.epa.gov/ttn/atw/boiler/boilerpg.html* .

(b) For each existing affected boiler for which you intend to apply emissions credits, establish a benchmark from which emission reduction credits may be generated by determining the actual annual fuel heat input to the affected boiler before initiation of an energy conservation activity to reduce energy demand (*i.e.,* fuel usage) according to paragraphs (b)(1) through (4) of this section. The benchmark shall be expressed in trillion Btu per year heat input.

(1) The benchmark from which efficiency credits may be generated shall be determined by using the most representative, accurate, and reliable process available for the source. The benchmark shall be established for a one-year period before the date that an energy demand reduction occurs, unless it can be demonstrated that a different time period is more representative of historical operations.

(2) Determine the starting point from which to measure progress. Inventory all fuel purchased and generated on-site (off-gases, residues) in physical units (MMBtu, million cubic feet, etc.).

(3) Document all uses of energy from the affected boiler. Use the most recent data available.

(4) Collect non-energy related facility and operational data to normalize, if necessary, the benchmark to current operations, such as building size, operating hours, etc. If possible, use actual data that are current and timely rather than estimated data.

(c) Efficiency credits can be generated if the energy conservation measures were implemented after January 1, 2008 and if sufficient information is available to determine the appropriate value of credits.

(1) The following emission points cannot be used to generate efficiency credits:

(i) Energy conservation measures implemented on or before January 1, 2008, unless the level of energy demand reduction is increased after January 1, 2008, in which case credit will be allowed only for change in demand reduction achieved after January 1, 2008.

(ii) Efficiency credits on shut-down boilers. Boilers that are shut down cannot be used to generate credits unless the facility provides documentation linking the permanent shutdown to energy conservation measures identified in the energy assessment. In this case, the bench established for the affected boiler to which the credits from the shutdown will be applied must be revised to include the benchmark established for the shutdown boiler.

(2) For all points included in calculating emissions credits, the owner or operator shall:

(i) Calculate annual credits for all energy demand points. Use Equation 19 to calculate credits. Energy conservation measures that meet the criteria of paragraph (c)(1) of this section shall not be included, except as specified in paragraph (c)(1)(i) of this section.

(3) Credits are generated by the difference between the benchmark that is established for each affected boiler, and the actual energy demand reductions from energy conservation measures implemented after January 1, 2008. Credits shall be calculated using Equation 19 of this section as follows:

(i) The overall equation for calculating credits is:

$$ECredits = \left(\sum_{i=1}^{n} EIS_{iactual} \right) \div EI_{baseline} \qquad \text{(Eq. 19)}$$

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Where:

ECredits = Energy Input Savings for all energy conservation measures implemented for an affected boiler, expressed as a decimal fraction of the baseline energy input.

$EIS_{iactual}$ = Energy Input Savings for each energy conservation measure, i, implemented for an affected boiler, million Btu per year.

$EI_{baseline}$ = Energy Input baseline for the affected boiler, million Btu per year.

n = Number of energy conservation measures included in the efficiency credit for the affected boiler.

(ii) [Reserved]

(d) The owner or operator shall develop, and submit for approval upon request by the Administrator, an Implementation Plan containing all of the information required in this paragraph for all boilers to be included in an efficiency credit approach. The Implementation Plan shall identify all existing affected boilers to be included in applying the efficiency credits. The Implementation Plan shall include a description of the energy conservation measures implemented and the energy savings generated from each measure and an explanation of the criteria used for determining that savings. If requested, you must submit the implementation plan for efficiency credits to the Administrator for review and approval no later than 180 days before the date on which the facility intends to demonstrate compliance using the efficiency credit approach.

(e) The emissions rate as calculated using Equation 20 of this section from each existing boiler participating in the efficiency credit option must be in compliance with the limits in Table 2 to this subpart at all times the affected unit is operating, following the compliance date specified in § 63.7495.

(f) You must use Equation 20 of this section to demonstrate initial compliance by demonstrating that the emissions from the affected boiler participating in the efficiency credit compliance approach do not exceed the emission limits in Table 2 to this subpart.

$$E_{adj} = E_m \times (1 - ECredits) \quad \text{(Eq. 20)}$$

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Where:

E_{adj} = Emission level adjusted by applying the efficiency credits earned, lb per million Btu steam output (or lb per MWh) for the affected boiler.

E_m = Emissions measured during the performance test, lb per million Btu steam output (or lb per MWh) for the affected boiler.

ECredits = Efficiency credits from Equation 19 for the affected boiler.

(g) As part of each compliance report submitted as required under § 63.7550, you must include documentation that the energy conservation measures implemented continue to generate the credit for use in demonstrating compliance with the emission limits.

[76 FR 15664, Mar. 21, 2011, as amended at 78 FR 7178, Jan. 21, 2013]

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Continuous Compliance Requirements

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§ 63.7535 Is there a minimum amount of monitoring data I must obtain?

(a) You must monitor and collect data according to this section and the site-specific monitoring plan required by § 63.7505(d).

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

(c) You may not use data recorded during monitoring system malfunctions or out-of-control periods, repairs associated with monitoring system malfunctions or out-of-control periods, or required monitoring system quality assurance or control activities in data averages and calculations used to report emissions or operating levels. You must record and make available upon request results of CMS performance audits and dates and duration of periods when the CMS is out of control to completion of the corrective actions necessary to return the CMS to operation consistent with your site-specific monitoring plan. You must use all the data collected during all other periods in assessing compliance and the operation of the control device and associated control system.

(d) Except for periods of monitoring system malfunctions, repairs associated with monitoring system malfunctions, and required monitoring system quality assurance or quality control activities (including, as applicable, system accuracy audits, calibration checks, and required zero and span adjustments), failure to collect required data is a deviation of the monitoring requirements. In calculating monitoring results, do not use any data collected during periods when the monitoring system is out of control as specified in your site-specific monitoring plan, while conducting repairs associated with periods when the monitoring system is out of control, or while conducting required monitoring system quality assurance or quality control activities. You must calculate monitoring results using all other monitoring data collected while the process is operating. You must report all periods when the monitoring system is out of control in your annual report.

[76 FR 15664, Mar. 21, 2011, as amended at 78 FR 7179, Jan. 31, 2013]

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§ 63.7540 How do I demonstrate continuous compliance with the emission limitations, fuel specifications and work practice standards?

(a) You must demonstrate continuous compliance with each emission limit in Tables 1 and 2 or 11 through 13 to this subpart, the work practice standards in Table 3 to this subpart, and the operating limits in Table 4 to this subpart that applies to you according to the methods specified in Table 8 to this subpart and paragraphs (a)(1) through (19) of this section.

(1) Following the date on which the initial compliance demonstration is completed or is required to be completed under §§ 63.7 and 63.7510, whichever date comes first, operation above the established maximum or below the established minimum operating limits shall constitute a deviation of established operating limits listed in Table 4 of this subpart except during performance tests conducted to determine compliance with the emission limits or to establish new operating limits. Operating limits must be confirmed or reestablished during performance tests.

(2) As specified in § 63.7550(c), 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 result in either of the following:

(i) Lower emissions of HCl, mercury, and TSM than the applicable emission limit for each pollutant, if you demonstrate compliance through fuel analysis.

(ii) Lower fuel input of chlorine, mercury, and TSM than the maximum values calculated during the last performance test, if you demonstrate compliance through performance testing.

(3) If you demonstrate compliance with an applicable HCl emission limit through fuel analysis for a solid or liquid fuel and you plan to burn a new type of solid or liquid fuel, you must recalculate the HCl emission rate using Equation 12 of § 63.7530 according to paragraphs (a)(3)(i) through (iii) of this section. You are not required to conduct fuel analyses for the fuels described in § 63.7510(a)(2)(i) through (iii). You may exclude the fuels described in § 63.7510(a)(2)(i) through (iii) when recalculating the HCl emission rate.

(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 12 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 7 of § 63.7530. If the results of recalculating the maximum chlorine input using Equation 7 of § 63.7530 are greater 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(b). In recalculating the maximum chlorine input and establishing the new operating limits, you are not required to conduct fuel analyses for and include the fuels described in § 63.7510(a)(2)(i) through (iii).

(5) 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 13 of § 63.7530 according to the procedures specified in paragraphs (a)(5)(i) through (iii) of this section. You are not required to conduct fuel analyses for the fuels described in § 63.7510(a)(2)(i) through (iii). You may exclude the fuels described in § 63.7510(a)(2)(i) through (iii) when recalculating the mercury emission rate.

(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 13 of § 63.7530. The recalculated mercury emission rate must be less than the applicable emission limit.

(6) 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 8 of § 63.7530. If the results of recalculating the maximum mercury input using Equation 8 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(b). You are not required to conduct fuel analyses for the fuels described in § 63.7510(a)(2)(i) through (iii). You may exclude the fuels described in § 63.7510(a)(2)(i) through (iii) when recalculating the mercury emission rate.

(7) 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 alert and complete corrective actions as soon as practical, and operate and maintain the fabric filter system such that the periods which would cause an alert are no 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 alert, the time corrective action was initiated and completed, and a brief description of the cause of the alert and the corrective action taken. You must also record the percent of the operating time during each 6-month period that the conditions exist for an alert. In calculating this operating time percentage, if inspection of the fabric filter demonstrates that no corrective action is required, no alert time is counted. If corrective action is required, each alert shall be counted as a minimum of 1 hour. If you take longer than 1 hour to initiate corrective action, the alert time shall be counted as the actual amount of time taken to initiate corrective action.

(8) To demonstrate compliance with the applicable alternative CO CEMS emission limit listed in Tables 1, 2, or 11 through 13 to this subpart, you must meet the requirements in paragraphs (a)(8)(i) through (iv) of this section.

(i) Continuously monitor CO according to §§ 63.7525(a) and 63.7535.

(ii) Maintain a CO emission level below or at your applicable alternative CO CEMS-based standard in Tables 1 or 2 or 11 through 13 to this subpart at all times the affected unit is operating.

(iii) Keep records of CO levels according to § 63.7555(b).

(iv) You must record and make available upon request results of CO CEMS performance audits, dates and duration of periods when the CO CEMS is out of control to completion of the corrective actions necessary to return the CO CEMS to operation consistent with your site-specific monitoring plan.

(9) The owner or operator of a boiler or process heater using a PM CPMS or a PM CEMS to meet requirements of this subpart shall install, certify, operate, and maintain the PM CPMS or PM CEMS in accordance with your site-specific monitoring plan as required in § 63.7505(d).

(10) If your boiler or process heater has a heat input capacity of 10 million Btu per hour or greater, you must conduct an annual tune-up of the boiler or process heater to demonstrate continuous compliance as specified in paragraphs (a)(10)(i) through (vi) of this section. This frequency does not apply to limited-use boilers and process heaters, as defined in § 63.7575, or units with continuous oxygen trim systems that maintain an optimum air to fuel ratio.

(i) As applicable, inspect the burner, and clean or replace any components of the burner as necessary (you may delay the burner inspection until the next scheduled unit shutdown). Units that produce electricity for sale may delay the burner inspection until the first outage, not to exceed 36 months from the previous inspection. At units where entry into a piece of process equipment or into a storage vessel is required to complete the tune-up inspections, inspections are required only during planned entries into the storage vessel or process equipment;

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

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

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

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

(vi) Maintain on-site and submit, if requested by the Administrator, an annual report containing the information in paragraphs (a)(10)(vi)(A) through (C) of this section,

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

(B) A description of any corrective actions taken as a part of the tune-up; and

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

(11) If your boiler or process heater has a heat input capacity of less than 10 million Btu per hour (except as specified in paragraph (a)(12) of this section), you must conduct a biennial tune-up of the boiler or process heater as specified in paragraphs (a)(10)(i) through (vi) of this section to demonstrate continuous compliance.

(12) If your boiler or process heater has a continuous oxygen trim system that maintains an optimum air to fuel ratio, or a heat input capacity of less than or equal to 5 million Btu per hour and the unit is in the units designed to burn gas 1; units designed to burn gas 2 (other); or units designed to burn light liquid subcategories, or meets the definition of limited-use boiler or process heater in § 63.7575, you must conduct a tune-up of the boiler or process heater every 5 years as specified in paragraphs (a)(10)(i) through (vi) of this section to demonstrate continuous compliance. You may delay the burner inspection specified in paragraph (a)(10)(i) of this section until the next scheduled or unscheduled unit shutdown, but you must inspect each burner at least once every 72 months.

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

(14) If you are using a CEMS measuring mercury emissions to meet requirements of this subpart you must install, certify, operate, and maintain the mercury CEMS as specified in paragraphs (a)(14)(i) and (ii) of this section.

(i) Operate the mercury CEMS in accordance with performance specification 12A of 40 CFR part 60, appendix B or operate a sorbent trap based integrated monitor in accordance with performance specification 12B of 40 CFR part 60, appendix B. The duration of the performance test must be the maximum of 30 unit operating days or 720 hours. For each day in which the unit operates, you must obtain hourly mercury concentration data, and stack gas volumetric flow rate data.

(ii) If you are using a mercury CEMS, you must install, operate, calibrate, and maintain an instrument for continuously measuring and recording the mercury mass emissions rate to the atmosphere according to the requirements of performance specifications 6 and 12A of 40 CFR part 60, appendix B, and quality assurance procedure 6 of 40 CFR part 60, appendix F.

(15) If you are using a CEMS to measure HCl emissions to meet requirements of this subpart, you must install, certify, operate, and maintain the HCl CEMS as specified in paragraphs (a)(15)(i) and (ii) of this section. This option for an affected unit takes effect on the date a final performance specification for an HCl CEMS is published in the FEDERAL REGISTER or the date of approval of a site-specific monitoring plan.

(i) Operate the continuous emissions monitoring system in accordance with the applicable performance specification in 40 CFR part 60, appendix B. The duration of the performance test must be the maximum of 30 unit operating days or 720 hours. For each day in which the unit operates, you must obtain hourly HCl concentration data, and stack gas volumetric flow rate data.

(ii) If you are using a HCl CEMS, you must install, operate, calibrate, and maintain an instrument for continuously measuring and recording the HCl mass emissions rate to the atmosphere according to the requirements of the applicable performance specification of 40 CFR part 60, appendix B, and the quality assurance procedures of 40 CFR part 60, appendix F.

(16) 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 9 of § 63.7530. If the results of recalculating the maximum TSM input using Equation 9 of § 63.7530 are higher than the maximum total selected 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(b). You are not required to conduct fuel analyses for the fuels described in § 63.7510(a)(2)(i) through (iii). You may exclude the fuels described in § 63.7510(a)(2)(i) through (iii) when recalculating the TSM emission rate.

(17) If you demonstrate compliance with an applicable TSM emission limit through fuel analysis for solid or liquid fuels, and you plan to burn a new type of fuel, you must recalculate the TSM emission rate using Equation 14 of § 63.7530 according to the procedures specified in paragraphs (a)(5)(i) through (iii) of this section. You are not required to conduct fuel analyses for the fuels described in § 63.7510(a)(2)(i) through (iii). You may exclude the fuels described in § 63.7510(a)(2)(i) through (iii) when recalculating the TSM emission rate.

(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 14 of § 63.7530. The recalculated TSM emission rate must be less than the applicable emission limit.

(18) If you demonstrate continuous PM emissions compliance with a PM CPMS you will use a PM CPMS to establish a site-specific operating limit corresponding to the results of the performance test demonstrating compliance with the PM limit. You will conduct your performance test using the test method criteria in Table 5 of this subpart. You will use the PM CPMS to demonstrate continuous compliance with this operating limit. You must repeat the performance test annually and reassess and adjust the site-specific operating limit in accordance with the results of the performance test.

(i) To determine continuous compliance, you must record the PM CPMS output data for all periods when the process is operating and the PM CPMS is not out-of-control. You must demonstrate continuous compliance by using all quality-assured hourly average data collected by the PM CPMS for all operating hours to calculate the arithmetic average operating parameter in units of the operating limit (milliamps) on a 30-day rolling average basis, updated at the end of each new boiler or process heater operating hour.

(ii) For any deviation of the 30-day rolling PM CPMS average value from the established operating parameter limit, you must:

(A) Within 48 hours of the deviation, visually inspect the air pollution control device (APCD);

(B) If inspection of the APCD identifies the cause of the deviation, take corrective action as soon as possible and return the PM CPMS measurement to within the established value; and

(C) Within 30 days of the deviation or at the time of the annual compliance test, whichever comes first, conduct a PM emissions compliance test to determine compliance with the PM emissions limit and to verify or re-establish the CPMS operating limit. You are not required to conduct additional testing for any deviations that occur between the time of the original deviation and the PM emissions compliance test required under this paragraph.

(iii) PM CPMS deviations from the operating limit leading to more than four required performance tests in a 12-month operating period constitute a separate violation of this subpart.

(19) If you choose to comply with the PM filterable emissions limit by using PM CEMS you must install, certify, operate, and maintain a PM CEMS and record the output of the PM CEMS as specified in paragraphs (a)(19)(i) through (vii) of this section. The compliance limit will be expressed as a 30-day rolling average of the numerical emissions limit value applicable for your unit in Tables 1 or 2 or 11 through 13 of this subpart.

(i) Install and certify your PM CEMS according to the procedures and requirements in Performance Specification 11—Specifications and Test Procedures for Particulate Matter Continuous Emission Monitoring Systems at Stationary Sources in Appendix B to part 60 of this chapter, using test criteria outlined in Table V of this rule. The reportable measurement output from the PM CEMS must be expressed in units of the applicable emissions limit (e.g., lb/MMBtu, lb/MWh).

(ii) Operate and maintain your PM CEMS according to the procedures and requirements in Procedure 2— Quality Assurance Requirements for Particulate Matter Continuous Emission Monitoring Systems at Stationary Sources in Appendix F to part 60 of this chapter.

(A) You must conduct the relative response audit (RRA) for your PM CEMS at least once annually.

(B) You must conduct the relative correlation audit (RCA) for your PM CEMS at least once every 3 years.

(iii) Collect PM CEMS hourly average output data for all boiler operating hours except as indicated in paragraph (i) of this section.

(iv) Calculate the arithmetic 30-day rolling average of all of the hourly average PM CEMS output data collected during all nonexempt boiler or process heater operating hours.

(v) You must collect data using the PM CEMS at all times the unit is operating and at the intervals specified this paragraph (a), except for periods of monitoring system malfunctions, repairs associated with monitoring system malfunctions, and required monitoring system quality assurance or quality control activities.

(vi) You must use all the data collected during all boiler or process heater operating hours in assessing the compliance with your operating limit except:

(A) Any data collected during monitoring system malfunctions, repairs associated with monitoring system malfunctions, or required monitoring system quality assurance or control activities conducted during monitoring system malfunctions in calculations and report any such periods in your annual deviation report;

(B) Any data collected during periods when the monitoring system is out of control as specified in your site-specific monitoring plan, repairs associated with periods when the monitoring system is out of control, or required monitoring system quality assurance or control activities conducted during out of control periods in calculations used to report emissions or operating levels and report any such periods in your annual deviation report;

(C) Any data recorded during periods of startup or shutdown.

(vii) You must record and make available upon request results of PM CEMS system performance audits, dates and duration of periods when the PM CEMS is out of control to completion of the corrective actions necessary to return the PM CEMS to operation consistent with your site-specific monitoring plan.

(b) You must report each instance in which you did not meet each emission limit and operating limit in Tables 1 through 4 or 11 through 13 to this subpart that apply to you. These instances are deviations from the emission limits or operating limits, respectively, in this subpart. These deviations must be reported according to the requirements in § 63.7550.

(c) If you elected to demonstrate that the unit meets the specification for mercury for the unit designed to burn gas 1 subcategory, you must follow the sampling frequency specified in paragraphs (c)(1) through (4) of this section and conduct this sampling according to the procedures in § 63.7521(f) through (i).

(1) If the initial mercury constituents in the gaseous fuels are measured to be equal to or less than half of the mercury specification as defined in § 63.7575, you do not need to conduct further sampling.

(2) If the initial mercury constituents are greater than half but equal to or less than 75 percent of the mercury specification as defined in § 63.7575, you will conduct semi-annual sampling. If 6 consecutive semi-annual fuel analyses demonstrate 50 percent or less of the mercury specification, you do not need to conduct further sampling. If any semi-annual sample exceeds 75 percent of the mercury specification, you must return to monthly sampling for that fuel, until 12 months of fuel analyses again are less than 75 percent of the compliance level.

(3) If the initial mercury constituents are greater than 75 percent of the mercury specification as defined in § 63.7575, you will conduct monthly sampling. If 12 consecutive monthly fuel analyses demonstrate 75 percent or less of the mercury specification, you may decrease the fuel analysis frequency to semi-annual for that fuel.

(4) If the initial sample exceeds the mercury specification as defined in § 63.7575, each affected boiler or process heater combusting this fuel is not part of the unit designed to burn gas 1 subcategory and must be in compliance with the emission and operating limits for the appropriate subcategory. You may elect to conduct additional monthly sampling while complying with these emissions and operating limits to demonstrate that the fuel qualifies as another gas 1 fuel. If 12 consecutive monthly fuel analyses samples are at or below the mercury specification as defined in § 63.7575, each affected boiler or process heater combusting the fuel can elect to switch back into the unit designed to burn gas 1 subcategory until the mercury specification is exceeded.

(d) For startup and shutdown, you must meet the work practice standards according to item 5 of Table 3 of this subpart.

[78 FR 7179, Jan. 31, 2013]

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§ 63.7541 How do I demonstrate continuous compliance under the emissions 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 units 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) and (ii) of this section.

(i) For each existing unit 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 units participating in the emissions averaging option where each unit in the group is equipped with a dry control system and vented to a common stack that does not receive emissions from non-affected units, maintain opacity at or below the applicable limit at the common stack.

(3) For each existing unit participating in the emissions averaging option that is equipped with a wet scrubber, maintain the 30-day rolling average parameter values at or above the operating limits established during the most recent performance test.

(4) For each existing unit participating in the emissions averaging option that has an approved alternative operating parameter, maintain the 30-day rolling average parameter values consistent with the approved monitoring plan.

(5) For each existing unit participating in the emissions averaging option venting to a common stack configuration containing affected units from other subcategories, maintain the appropriate operating limit for each unit as specified in Table 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 is a deviation.

[76 FR 15664, Mar. 21, 2013, as amended at 78 FR 7182, Jan. 31, 2013]

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Notification, Reports, and Records

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§ 63.7545 What notifications must I submit and when?

(a) You must submit to the Administrator 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 January 31, 2013, you must submit an Initial Notification not later than 120 days after January 31, 2013.

(c) As specified in § 63.9(b)(4) and (5), if you startup your new or reconstructed affected source on or after January 31, 2013, 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 60 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, you must submit a Notification of Compliance Status according to § 63.9(h)(2)(ii). For the initial compliance demonstration for each boiler or process heater, 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 all performance test and/or other initial compliance demonstrations for all boiler or process heaters at the facility according to § 63.10(d)(2). The Notification of Compliance Status report must contain all the information specified in paragraphs (e)(1) through (8), as applicable. If you are not required to conduct an initial compliance demonstration as specified in § 63.7530(a), the Notification of Compliance Status must only contain the information specified in paragraphs (e)(1) and (8).

(1) A description of the affected unit(s) including identification of which subcategories the unit is in, the design heat input capacity of the unit, a description of the add-on controls used on the unit to comply with this subpart, description of the fuel(s) burned, including whether the fuel(s) were a secondary material determined by you or the EPA through a petition process to be a non-waste under § 241.3 of this chapter, whether the fuel(s) were a secondary material processed from discarded non-hazardous secondary materials within the meaning of § 241.3 of this chapter, and justification for the selection of fuel(s) burned during the compliance demonstration.

(2) Summary of the results of all performance tests and fuel analyses, and calculations conducted to demonstrate initial compliance including all established operating limits, and including:

(i) Identification of whether you are complying with the PM emission limit or the alternative TSM emission limit.

(ii) Identification of whether you are complying with the output-based emission limits or the heat input-based (i.e., lb/MMBtu or ppm) emission limits,

(3) A summary of the maximum CO emission levels recorded during the performance test to show that you have met any applicable emission standard in Tables 1, 2, or 11 through 13 to this subpart, if you are not using a CO CEMS to demonstrate compliance.

(4) Identification of whether you plan to demonstrate compliance with each applicable emission limit through performance testing, a CEMS, or fuel analysis.

(5) Identification of whether you plan to demonstrate compliance by emissions averaging and identification of whether you plan to demonstrate compliance by using efficiency credits through energy conservation:

(i) If you plan to demonstrate compliance by emission averaging, report the emission level that was being achieved or the control technology employed on January 31, 2013.

(ii) [Reserved]

(6) A signed certification that you have met all applicable emission limits and work practice standards.

(7) If you had a deviation from any emission limit, work practice standard, or operating limit, 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.

(8) In addition to the information required in § 63.9(h)(2), your notification of compliance status must include the following certification(s) of compliance, as applicable, and signed by a responsible official:

(i) "This facility complies with the required initial tune-up according to the procedures in § 63.7540(a)(10)(i) through (vi)."

(ii) "This facility has had an energy assessment performed according to § 63.7530(e)."

(iii) Except for units that burn only natural gas, refinery gas, or other gas 1 fuel, or units that qualify for a statutory exemption as provided in section 129(g)(1) of the Clean Air Act, include the following: "No secondary materials that are solid waste were combusted in any affected unit."

(f) If you operate a unit designed to burn natural gas, refinery gas, or other gas 1 fuels that is subject to this subpart, and you intend to use a fuel other than natural gas, refinery gas, gaseous fuel subject to another subpart of this part, part 60, 61, or 65, or other gas 1 fuel to fire the affected unit during a period of natural gas curtailment or supply interruption, as defined in § 63.7575, you must submit a notification of alternative fuel use within 48 hours of the declaration of each period of natural gas curtailment or supply interruption, as defined in § 63.7575. The notification must include the information specified in paragraphs (f)(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.

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

(1) The name of the owner or operator of the affected source, as defined in § 63.7490, the location of the source, the boiler(s) or process heater(s) that will commence burning solid waste, and the date of the notice.

(2) The currently applicable subcategories under this subpart.

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

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

(h) If you have switched fuels or made a physical change to the boiler and the fuel switch or physical change resulted in the applicability of a different subcategory, you must provide notice of the date upon which you switched fuels or made the physical change within 30 days of the switch/change. The notification must identify:

(1) The name of the owner or operator of the affected source, as defined in § 63.7490, the location of the source, the boiler(s) and process heater(s) that have switched fuels, were physically changed, and the date of the notice.

(2) The currently applicable subcategory under this subpart.

(3) The date upon which the fuel switch or physical change occurred.

[76 FR 15664, Mar. 21, 2011, as amended at 78 FR 7183, Jan. 31, 2013]

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§ 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, according to paragraph (h) of this section, by the date in Table 9 to this subpart and according to the requirements in paragraphs (b)(1) through (4) of this section. For units that are subject only to a requirement to conduct an annual, biennial, or 5-year tune-up according to § 63.7540(a)(10), (11), or (12), respectively, and not subject to emission limits or operating limits, you may submit only an annual, biennial, or 5-year compliance report, as applicable, as specified in paragraphs (b)(1) through (4) of this section, instead of a semi-annual compliance report.

(1) The first compliance report must cover the period beginning on the compliance date that is specified for each boiler or process heater in § 63.7495 and ending on July 31 or January 31, whichever date is the first date that occurs at least 180 days (or 1, 2, or 5 years, as applicable, if submitting an annual, biennial, or 5-year compliance report) after the compliance date that is specified for your source in § 63.7495.

(2) The first compliance report must be postmarked or submitted 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 each boiler or process heater in § 63.7495. The first annual, biennial, or 5-year compliance report must be postmarked or submitted no later than January 31.

(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. Annual, biennial, and 5-year compliance reports must cover the applicable 1-, 2-, or 5-year periods from January 1 to December 31.

(4) Each subsequent compliance report must be postmarked or submitted no later than July 31 or January 31, whichever date is the first date following the end of the semiannual reporting period. Annual, biennial, and 5-year compliance reports must be postmarked or submitted no later than January 31.

(c) A compliance report must contain the following information depending on how the facility chooses to comply with the limits set in this rule.

(1) If the facility is subject to a the requirements of a tune up they must submit a compliance report with the information in paragraphs (c)(5)(i) through (iv) and (xiv) of this section.

(2) If a facility is complying with the fuel analysis they must submit a compliance report with the information in paragraphs (c)(5)(i) through (iv), (vi), (x), (xi), (xiii), (xv) and paragraph (d) of this section.

(3) If a facility is complying with the applicable emissions limit with performance testing they must submit a compliance report with the information in (c)(5)(i) through (iv), (vi), (vii), (ix), (xi), (xiii), (xv) and paragraph (d) of this section.

(4) If a facility is complying with an emissions limit using a CMS the compliance report must contain the information required in paragraphs (c)(5)(i) through (vi), (xi), (xiii), (xv) through (xvii), and paragraph (e) of this section.

(5)(i) Company and Facility name and address.

(ii) Process unit information, emissions limitations, and operating parameter limitations.

(iii) Date of report and beginning and ending dates of the reporting period.

(iv) The total operating time during the reporting period.

(v) If you use a CMS, including CEMS, COMS, or CPMS, you must include the monitoring equipment manufacturer(s) and model numbers and the date of the last CMS certification or audit.

(vi) The total fuel use by each individual boiler or process heater subject to an emission limit within the reporting period, including, but not limited to, a description of the fuel, whether the fuel has received a non-waste determination by the EPA or your basis for concluding that the fuel is not a waste, and the total fuel usage amount with units of measure.

(vii) If you are conducting performance tests once every 3 years consistent with § 63.7515(b) or (c), the date of the last 2 performance tests and a statement as to whether there have been any operational changes since the last performance test that could increase emissions.

(viii) A statement indicating that you burned no new types of fuel in an individual boiler or process heater subject to an emission limit. Or, if you did burn a new type of fuel and are subject to a HCl emission limit, you must submit the calculation of chlorine input, using Equation 7 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 12 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 and are subject to a mercury emission limit, you must submit the calculation of mercury input, using Equation 8 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 13 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). If you burned a new type of fuel and are subject to a TSM emission limit, you must submit the calculation of TSM input, using Equation 9 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 14 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).

(ix) If you wish to burn a new type of fuel in an individual boiler or process heater subject to an emission limit and you cannot demonstrate compliance with the maximum chlorine input operating limit using Equation 7 of § 63.7530 or the maximum mercury input operating limit using Equation 8 of § 63.7530, or the maximum TSM input operating limit using Equation 9 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.

(x) A summary of any monthly fuel analyses conducted to demonstrate compliance according to §§ 63.7521 and 63.7530 for individual boilers or process heaters subject to emission limits, and any fuel specification analyses conducted according to §§ 63.7521(f) and 63.7530(g).

(xi) If there are no deviations from any emission limits or operating limits in this subpart that apply to you, a statement that there were no deviations from the emission limits or operating limits during the reporting period.

(xii) If there were no deviations from the monitoring requirements including 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 deviations and no periods during which the CMS were out of control during the reporting period.

(xiii) If a malfunction occurred during the reporting period, the report must include the number, duration, and a brief description for each type of malfunction which occurred during the reporting period and which caused or may have caused any applicable emission limitation to be exceeded. The report must also include a description of actions taken by you during a malfunction of a boiler, process heater, or associated air pollution control device or CMS to minimize emissions in accordance with § 63.7500(a)(3), including actions taken to correct the malfunction.

(xiv) Include the date of the most recent tune-up for each unit subject to only the requirement to conduct an annual, biennial, or 5-year tune-up according to § 63.7540(a)(10), (11), or (12) respectively. Include the date of the most recent burner inspection if it was not done annually, biennially, or on a 5-year period and was delayed until the next scheduled or unscheduled unit shutdown.

(xv) If you plan to demonstrate compliance by emission averaging, certify the emission level achieved or the control technology employed is no less stringent than the level or control technology contained in the notification of compliance status in § 63.7545(e)(5)(i).

(xvi) For each reporting period, the compliance reports must include all of the calculated 30 day rolling average values based on the daily CEMS (CO and mercury) and CPMS (PM CPMS output, scrubber pH, scrubber liquid flow rate, scrubber pressure drop) data.

(xvii) 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.

(d) For each deviation from an emission limit or operating limit in this subpart that occurs at an individual boiler or process heater where you are not using a CMS to comply with that emission limit or

operating limit, the compliance report must additionally contain the information required in paragraphs (d)(1) through (3) of this section.

(1) A description of the deviation and which emission limit or operating limit from which you deviated.

(2) Information on the number, duration, and cause of deviations (including unknown cause), as applicable, and the corrective action taken.

(3) If the deviation occurred during an annual performance test, provide the date the annual performance test was completed.

(e) For each deviation from an emission limit, operating limit, and monitoring requirement in this subpart occurring at an individual boiler or process heater where you are using a CMS to comply with that emission limit or operating limit, the compliance report must additionally contain the information required in paragraphs (e)(1) through (9) of this section. This includes any deviations from your site-specific monitoring plan as required in § 63.7505(d).

(1) The date and time that each deviation 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.

(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 characterization of the total duration of the deviations during the reporting period into those that are due to control equipment problems, process problems, other known causes, and other unknown causes.

(7) A summary of the total duration of CMS's 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) A brief description of the source for which there was a deviation.

(9) 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)-(g) [Reserved]

(h) You must submit the reports according to the procedures specified in paragraphs (h)(1) through (3) of this section.

(1) Within 60 days after the date of completing each performance test (defined in § 63.2) as required by this subpart you must submit the results of the performance tests, including any associated fuel analyses, required by this subpart and the compliance reports required in § 63.7550(b) to the EPA's WebFIRE database by using the Compliance and Emissions Data Reporting Interface (CEDRI) that is accessed through the EPA's Central Data Exchange (CDX) (*www.epa.gov/cdx*). Performance test data must be submitted in the file format generated through use of the EPA's Electronic Reporting Tool (ERT) (see *http://www.epa.gov/ttn/chief/ert/index.html*). Only data collected using test methods on the ERT Web site are

subject to this requirement for submitting reports electronically to WebFIRE. Owners or operators who claim that some of the information being submitted for performance tests is confidential business information (CBI) must submit a complete ERT file including information claimed to be CBI on a compact disk or other commonly used electronic storage media (including, but not limited to, flash drives) to the EPA. The electronic media must be clearly marked as CBI and mailed to U.S. EPA/OAPQS/CORE CBI Office, Attention: WebFIRE Administrator, MD C404-02, 4930 Old Page Rd., Durham, NC 27703. The same ERT file with the CBI omitted must be submitted to the EPA via CDX as described earlier in this paragraph. At the discretion of the Administrator, you must also submit these reports, including the confidential business information, to the Administrator in the format specified by the Administrator. For any performance test conducted using test methods that are not listed on the ERT Web site, the owner or operator shall submit the results of the performance test in paper submissions to the Administrator.

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

(3) You must submit all reports required by Table 9 of this subpart electronically using CEDRI that is accessed through the EPA's Central Data Exchange (CDX) (*www.epa.gov/cdx*). However, if the reporting form specific to this subpart is not available in CEDRI at the time that the report is due the report you must submit the report to the Administrator at the appropriate address listed in § 63.13. At the discretion of the Administrator, you must also submit these reports, to the Administrator in the format specified by the Administrator.

[78 FR 7183, Jan. 31, 2013]

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§ 63.7555 What records must I keep?

(a) You must keep records according to paragraphs (a)(1) and (2) 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) Records of performance tests, fuel analyses, or other compliance demonstrations and performance evaluations as required in § 63.10(b)(2)(viii).

(b) For each CEMS, COMS, and continuous monitoring system you must keep records according to paragraphs (b)(1) through (5) of this section.

(1) Records described in § 63.10(b)(2)(vii) 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.

(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, pH, and operating load, to show continuous compliance with each emission limit and operating limit that applies to you.

(d) For each boiler or process heater subject to an emission limit in Tables 1, 2, or 11 through 13 to this subpart, you must also keep the applicable records in paragraphs (d)(1) through (11) of this section.

(2) If you combust non-hazardous secondary materials that have been determined not to be solid waste pursuant to § 241.3(b)(1) and (2) of this chapter, you must keep a record that documents how the secondary material meets each of the legitimacy criteria under § 241.3(d)(1) of this chapter. If you combust a fuel that has been processed from a discarded non-hazardous secondary material pursuant to § 241.3(b)(4) of this chapter, you must keep records as to how the operations that produced the fuel satisfy the definition of processing in § 241.2 of this chapter. If the fuel received a non-waste determination pursuant to the petition process submitted under § 241.3(c) of this chapter, you must keep a record that documents how the fuel satisfies the requirements of the petition process. For operating units that combust non-hazardous secondary materials as fuel per § 241.4 of this chapter, you must keep records documenting that the material is listed as a non-waste under § 241.4(a) of this chapter. Units exempt from the incinerator standards under section 129(g)(1) of the Clean Air Act because they are qualifying facilities burning a homogeneous waste stream do not need to maintain the records described in this paragraph (d)(2).

(3) For units in the limited use subcategory, you must keep a copy of the federally enforceable permit that limits the annual capacity factor to less than or equal to 10 percent and fuel use records for the days the boiler or process heater was operating.

(4) A copy of all calculations and supporting documentation of maximum chlorine fuel input, using Equation 7 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 12 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.

(5) A copy of all calculations and supporting documentation of maximum mercury fuel input, using Equation 8 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 13 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.

(6) If, consistent with § 63.7515(b), you choose to stack test less frequently than annually, you must keep a record that documents that your emissions in the previous stack test(s) were less than 75 percent of the applicable emission limit (or, in specific instances noted in Tables 1 and 2 or 11 through 13 to this subpart, less than the applicable emission limit), and document that there was no change in source operations including fuel composition and operation of air pollution control equipment that would cause emissions of the relevant pollutant to increase within the past year.

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

(8) Records of actions taken during periods of malfunction to minimize emissions in accordance with the general duty to minimize emissions in § 63.7500(a)(3), including corrective actions to restore the malfunctioning boiler or process heater, air pollution control, or monitoring equipment to its normal or usual manner of operation.

(9) A copy of all calculations and supporting documentation of maximum TSM fuel input, using Equation 9 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 14 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.

(10) You must maintain records of the calendar date, time, occurrence and duration of each startup and shutdown.

(11) You must maintain records of the type(s) and amount(s) of fuels used during each startup and shutdown.

(e) If you elect to average emissions consistent with § 63.7522, you must additionally keep a copy of the emission averaging implementation plan required in § 63.7522(g), all calculations required under § 63.7522, including monthly records of heat input or steam generation, as applicable, and monitoring records consistent with § 63.7541.

(f) If you elect to use efficiency credits from energy conservation measures to demonstrate compliance according to § 63.7533, you must keep a copy of the Implementation Plan required in § 63.7533(d) and copies of all data and calculations used to establish credits according to § 63.7533(b), (c), and (f).

(g) If you elected to demonstrate that the unit meets the specification for mercury for the unit designed to burn gas 1 subcategory, you must maintain monthly records (or at the frequency required by § 63.7540(c)) of the calculations and results of the fuel specification for mercury in Table 6.

(h) If you operate a unit in the unit designed to burn gas 1 subcategory that is subject to this subpart, and you use an alternative fuel other than natural gas, refinery gas, gaseous fuel subject to another subpart under this part, other gas 1 fuel, or gaseous fuel subject to another subpart of this part or part 60, 61, or 65, you must keep records of the total hours per calendar year that alternative fuel is burned and the total hours per calendar year that the unit operated during periods of gas curtailment or gas supply emergencies.

(i) You must maintain records of the calendar date, time, occurrence and duration of each startup and shutdown.

(j) You must maintain records of the type(s) and amount(s) of fuels used during each startup and shutdown.

[76 FR 15664, Mar. 21, 2011 as amended at 78 FR 715, Jan. 31, 2013]

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§ 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, or they must be accessible from on site (for example, through a computer network), 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.

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Other Requirements and Information

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§ 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.

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§ 63.7570 Who implements and enforces this subpart?

(a) This subpart can be implemented and enforced by the EPA, or an Administrator such as your state, local, or tribal agency. If the EPA Administrator has delegated authority to your state, local, or tribal agency, then that agency (as well as the 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 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, and alternative analytical methods requested under § 63.7521(b)(2).

(4) Approval of major change to monitoring under § 63.8(f) and as defined in § 63.90, and approval of alternative operating parameters under § 63.7500(a)(2) and § 63.7522(g)(2).

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

[76 FR 15664, Mar. 21, 2011 as amended at 78 FR 7186, Jan. 31, 2013]

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§ 63.7575 What definitions apply to this subpart?

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

10-day rolling average means the arithmetic mean of the previous 240 hours of valid operating data. Valid data excludes hours during startup and shutdown, data collected during periods when the monitoring system is out of control as specified in your site-specific monitoring plan, while conducting repairs associated with periods when the monitoring system is out of control, or while conducting required monitoring system quality assurance or quality control activities, and periods when this unit is not operating. The 240 hours should be consecutive, but not necessarily continuous if operations were intermittent.

30-day rolling average means the arithmetic mean of the previous 720 hours of valid operating data. Valid data excludes hours during startup and shutdown, data collected during periods when the monitoring system is out of control as specified in your site-specific monitoring plan, while conducting repairs associated with periods when the monitoring system is out of control, or while conducting required monitoring system quality assurance or quality control activities, and periods when this unit is not operating. The 720 hours should be consecutive, but not necessarily continuous if operations were intermittent.

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

Annual 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.

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

Average annual heat input rate means total heat input divided by the hours of operation for the 12 months preceding the compliance demonstration.

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

Benchmark means the fuel heat input for a boiler or process heater for the one-year period before the date that an energy demand reduction occurs, unless it can be demonstrated that a different time period is more representative of historical operations.

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

Biomass or bio-based solid fuel means any biomass-based solid fuel that is not a solid waste. This includes, but is not limited to, wood residue; wood products (*e.g.,* trees, tree stumps, tree limbs, bark,

lumber, sawdust, sander dust, chips, scraps, slabs, millings, and shavings); animal manure, including litter and other bedding materials; vegetative agricultural and silvicultural materials, such as logging residues (slash), nut and grain hulls and chaff (*e.g.,* almond, walnut, peanut, rice, and wheat), bagasse, orchard prunings, corn stalks, coffee bean hulls and grounds. This definition of biomass is not intended to suggest that these materials are or are not solid waste.

***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 annual gas volume 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. Controlled flame combustion refers to a steady-state, or near steady-state, process wherein fuel and/or oxidizer feed rates are controlled. A device combusting solid waste, as defined in § 241.3 of this chapter, is not a boiler unless the device is exempt from the definition of a solid waste incineration unit as provided in section 129(g)(1) of the Clean Air Act. Waste heat boilers are excluded from this definition.**

***Boiler system* means the boiler and associated components, such as, the feed water system, the combustion air system, the fuel system (including burners), blowdown system, combustion control systems, steam systems, and condensate return systems.**

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

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

***Coal 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, nursing homes, research centers, institutions of higher education, elementary and secondary schools, libraries, religious establishments, governmental buildings, hotels, restaurants, and laundries to provide electricity, steam, and/or hot water.**

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

***Cost-effective energy conservation measure* means a measure that is implemented to improve the energy efficiency of the boiler or facility that has a payback (return of investment) period of 2 years or less.**

***Daily block average* means the arithmetic mean of all valid emission concentrations or parameter levels recorded when a unit is operating measured over the 24-hour period from 12 a.m. (midnight) to 12 a.m. (midnight), except for periods of startup and shutdown or downtime.**

***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 applicable requirement or obligation established by this subpart including, but not limited to, any emission limit, operating limit, or work practice standard; or

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

(2) A deviation is not always a violation.

Dioxins/furans **means tetra- through octa-chlorinated dibenzo-p-dioxins and dibenzofurans.**

Distillate oil **means fuel oils that contain 0.05 weight percent nitrogen or less and comply with the specifications for fuel oil numbers 1 and 2, as defined by the American Society of Testing and Materials in ASTM D396 (incorporated by reference, see § 63.14) or diesel fuel oil numbers 1 and 2, as defined by the American Society for Testing and Materials in ASTM D975 (incorporated by reference, see § 63.14), kerosene, and biodiesel as defined by the American Society of Testing and Materials in ASTM D6751-11b (incorporated by reference, see § 60.14).**

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

Dutch oven **means a unit having a refractory-walled cell connected to a conventional boiler setting. Fuel materials are introduced through an opening in the roof of the dutch oven and burn in a pile on its floor. Fluidized bed boilers are not part of the dutch oven design category.**

Efficiency credit **means emission reductions above those required by this subpart. Efficiency credits generated may be used to comply with the emissions limits. Credits may come from pollution prevention projects that result in reduced fuel use by affected units. Boilers that are shut down cannot be used to generate credits unless the facility provides documentation linking the permanent shutdown to implementation of the energy conservation measures identified in the energy assessment.**

Electric utility steam generating unit (EGU) **means a fossil fuel-fired combustion unit of more than 25 megawatts electric (MWe) 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 MWe output to any utility power distribution system for sale is considered an electric utility steam generating unit. To be “capable of combusting” fossil fuels, an EGU would need to have these fuels allowed in their operating permits and have the appropriate fuel handling facilities on-site or otherwise available (e.g., coal handling equipment, including coal storage area, belts and conveyers, pulverizers, etc.; oil storage facilities). In addition, fossil fuel-fired EGU means any EGU that fired fossil fuel for more than 10.0 percent of the average annual heat input in any 3 consecutive calendar years or for more than 15.0 percent of the annual heat input during any one calendar year after April 16, 2012.**

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

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

(1) The energy assessment for facilities with affected boilers and process heaters with a combined heat input capacity of less than 0.3 trillion Btu (TBtu) per year will be 8 on-site technical labor hours in length maximum, but may be longer at the discretion of the owner or operator of the affected source. The boiler

system(s) and any on-site energy use system(s) accounting for at least 50 percent of the affected boiler(s) energy (e.g., steam, hot water, process heat, or electricity) production, as applicable, will be evaluated to identify energy savings opportunities, within the limit of performing an 8-hour on-site energy assessment.

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

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

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

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

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

***Energy use system* includes the following systems located on-site that use energy (steam, hot water, or electricity) provided by the affected boiler or process heater: process heating; compressed air systems; machine drive (motors, pumps, fans); process cooling; facility heating, ventilation, and air-conditioning systems; hot water systems; building envelop; and lighting; or other systems that use steam, hot water, process heat, or electricity provided by the affected boiler or process heater. Energy use systems are only those systems using energy clearly produced by affected boilers and process heaters.**

***Equivalent* means the following only as this term is used in Table 6 to this subpart:**

(1) An equivalent sample collection procedure means a published voluntary consensus standard or practice (VCS) or EPA method that includes collection of a minimum of three composite fuel samples, with each composite consisting of a minimum of three increments collected at approximately equal intervals over the test period.

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

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

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

(5) An equivalent procedure for determining fuel moisture content means a published VCS or EPA method to obtain moisture content. If the sample analysis plan calls for determining 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, HCl) 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 this subpart for the same purpose.

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

Federally enforceable **means all limitations and conditions that are enforceable by the EPA Administrator, including, but not limited to, the requirements of 40 CFR parts 60, 61, 63, and 65, requirements within any applicable state implementation plan, and any permit requirements established under 40 CFR 52.21 or under 40 CFR 51.18 and 40 CFR 51.24.**

Fluidized bed boiler **means a boiler utilizing a fluidized bed combustion process that is not a pulverized coal boiler.**

Fluidized bed boiler with an integrated fluidized bed heat exchanger **means a boiler utilizing a fluidized bed combustion where the entire tube surface area is located outside of the furnace section at the exit of the cyclone section and exposed to the flue gas stream for conductive heat transfer. This design applies only to boilers in the unit designed to burn coal/solid fossil fuel subcategory that fire coal refuse.**

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

Fuel cell **means a boiler type in which the fuel is dropped onto suspended fixed grates and is fired in a pile. The refractory-lined fuel cell uses combustion air preheating and positioning of secondary and tertiary air injection ports to improve boiler efficiency. Fluidized bed, dutch oven, pile burner, hybrid suspension grate, and suspension burners are not part of the fuel cell subcategory.**

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

Gaseous fuel **includes, but is not limited to, natural gas, process gas, landfill gas, coal derived gas, refinery gas, and biogas. Blast furnace gas and process gases that are regulated under another subpart of this part, or part 60, part 61, or part 65 of this chapter, are 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, returned condensate, or exhaust gases from other sources such as gas turbines, internal combustion engines, kilns, etc.**

Heavy liquid **includes residual oil and any other liquid fuel not classified as a light liquid.**

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

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

Hybrid suspension grate boiler **means a boiler designed with air distributors to spread the fuel material over the entire width and depth of the boiler combustion zone. The biomass fuel combusted in these units exceeds a moisture content of 40 percent on an as-fired annual heat input basis. The drying and much of the combustion of the fuel takes place in suspension, and the combustion is completed on the grate or floor of the boiler. Fluidized bed, dutch oven, and pile burner designs are not part of the hybrid suspension grate boiler design category.**

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

Light liquid **includes distillate oil, biodiesel, or vegetable oil.**

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

Liquid fuel **includes, but is not limited to, light liquid, heavy liquid, any form of liquid fuel derived from petroleum, used oil, liquid biofuels, biodiesel, vegetable oil, and comparable fuels as defined under 40 CFR 261.38.**

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

Major source for oil and natural gas production facilities, **as used in this subpart, shall have the same meaning as in § 63.2, except that:**

(1) Emissions from any oil or gas exploration or production well (with its associated equipment, as defined in this section), and emissions from any pipeline compressor station or pump station shall not be aggregated with emissions from other similar units to determine whether such emission points or stations are major sources, even when emission points are in a contiguous area or under common control;

(2) Emissions from processes, operations, or equipment that are not part of the same facility, as defined in this section, shall not be aggregated; and

(3) For facilities that are production field facilities, only HAP emissions from glycol dehydration units and storage vessels with the potential for flash emissions shall be aggregated for a major source determination. For facilities that are not production field facilities, HAP emissions from all HAP emission units shall be aggregated for a major source determination.

***Metal process furnaces* are a subcategory of process heaters, as defined in this subpart, which include natural gas-fired annealing furnaces, preheat furnaces, reheat furnaces, aging furnaces, heat treat furnaces, and homogenizing furnaces.**

***Million Btu (MMBtu)* means one million British thermal units.**

***Minimum activated carbon injection rate* means load fraction multiplied by the lowest hourly average activated carbon injection rate measured according to Table 7 to this subpart during the most recent performance test demonstrating compliance with the applicable emission limit.**

***Minimum oxygen level* means the lowest hourly average oxygen level measured according to Table 7 to this subpart during the most recent performance test demonstrating compliance with the applicable emission limit.**

***Minimum pressure drop* means the lowest hourly 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 the lowest hourly average sorbent liquid pH measured at the inlet to 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 liquid flow rate* means the lowest hourly average liquid flow rate (e.g., to the PM scrubber or to the acid gas scrubber) measured according to Table 7 to this subpart during the most recent performance stack test demonstrating compliance with the applicable emission limit.**

***Minimum scrubber pressure drop* means the lowest hourly average scrubber pressure drop measured according to Table 7 to this subpart during the most recent performance test demonstrating compliance with the applicable emission limit.**

***Minimum sorbent injection rate* means:**

(1) The load fraction multiplied by the lowest hourly average sorbent injection rate for each sorbent measured according to Table 7 to this subpart during the most recent performance test demonstrating compliance with the applicable emission limits; or

(2) For fluidized bed combustion, the lowest average ratio of sorbent to sulfur measured during the most recent performance test.

***Minimum total secondary electric power* means the lowest hourly average total secondary electric power determined from the values of secondary voltage and secondary current to the electrostatic precipitator measured according to Table 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) Liquefied petroleum gas, as defined in ASTM D1835 (incorporated by reference, see § 63.14); 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 35 and 41 megajoules (MJ) per dry standard cubic meter (950 and 1,100 Btu per dry standard cubic foot); or

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

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

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

***Other combustor* means a unit designed to burn solid fuel that is not classified as a dutch oven, fluidized bed, fuel cell, hybrid suspension grate boiler, pulverized coal boiler, stoker, sloped grate, or suspension boiler as defined in this subpart.**

***Other gas 1 fuel* means a gaseous fuel that is not natural gas or refinery gas and does not exceed a maximum concentration of 40 micrograms/cubic meters of mercury.**

***Oxygen analyzer system* means all equipment required to determine the oxygen content of a gas stream and used to monitor oxygen in the boiler or process heater flue gas, boiler or process heater, firebox, or other appropriate location. This definition includes oxygen trim systems. The source owner or operator must install, calibrate, maintain, and operate the oxygen analyzer system in accordance with the manufacturer's recommendations.**

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

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

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

***Pile burner* means a boiler design incorporating a design where the anticipated biomass fuel has a high relative moisture content. Grates serve to support the fuel, and underfire air flowing up through the grates provides oxygen for combustion, cools the grates, promotes turbulence in the fuel bed, and fires the fuel. The most common form of pile burning is the dutch oven.**

***Process heater* means an enclosed device using controlled flame, and the unit's primary purpose is to transfer heat indirectly to a process material (liquid, gas, or solid) or to a heat transfer material (e.g.,**

glycol or a mixture of glycol and water) for use in a process unit, instead of generating steam. Process heaters are devices in which the combustion gases do not come into direct contact with process materials. A device combusting solid waste, as defined in § 241.3 of this chapter, is not a process heater unless the device is exempt from the definition of a solid waste incineration unit as provided in section 129(g)(1) of the Clean Air Act. Process heaters do not include units used for comfort heat or space heat, food preparation for on-site consumption, or autoclaves. Waste heat process heaters are excluded from this definition.

Pulverized coal boiler **means a boiler in which pulverized coal or other solid fossil fuel is introduced into an air stream that carries the coal to the combustion chamber of the boiler where it is fired in suspension.**

Qualified energy assessor **means:**

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

(i) Boiler combustion management.

(ii) Boiler thermal energy recovery, including

(A) Conventional feed water economizer,

(B) Conventional combustion air preheater, and

(C) Condensing economizer.

(iii) Boiler blowdown thermal energy recovery.

(iv) Primary energy resource selection, including

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

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

(v) Insulation issues.

(vi) Steam trap and steam leak management.

(vi) Condensate recovery.

(viii) Steam end-use management.

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

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

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

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

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

(v) Boiler-steam turbine cogeneration systems.

(vi) Industry specific steam end-use systems.

Refinery gas **means any gas that is generated at a petroleum refinery and is combusted. Refinery gas includes natural gas when the natural gas is combined and combusted in any proportion with a gas generated at a refinery. Refinery gas includes gases generated from other facilities when that gas is combined and combusted in any proportion with gas generated at a refinery.**

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

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

(1) A dwelling containing four or fewer families; or

(2) A single unit residence dwelling that has since been converted or subdivided into condominiums or apartments.

Residual oil **means crude oil, fuel oil that does not comply with the specifications under the definition of distillate oil, and all fuel oil numbers 4, 5, and 6, as defined by the American Society of Testing and Materials in ASTM D396-10 (incorporated by reference, *see* § 63.14(b)).**

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

Secondary material **means the material as defined in § 241.2 of this chapter.**

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

Sloped grate **means a unit where the solid fuel is fed to the top of the grate from where it slides downwards; while sliding the fuel first dries and then ignites and burns. The ash is deposited at the bottom of the grate. Fluidized bed, dutch oven, pile burner, hybrid suspension grate, suspension burners, and fuel cells are not considered to be a sloped grate design.**

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

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

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

***Steam output* means:**

(1) For a boiler that produces steam for process or heating only (no power generation), the energy content in terms of MMBtu of the boiler steam output,

(2) For a boiler that cogenerates process steam and electricity (also known as combined heat and power), the total energy output, which is the sum of the energy content of the steam exiting the turbine and sent to process in MMBtu and the energy of the electricity generated converted to MMBtu at a rate of 10,000 Btu per kilowatt-hour generated (10 MMBtu per megawatt-hour), and

(3) For a boiler that generates only electricity, the alternate output-based emission limits would be calculated using Equations 21 through 25 of this section, as appropriate:

(i) For emission limits for boilers in the unit designed to burn solid fuel subcategory use Equation 21 of this section:

$$EL_{OBE} = EL_T \times 12.7 \text{ MMBtu/Mwh} \quad \text{(Eq. 21)}$$

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Where:

EL_{OBE} = Emission limit in units of pounds per megawatt-hour.

EL_T = Appropriate emission limit from Table 1 or 2 of this subpart in units of pounds per million Btu heat input.

(ii) For PM and CO emission limits for boilers in one of the subcategories of units designed to burn coal use Equation 22 of this section:

$$EL_{OBE} = EL_T \times 12.2 \text{ MMBtu/Mwh} \quad \text{(Eq. 22)}$$

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Where:

EL_{OBE} = Emission limit in units of pounds per megawatt-hour.

EL_T = Appropriate emission limit from Table 1 or 2 of this subpart in units of pounds per million Btu heat input.

(iii) For PM and CO emission limits for boilers in one of the subcategories of units designed to burn biomass use Equation 23 of this section:

$$EL_{OBE} = EL_T \times 13.9 \text{ MMBtu/Mwh} \quad \text{(Eq. 23)}$$

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Where:

EL_{OBE} = Emission limit in units of pounds per megawatt-hour.

EL_T = Appropriate emission limit from Table 1 or 2 of this subpart in units of pounds per million Btu heat input.

(iv) For emission limits for boilers in one of the subcategories of units designed to burn liquid fuels use Equation 24 of this section:

$$EL_{OBE} = EL_{T} \times 13.8 \text{ MMBtu/Mwh} \quad \text{(Eq. 24)}$$

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Where:

EL_{OBE} = Emission limit in units of pounds per megawatt-hour.

EL_{T} = Appropriate emission limit from Table 1 or 2 of this subpart in units of pounds per million Btu heat input.

(v) For emission limits for boilers in the unit designed to burn gas 2 (other) subcategory, use Equation 25 of this section:

$$EL_{OBE} = EL_{T} \times 10.4 \text{ MMBtu/Mwh} \quad \text{(Eq. 25)}$$

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Where:

EL_{OBE} = Emission limit in units of pounds per megawatt-hour.

EL_{T} = Appropriate emission limit from Table 1 or 2 of this subpart in units of pounds per million Btu heat input.

Stoker means a unit consisting of a mechanically operated fuel feeding mechanism, a stationary or moving grate to support the burning of fuel and admit under-grate air to the fuel, an overfire air system to complete combustion, and an ash discharge system. This definition of stoker includes air swept stokers. There are two general types of stokers: Underfeed and overfeed. Overfeed stokers include mass feed and spreader stokers. Fluidized bed, dutch oven, pile burner, hybrid suspension grate, suspension burners, and fuel cells are not considered to be a stoker design.

Stoker/sloped grate/other unit designed to burn kiln dried biomass means the unit is in the units designed to burn biomass/bio-based solid subcategory that is either a stoker, sloped grate, or other combustor design and is not in the stoker/sloped grate/other units designed to burn wet biomass subcategory.

Stoker/sloped grate/other unit designed to burn wet biomass means the unit is in the units designed to burn biomass/bio-based solid subcategory that is either a stoker, sloped grate, or other combustor design and any of the biomass/bio-based solid fuel combusted in the unit exceeds 20 percent moisture on an annual heat input basis.

Suspension burner means a unit designed to fire dry biomass/biobased solid particles in suspension that are conveyed in an airstream to the furnace like pulverized coal. The combustion of the fuel material is completed on a grate or floor below. The biomass/biobased fuel combusted in the unit shall not exceed 20 percent moisture on an annual heat input basis. Fluidized bed, dutch oven, pile burner, and hybrid suspension grate units are not part of the suspension burner subcategory.

Temporary boiler means any gaseous or liquid fuel boiler that is designed to, and is capable of, being carried or moved from one location to another by means of, for example, wheels, skids, carrying

handles, dollies, trailers, or platforms. A boiler is not a temporary boiler if any one of the following conditions exists:

(1) The equipment is attached to a foundation.

(2) The boiler or a replacement remains at a location within the facility and performs the same or similar function for more than 12 consecutive months, unless the regulatory agency approves an extension. An extension may be granted by the regulating agency upon petition by the owner or operator of a unit specifying the basis for such a request. Any temporary boiler that replaces a temporary boiler at a location and performs the same or similar function will be included in calculating the consecutive time period.

(3) The equipment is located at a seasonal facility and operates during the full annual operating period of the seasonal facility, remains at the facility for at least 2 years, and operates at that facility for at least 3 months each year.

(4) The equipment is moved from one location to another within the facility but continues to perform the same or similar function and serve the same electricity, steam, and/or hot water system in an attempt to circumvent the residence time requirements of this definition.

***Total selected metals (TSM)* means the sum of the following metallic hazardous air pollutants: arsenic, beryllium, cadmium, chromium, lead, manganese, nickel and selenium.**

***Traditional fuel* means the fuel as defined in § 241.2 of this chapter.**

***Tune-up* means adjustments made to a boiler or process heater in accordance with the procedures outlined in § 63.7540(a)(10).**

*** * * * ***

***Ultra low sulfur liquid fuel* means a distillate oil that has less than or equal to 15 ppm sulfur.**

***Unit designed to burn biomass/bio-based solid subcategory* includes any boiler or process heater that burns at least 10 percent biomass or bio-based solids on an annual heat input basis in combination with solid fossil fuels, liquid fuels, or gaseous fuels.**

***Unit designed to burn coal/solid fossil fuel subcategory* includes any boiler or process heater that burns any coal or other solid fossil fuel alone or at least 10 percent coal or other solid fossil fuel on an annual heat input basis in combination with liquid fuels, gaseous fuels, or less than 10 percent biomass and bio-based solids on an annual heat input basis.**

***Unit designed to burn gas 1 subcategory* includes any boiler or process heater that burns only natural gas, refinery gas, and/or other gas 1 fuels. Gaseous fuel boilers and process heaters that burn liquid fuel for periodic testing of liquid fuel, maintenance, or operator training, not to exceed a combined total of 48 hours during any calendar year, are included in this definition. Gaseous fuel boilers and process heaters that burn liquid fuel during periods of gas curtailment or gas supply interruptions of any duration are also included in this definition.**

***Unit designed to burn gas 2 (other) subcategory* includes any boiler or process heater that is not in the unit designed to burn gas 1 subcategory and burns any gaseous fuels either alone or in combination with less than 10 percent coal/solid fossil fuel, and less than 10 percent biomass/bio-based solid fuel on an annual heat input basis, and no liquid fuels. Gaseous fuel boilers and process heaters that are not in the unit designed to burn gas 1 subcategory and that burn liquid fuel for periodic testing of liquid fuel, maintenance, or operator training, not to exceed a combined total of 48 hours during any calendar year,**

are included in this definition. Gaseous fuel boilers and process heaters that are not in the unit designed to burn gas 1 subcategory and that burn liquid fuel during periods of gas curtailment or gas supply interruption of any duration are also included in this definition.

Unit designed to burn heavy liquid subcategory **means a unit in the unit designed to burn liquid subcategory where at least 10 percent of the heat input from liquid fuels on an annual heat input basis comes from heavy liquids.**

Unit designed to burn light liquid subcategory **means a unit in the unit designed to burn liquid subcategory that is not part of the unit designed to burn heavy liquid subcategory.**

Unit designed to burn liquid subcategory **includes any boiler or process heater that burns any liquid fuel, but less than 10 percent coal/solid fossil fuel and less than 10 percent biomass/bio-based solid fuel on an annual heat input basis, either alone or in combination with gaseous fuels. Units in the unit design to burn gas 1 or unit designed to burn gas 2 (other) subcategories that burn liquid fuel for periodic testing of liquid fuel, maintenance, or operator training, not to exceed a combined total of 48 hours during any calendar year are not included in this definition. Units in the unit design to burn gas 1 or unit designed to burn gas 2 (other) subcategories during periods of gas curtailment or gas supply interruption of any duration are also not included in this definition.**

Unit designed to burn liquid fuel that is a non-continental unit **means an industrial, commercial, or institutional boiler or process heater meeting the definition of the unit designed to burn liquid subcategory located in the State of Hawaii, the Virgin Islands, Guam, American Samoa, the Commonwealth of Puerto Rico, or the Northern Mariana Islands.**

Unit designed to burn solid fuel subcategory **means any boiler or process heater that burns only solid fuels or at least 10 percent solid fuel on an annual heat input basis in combination with liquid fuels or gaseous fuels.**

Vegetable oil **means oils extracted from vegetation.**

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

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

Waste heat process heater **means an enclosed device that recovers normally unused energy (i.e., hot exhaust gas) and converts it to usable heat. Waste heat process heaters are also referred to as recuperative process heaters. This definition includes both fired and unfired waste heat process heaters.**

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 or to absorb and neutralize acid gases, such as hydrogen chloride. A wet scrubber creates an aqueous stream or slurry as a byproduct of the emissions control process.**

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

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Table 1 to Subpart DDDDD of Part 63—Emission Limits for New or Reconstructed Boilers and Process Heaters

As stated in § 63.7500, you must comply with the following applicable emission limits:

[Units with heat input capacity of 10 million Btu per hour or greater]

If your boiler or process heater is in this subcategory . . .	For the following pollutants . . .	The emissions must not exceed the following emission limits, except during startup and shutdown . . .	Or the emissions must not exceed the following alternative output-based limits, except during startup and shutdown . . .	Using this specified sampling volume or test run duration . . .
1. Units in all subcategories designed to burn solid fuel.	a. HCl	2.2E-02 lb per MMBtu of heat input	2.5E-02 lb per MMBtu of steam output or 0.28 lb per MWh	For M26A, collect a minimum of 1 dscm per run; for M26 collect a minimum of 120 liters per run.
	b. Mercury	8.0E-07 [a]lb per MMBtu of heat input	8.7E-07 [a]lb per MMBtu of steam output or 1.1E-05 [a]lb per MWh	For M29, collect a minimum of 4 dscm per run; for M30A or M30B, collect a minimum sample as specified in the method; for ASTM D6784 [b]collect a minimum of 4 dscm.

If your boiler or process heater is in this subcategory . . .	**For the following pollutants . . .**	**The emissions must not exceed the following emission limits, except during startup and shutdown . . .**	**Or the emissions must not exceed the following alternative output-based limits, except during startup and shutdown . . .**	**Using this specified sampling volume or test run duration . . .**
2. Units designed to burn coal/solid fossil fuel	**a. Filterable PM (or TSM)**	**1.1E-03 lb per MMBtu of heat input; or (2.3E-05 lb per MMBtu of heat input)**	**1.1E-03 lb per MMBtu of steam output or 1.4E-02 lb per MWh; or (2.7E-05 lb per MMBtu of steam output or 2.9E-04 lb per MWh)**	**Collect a minimum of 3 dscm per run.**
3. Pulverized coal boilers designed to burn coal/solid fossil fuel	**a. Carbon monoxide (CO) (or CEMS)**	**130 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (320 ppm by volume on a dry basis corrected to 3 percent oxygen, 30-day rolling average)**	**0.11 lb per MMBtu of steam output or 1.4 lb per MWh; 3-run average**	**1 hr minimum sampling time.**
4. Stokers designed to burn coal/solid fossil fuel	**a. CO (or CEMS)**	**130 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (340 ppm by volume on a dry basis corrected to 3 percent oxygen, 30-day rolling average)**	**0.12 lb per MMBtu of steam output or 1.4 lb per MWh; 3-run average**	**1 hr minimum sampling time.**
5. Fluidized bed units designed to burn coal/solid fossil fuel	**a. CO (or CEMS)**	**130 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (230 ppm by volume on a dry basis corrected to 3 percent oxygen, 30-day rolling average)**	**0.11 lb per MMBtu of steam output or 1.4 lb per MWh; 3-run average**	**1 hr minimum sampling time.**
6. Fluidized bed units with an integrated heat exchanger designed to burn coal/solid fossil fuel	**a. CO (or CEMS)**	**140 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (150 ppm by volume on a dry basis corrected to 3 percent oxygen, 30-day rolling average)**	**1.2E-01 lb per MMBtu of steam output or 1.5 lb per MWh; 3-run average**	**1 hr minimum sampling time.**

If your boiler or process heater is in this subcategory . . .	For the following pollutants . . .	The emissions must not exceed the following emission limits, except during startup and shutdown . . .	Or the emissions must not exceed the following alternative output-based limits, except during startup and shutdown . . .	Using this specified sampling volume or test run duration . . .
7. Stokers/sloped grate/others designed to burn wet biomass fuel	**a. CO (or CEMS)**	**620 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (390 ppm by volume on a dry basis corrected to 3 percent oxygen, 30-day rolling average)**	**5.8E-01 lb per MMBtu of steam output or 6.8 lb per MWh; 3-run average**	**1 hr minimum sampling time.**
	b. Filterable PM (or TSM)	**3.0E-02 lb per MMBtu of heat input; or (2.6E-05 lb per MMBtu of heat input)**	**3.5E-02 lb per MMBtu of steam output or 4.2E-01 lb per MWh; or (2.7E-05 lb per MMBtu of steam output or 3.7E-04 lb per MWh)**	**Collect a minimum of 2 dscm per run.**
8. Stokers/sloped grate/others designed to burn kiln-dried biomass fuel	**a. CO**	**460 ppm by volume on a dry basis corrected to 3 percent oxygen**	**4.2E-01 lb per MMBtu of steam output or 5.1 lb per MWh**	**1 hr minimum sampling time.**
	b. Filterable PM (or TSM)	**3.0E-02 lb per MMBtu of heat input; or (4.0E-03 lb per MMBtu of heat input)**	**3.5E-02 lb per MMBtu of steam output or 4.2E-01 lb per MWh; or (4.2E-03 lb per MMBtu of steam output or 5.6E-02 lb per MWh)**	**Collect a minimum of 2 dscm per run.**
9. Fluidized bed units designed to burn biomass/bio-based solids	**a. CO (or CEMS)**	**230 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (310 ppm by volume on a dry basis corrected to 3 percent oxygen, 30-day rolling average)**	**2.2E-01 lb per MMBtu of steam output or 2.6 lb per MWh; 3-run average**	**1 hr minimum sampling time.**

If your boiler or process heater is in this subcategory . . .	**For the following pollutants . . .**	**The emissions must not exceed the following emission limits, except during startup and shutdown . . .**	**Or the emissions must not exceed the following alternative output-based limits, except during startup and shutdown . . .**	**Using this specified sampling volume or test run duration . . .**
	b. Filterable PM (or TSM)	**9.8E-03 lb per MMBtu of heat input; or (8.3E-05 [a]lb per MMBtu of heat input)**	**1.2E-02 lb per MMBtu of steam output or 0.14 lb per MWh; or (1.1E-04 [a]lb per MMBtu of steam output or 1.2E-03 [a]lb per MWh)**	**Collect a minimum of 3 dscm per run.**
10. Suspension burners designed to burn biomass/bio-based solids	**a. CO (or CEMS)**	**2,400 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (2,000 ppm by volume on a dry basis corrected to 3 percent oxygen, 10-day rolling average)**	**1.9 lb per MMBtu of steam output or 27 lb per MWh; 3-run average**	**1 hr minimum sampling time.**
	b. Filterable PM (or TSM)	**3.0E-02 lb per MMBtu of heat input; or (6.5E-03 lb per MMBtu of heat input)**	**3.1E-02 lb per MMBtu of steam output or 4.2E-01 lb per MWh; or (6.6E-03 lb per MMBtu of steam output or 9.1E-02 lb per MWh)**	**Collect a minimum of 2 dscm per run.**
11. Dutch Ovens/Pile burners designed to burn biomass/bio-based solids	**a. CO (or CEMS)**	**330 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (520 ppm by volume on a dry basis corrected to 3 percent oxygen, 10-day rolling average)**	**3.5E-01 lb per MMBtu of steam output or 3.6 lb per MWh; 3-run average**	**1 hr minimum sampling time.**
	b. Filterable PM (or TSM)	**3.2E-03 lb per MMBtu of heat input; or (3.9E-05 lb per MMBtu of heat input)**	**4.3E-03 lb per MMBtu of steam output or 4.5E-02 lb per MWh; or (5.2E-05 lb per MMBtu of steam output or 5.5E-04 lb per MWh)**	**Collect a minimum of 3 dscm per run.**

If your boiler or process heater is in this subcategory . . .	**For the following pollutants . . .**	**The emissions must not exceed the following emission limits, except during startup and shutdown . . .**	**Or the emissions must not exceed the following alternative output-based limits, except during startup and shutdown . . .**	**Using this specified sampling volume or test run duration . . .**
12. Fuel cell units designed to burn biomass/bio-based solids	**a. CO**	**910 ppm by volume on a dry basis corrected to 3 percent oxygen**	**1.1 lb per MMBtu of steam output or 1.0E+01 lb per MWh**	**1 hr minimum sampling time.**
	b. Filterable PM (or TSM)	**2.0E-02 lb per MMBtu of heat input; or (2.9E-05 [a]lb per MMBtu of heat input)**	**3.0E-02 lb per MMBtu of steam output or 2.8E-01 lb per MWh; or (5.1E-05 lb per MMBtu of steam output or 4.1E-04 lb per MWh)**	**Collect a minimum of 2 dscm per run.**
13. Hybrid suspension grate boiler designed to burn biomass/bio-based solids	**a. CO (or CEMS)**	**1,100 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (900 ppm by volume on a dry basis corrected to 3 percent oxygen, 30-day rolling average)**	**1.4 lb per MMBtu of steam output or 12 lb per MWh; 3-run average**	**1 hr minimum sampling time.**
	b. Filterable PM (or TSM)	**2.6E-02 lb per MMBtu of heat input; or (4.4E-04 lb per MMBtu of heat input)**	**3.3E-02 lb per MMBtu of steam output or 3.7E-01 lb per MWh; or (5.5E-04 lb per MMBtu of steam output or 6.2E-03 lb per MWh)**	**Collect a minimum of 3 dscm per run.**
14. Units designed to burn liquid fuel	**a. HCl**	**4.4E-04 lb per MMBtu of heat input**	**4.8E-04 lb per MMBtu of steam output or 6.1E-03 lb per MWh**	**For M26A: Collect a minimum of 2 dscm per run; for M26, collect a minimum of 240 liters per run.**
	b. Mercury	**4.8E-07 [a]lb per MMBtu of heat input**	**5.3E-07 [a]lb per MMBtu of steam output or 6.7E-06 [a]lb per MWh**	**For M29, collect a minimum of 4 dscm per run; for M30A or M30B, collect a minimum sample as specified in the method; for ASTM D6784 [b]collect a minimum of 4 dscm.**

If your boiler or process heater is in this subcategory . . .	For the following pollutants . . .	The emissions must not exceed the following emission limits, except during startup and shutdown . . .	Or the emissions must not exceed the following alternative output-based limits, except during startup and shutdown . . .	Using this specified sampling volume or test run duration . . .
15. Units designed to burn heavy liquid fuel	**a. CO**	**130 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average**	**0.13 lb per MMBtu of steam output or 1.4 lb per MWh; 3-run average**	**1 hr minimum sampling time.**
	b. Filterable PM (or TSM)	**1.3E-02 lb per MMBtu of heat input; or (7.5E-05 lb per MMBtu of heat input)**	**1.5E-02 lb per MMBtu of steam output or 1.8E-01 lb per MWh; or (8.2E-05 lb per MMBtu of steam output or 1.1E-03 lb per MWh)**	**Collect a minimum of 3 dscm per run.**
16. Units designed to burn light liquid fuel	**a. CO**	**130 ppm by volume on a dry basis corrected to 3 percent oxygen**	**0.13 lb per MMBtu of steam output or 1.4 lb per MWh**	**1 hr minimum sampling time.**
	b. Filterable PM (or TSM)	**1.1E-03 [a]lb per MMBtu of heat input; or (2.9E-05 lb per MMBtu of heat input)**	**1.2E-03 [a]lb per MMBtu of steam output or 1.6E-02 [a]lb per MWh; or (3.2E-05 lb per MMBtu of steam output or 4.0E-04 lb per MWh)**	**Collect a minimum of 3 dscm per run.**
17. Units designed to burn liquid fuel that are non-continental units	**a. CO**	**130 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average based on stack test**	**0.13 lb per MMBtu of steam output or 1.4 lb per MWh; 3-run average**	**1 hr minimum sampling time.**
	b. Filterable PM (or TSM)	**2.3E-02 lb per MMBtu of heat input; or (8.6E-04 lb per MMBtu of heat input)**	**2.5E-02 lb per MMBtu of steam output or 3.2E-01 lb per MWh; or (9.4E-04 lb per MMBtu of steam output or 1.2E-02 lb per MWh)**	**Collect a minimum of 4 dscm per run.**
18. Units designed to burn gas 2 (other) gases	**a. CO**	**130 ppm by volume on a dry basis corrected to 3 percent oxygen**	**0.16 lb per MMBtu of steam output or 1.0 lb per MWh**	**1 hr minimum sampling time.**

If your boiler or process heater is in this subcategory . . .	For the following pollutants . . .	The emissions must not exceed the following emission limits, except during startup and shutdown . . .	Or the emissions must not exceed the following alternative output-based limits, except during startup and shutdown . . .	Using this specified sampling volume or test run duration . . .
	b. HCl	**1.7E-03 lb per MMBtu of heat input**	**2.9E-03 lb per MMBtu of steam output or 1.8E-02 lb per MWh**	**For M26A, Collect a minimum of 2 dscm per run; for M26, collect a minimum of 240 liters per run.**
	c. Mercury	**7.9E-06 lb per MMBtu of heat input**	**1.4E-05 lb per MMBtu of steam output or 8.3E-05 lb per MWh**	**For M29, collect a minimum of 3 dscm per run; for M30A or M30B, collect a minimum sample as specified in the method; for ASTM D6784 [b]collect a minimum of 3 dscm.**
	d. Filterable PM (or TSM)	**6.7E-03 lb per MMBtu of heat input; or (2.1E-04 lb per MMBtu of heat input)**	**1.2E-02 lb per MMBtu of steam output or 7.0E-02 lb per MWh; or (3.5E-04 lb per MMBtu of steam output or 2.2E-03 lb per MWh)**	**Collect a minimum of 3 dscm per run.**

[a] If you are conducting stack tests to demonstrate compliance and your performance tests for this pollutant for at least 2 consecutive years show that your emissions are at or below this limit, you can skip testing according to § 63.7515 if all of the other provisions of § 63.7515 are met. For all other pollutants that do not contain a footnote "a", your performance tests for this pollutant for at least 2 consecutive years must show that your emissions are at or below 75 percent of this limit in order to qualify for skip testing.

[b] Incorporated by reference, see § 63.14.

[c] If your affected source is a new or reconstructed affected source that commenced construction or reconstruction after June 4, 2010, and before January 31, 2013, you may comply with the emission limits in Tables 11, 12 or 13 to this subpart until January 31, 2016. On and after January 31, 2016, you must comply with the emission limits in Table 1 to this subpart.

[78 FR 7193, Jan. 31, 2013]

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Table 2 to Subpart DDDDD of Part 63—Emission Limits for Existing Boilers and Process Heaters

As stated in § 63.7500, you must comply with the following applicable emission limits:

[Units with heat input capacity of 10 million Btu per hour or greater]

If your boiler or process heater is in this subcategory . . .	For the following pollutants . . .	The emissions must not exceed the following emission limits, except during startup and shutdown . . .	The emissions must not exceed the following alternative output-based limits, except during startup and shutdown . . .	Using this specified sampling volume or test run duration . . .
1. Units in all subcategories designed to burn solid fuel	a. HCl	2.2E-02 lb per MMBtu of heat input	2.5E-02 lb per MMBtu of steam output or 0.27 lb per MWh	For M26A, Collect a minimum of 1 dscm per run; for M26, collect a minimum of 120 liters per run.
	b. Mercury	5.7E-06 lb per MMBtu of heat input	6.4E-06 lb per MMBtu of steam output or 7.3E-05 lb per MWh	For M29, collect a minimum of 3 dscm per run; for M30A or M30B, collect a minimum sample as specified in the method; for ASTM D6784 [b]collect a minimum of 3 dscm.
2. Units design to burn coal/solid fossil fuel	a. Filterable PM (or TSM)	4.0E-02 lb per MMBtu of heat input; or (5.3E-05 lb per MMBtu of heat input)	4.2E-02 lb per MMBtu of steam output or 4.9E-01 lb per MWh; or (5.6E-05 lb per MMBtu of steam output or 6.5E-04 lb per MWh)	Collect a minimum of 2 dscm per run.
3. Pulverized coal boilers designed to burn coal/solid fossil fuel	a. CO (or CEMS)	130 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (320 ppm by volume on a dry basis corrected to 3 percent oxygen, 30-day rolling average)	0.11 lb per MMBtu of steam output or 1.4 lb per MWh; 3-run average	1 hr minimum sampling time.
4. Stokers designed to burn coal/solid fossil fuel	a. CO (or CEMS)	160 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (340 ppm by volume on a dry basis corrected to 3 percent oxygen, 30-day rolling average)	0.14 lb per MMBtu of steam output or 1.7 lb per MWh; 3-run average	1 hr minimum sampling time.

If your boiler or process heater is in this subcategory . . .	For the following pollutants . . .	The emissions must not exceed the following emission limits, except during startup and shutdown . . .	The emissions must not exceed the following alternative output-based limits, except during startup and shutdown . . .	Using this specified sampling volume or test run duration . . .
5. Fluidized bed units designed to burn coal/solid fossil fuel	**a. CO (or CEMS)**	**130 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (230 ppm by volume on a dry basis corrected to 3 percent oxygen, 30-day rolling average)**	**0.12 lb per MMBtu of steam output or 1.4 lb per MWh; 3-run average**	**1 hr minimum sampling time.**
6. Fluidized bed units with an integrated heat exchanger designed to burn coal/solid fossil fuel	**a. CO (or CEMS)**	**140 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (150 ppm by volume on a dry basis corrected to 3 percent oxygen, 30-day rolling average)**	**1.3E-01 lb per MMBtu of steam output or 1.5 lb per MWh; 3-run average**	**1 hr minimum sampling time.**
7. Stokers/sloped grate/others designed to burn wet biomass fuel	**a. CO (or CEMS)**	**1,500 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (720 ppm by volume on a dry basis corrected to 3 percent oxygen, 30-day rolling average)**	**1.4 lb per MMBtu of steam output or 17 lb per MWh; 3-run average**	**1 hr minimum sampling time.**
	b. Filterable PM (or TSM)	**3.7E-02 lb per MMBtu of heat input; or (2.4E-04 lb per MMBtu of heat input)**	**4.3E-02 lb per MMBtu of steam output or 5.2E-01 lb per MWh; or (2.8E-04 lb per MMBtu of steam output or 3.4E-04 lb per MWh)**	**Collect a minimum of 2 dscm per run.**
8. Stokers/sloped grate/others designed to burn kiln-dried biomass fuel	**a. CO**	**460 ppm by volume on a dry basis corrected to 3 percent oxygen**	**4.2E-01 lb per MMBtu of steam output or 5.1 lb per MWh**	**1 hr minimum sampling time.**

If your boiler or process heater is in this subcategory . . .	**For the following pollutants . . .**	**The emissions must not exceed the following emission limits, except during startup and shutdown . . .**	**The emissions must not exceed the following alternative output-based limits, except during startup and shutdown . . .**	**Using this specified sampling volume or test run duration . . .**
	b. Filterable PM (or TSM)	**3.2E-01 lb per MMBtu of heat input; or (4.0E-03 lb per MMBtu of heat input)**	**3.7E-01 lb per MMBtu of steam output or 4.5 lb per MWh; or (4.6E-03 lb per MMBtu of steam output or 5.6E-02 lb per MWh)**	**Collect a minimum of 1 dscm per run.**
9. Fluidized bed units designed to burn biomass/bio-based solid	**a. CO (or CEMS)**	**470 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (310 ppm by volume on a dry basis corrected to 3 percent oxygen, 30-day rolling average)**	**4.6E-01 lb per MMBtu of steam output or 5.2 lb per MWh; 3-run average**	**1 hr minimum sampling time.**
	b. Filterable PM (or TSM)	**1.1E-01 lb per MMBtu of heat input; or (1.2E-03 lb per MMBtu of heat input)**	**1.4E-01 lb per MMBtu of steam output or 1.6 lb per MWh; or (1.5E-03 lb per MMBtu of steam output or 1.7E-02 lb per MWh)**	**Collect a minimum of 1 dscm per run.**
10. Suspension burners designed to burn biomass/bio-based solid	**a. CO (or CEMS)**	**2,400 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (2,000 ppm by volume on a dry basis corrected to 3 percent oxygen, 10-day rolling average)**	**1.9 lb per MMBtu of steam output or 27 lb per MWh; 3-run average**	**1 hr minimum sampling time.**
	b. Filterable PM (or TSM)	**5.1E-02 lb per MMBtu of heat input; or (6.5E-03 lb per MMBtu of heat input)**	**5.2E-02 lb per MMBtu of steam output or 7.1E-01 lb per MWh; or (6.6E-03 lb per MMBtu of steam output or 9.1E-02 lb per MWh)**	**Collect a minimum of 2 dscm per run.**

If your boiler or process heater is in this subcategory . . .	**For the following pollutants . . .**	**The emissions must not exceed the following emission limits, except during startup and shutdown . . .**	**The emissions must not exceed the following alternative output-based limits, except during startup and shutdown . . .**	**Using this specified sampling volume or test run duration . . .**
11. Dutch Ovens/Pile burners designed to burn biomass/bio-based solid	**a. CO (or CEMS)**	**770 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (520 ppm by volume on a dry basis corrected to 3 percent oxygen, 10-day rolling average)**	**8.4E-01 lb per MMBtu of steam output or 8.4 lb per MWh; 3-run average**	**1 hr minimum sampling time.**
	b. Filterable PM (or TSM)	**2.8E-01 lb per MMBtu of heat input; or (2.0E-03 lb per MMBtu of heat input)**	**3.9E-01 lb per MMBtu of steam output or 3.9 lb per MWh; or (2.8E-03 lb per MMBtu of steam output or 2.8E-02 lb per MWh)**	**Collect a minimum of 1 dscm per run.**
12. Fuel cell units designed to burn biomass/bio-based solid	**a. CO**	**1,100 ppm by volume on a dry basis corrected to 3 percent oxygen**	**2.4 lb per MMBtu of steam output or 12 lb per MWh**	**1 hr minimum sampling time.**
	b. Filterable PM (or TSM)	**2.0E-02 lb per MMBtu of heat input; or (5.8E-03 lb per MMBtu of heat input)**	**5.5E-02 lb per MMBtu of steam output or 2.8E-01 lb per MWh; or (1.6E-02 lb per MMBtu of steam output or 8.1E-02 lb per MWh)**	**Collect a minimum of 2 dscm per run.**
13. Hybrid suspension grate units designed to burn biomass/bio-based solid	**a. CO (or CEMS)**	**2,800 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (900 ppm by volume on a dry basis corrected to 3 percent oxygen, 30-day rolling average)**	**2.8 lb per MMBtu of steam output or 31 lb per MWh; 3-run average**	**1 hr minimum sampling time.**

If your boiler or process heater is in this subcategory . . .	For the following pollutants . . .	The emissions must not exceed the following emission limits, except during startup and shutdown . . .	The emissions must not exceed the following alternative output-based limits, except during startup and shutdown . . .	Using this specified sampling volume or test run duration . . .
	b. Filterable PM (or TSM)	4.4E-01 lb per MMBtu of heat input; or (4.5E-04 lb per MMBtu of heat input)	5.5E-01 lb per MMBtu of steam output or 6.2 lb per MWh; or (5.7E-04 lb per MMBtu of steam output or 6.3E-03 lb per MWh)	Collect a minimum of 1 dscm per run.
14. Units designed to burn liquid fuel	a. HCl	1.1E-03 lb per MMBtu of heat input	1.4E-03 lb per MMBtu of steam output or 1.6E-02 lb per MWh	For M26A, collect a minimum of 2 dscm per run; for M26, collect a minimum of 240 liters per run.
	b. Mercury	2.0E-06 lb per MMBtu of heat input	2.5E-06 lb per MMBtu of steam output or 2.8E-05 lb per MWh	For M29, collect a minimum of 3 dscm per run; for M30A or M30B collect a minimum sample as specified in the method, for ASTM D6784 [b]collect a minimum of 2 dscm.
15. Units designed to burn heavy liquid fuel	a. CO	130 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average	0.13 lb per MMBtu of steam output or 1.4 lb per MWh; 3-run average	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	6.2E-02 lb per MMBtu of heat input; or (2.0E-04 lb per MMBtu of heat input)	7.5E-02 lb per MMBtu of steam output or 8.6E-01 lb per MWh; or (2.5E-04 lb per MMBtu of steam output or 2.8E-03 lb per MWh)	Collect a minimum of 1 dscm per run.
16. Units designed to burn light liquid fuel	a. CO	130 ppm by volume on a dry basis corrected to 3 percent oxygen	0.13 lb per MMBtu of steam output or 1.4 lb per MWh	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	7.9E-03 lb per MMBtu of heat input; or (6.2E-05 lb per MMBtu of heat input)	9.6E-03 lb per MMBtu of steam output or 1.1E-01 lb per MWh; or (7.5E-05 lb per MMBtu of steam output or 8.6E-04 lb per MWh)	Collect a minimum of 3 dscm per run.

If your boiler or process heater is in this subcategory . . .	**For the following pollutants . . .**	**The emissions must not exceed the following emission limits, except during startup and shutdown . . .**	**The emissions must not exceed the following alternative output-based limits, except during startup and shutdown . . .**	**Using this specified sampling volume or test run duration . . .**
17. Units designed to burn liquid fuel that are non-continental units	**a. CO**	**130 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average based on stack test**	**0.13 lb per MMBtu of steam output or 1.4 lb per MWh; 3-run average**	**1 hr minimum sampling time.**
	b. Filterable PM (or TSM)	**2.7E-01 lb per MMBtu of heat input; or (8.6E-04 lb per MMBtu of heat input)**	**3.3E-01 lb per MMBtu of steam output or 3.8 lb per MWh; or (1.1E-03 lb per MMBtu of steam output or 1.2E-02 lb per MWh)**	**Collect a minimum of 2 dscm per run.**
18. Units designed to burn gas 2 (other) gases	**a. CO**	**130 ppm by volume on a dry basis corrected to 3 percent oxygen**	**0.16 lb per MMBtu of steam output or 1.0 lb per MWh**	**1 hr minimum sampling time.**
	b. HCl	**1.7E-03 lb per MMBtu of heat input**	**2.9E-03 lb per MMBtu of steam output or 1.8E-02 lb per MWh**	**For M26A, collect a minimum of 2 dscm per run; for M26, collect a minimum of 240 liters per run.**
	c. Mercury	**7.9E-06 lb per MMBtu of heat input**	**1.4E-05 lb per MMBtu of steam output or 8.3E-05 lb per MWh**	**For M29, collect a minimum of 3 dscm per run; for M30A or M30B, collect a minimum sample as specified in the method; for ASTM D6784 [b]collect a minimum of 2 dscm.**
	d. Filterable PM (or TSM)	**6.7E-03 lb per MMBtu of heat input or (2.1E-04 lb per MMBtu of heat input)**	**1.2E-02 lb per MMBtu of steam output or 7.0E-02 lb per MWh; or (3.5E-04 lb per MMBtu of steam output or 2.2E-03 lb per MWh)**	**Collect a minimum of 3 dscm per run.**

[a] If you are conducting stack tests to demonstrate compliance and your performance tests for this pollutant for at least 2 consecutive years show that your emissions are at or below this limit, you can skip testing according to § 63.7515 if all of the other provisions of § 63.7515 are met. For all other pollutants that do not contain a footnote a, your performance tests for this pollutant for at least 2 consecutive years must show that your emissions are at or below 75 percent of this limit in order to qualify for skip testing.

[b] Incorporated by reference, see § 63.14.

[78 FR 7195, Jan. 31, 2013]

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Table 3 to Subpart DDDDD of Part 63—Work Practice Standards

As stated in § 63.7500, you must comply with the following applicable work practice standards:

If your unit is . . .	You must meet the following . . .
1. A new or existing boiler or process heater with a continuous oxygen trim system that maintains an optimum air to fuel ratio, or a heat input capacity of less than or equal to 5 million Btu per hour in any of the following subcategories: unit designed to burn gas 1; unit designed to burn gas 2 (other); or unit designed to burn light liquid, or a limited use boiler or process heater	Conduct a tune-up of the boiler or process heater every 5 years as specified in § 63.7540.
2. A new or existing boiler or process heater without a continuous oxygen trim system and with heat input capacity of less than 10 million Btu per hour in the unit designed to burn heavy liquid or unit designed to burn solid fuel subcategories; or a new or existing boiler or process heater with heat input capacity of less than 10 million Btu per hour, but greater than 5 million Btu per hour, in any of the following subcategories: unit designed to burn gas 1; unit designed to burn gas 2 (other); or unit designed to burn light liquid	Conduct a tune-up of the boiler or process heater biennially as specified in § 63.7540.
3. A new or existing boiler or process heater without a continuous oxygen trim system and with heat input capacity of 10 million Btu per hour or greater	Conduct a tune-up of the boiler or process heater annually as specified in § 63.7540. Units in either the Gas 1 or Metal Process Furnace subcategories will conduct this tune-up as a work practice for all regulated emissions under this subpart. Units in all other subcategories will conduct this tune-up as a work practice for dioxins/furans.
4. An existing boiler or process heater located at a major source facility, not including limited use units	Must have a one-time energy assessment performed by a qualified energy assessor. An energy assessment completed on or after January 1, 2008, that meets or is amended to meet the energy assessment requirements in this table, satisfies the energy assessment requirement. A facility that operates under an energy management program compatible with ISO 50001 that includes the affected units also satisfies the energy assessment requirement. The energy assessment must include the following with extent of the evaluation for items a. to e. appropriate for the on-site technical hours listed in § 63.7575:
	a. A visual inspection of the boiler or process heater system.

If your unit is . . .	You must meet the following . . .
	b. An evaluation of operating characteristics of the boiler or process heater systems, specifications of energy using systems, operating and maintenance procedures, and unusual operating constraints.
	c. An inventory of major energy use systems consuming energy from affected boilers and process heaters and which are under the control of the boiler/process heater owner/operator.
	d. A review of available architectural and engineering plans, facility operation and maintenance procedures and logs, and fuel usage.
	e. A review of the facility's energy management practices and provide recommendations for improvements consistent with the definition of energy management practices, if identified.
	f. A list of cost-effective energy conservation measures that are within the facility's control.
	g. A list of the energy savings potential of the energy conservation measures identified.
	h. A comprehensive report detailing the ways to improve efficiency, the cost of specific improvements, benefits, and the time frame for recouping those investments.
5. An existing or new boiler or process heater subject to emission limits in Table 1 or 2 or 11 through 13 to this subpart during startup	You must operate all CMS during startup. For startup of a boiler or process heater, you must use one or a combination of the following clean fuels: natural gas, synthetic natural gas, propane, distillate oil, syngas, ultra-low sulfur diesel, fuel oil-soaked rags, kerosene, hydrogen, paper, cardboard, refinery gas, and liquefied petroleum gas.
	If you start firing coal/solid fossil fuel, biomass/bio-based solids, heavy liquid fuel, or gas 2 (other) gases, you must vent emissions to the main stack(s) and engage all of the applicable control devices except limestone injection in fluidized bed combustion (FBC) boilers, dry scrubber, fabric filter, selective non-catalytic reduction (SNCR), and selective catalytic reduction (SCR). You must start your limestone injection in FBC boilers, dry scrubber, fabric filter, SNCR, and SCR systems as expeditiously as possible. Startup ends when steam or heat is supplied for any purpose.

If your unit is . . .	**You must meet the following . . .**
	You must comply with all applicable emission limits at all times except for startup or shutdown periods conforming with this work practice. You must collect monitoring data during periods of startup, as specified in § 63.7535(b). You must keep records during periods of startup. You must provide reports concerning activities and periods of startup, as specified in § 63.7555.
6. An existing or new boiler or process heater subject to emission limits in Tables 1 or 2 or 11 through 13 to this subpart during shutdown	**You must operate all CMS during shutdown. While firing coal/solid fossil fuel, biomass/bio-based solids, heavy liquid fuel, or gas 2 (other) gases during shutdown, you must vent emissions to the main stack(s) and operate all applicable control devices, except limestone injection in FBC boilers, dry scrubber, fabric filter, SNCR, and SCR.**
	You must comply with all applicable emissions limits at all times except for startup or shutdown periods conforming with this work practice. You must collect monitoring data during periods of shutdown, as specified in § 63.7535(b). You must keep records during periods of shutdown. You must provide reports concerning activities and periods of shutdown, as specified in § 63.7555.

[78 FR 7198, Jan. 31, 2013]

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Table 4 to Subpart DDDDD of Part 63—Operating Limits for Boilers and Process Heaters

As stated in § 63.7500, you must comply with the applicable operating limits:

When complying with a Table 1, 2, 11, 12, or 13 numerical emission limit using . . .	**You must meet these operating limits . . .**
1. Wet PM scrubber control on a boiler not using a PM CPMS	**Maintain the 30-day rolling average pressure drop and the 30-day rolling average liquid flow rate at or above the lowest one-hour average pressure drop and the lowest one-hour average liquid flow rate, respectively, measured during the most recent performance test demonstrating compliance with the PM emission limitation according to § 63.7530(b) and Table 7 to this subpart.**
2. Wet acid gas (HCl) scrubber control on a boiler not using a HCl CEMS	**Maintain the 30-day rolling average effluent pH at or above the lowest one-hour average pH and the 30-day rolling average liquid flow rate at or above the lowest one-hour average liquid flow rate measured during the most recent performance test demonstrating compliance with the HCl emission limitation according to § 63.7530(b) and Table 7 to this subpart.**
3. Fabric filter control on units not using a PM CPMS	**a. Maintain opacity to less than or equal to 10 percent opacity (daily block average); or**

When complying with a Table 1, 2, 11, 12, or 13 numerical emission limit using . . .	You must meet these operating limits . . .
	b. Install and operate a bag leak detection system according to § 63.7525 and operate the fabric filter such that the bag leak detection system alert is not activated more than 5 percent of the operating time during each 6-month period.
4. Electrostatic precipitator control on units not using a PM CPMS	a. This option is for boilers and process heaters that operate dry control systems (i.e., an ESP without a wet scrubber). Existing and new boilers and process heaters must maintain opacity to less than or equal to 10 percent opacity (daily block average); or
	b. This option is only for boilers and process heaters not subject to PM CPMS or continuous compliance with an opacity limit (i.e., COMS). Maintain the 30-day rolling average total secondary electric power input of the electrostatic precipitator at or above the operating limits established during the performance test according to § 63.7530(b) and Table 7 to this subpart.
5. Dry scrubber or carbon injection control on a boiler not using a mercury CEMS	Maintain the minimum sorbent or carbon injection rate as defined in § 63.7575 of this subpart.
6. Any other add-on air pollution control type on units not using a PM CPMS	This option is for boilers and process heaters that operate dry control systems. Existing and new boilers and process heaters must maintain opacity to less than or equal to 10 percent opacity (daily block average).
7. Fuel analysis	Maintain the fuel type or fuel mixture such that the applicable emission rates calculated according to § 63.7530(c)(1), (2) and/or (3) is less than the applicable emission limits.
8. Performance testing	For boilers and process heaters that demonstrate compliance with a performance test, maintain the operating load of each unit such that it does not exceed 110 percent of the highest hourly average operating load recorded during the most recent performance test.
9. Oxygen analyzer system	For boilers and process heaters subject to a CO emission limit that demonstrate compliance with an O_2analyzer system as specified in § 63.7525(a), maintain the 30-day rolling average oxygen content at or above the lowest hourly average oxygen concentration measured during the most recent CO performance test, as specified in Table 8. This requirement does not apply to units that install an oxygen trim system since these units will set the trim system to the level specified in § 63.7525(a).
10. SO_2CEMS	For boilers or process heaters subject to an HCl emission limit that demonstrate compliance with an SO_2CEMS, maintain the 30-day rolling average SO_2emission rate at or below the highest hourly average SO_2concentration measured during the most recent HCl performance test, as specified in Table 8.

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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 testing for existing, new or reconstructed affected sources:

To conduct a performance test for the following pollutant...	You must...	Using...
1. Filterable PM	a. Select sampling ports location and the number of traverse points	Method 1 at 40 CFR part 60, appendix A-1 of this chapter.
	b. Determine velocity and volumetric flow-rate of the stack gas	Method 2, 2F, or 2G at 40 CFR part 60, appendix A-1 or A-2 to part 60 of this chapter.
	c. Determine oxygen or carbon dioxide concentration of the stack gas	Method 3A or 3B at 40 CFR part 60, appendix A-2 to part 60 of this chapter, or ANSI/ASME PTC 19.10-1981.[a]
	d. Measure the moisture content of the stack gas	Method 4 at 40 CFR part 60, appendix A-3 of this chapter.
	e. Measure the PM emission concentration	Method 5 or 17 (positive pressure fabric filters must use Method 5D) at 40 CFR part 60, appendix A-3 or A-6 of this chapter.
	f. Convert emissions concentration to lb per MMBtu emission rates	Method 19 F-factor methodology at 40 CFR part 60, appendix A-7 of this chapter.
2. TSM	a. Select sampling ports location and the number of traverse points	Method 1 at 40 CFR part 60, appendix A-1 of this chapter.
	b. Determine velocity and volumetric flow-rate of the stack gas	Method 2, 2F, or 2G at 40 CFR part 60, appendix A-1 or A-2 of this chapter.
	c. Determine oxygen or carbon dioxide concentration of the stack gas	Method 3A or 3B at 40 CFR part 60, appendix A-1 of this chapter, or ANSI/ASME PTC 19.10-1981.[a]
	d. Measure the moisture content of the stack gas	Method 4 at 40 CFR part 60, appendix A-3 of this chapter.
	e. Measure the TSM emission concentration	Method 29 at 40 CFR part 60, appendix A-8 of this chapter
	f. Convert emissions concentration to lb per MMBtu emission rates	Method 19 F-factor methodology at 40 CFR part 60, appendix A-7 of this chapter.
3. HCl	a. Select sampling ports location and the number of traverse points	Method 1 at 40 CFR part 60, appendix A-1 of this chapter.

To conduct a performance test for the following pollutant...	You must...	Using...
	b. Determine velocity and volumetric flow-rate of the stack gas	Method 2, 2F, or 2G at 40 CFR part 60, appendix A-2 of this chapter.
	c. Determine oxygen or carbon dioxide concentration of the stack gas	Method 3A or 3B at 40 CFR part 60, appendix A-2 of this chapter, or ANSI/ASME PTC 19.10-1981.[a]
	d. Measure the moisture content of the stack gas	Method 4 at 40 CFR part 60, appendix A-3 of this chapter.
	e. Measure the HCl emission concentration	Method 26 or 26A (M26 or M26A) at 40 CFR part 60, appendix A-8 of this chapter.
	f. Convert emissions concentration to lb per MMBtu emission rates	Method 19 F-factor methodology at 40 CFR part 60, appendix A-7 of this chapter.
3. Hydrogen chloride	a. Select sampling ports location and the number of traverse points	Method 1 at 40 CFR part 60, appendix A-1 of this chapter.
	b. Determine velocity and volumetric flow-rate of the stack gas	Method 2, 2F, or 2G at 40 CFR part 60, appendix A-2 of this chapter.
	c. Determine oxygen or carbon dioxide concentration of the stack gas	Method 3A or 3B at 40 CFR part 60, appendix A-2 of this chapter, or ANSI/ASME PTC 19.10-1981.[a]
	d. Measure the moisture content of the stack gas	Method 4 at 40 CFR part 60, appendix A-3 of this chapter.
	e. Measure the hydrogen chloride emission concentration	Method 26 or 26A (M26 or M26A) at 40 CFR part 60, appendix A-8 of this chapter.
	f. Convert emissions concentration to lb per MMBtu emission rates	Method 19 F-factor methodology at 40 CFR part 60, appendix A-7 of this chapter.
4. Mercury	a. Select sampling ports location and the number of traverse points	Method 1 at 40 CFR part 60, appendix A-1 of this chapter.
	b. Determine velocity and volumetric flow-rate of the stack gas	Method 2, 2F, or 2G at 40 CFR part 60, appendix A-1 or A-2 of this chapter.
	c. Determine oxygen or carbon dioxide concentration of the stack gas	Method 3A or 3B at 40 CFR part 60, appendix A-1 of this chapter, or ANSI/ASME PTC 19.10-1981.[a]

To conduct a performance test for the following pollutant...	You must...	Using...
	d. Measure the moisture content of the stack gas	Method 4 at 40 CFR part 60, appendix A-3 of this chapter.
	e. Measure the mercury emission concentration	Method 29, 30A, or 30B (M29, M30A, or M30B) at 40 CFR part 60, appendix A-8 of this chapter or Method 101A at 40 CFR part 61, appendix B of this chapter, or ASTM Method D6784.[a]
	f. Convert emissions concentration to lb per MMBtu emission rates	Method 19 F-factor methodology at 40 CFR part 60, appendix A-7 of this chapter.
5. CO	a. Select the sampling ports location and the number of traverse points	Method 1 at 40 CFR part 60, appendix A-1 of this chapter.
	b. Determine oxygen concentration of the stack gas	Method 3A or 3B at 40 CFR part 60, appendix A-3 of this chapter, or ASTM D6522-00 (Reapproved 2005), or ANSI/ASME PTC 19.10-1981.[a]
	c. Measure the moisture content of the stack gas	Method 4 at 40 CFR part 60, appendix A-3 of this chapter.
	d. Measure the CO emission concentration	Method 10 at 40 CFR part 60, appendix A-4 of this chapter. Use a measurement span value of 2 times the concentration of the applicable emission limit.

[76 FR 15664, Mar. 21, 2011, as amended at 78 FR 7200, Jan. 31, 2013]

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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 (as defined in § 63.7575) may be used in lieu of the prescribed methods at the discretion of the source owner or operator:

To conduct a fuel analysis for the following pollutant . . .	You must . . .	Using . . .
1. Mercury	a. Collect fuel samples	Procedure in § 63.7521(c) or ASTM D5192 [a], or ASTM D7430 [a], or ASTM D6883 [a], or ASTM D2234/D2234M [a](for coal) or EPA 1631 or EPA 1631E or ASTM D6323 [a](for solid), or EPA 821-R-01-013 (for liquid or solid), or ASTM D4177 [a](for liquid), or ASTM D4057 [a](for liquid), or equivalent.
	b. Composite fuel samples	Procedure in § 63.7521(d) or equivalent.

To conduct a fuel analysis for the following pollutant . . .	You must . . .	Using . . .
	c. Prepare composited fuel samples	EPA SW-846-3050B [a](for solid samples), EPA SW-846-3020A [a](for liquid samples), ASTM D2013/D2013M [a](for coal), ASTM D5198 [a](for biomass), or EPA 3050 [a](for solid fuel), or EPA 821-R-01-013 [a](for liquid or solid), or equivalent.
	d. Determine heat content of the fuel type	ASTM D5865 [a](for coal) or ASTM E711 [a](for biomass), or ASTM D5864 [a]for liquids and other solids, or ASTM D240 [a]or equivalent.
	e. Determine moisture content of the fuel type	ASTM D3173 [a], ASTM E871 [a], or ASTM D5864 [a], or ASTM D240, or ASTM D95 [a](for liquid fuels), or ASTM D4006 [a](for liquid fuels), or ASTM D4177 [a](for liquid fuels) or ASTM D4057 [a](for liquid fuels), or equivalent.
	f. Measure mercury concentration in fuel sample	ASTM D6722 [a](for coal), EPA SW-846-7471B [a](for solid samples), or EPA SW-846-7470A [a](for liquid samples), or equivalent.
	g. Convert concentration into units of pounds of mercury per MMBtu of heat content	Equation 8 in § 63.7530.
	h. Calculate the mercury emission rate from the boiler or process heater in units of pounds per million Btu	Equations 10 and 12 in § 63.7530.
2. HCl	a. Collect fuel samples	Procedure in § 63.7521(c) or ASTM D5192 [a], or ASTM D7430 [a], or ASTM D6883 [a], or ASTM D2234/D2234M [a](for coal) or ASTM D6323 [a](for coal or biomass), ASTM D4177 [a](for liquid fuels) or ASTM D4057 [a](for liquid fuels), or equivalent.
	b. Composite fuel samples	Procedure in § 63.7521(d) or equivalent.
	c. Prepare composited fuel samples	EPA SW-846-3050B [a](for solid samples), EPA SW-846-3020A [a](for liquid samples), ASTM D2013/D2013M§[a](for coal), or ASTM D5198§[a](for biomass), or EPA 3050 [a]or equivalent.
	d. Determine heat content of the fuel type	ASTM D5865 [a](for coal) or ASTM E711 [a](for biomass), ASTM D5864, ASTM D240 [a]or equivalent.
	e. Determine moisture content of the fuel type	ASTM D3173 [a]or ASTM E871 [a], or D5864 [a], or ASTM D240 [a], or ASTM D95[a](for liquid fuels), or ASTM D4006 [a](for liquid fuels), or ASTM D4177 [a](for liquid fuels) or ASTM D4057 [a](for liquid fuels) or equivalent.
	f. Measure chlorine concentration in fuel sample	EPA SW-846-9250 [a], ASTM D6721 [a], ASTM D4208 [a](for coal), or EPA SW-846-5050 [a]or ASTM E776 [a](for solid fuel), or EPA SW-846-9056 [a]or SW-846-9076 [a](for solids or liquids) or equivalent.

To conduct a fuel analysis for the following pollutant . . .	**You must . . .**	**Using . . .**
	g. Convert concentrations into units of pounds of HCl per MMBtu of heat content	**Equation 7 in § 63.7530.**
	h. Calculate the HCl emission rate from the boiler or process heater in units of pounds per million Btu	**Equations 10 and 11 in § 63.7530.**
3. Mercury Fuel Specification for other gas 1 fuels	**a. Measure mercury concentration in the fuel sample and convert to units of micrograms per cubic meter**	**Method 30B (M30B) at 40 CFR part 60, appendix A-8 of this chapter or ASTM D5954 [a], ASTM D6350 [a], ISO 6978-1:2003(E) [a], or ISO 6978-2:2003(E) [a], or EPA-1631 [a]or equivalent.**
	b. Measure mercury concentration in the exhaust gas when firing only the other gas 1 fuel is fired in the boiler or process heater	**Method 29, 30A, or 30B (M29, M30A, or M30B) at 40 CFR part 60, appendix A-8 of this chapter or Method 101A or Method 102 at 40 CFR part 61, appendix B of this chapter, or ASTM Method D6784 [a]or equivalent.**
4. TSM for solid fuels	**a. Collect fuel samples**	**Procedure in § 63.7521(c) or ASTM D5192 [a], or ASTM D7430 [a], or ASTM D6883 [a], or ASTM D2234/D2234M [a](for coal) or ASTM D6323 [a](for coal or biomass), or ASTM D4177 [a],(for liquid fuels)or ASTM D4057 [a](for liquid fuels),or equivalent.**
	b. Composite fuel samples	**Procedure in § 63.7521(d) or equivalent.**
	c. Prepare composited fuel samples	**EPA SW-846-3050B [a](for solid samples), EPA SW-846-3020A [a](for liquid samples), ASTM D2013/D2013M [a](for coal), ASTM D5198 [a]or TAPPI T266 [a](for biomass), or EPA 3050 [a]or equivalent.**
	d. Determine heat content of the fuel type	**ASTM D5865 [a](for coal) or ASTM E711 [a](for biomass), or ASTM D5864 [a]for liquids and other solids, or ASTM D240 [a]or equivalent.**
	e. Determine moisture content of the fuel type	**ASTM D3173 [a]or ASTM E871 [a], or D5864, or ASTM D240 [a], or ASTM D95 [a](for liquid fuels), or ASTM D4006[a](for liquid fuels), or ASTM D4177 [a](for liquid fuels) or ASTM D4057 [a](for liquid fuels), or equivalent.**
	f. Measure TSM concentration in fuel sample	**ASTM D3683 [a], or ASTM D4606 [a], or ASTM D6357 [a]or EPA 200.8 [a]or EPA SW-846-6020 [a], or EPA SW-846-6020A [a], or EPA SW-846-6010C [a], EPA 7060 [a]or EPA 7060A [a](for arsenic only), or EPA SW-846-7740 [a](for selenium only).**
	g. Convert concentrations into units of pounds of TSM per MMBtu of heat content	**Equation 9 in § 63.7530.**

To conduct a fuel analysis for the following pollutant . . .	You must . . .	Using . . .
	h. Calculate the TSM emission rate from the boiler or process heater in units of pounds per million Btu	Equations 10 and 13 in § 63.7530.

[a] Incorporated by reference, see § 63.14.

[78 FR 7201, Jan. 31, 2013]

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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. PM, TSM, or mercury	a. Wet scrubber operating parameters	i. Establish a site-specific minimum scrubber pressure drop and minimum flow rate operating limit according to § 63.7530(b)	(1) Data from the scrubber pressure drop and liquid flow rate monitors and the PM or mercury performance test	(a) You must collect scrubber pressure drop and liquid flow rate data every 15 minutes during the entire period of the performance tests.
				(b) Determine the lowest hourly average scrubber pressure drop and liquid flow rate by computing the hourly averages using all of the 15-minute readings taken during each performance test.
	b. Electrostatic precipitator operating parameters (option only for units that operate wet scrubbers)	i. Establish a site-specific minimum total secondary electric power input according to § 63.7530(b)	(1) Data from the voltage and secondary amperage monitors during the PM or mercury performance test	(a) You must collect secondary voltage and secondary amperage for each ESP cell and calculate total secondary electric power input 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 total secondary electric power input by computing the hourly averages using all of the 15-minute readings taken during each performance test.
2. HCl	**a. Wet scrubber operating parameters**	**i. Establish site-specific minimum pressure drop, effluent pH, and flow rate operating limits according to § 63.7530(b)**	**(1) Data from the pressure drop, pH, and liquid flow-rate monitors and the HCl performance test**	**(a) You must collect pH and liquid flow-rate data every 15 minutes during the entire period of the performance tests.**
				(b) Determine the hourly average pH and liquid flow rate by computing the hourly averages using all of the 15-minute readings taken during each performance test.
	b. Dry scrubber operating parameters	**i. Establish a site-specific minimum sorbent injection rate operating limit according to § 63.7530(b). If different acid gas sorbents are used during the HCl performance test, the average value for each sorbent becomes the site-specific operating limit for that sorbent**	**(1) Data from the sorbent injection rate monitors and HCl or mercury performance test**	**(a) You must collect sorbent injection rate data every 15 minutes during the entire period of the performance tests.**
				(b) Determine the hourly average sorbent injection rate by computing the hourly averages using all of the 15-minute readings taken during each performance test.

If you have an applicable emission limit for . . .	**And your operating limits are based on . . .**	**You must . . .**	**Using . . .**	**According to the following requirements**
				(c) Determine the lowest hourly average of the three test run averages established during the performance test as your operating limit. When your unit operates at lower loads, multiply your sorbent injection rate by the load fraction (e.g., for 50 percent load, multiply the injection rate operating limit by 0.5) to determine the required injection rate.
	c. Alternative Maximum SO_2emission rate	**i. Establish a site-specific maximum SO_2emission rate operating limit according to § 63.7530(b)**	**(1) Data from SO_2CEMS and the HCl performance test**	**(a) You must collect the SO_2emissions data according to § 63.7525(m) during the most recent HCl performance tests.**
				(b) The maximum SO_2emission rate is equal to the lowest hourly average SO_2emission rate measured during the most recent HCl performance tests.
3. Mercury	**a. Activated carbon injection**	**i. Establish a site-specific minimum activated carbon injection rate operating limit according to § 63.7530(b)**	**(1) Data from the activated carbon rate monitors and mercury performance test**	**(a) You must collect activated carbon injection rate data every 15 minutes during the entire period of the performance tests.**
				(b) Determine the hourly average activated carbon injection rate by computing the hourly averages using all of the 15-minute readings taken during each performance test.

If you have an applicable emission limit for . . .	And your operating limits are based on . . .	You must . . .	Using . . .	According to the following requirements
				(c) Determine the lowest hourly average established during the performance test as your operating limit. When your unit operates at lower loads, multiply your activated carbon injection rate by the load fraction (e.g., actual heat input divided by heat input during performance test, for 50 percent load, multiply the injection rate operating limit by 0.5) to determine the required injection rate.
4. Carbon monoxide	**a. Oxygen**	**i. Establish a unit-specific limit for minimum oxygen level according to § 63.7520**	**(1) Data from the oxygen analyzer system specified in § 63.7525(a)**	**(a) You must collect oxygen data every 15 minutes during the entire period of the performance tests.**
				(b) Determine the hourly average oxygen concentration by computing the hourly averages using all of the 15-minute readings taken during each performance test.
				(c) Determine the lowest hourly average established during the performance test as your minimum operating limit.
5. Any pollutant for which compliance is demonstrated by a performance test	**a. Boiler or process heater operating load**	**i. Establish a unit specific limit for maximum operating load according to § 63.7520(c)**	**(1) Data from the operating load monitors or from steam generation monitors**	**(a) You must collect operating load or steam generation data every 15 minutes during the entire period of the performance test.**
				(b) Determine the average operating load by computing the hourly averages using all of the 15-minute readings taken during each performance test.

If you have an applicable emission limit for . . .	And your operating limits are based on . . .	You must . . .	Using . . .	According to the following requirements
				(c) Determine the average of the three test run averages during the performance test, and multiply this by 1.1 (110 percent) as your operating limit.

[76 FR 15664, Mar. 21, 2011, as amended at 78 FR 7203, Jan. 31, 2013]

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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 each boiler or process heater 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(c) and § 63.7535; and
	b. Reducing the opacity monitoring data to 6-minute averages; and
	c. Maintaining opacity to less than or equal to 10 percent (daily block average).
2. PM CPMS	a. Collecting the PM CPMS output data according to § 63.7525;
	b. Reducing the data to 30-day rolling averages; and
	c. Maintaining the 30-day rolling average PM CPMS output data to less than the operating limit established during the performance test according to § 63.7530(b)(4).
3. 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.
4. 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
	b. Reducing the data to 30-day rolling averages; and
	c. Maintaining the 30-day rolling average pressure drop and liquid flow-rate at or above the operating limits established during the performance test according to § 63.7530(b).
5. Wet Scrubber pH	a. Collecting the pH monitoring system data according to §§ 63.7525 and 63.7535; and
	b. Reducing the data to 30-day rolling averages; and

If you must meet the following operating limits or work practice standards . . .	You must demonstrate continuous compliance by . . .
	c. Maintaining the 30-day rolling average pH at or above the operating limit established during the performance test according to § 63.7530(b).
6. Dry Scrubber Sorbent or Carbon Injection Rate	a. Collecting the sorbent or carbon injection rate monitoring system data for the dry scrubber according to §§ 63.7525 and 63.7535; and
	b. Reducing the data to 30-day rolling averages; and
	c. Maintaining the 30-day rolling average sorbent or carbon injection rate at or above the minimum sorbent or carbon injection rate as defined in § 63.7575.
7. Electrostatic Precipitator Total Secondary Electric Power Input	a. Collecting the total secondary electric power input monitoring system data for the electrostatic precipitator according to §§ 63.7525 and 63.7535; and
	b. Reducing the data to 30-day rolling averages; and
	c. Maintaining the 30-day rolling average total secondary electric power input at or above the operating limits established during the performance test according to § 63.7530(b).
8. Emission limits using fuel analysis	a. Conduct monthly fuel analysis for HCl or mercury or TSM according to Table 6 to this subpart; and
	b. Reduce the data to 12-month rolling averages; and
	c. Maintain the 12-month rolling average at or below the applicable emission limit for HCl or mercury or TSM in Tables 1 and 2 or 11 through 13 to this subpart.
9. Oxygen content	a. Continuously monitor the oxygen content using an oxygen analyzer system according to § 63.7525(a). This requirement does not apply to units that install an oxygen trim system since these units will set the trim system to the level specified in § 63.7525(a)(2).
	b. Reducing the data to 30-day rolling averages; and
	c. Maintain the 30-day rolling average oxygen content at or above the lowest hourly average oxygen level measured during the most recent CO performance test.
10. Boiler or process heater operating load	a. Collecting operating load data or steam generation data every 15 minutes.
	b. Maintaining the operating load such that it does not exceed 110 percent of the highest hourly average operating load recorded during the most recent performance test according to § 63.7520(c).
11. SO_2emissions using SO_2CEMS	a. Collecting the SO_2CEMS output data according to § 63.7525;
	b. Reducing the data to 30-day rolling averages; and
	c. Maintaining the 30-day rolling average SO_2CEMS emission rate to a level at or below the minimum hourly SO_2rate measured during the most recent HCl performance test according to § 63.7530.

[78 FR 7204, Jan. 31, 2013]

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Table 9 to Subpart DDDDD of Part 63—Reporting Requirements

As stated in § 63.7550, you must comply with the following requirements for reports:

You must submit a(n)	The report must contain . . .	You must submit the report . . .
1. Compliance report	a. Information required in § 63.7550(c)(1) through (5); and	Semiannually, annually, biennially, or every 5 years 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 3 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) where you are not using a CMS to comply with that emission limit or operating limit, or a deviation from a work practice standard during the reporting period, the report must contain the information in § 63.7550(d); and	
	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), or otherwise not operating, the report must contain the information in § 63.7550(e)	

[76 FR 15664, Mar. 21, 2011, as amended at 78 FR 7205, Jan. 31, 2013]

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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	Applies to subpart DDDDD
§ 63.1	Applicability	Yes.
§ 63.2	Definitions	Yes. Additional terms defined in § 63.7575
§ 63.3	Units and Abbreviations	Yes.
§ 63.4	Prohibited Activities and Circumvention	Yes.
§ 63.5	Preconstruction Review and Notification Requirements	Yes.
§ 63.6(a), (b)(1)-(b)(5), (b)(7), (c)	Compliance with Standards and Maintenance Requirements	Yes.
§ 63.6(e)(1)(i)	General duty to minimize emissions.	No. See § 63.7500(a)(3) for the general duty requirement.
§ 63.6(e)(1)(ii)	Requirement to correct malfunctions as soon as practicable.	No.
§ 63.6(e)(3)	Startup, shutdown, and malfunction plan requirements.	No.
§ 63.6(f)(1)	Startup, shutdown, and malfunction exemptions for compliance with non-opacity emission standards.	No.
§ 63.6(f)(2) and (3)	Compliance with non-opacity emission standards.	Yes.
§ 63.6(g)	Use of alternative standards	Yes.
§ 63.6(h)(1)	Startup, shutdown, and malfunction exemptions to opacity standards.	No. See § 63.7500(a).
§ 63.6(h)(2) to (h)(9)	Determining compliance with opacity emission standards	Yes.

Citation	**Subject**	**Applies to subpart DDDDD**
§ 63.6(i)	**Extension of compliance**	**Yes. Note: Facilities may also request extensions of compliance for the installation of combined heat and power, waste heat recovery, or gas pipeline or fuel feeding infrastructure as a means of complying with this subpart.**
§ 63.6(j)	**Presidential exemption.**	**Yes.**
§ 63.7(a), (b), (c), and (d)	**Performance Testing Requirements**	**Yes.**
§ 63.7(e)(1)	**Conditions for conducting performance tests**	**No. Subpart DDDDD specifies conditions for conducting performance tests at § 63.7520(a) to (c).**
§ 63.7(e)(2)-(e)(9), (f), (g), and (h)	**Performance Testing Requirements**	**Yes.**
§ 63.8(a) and (b)	**Applicability and Conduct of Monitoring**	**Yes.**
§ 63.8(c)(1)	**Operation and maintenance of CMS**	**Yes.**
§ 63.8(c)(1)(i)	**General duty to minimize emissions and CMS operation**	**No. See § 63.7500(a)(3).**
§ 63.8(c)(1)(ii)	**Operation and maintenance of CMS**	**Yes.**
§ 63.8(c)(1)(iii)	**Startup, shutdown, and malfunction plans for CMS**	**No.**
§ 63.8(c)(2) to (c)(9)	**Operation and maintenance of CMS**	**Yes.**
§ 63.8(d)(1) and (2)	**Monitoring Requirements, Quality Control Program**	**Yes.**
§ 63.8(d)(3)	**Written procedures for CMS**	**Yes, except for the last sentence, which refers to a startup, shutdown, and malfunction plan. Startup, shutdown, and malfunction plans are not required.**
§ 63.8(e)	**Performance evaluation of a CMS**	**Yes.**
§ 63.8(f)	**Use of an alternative monitoring method.**	**Yes.**
§ 63.8(g)	**Reduction of monitoring data**	**Yes.**
§ 63.9	**Notification Requirements**	**Yes.**
§ 63.10(a), (b)(1)	**Recordkeeping and Reporting Requirements**	**Yes.**

Citation	**Subject**	**Applies to subpart DDDDD**
§ 63.10(b)(2)(i)	**Recordkeeping of occurrence and duration of startups or shutdowns**	**Yes.**
§ 63.10(b)(2)(ii)	**Recordkeeping of malfunctions**	**No. See § 63.7555(d)(7) for recordkeeping of occurrence and duration and § 63.7555(d)(8) for actions taken during malfunctions.**
§ 63.10(b)(2)(iii)	**Maintenance records**	**Yes.**
§ 63.10(b)(2)(iv) and (v)	**Actions taken to minimize emissions during startup, shutdown, or malfunction**	**No.**
§ 63.10(b)(2)(vi)	**Recordkeeping for CMS malfunctions**	**Yes.**
§ 63.10(b)(2)(vii) to (xiv)	**Other CMS requirements**	**Yes.**
§ 63.10(b)(3)	**Recordkeeping requirements for applicability determinations**	**No.**
§ 63.10(c)(1) to (9)	**Recordkeeping for sources with CMS**	**Yes.**
§ 63.10(c)(10) and (11)	**Recording nature and cause of malfunctions, and corrective actions**	**No. See § 63.7555(d)(7) for recordkeeping of occurrence and duration and § 63.7555(d)(8) for actions taken during malfunctions.**
§ 63.10(c)(12) and (13)	**Recordkeeping for sources with CMS**	**Yes.**
§ 63.10(c)(15)	**Use of startup, shutdown, and malfunction plan**	**No.**
§ 63.10(d)(1) and (2)	**General reporting requirements**	**Yes.**
§ 63.10(d)(3)	**Reporting opacity or visible emission observation results**	**No.**
§ 63.10(d)(4)	**Progress reports under an extension of compliance**	**Yes.**
§ 63.10(d)(5)	**Startup, shutdown, and malfunction reports**	**No. See § 63.7550(c)(11) for malfunction reporting requirements.**
§ 63.10(e)	**Additional reporting requirements for sources with CMS**	**Yes.**
§ 63.10(f)	**Waiver of recordkeeping or reporting requirements**	**Yes.**
§ 63.11	**Control Device Requirements**	**No.**

Citation	**Subject**	**Applies to subpart DDDDD**
§ 63.12	**State Authority and Delegation**	**Yes.**
§ 63.13-63.16	**Addresses, Incorporation by Reference, Availability of Information, Performance Track Provisions**	**Yes.**
§ 63.1(a)(5),(a)(7)-(a)(9), (b)(2), (c)(3)-(4), (d), 63.6(b)(6), (c)(3), (c)(4), (d), (e)(2), (e)(3)(ii), (h)(3), (h)(5)(iv), 63.8(a)(3), 63.9(b)(3), (h)(4), 63.10(c)(2)-(4), (c)(9).	**Reserved**	**No.**

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Table 11 to Subpart DDDDD of Part 63—Toxic Equivalency Factors for Dioxins/Furans

Dioxin/furan congener	**Toxic equivalency factor**
2,3,7,8-tetrachlorinated dibenzo-p-dioxin	**1**
1,2,3,7,8-pentachlorinated dibenzo-p-dioxin	**1**
1,2,3,4,7,8-hexachlorinated dibenzo-p-dioxin	**0.1**
1,2,3,7,8,9-hexachlorinated dibenzo-p-dioxin	**0.1**
1,2,3,6,7,8-hexachlorinated dibenzo-p-dioxin	**0.1**
1,2,3,4,6,7,8-heptachlorinated dibenzo-p-dioxin	**0.01**
octachlorinated dibenzo-p-dioxin	**0.0003**
2,3,7,8-tetrachlorinated dibenzofuran	**0.1**
2,3,4,7,8-pentachlorinated dibenzofuran	**0.3**
1,2,3,7,8-pentachlorinated dibenzofuran	**0.03**
1,2,3,4,7,8-hexachlorinated dibenzofuran	**0.1**
1,2,3,6,7,8-hexachlorinated dibenzofuran	**0.1**
1,2,3,7,8,9-hexachlorinated dibenzofuran	**0.1**
2,3,4,6,7,8-hexachlorinated dibenzofuran	**0.1**
1,2,3,4,6,7,8-heptachlorinated dibenzofuran	**0.01**
1,2,3,4,7,8,9-heptachlorinated dibenzofuran	**0.01**
octachlorinated dibenzofuran	**0.0003**

Table 12 to Subpart DDDDD of Part 63—Alternative Emission Limits for New or Reconstructed Boilers and Process Heaters That Commenced Construction or Reconstruction After June 4, 2010, and Before May 20, 2011

If your boiler or process heater is in this subcategory	**For the following pollutants**	**The emissions must not exceed the following emission limits, except during periods of startup and shutdown**	**Using this specified sampling volume or test run duration**
1. Units in all subcategories designed to burn solid fuel	**a. Mercury**	**3.5E-06 lb per MMBtu of heat input**	**For M29, collect a minimum of 2 dscm per run; for M30A or M30B, collect a minimum sample as specified in the method; for ASTM D6784 [a]collect a minimum of 2 dscm.**
2. Units in all subcategories designed to burn solid fuel that combust at least 10 percent biomass/bio-based solids on an annual heat input basis and less than 10 percent coal/solid fossil fuels on an annual heat input basis	**a. Particulate Matter**	**0.008 lb per MMBtu of heat input (30-day rolling average for units 250 MMBtu/hr or greater, 3-run average for units less than 250 MMBtu/hr)**	**Collect a minimum of 1 dscm per run.**
	b. Hydrogen Chloride	**0.004 lb per MMBtu of heat input**	**For M26A, collect a minimum of 1 dscm per run; for M26, collect a minimum of 60 liters per run.**
3. Units in all subcategories designed to burn solid fuel that combust at least 10 percent coal/solid fossil fuels on an annual heat input basis and less than 10 percent biomass/bio-based solids on an annual heat input basis	**a. Particulate Matter**	**0.0011 lb per MMBtu of heat input (30-day rolling average for units 250 MMBtu/hr or greater, 3-run average for units less than 250 MMBtu/hr)**	**Collect a minimum of 3 dscm per run.**
	b. Hydrogen Chloride	**0.0022 lb per MMBtu of heat input**	**For M26A, collect a minimum of 1 dscm per run; for M26, collect a minimum of 60 liters per run.**
4. Units designed to burn pulverized coal/solid fossil fuel	**a. CO**	**90 ppm by volume on a dry basis corrected to 3 percent oxygen**	**1 hr minimum sampling time.**
	b. Dioxins/Furans	**0.003 ng/dscm (TEQ) corrected to 7 percent oxygen**	**Collect a minimum of 4 dscm per run.**
5. Stokers designed to burn coal/solid fossil fuel	**a. CO**	**7 ppm by volume on a dry basis corrected to 3 percent oxygen**	**1 hr minimum sampling time.**
	b. Dioxins/Furans	**0.003 ng/dscm (TEQ) corrected to 7 percent oxygen**	**Collect a minimum of 4 dscm per run.**
6. Fluidized bed units designed to burn coal/solid fossil fuel	**a. CO**	**30 ppm by volume on a dry basis corrected to 3 percent oxygen**	**1 hr minimum sampling time.**

If your boiler or process heater is in this subcategory	**For the following pollutants**	**The emissions must not exceed the following emission limits, except during periods of startup and shutdown**	**Using this specified sampling volume or test run duration**
	b. Dioxins/Furans	**0.002 ng/dscm (TEQ) corrected to 7 percent oxygen**	**Collect a minimum of 4 dscm per run.**
7. Stokers designed to burn biomass/bio-based solids	**a. CO**	**560 ppm by volume on a dry basis corrected to 3 percent oxygen**	**1 hr minimum sampling time.**
	b. Dioxins/Furans	**0.005 ng/dscm (TEQ) corrected to 7 percent oxygen**	**Collect a minimum of 4 dscm per run.**
8. Fluidized bed units designed to burn biomass/bio-based solids	**a. CO**	**260 ppm by volume on a dry basis corrected to 3 percent oxygen**	**1 hr minimum sampling time.**
	b. Dioxins/Furans	**0.02 ng/dscm (TEQ) corrected to 7 percent oxygen**	**Collect a minimum of 4 dscm per run.**
9. Suspension burners/Dutch Ovens designed to burn biomass/bio-based solids	**a. CO**	**1,010 ppm by volume on a dry basis corrected to 3 percent oxygen**	**1 hr minimum sampling time.**
	b. Dioxins/Furans	**0.2 ng/dscm (TEQ) corrected to 7 percent oxygen**	**Collect a minimum of 4 dscm per run.**
10. Fuel cells designed to burn biomass/bio-based solids	**a. CO**	**470 ppm by volume on a dry basis corrected to 3 percent oxygen**	**1 hr minimum sampling time.**
	b. Dioxins/Furans	**0.003 ng/dscm (TEQ) corrected to 7 percent oxygen**	**Collect a minimum of 4 dscm per run.**
11. Hybrid suspension/grate units designed to burn biomass/bio-based solids	**a. CO**	**1,500 ppm by volume on a dry basis corrected to 3 percent oxygen**	**1 hr minimum sampling time.**
	b. Dioxins/Furans	**0.2 ng/dscm (TEQ) corrected to 7 percent oxygen**	**Collect a minimum of 4 dscm per run.**

If your boiler or process heater is in this subcategory	**For the following pollutants**	**The emissions must not exceed the following emission limits, except during periods of startup and shutdown**	**Using this specified sampling volume or test run duration**
12. Units designed to burn liquid fuel	**a. Particulate Matter**	**0.002 lb per MMBtu of heat input (30-day rolling average for units 250 MMBtu/hr or greater, 3-run average for units less than 250 MMBtu/hr)**	**Collect a minimum of 2 dscm per run.**
	b. Hydrogen Chloride	**0.0032 lb per MMBtu of heat input**	**For M26A, collect a minimum of 1 dscm per run; for M26, collect a minimum of 60 liters per run.**
	c. Mercury	**3.0E-07 lb per MMBtu of heat input**	**For M29, collect a minimum of 2 dscm per run; for M30A or M30B, collect a minimum sample as specified in the method; for ASTM D6784 [a]collect a minimum of 2 dscm.**
	d. CO	**3 ppm by volume on a dry basis corrected to 3 percent oxygen**	**1 hr minimum sampling time.**
	e. Dioxins/Furans	**0.002 ng/dscm (TEQ) corrected to 7 percent oxygen**	**Collect a minimum of 4 dscm per run.**
13. Units designed to burn liquid fuel located in non-continental States and territories	**a. Particulate Matter**	**0.002 lb per MMBtu of heat input (30-day rolling average for units 250 MMBtu/hr or greater, 3-run average for units less than 250 MMBtu/hr)**	**Collect a minimum of 2 dscm per run.**
	b. Hydrogen Chloride	**0.0032 lb per MMBtu of heat input**	**For M26A, collect a minimum of 1 dscm per run; for M26, collect a minimum of 60 liters per run.**
	c. Mercury	**7.8E-07 lb per MMBtu of heat input**	**For M29, collect a minimum of 1 dscm per run; for M30A or M30B, collect a minimum sample as specified in the method; for ASTM D6784 [a]collect a minimum of 2 dscm.**

If your boiler or process heater is in this subcategory	For the following pollutants	The emissions must not exceed the following emission limits, except during periods of startup and shutdown	Using this specified sampling volume or test run duration
	d. CO	51 ppm by volume on a dry basis corrected to 3 percent oxygen	1 hr minimum sampling time.
	e. Dioxins/Furans	0.002 ng/dscm (TEQ) corrected to 7 percent oxygen	Collect a minimum of 4 dscm per run.
14. Units designed to burn gas 2 (other) gases	a. Particulate Matter	0.0067 lb per MMBtu of heat input (30-day rolling average for units 250 MMBtu/hr or greater, 3-run average for units less than 250 MMBtu/hr)	Collect a minimum of 1 dscm per run.
	b. Hydrogen Chloride	0.0017 lb per MMBtu of heat input	For M26A, collect a minimum of 1 dscm per run; for M26, collect a minimum of 60 liters per run.
	c. Mercury	7.9E-06 lb per MMBtu of heat input	For M29, collect a minimum of 1 dscm per run; for M30A or M30B, collect a minimum sample as specified in the method; for ASTM D6784 [a]collect a minimum of 2 dscm.
	d. CO	3 ppm by volume on a dry basis corrected to 3 percent oxygen	1 hr minimum sampling time.
	e. Dioxins/Furans	0.08 ng/dscm (TEQ) corrected to 7 percent oxygen	Collect a minimum of 4 dscm per run.

[a] Incorporated by reference, see § 63.14.

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Table 11 to Subpart DDDDD of Part 63—Alternative Emission Limits for New or Reconstructed Boilers and Process Heaters That Commenced Construction or Reconstruction After June 4, 2010, and Before May 20, 2011

If your boiler or process heater is in this subcategory . . .	For the following pollutants . . .	The emissions must not exceed the following emission limits, except during periods of startup and shutdown . . .	Using this specified sampling volume or test run duration . . .
1. Units in all subcategories designed to burn solid fuel	a. HCl	0.022 lb per MMBtu of heat input	For M26A, collect a minimum of 1 dscm per run; for M26 collect a minimum of 120 liters per run.
2. Units in all subcategories designed to burn solid fuel that combust at least 10 percent biomass/bio-based solids on an annual heat input basis and less than 10 percent coal/solid fossil fuels on an annual heat input basis	a. Mercury	8.0E-07 [a]lb per MMBtu of heat input	For M29, collect a minimum of 4 dscm per run; for M30A or M30B, collect a minimum sample as specified in the method; for ASTM D6784 [b]collect a minimum of 4 dscm.
3. Units in all subcategories designed to burn solid fuel that combust at least 10 percent coal/solid fossil fuels on an annual heat input basis and less than 10 percent biomass/bio-based solids on an annual heat input basis	a. Mercury	2.0E-06 lb per MMBtu of heat input	For M29, collect a minimum of 4 dscm per run; for M30A or M30B, collect a minimum sample as specified in the method; for ASTM D6784 [b]collect a minimum of 4 dscm.
4. Units designed to burn coal/solid fossil fuel	a. Filterable PM (or TSM)	1.1E-03 lb per MMBtu of heat input; or (2.3E-05 lb per MMBtu of heat input)	Collect a minimum of 3 dscm per run.
5. Pulverized coal boilers designed to burn coal/solid fossil fuel	a. Carbon monoxide (CO) (or CEMS)	130 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (320 ppm by volume on a dry basis corrected to 3 percent oxygen, 30-day rolling average)	1 hr minimum sampling time.
6. Stokers designed to burn coal/solid fossil fuel	a. CO (or CEMS)	130 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (340 ppm by volume on a dry basis corrected to 3 percent oxygen, 10-day rolling average)	1 hr minimum sampling time.

If your boiler or process heater is in this subcategory . . .	For the following pollutants . . .	The emissions must not exceed the following emission limits, except during periods of startup and shutdown . . .	Using this specified sampling volume or test run duration . . .
7. Fluidized bed units designed to burn coal/solid fossil fuel	a. CO (or CEMS)	130 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (230 ppm by volume on a dry basis corrected to 3 percent oxygen, 30-day rolling average)	1 hr minimum sampling time.
8. Fluidized bed units with an integrated heat exchanger designed to burn coal/solid fossil fuel	a. CO (or CEMS)	140 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (150 ppm by volume on a dry basis corrected to 3 percent oxygen, 30-day rolling average)	1 hr minimum sampling time.
9. Stokers/sloped grate/others designed to burn wet biomass fuel	a. CO (or CEMS)	620 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (390 ppm by volume on a dry basis corrected to 3 percent oxygen, 30-day rolling average)	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	3.0E-02 lb per MMBtu of heat input; or (2.6E-05 lb per MMBtu of heat input)	Collect a minimum of 2 dscm per run.
10. Stokers/sloped grate/others designed to burn kiln-dried biomass fuel	a. CO	560 ppm by volume on a dry basis corrected to 3 percent oxygen	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	3.0E-02 lb per MMBtu of heat input; or (4.0E-03 lb per MMBtu of heat input)	Collect a minimum of 2 dscm per run.
11. Fluidized bed units designed to burn biomass/bio-based solids	a. CO (or CEMS)	230 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (310 ppm by volume on a dry basis corrected to 3 percent oxygen, 30-day rolling average)	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	9.8E-03 lb per MMBtu of heat input; or (8.3E-05 [a]lb per MMBtu of heat input)	Collect a minimum of 3 dscm per run

If your boiler or process heater is in this subcategory . . .	For the following pollutants . . .	The emissions must not exceed the following emission limits, except during periods of startup and shutdown . . .	Using this specified sampling volume or test run duration . . .
12. Suspension burners designed to burn biomass/bio-based solids	**a. CO (or CEMS)**	**2,400 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (2,000 ppm by volume on a dry basis corrected to 3 percent oxygen, 10-day rolling average)**	**1 hr minimum sampling time.**
	b. Filterable PM (or TSM)	**3.0E-02 lb per MMBtu of heat input; or (6.5E-03 lb per MMBtu of heat input)**	**Collect a minimum of 2 dscm per run.**
13. Dutch Ovens/Pile burners designed to burn biomass/bio-based solids	**a. CO (or CEMS)**	**1,010 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (520 ppm by volume on a dry basis corrected to 3 percent oxygen, 10-day rolling average)**	**1 hr minimum sampling time.**
	b. Filterable PM (or TSM)	**8.0E-03 lb per MMBtu of heat input; or (3.9E-05 lb per MMBtu of heat input)**	**Collect a minimum of 3 dscm per run.**
14. Fuel cell units designed to burn biomass/bio-based solids	**a. CO**	**910 ppm by volume on a dry basis corrected to 3 percent oxygen**	**1 hr minimum sampling time.**
	b. Filterable PM (or TSM)	**2.0E-02 lb per MMBtu of heat input; or (2.9E-05 lb per MMBtu of heat input)**	**Collect a minimum of 2 dscm per run.**
15. Hybrid suspension grate boiler designed to burn biomass/bio-based solids	**a. CO (or CEMS)**	**1,100 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (900 ppm by volume on a dry basis corrected to 3 percent oxygen, 30-day rolling average)**	**1 hr minimum sampling time.**
	b. Filterable PM (or TSM)	**2.6E-02 lb per MMBtu of heat input; or (4.4E-04 lb per MMBtu of heat input)**	**Collect a minimum of 3 dscm per run.**
16. Units designed to burn liquid fuel	**a. HCl**	**4.4E-04 lb per MMBtu of heat input**	**For M26A: Collect a minimum of 2 dscm per run; for M26, collect a minimum of 240 liters per run.**

If your boiler or process heater is in this subcategory . . .	For the following pollutants . . .	The emissions must not exceed the following emission limits, except during periods of startup and shutdown . . .	Using this specified sampling volume or test run duration . . .
	b. Mercury	4.8E-07 [a]lb per MMBtu of heat input	For M29, collect a minimum of 4 dscm per run; for M30A or M30B, collect a minimum sample as specified in the method; for ASTM D6784 [b]collect a minimum of 4 dscm.
17. Units designed to burn heavy liquid fuel	a. CO	130 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	1.3E-02 lb per MMBtu of heat input; or (7.5E-05 lb per MMBtu of heat input)	Collect a minimum of 3 dscm per run.
18. Units designed to burn light liquid fuel	a. CO	130 ppm by volume on a dry basis corrected to 3 percent oxygen	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	2.0E-03 [a]lb per MMBtu of heat input; or (2.9E-05 lb per MMBtu of heat input)	Collect a minimum of 3 dscm per run
19. Units designed to burn liquid fuel that are non-continental units	a. CO	130 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average based on stack test	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	2.3E-02 lb per MMBtu of heat input; or (8.6E-04 lb per MMBtu of heat input)	Collect a minimum of 4 dscm per run
20. Units designed to burn gas 2 (other) gases	a. CO	130 ppm by volume on a dry basis corrected to 3 percent oxygen	1 hr minimum sampling time.
	b. HCl	1.7E-03 lb per MMBtu of heat input	For M26A, collect a minimum of 2 dscm per run; for M26, collect a minimum of 240 liters per run.
	c. Mercury	7.9E-06 lb per MMBtu of heat input	For M29, collect a minimum of 3 dscm per run; for M30A or M30B, collect a minimum sample as specified in the method; for ASTM D6784 [b]collect a minimum of 3 dscm.

If your boiler or process heater is in this subcategory . . .	For the following pollutants . . .	The emissions must not exceed the following emission limits, except during periods of startup and shutdown . . .	Using this specified sampling volume or test run duration . . .
	d. Filterable PM (or TSM)	6.7E-03 lb per MMBtu of heat input; or (2.1E-04 lb per MMBtu of heat input)	Collect a minimum of 3 dscm per run

[a] If you are conducting stack tests to demonstrate compliance and your performance tests for this pollutant for at least 2 consecutive years show that your emissions are at or below this limit, you can skip testing according to § 63.7515 if all of the other provisions of § 63.7515 are met. For all other pollutants that do not contain a footnote "a", your performance tests for this pollutant for at least 2 consecutive years must show that your emissions are at or below 75 percent of this limit in order to qualify for skip testing.

[b] Incorporated by reference, see § 63.14.

[78 FR 7206, Jan. 31, 2013]

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Table 12 to Subpart DDDDD of Part 63—Alternative Emission Limits for New or Reconstructed Boilers and Process Heaters that Commenced Construction or Reconstruction after May 20, 2011, and Before December 23, 2011

If your boiler or process heater is in this subcategory . . .	For the following pollutants . . .	The emissions must not exceed the following emission limits, except during periods of startup and shutdown . . .	Using this specified sampling volume or test run duration . . .
1. Units in all subcategories designed to burn solid fuel	a. HCl	0.022 lb per MMBtu of heat input	For M26A, collect a minimum of 1 dscm per run; for M26 collect a minimum of 120 liters per run.
	b. Mercury	3.5E-06 [a]lb per MMBtu of heat input	For M29, collect a minimum of 3 dscm per run; for M30A or M30B, collect a minimum sample as specified in the method; for ASTM D6784 [b]collect a minimum of 3 dscm.
2. Units design to burn coal/solid fossil fuel	a. Filterable PM (or TSM)	1.1E-03 lb per MMBtu of heat input; or (2.3E-05 lb per MMBtu of heat input)	Collect a minimum of 3 dscm per run.
3. Pulverized coal boilers designed to burn coal/solid fossil fuel	a. Carbon monoxide (CO) (or CEMS)	130 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (320 ppm by volume on a dry basis corrected to 3 percent oxygen, 30-day rolling average)	1 hr minimum sampling time.

If your boiler or process heater is in this subcategory . . .	**For the following pollutants . . .**	**The emissions must not exceed the following emission limits, except during periods of startup and shutdown . . .**	**Using this specified sampling volume or test run duration . . .**
4. Stokers designed to burn coal/solid fossil fuel	**a. CO (or CEMS)**	**130 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (340 ppm by volume on a dry basis corrected to 3 percent oxygen, 10-day rolling average)**	**1 hr minimum sampling time.**
5. Fluidized bed units designed to burn coal/solid fossil fuel	**a. CO (or CEMS)**	**130 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (230 ppm by volume on a dry basis corrected to 3 percent oxygen, 30-day rolling average)**	**1 hr minimum sampling time.**
6. Fluidized bed units with an integrated heat exchanger designed to burn coal/solid fossil fuel	**a. CO (or CEMS)**	**140 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (150 ppm by volume on a dry basis corrected to 3 percent oxygen, 30-day rolling average)**	**1 hr minimum sampling time.**
7. Stokers/sloped grate/others designed to burn wet biomass fuel	**a. CO (or CEMS)**	**620 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (390 ppm by volume on a dry basis corrected to 3 percent oxygen, 30-day rolling average)**	**1 hr minimum sampling time.**
	b. Filterable PM (or TSM)	**3.0E-02 lb per MMBtu of heat input; or (2.6E-05 lb per MMBtu of heat input)**	**Collect a minimum of 2 dscm per run.**
8. Stokers/sloped grate/others designed to burn kiln-dried biomass fuel	**a. CO**	**460 ppm by volume on a dry basis corrected to 3 percent oxygen**	**1 hr minimum sampling time.**
	b. Filterable PM (or TSM)	**3.0E-02 lb per MMBtu of heat input; or (4.0E-03 lb per MMBtu of heat input)**	**Collect a minimum of 2 dscm per run.**
9. Fluidized bed units designed to burn biomass/bio-based solids	**a. CO (or CEMS)**	**260 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (310 ppm by volume on a dry basis corrected to 3 percent oxygen, 30-day rolling average)**	**1 hr minimum sampling time.**
	b. Filterable PM (or TSM)	**9.8E-03 lb per MMBtu of heat input; or (8.3E-05 [a]lb per MMBtu of heat input)**	**Collect a minimum of 3 dscm per run.**

If your boiler or process heater is in this subcategory . . .	For the following pollutants . . .	The emissions must not exceed the following emission limits, except during periods of startup and shutdown . . .	Using this specified sampling volume or test run duration . . .
10. Suspension burners designed to burn biomass/bio-based solids	a. CO (or CEMS)	2,400 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (2,000 ppm by volume on a dry basis corrected to 3 percent oxygen, 10-day rolling average)	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	3.0E-02 lb per MMBtu of heat input; or (6.5E-03 lb per MMBtu of heat input)	Collect a minimum of 2 dscm per run.
11. Dutch Ovens/Pile burners designed to burn biomass/bio-based solids	a. CO (or CEMS)	470 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (520 ppm by volume on a dry basis corrected to 3 percent oxygen, 10-day rolling average)	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	3.2E-03 lb per MMBtu of heat input; or (3.9E-05 lb per MMBtu of heat input)	Collect a minimum of 3 dscm per run.
12. Fuel cell units designed to burn biomass/bio-based solids	a. CO	910 ppm by volume on a dry basis corrected to 3 percent oxygen	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	2.0E-02 lb per MMBtu of heat input; or (2.9E-05 lb per MMBtu of heat input)	Collect a minimum of 2 dscm per run.
13. Hybrid suspension grate boiler designed to burn biomass/bio-based solids	a. CO (or CEMS)	1,500 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (900 ppm by volume on a dry basis corrected to 3 percent oxygen, 30-day rolling average)	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	2.6E-02 lb per MMBtu of heat input; or (4.4E-04 lb per MMBtu of heat input)	Collect a minimum of 3 dscm per run.
14. Units designed to burn liquid fuel	a. HCl	4.4E-04 lb per MMBtu of heat input	For M26A: Collect a minimum of 2 dscm per run; for M26, collect a minimum of 240 liters per run.
	b. Mercury	4.8E-07 [a]lb per MMBtu of heat input	For M29, collect a minimum of 4 dscm per run; for M30A or M30B, collect a minimum sample as specified in the method; for ASTM D6784 [b]collect a minimum of 4 dscm.

If your boiler or process heater is in this subcategory . . .	For the following pollutants . . .	The emissions must not exceed the following emission limits, except during periods of startup and shutdown . . .	Using this specified sampling volume or test run duration . . .
15. Units designed to burn heavy liquid fuel	a. CO	130 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	1.3E-02 lb per MMBtu of heat input; or (7.5E-05 lb per MMBtu of heat input)	Collect a minimum of 2 dscm per run.
16. Units designed to burn light liquid fuel	a. CO	130 ppm by volume on a dry basis corrected to 3 percent oxygen	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	1.3E-03 [a]lb per MMBtu of heat input; or (2.9E-05 lb per MMBtu of heat input)	Collect a minimum of 3 dscm per run.
17. Units designed to burn liquid fuel that are non-continental units	a. CO	130 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average based on stack test	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	2.3E-02 lb per MMBtu of heat input; or (8.6E-04 lb per MMBtu of heat input)	Collect a minimum of 4 dscm per run.
18. Units designed to burn gas 2 (other) gases	a. CO	130 ppm by volume on a dry basis corrected to 3 percent oxygen	1 hr minimum sampling time.
	b. HCl	1.7E-03 lb per MMBtu of heat input	For M26A, Collect a minimum of 2 dscm per run; for M26, collect a minimum of 240 liters per run.
	c. Mercury	7.9E-06 lb per MMBtu of heat input	For M29, collect a minimum of 3 dscm per run; for M30A or M30B, collect a minimum sample as specified in the method; for ASTM D6784 [b]collect a minimum of 3 dscm.
	d. Filterable PM (or TSM)	6.7E-03 lb per MMBtu of heat input; or (2.1E-04 lb per MMBtu of heat input)	Collect a minimum of 3 dscm per run.

[a] **If you are conducting stack tests to demonstrate compliance and your performance tests for this pollutant for at least 2 consecutive years show that your emissions are at or below this limit, you can skip testing according to § 63.7515 if all of the other provision of § 63.7515 are met. For all other pollutants that do not contain a footnote "a", your performance tests for this pollutant for at least 2 consecutive years must show that your emissions are at or below 75 percent of this limit in order to qualify for skip testing.**

[b] **Incorporated by reference, see § 63.14.**

[78 FR 7208, Jan. 31, 2013]

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Table 13 to Subpart DDDDD of Part 63—Alternative Emission Limits for New or Reconstructed Boilers and Process Heaters That Commenced Construction or Reconstruction After December 23, 2011, and Before January 31, 2013

If your boiler or process heater is in this subcategory . . .	For the following pollutants . . .	The emissions must not exceed the following emission limits, except during periods of startup and shutdown . . .	Using this specified sampling volume or test run duration . . .
1. Units in all subcategories designed to burn solid fuel	a. HCl	0.022 lb per MMBtu of heat input	For M26A, collect a minimum of 1 dscm per run; for M26 collect a minimum of 120 liters per run.
	b. Mercury	8.6E-07 [a]lb per MMBtu of heat input	For M29, collect a minimum of 4 dscm per run; for M30A or M30B, collect a minimum sample as specified in the method; for ASTM D6784 [b]collect a minimum of 4 dscm.
2. Pulverized coal boilers designed to burn coal/solid fossil fuel	a. Carbon monoxide (CO) (or CEMS)	130 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (320 ppm by volume on a dry basis corrected to 3 percent oxygen, 30-day rolling average)	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	1.1E-03 lb per MMBtu of heat input; or (2.8E-05 lb per MMBtu of heat input)	Collect a minimum of 3 dscm per run.
3. Stokers designed to burn coal/solid fossil fuel	a. CO (or CEMS)	130 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (340 ppm by volume on a dry basis corrected to 3 percent oxygen, 10-day rolling average)	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	2.8E-02 lb per MMBtu of heat input; or (2.3E-05 lb per MMBtu of heat input)	Collect a minimum of 2 dscm per run.
4. Fluidized bed units designed to burn coal/solid fossil fuel	a. CO (or CEMS)	130 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (230 ppm by volume on a dry basis corrected to 3 percent oxygen, 30-day rolling average)	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	1.1E-03 lb per MMBtu of heat input; or (2.3E-05 lb per MMBtu of heat input)	Collect a minimum of 3 dscm per run.

If your boiler or process heater is in this subcategory . . .	For the following pollutants . . .	The emissions must not exceed the following emission limits, except during periods of startup and shutdown . . .	Using this specified sampling volume or test run duration . . .
5. Fluidized bed units with an integrated heat exchanger designed to burn coal/solid fossil fuel	**a. CO (or CEMS)**	**140 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (150 ppm by volume on a dry basis corrected to 3 percent oxygen, 30-day rolling average)**	**1 hr minimum sampling time.**
	b. Filterable PM (or TSM)	**1.1E-03 lb per MMBtu of heat input; or (2.3E-05 lb per MMBtu of heat input)**	**Collect a minimum of 3 dscm per run.**
6. Stokers/sloped grate/others designed to burn wet biomass fuel	**a. CO (or CEMS)**	**620 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (410 ppm by volume on a dry basis corrected to 3 percent oxygen, 10-day rolling average)**	**1 hr minimum sampling time.**
	b. Filterable PM (or TSM)	**3.0E-02 lb per MMBtu of heat input; or (2.6E-05 lb per MMBtu of heat input)**	**Collect a minimum of 2 dscm per run.**
7. Stokers/sloped grate/others designed to burn kiln-dried biomass fuel	**a. CO**	**460 ppm by volume on a dry basis corrected to 3 percent oxygen**	**1 hr minimum sampling time.**
	b. Filterable PM (or TSM)	**3.2E-01 lb per MMBtu of heat input; or (4.0E-03 lb per MMBtu of heat input)**	**Collect a minimum of 2 dscm per run.**
8. Fluidized bed units designed to burn biomass/bio-based solids	**a. CO (or CEMS)**	**230 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (310 ppm by volume on a dry basis corrected to 3 percent oxygen, 30-day rolling average)**	**1 hr minimum sampling time.**
	b. Filterable PM (or TSM)	**9.8E-03 lb per MMBtu of heat input; or (8.3E-05 [a]lb per MMBtu of heat input)**	**Collect a minimum of 3 dscm per run.**
9. Suspension burners designed to burn biomass/bio-based solids	**a. CO (or CEMS)**	**2,400 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (2,000 ppm by volume on a dry basis corrected to 3 percent oxygen, 10-day rolling average)**	**1 hr minimum sampling time.**
	b. Filterable PM (or TSM)	**5.1E-02 lb per MMBtu of heat input; or (6.5E-03 lb per MMBtu of heat input)**	**Collect a minimum of 2 dscm per run.**

If your boiler or process heater is in this subcategory . . .	For the following pollutants . . .	The emissions must not exceed the following emission limits, except during periods of startup and shutdown . . .	Using this specified sampling volume or test run duration . . .
10. Dutch Ovens/Pile burners designed to burn biomass/bio-based solids	**a. CO (or CEMS)**	**810 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (520 ppm by volume on a dry basis corrected to 3 percent oxygen, 10-day rolling average)**	**1 hr minimum sampling time.**
	b. Filterable PM (or TSM)	**3.6E-02 lb per MMBtu of heat input; or (3.9E-05 lb per MMBtu of heat input)**	**Collect a minimum of 2 dscm per run.**
11. Fuel cell units designed to burn biomass/bio-based solids	**a. CO**	**910 ppm by volume on a dry basis corrected to 3 percent oxygen**	**1 hr minimum sampling time.**
	b. Filterable PM (or TSM)	**2.0E-02 lb per MMBtu of heat input; or (2.9E-05 lb per MMBtu of heat input)**	**Collect a minimum of 2 dscm per run.**
12. Hybrid suspension grate boiler designed to burn biomass/bio-based solids	**a. CO (or CEMS)**	**1,500 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (900 ppm by volume on a dry basis corrected to 3 percent oxygen, 30-day rolling average)**	**1 hr minimum sampling time.**
	b. Filterable PM (or TSM)	**2.6E-02 lb per MMBtu of heat input; or (4.4E-04 lb per MMBtu of heat input)**	**Collect a minimum of 3 dscm per run.**
13. Units designed to burn liquid fuel	**a. HCl**	**1.2E-03 lb per MMBtu of heat input**	**For M26A: Collect a minimum of 2 dscm per run; for M26, collect a minimum of 240 liters per run.**
	b. Mercury	**4.9E-07 [a]lb per MMBtu of heat input**	**For M29, collect a minimum of 4 dscm per run; for M30A or M30B, collect a minimum sample as specified in the method; for ASTM D6784 [b]collect a minimum of 4 dscm.**
14. Units designed to burn heavy liquid fuel	**a. CO (or CEMS)**	**130 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (18 ppm by volume on a dry basis corrected to 3 percent oxygen, 10-day rolling average)**	**1 hr minimum sampling time.**
	b. Filterable PM (or TSM)	**1.3E-03 lb per MMBtu of heat input; or (7.5E-05 lb per MMBtu of heat input)**	**Collect a minimum of 3 dscm per run.**

If your boiler or process heater is in this subcategory . . .	For the following pollutants . . .	The emissions must not exceed the following emission limits, except during periods of startup and shutdown . . .	Using this specified sampling volume or test run duration . . .
15. Units designed to burn light liquid fuel	**a. CO (or CEMS)**	**130 [a]ppm by volume on a dry basis corrected to 3 percent oxygen; or (60 ppm by volume on a dry basis corrected to 3 percent oxygen, 1-day block average).**	**1 hr minimum sampling time.**
	b. Filterable PM (or TSM)	**1.1E-03 [a]lb per MMBtu of heat input; or (2.9E-05 lb per MMBtu of heat input)**	**Collect a minimum of 3 dscm per run.**
16. Units designed to burn liquid fuel that are non-continental units	**a. CO**	**130 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average based on stack test; or (91 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-hour rolling average)**	**1 hr minimum sampling time.**
	b. Filterable PM (or TSM)	**2.3E-02 lb per MMBtu of heat input; or (8.6E-04 lb per MMBtu of heat input)**	**Collect a minimum of 2 dscm per run.**
17. Units designed to burn gas 2 (other) gases	**a. CO**	**130 ppm by volume on a dry basis corrected to 3 percent oxygen**	**1 hr minimum sampling time.**
	b. HCl	**1.7E-03 lb per MMBtu of heat input**	**For M26A, Collect a minimum of 2 dscm per run; for M26, collect a minimum of 240 liters per run.**
	c. Mercury	**7.9E-06 lb per MMBtu of heat input**	**For M29, collect a minimum of 3 dscm per run; for M30A or M30B, collect a minimum sample as specified in the method; for ASTM D6784 [b]collect a minimum of 3 dscm.**
	d. Filterable PM (or TSM)	**6.7E-03 lb per MMBtu of heat input; or (2.1E-04 lb per MMBtu of heat input)**	**Collect a minimum of 3 dscm per run.**

[a] If you are conducting stack tests to demonstrate compliance and your performance tests for this pollutant for at least 2 consecutive years show that your emissions are at or below this limit and you are not required to conduct testing for CEMS or CPMS monitor certification, you can skip testing according to § 63.7515 if all of the other provision of § 63.7515 are met. For all other pollutants that do not contain a footnote “a”, your performance tests for this pollutant for at least 2 consecutive years must show that your emissions are at or below 75 percent of this limit in order to qualify for skip testing.

[b] Incorporated by reference, see § 63.14.

[78 FR 7210, Jan. 31, 2013]

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Modification No. 5: **Condition D.1.4 – PSD BACT Limits**

IDEM, OAQ is adding greenhouse gas (GHG) best available control technology (BACT) requirements for the boilers identified as EU-011A, EU-011B, EU-011C and EU-011D. The requirements for “good engineering design” have been clarified. Revisions are shown below:

D.1.4 PSD Best Available Control Technology Limits [326 IAC 2-2-3]

Pursuant to PSD/Operating Permit T 147-32322-00062 and 326 IAC 2-2-3 (Prevention of Significant Deterioration), the best available control technology (BACT) for Boiler Units EU-011A, EU-011B, EU-011C, and EU-011D shall be as follows: **********

GHG:

(i) CO_2 emissions from each of the boilers (EU-011A, EU-011B, EU-011C, and EU-011D) shall not exceed 59.61 tons/MMCF, based on a three-hour average.

(j) Each of the boilers (EU-011A, EU-011B, EU-011C and EU-011D) shall be equipped with the following energy efficient design features: air inlet controls, heat recovery, condensate recovery, and blowdown heat recovery.

(k) Each of the boilers (EU-011A, EU-011B, EU-011C and EU-011D) shall be designed to achieve a thermal efficiency of 80% (HHV).

Modification No. 6: **Condition D.1.11 – Testing Requirements**

IDEM, OAQ is correcting two typographical errors in D.1.11(a) and (b). A testing condition was added to verify the thermal efficiency of the boilers added above. Revisions are shown below:

D.1.11 Testing Requirements [326 IAC 2-7-6(1)] [326 IAC 2-7-6(6)]

(a) In order to demonstrate the compliance status with Condition **D.**1.4(g) and within sixty (60) days of reaching maximum capacity but no later than one hundred and eighty (180) days after initial startup, the Permittee shall perform CO testing on stacks EP-011A, EP-011B, EP-011C and EP-011D utilizing methods as approved by the Commissioner. Testing shall be conducted in accordance with the provisions of 326 IAC 3-6 (Source Sampling Procedures). Section C – Performance Testing contains the Permittee’s obligation with regard to the performance testing required by this condition.

(b) In order to demonstrate the compliance status with Condition **D.**1.4(i) and within sixty (60) days of reaching maximum capacity but no later than one hundred and eighty (180) days after initial startup, the Permittee shall perform CO_2 testing on stacks EP-011A, EP-011B, EP-011C and EP-011D utilizing methods as approved by the Commissioner. Testing shall be conducted in accordance with the provisions of 326 IAC 3-6 (Source Sampling Procedures). Section C – Performance Testing contains the Permittee’s obligation with regard to the performance testing required by this condition.

(c) In order to demonstrate the compliance status with Condition D.1.4(k) – GHGs PSD BACT, and within sixty (60) days of reaching maximum capacity but no later than one hundred and eighty (180) days after initial startup, the Permittee shall perform thermal efficiency testing on the natural gas-fired boilers, identified as EU-011A, EU-011B, EU-011C and EU-011D utilizing methods as approved by the Commissioner. These tests shall be conducted once. 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.

Modification No. 7: **Condition D.2.4 – PSD BACT and VOC BACT Limits**
IDEM, OAQ is revising the PSD BACT requirements because the source will install a NO_x CEMS. Also, a requirement describing good design was added and the CO_2 limit was revised to tons per year from tons per hour. The CO_2 limit eliminates the requirement for the fuel usage limit. The fuel for the reformer was narrowed. Revisions follow:

D.2.4 PSD Best Available Control Technology Limits [326 IAC 2-2-3] and VOC Best Available Control Technology (BACT) Limits [326 IAC 8-1-6]

Pursuant to PSD/Operating Permit T 147-32322-00062 and 326 IAC 2-2 (Prevention of Significant Deterioration (PSD)), the best available control technology (BACT) for the Primary Reformer (EU-003), the CO_2 Purification Process (EU-004), and the Front End Process Flare (EU-007) shall be as follows:

(a) **Primary Reformer (EU-003):**

Common PM, PM_{10}, $PM_{2.5}$, NO_x, CO, VOC and GHG Conditions:

(1) **********

(2) ~~Fuel usage in the Primary Reformer shall not exceed 8,643 MMCF per twelve consecutive month period with compliance determined at the end of each month.~~

~~(3)~~ The Primary Reformer (EU-003) shall combust natural gas~~, methane~~ and**/or** process off gas streams.

PM, PM_{10}, $PM_{2.5}$:

(**3**~~4~~) **********

NO_x:

(**4**~~5~~) **********

(**5**~~6~~) NO_x emissions from the Primary Reformer (EU-003) shall not exceed ~~142.80 lb/MMCF, based on a three-hour average.~~**9 ppm_{vd}, based on a thirty-day rolling average.**

CO:

(**6**~~7~~) **********

VOC:

(**7**~~8~~) **********

GHG:

(**8**~~9~~) **********

(9) The Primary Reformer (EU-003) shall be equipped with the following energy efficiency features: air inlet controls and flue gas heat recovery to pre-heat inlet fuel, inlet air and inlet steam flows.

(10) The Primary Reformer (EU-003) shall be designed to achieve a thermal efficiency of 90% (HHV).

(11) CO_2 emissions from the Primary Reformer (EU-003) shall not exceed 515,246 tons per twelve consecutive month period with compliance determined at the end of each month.

****

(c) <u>Front End Process Flare (EU-007):</u>

****

(4) NO_x, CO, PM, PM_{10} and $PM_{2.5}$, VOC, and GHG emissions shall be controlled **by the use of**~~using proper flare design and good combustion practices, which include~~ the following **practices**~~elements~~:

****

Modification No. 8: New **Condition D.2.11 – Flare Emissions**
IDEM, OAQ is adding additional compliance determination requirements for all flares and the Primary Reformer. Revisions to Section D.2 follow:

D.2.11 Flare Emissions [326 IAC 2-7-6(1)][326 IAC 2-7-6(6)]

(a) In order to demonstrate compliance with the emission limits in Conditions D.2.4(c)(8), (10), (12), and (14), the Permittee shall use the following equations:

<u>For NO_x, CO, VOC, and CO_2</u>:

$E = (H \times EF) + PE$

Where:

E= Pollutant Emissions (lb/hr)

EF_{NOx} = 0.068 lb/MMBtu

EF_{CO} = 0.3700 lb/MMBtu

EF_{VOC} = 0.0054 lb/MMBtu

EF_{CO2} = 116.8879 lb/MMBtu

PE_{NOx} = 2.566 lb/hr from pilot and purge

PE_{CO} = 13.964 lb/hr from pilot and purge

PE_{VOC} = 0.204 lb/hr from pilot and purge

PE_{CO2} = 4,411.47 lb/hr from pilot and purge

H = Hourly Heat Input (MMBtu/hr) = F_{1-4} (lb/hr) x HHV x 100% (portion of flare stream combusted) x 1 MMBtu/1,000,000 Btu

Where:

F_{1-4} = Flow of flared gas from ammonia free streams (lb/hr)

HHV_1 = 2,830.8 Btu/lb or other value determined by testing

HHV_2 = 2,775.0 Btu/lb or other value determined by testing

HHV_3 = 6,767.2 Btu/lb or other value determined by testing

HHV_4 = 2,830.8 Btu/lb or other value determined by testing

(b) The value F_{1-4} shall be determined through flow monitoring of gases sent to the flare, process operational data, mass balance or other engineering methods.

D.2.12 Carbon Dioxide (CO_2) Calculations

To determine the compliance status with Condition D.2.4(a)(12), the Permittee shall use the following equation for each fuel burned to determine the CO_2 emissions from the Primary Reformer (EU-003):

CO_2 emissions (ton/month) = (Fuel Usage (MMSCF/month) x (CO_2 EF (lb/MMSCF) x 1 ton/2,000 lb)

The monthly emission rate for each fuel shall be summed together.

Where:

Fuel Usage (MMSCF/month) = monthly reformer fuel usage data determined through flow monitoring, process operational data, mass balance, or other engineering methods.

CO_2 EF (lb/MMSCF) = 119,220 lb CO_2/MMSCF for natural gas
CO_2 EF (lb/MMSCF) = 119,220 lb CO_2/MMSCF x % volume methane in process off-gas

The percent volume methane in process off-gases shall be determined through measurement, process operational data, mass balance, or other engineering methods.

Modification No. 9: **Condition – D.2.11 – Parametric Monitoring**
The applicant intends to install a CEMS. Condition D.2.11 has been removed and replaced with requirements consistent with parametric monitoring using a CEMS. The condition was renumbered to account for the insertion of additional permit conditions. Revisions follow:

~~D.2.11 Parametric Monitoring Requirements~~

~~The Permittee shall monitor the catalyst inlet temperature used in conjunction with the Primary Reformer (EU-003) with a continuous temperature monitoring system. The Permittee shall comply with the following:~~

~~(a) A continuous monitoring system shall be installed, calibrated, maintained, and operated on the Primary Reformer (EU-003) for measuring operating temperature of the catalyst inlet bed temperature. For the purpose of this condition, continuous monitoring shall mean no less often than once per fifteen (15) minutes. The output from this monitoring system and the twenty-four hour average temperature shall be recorded whenever the Primary Reformer (EU-003) is in operation and is at steady-state operation.~~

~~(b) If the continuous monitoring system is not in operation, the catalyst bed inlet temperature shall be recorded using a secondary system consisting of a backup temperature probe. Temperature measurements shall be made no less than once per four (4) hours. In the event of a monitoring system malfunction, failure to measure the operating temperature of the catalyst bed inlet temperature is not a deviation of the permit. Failure to take response steps shall be considered a deviation from the permit.~~

~~(c) The Primary Reformer (EU-003) shall operate such that if the three-hour average temperature falls below the three-hour block temperature minimum required temperature of 380 °F, or a temperature determined during the most recent valid compliant stack test, reasonable~~

~~response steps shall be taken to return the Primary Reformer (EU-003) catalyst bed inlet temperature to the required minimum temperature. A reading that is below the minimum average required temperature is not a deviation from this permit. Failure to take response steps in accordance with Section C – Response to Excursions or Exceedances shall be considered a deviation from this permit. The Permittee shall operate at or above 380 °F or above until the stack test results are available. After the stack test results are available, the Permittee shall operate at or above the three-hour block average minimum required temperature determined during the latest valid compliant stack test.~~

D.2.13 Maintenance of Continuous Emission Monitoring Equipment [326 IAC 3-5]

(a) The Permittee shall install, calibrate, maintain, and operate all necessary continuous emission monitoring systems (CEMS) and related equipment for NO_x emissions on stack EP-003.

(b) All CEMS required by this permit shall meet all applicable performance specifications of 40 CFR 60, and are subject to monitor system certification requirements pursuant to 326 IAC 3-5-3.

(c) In the event that a breakdown of a continuous emission monitoring system occurs, a record shall be made of the times and reasons for the breakdown and the efforts made to correct the problem.

(d) Whenever a NO_x CEMS is down for more than twenty-four (24) hours, the Permittee shall monitor the catalyst bed inlet temperature used in conjunction with the Primary Reformer (EU-003) with a continuous temperature monitoring system no less often than once per four (4) hours. When for any one reading, the catalyst bed inlet temperature is below the minimum temperature, the Permittee shall take a reasonable response. The minimum temperature for this catalyst bed inlet is 380 °F, unless a new minimum temperature is determined during the most recent valid compliant stack test. Section C – Response to Excursions or Exceedances contains the Permittee's obligation with regard to the reasonable response steps required by this condition. A temperature reading that is below the minimum temperature is not a deviation from this permit. Failure to take response steps shall be considered a deviation from this permit.

Modification No. 10: **Condition D.2.12 – Record Keeping Requirements**
IDEM, OAQ is revising the condition to accommodate a NO_x CEMS. The permit condition has been renumbered. The purpose of each record keeping requirement has been clarified. Time frames for all monitoring have been provided. Revisions follow:

D.2.1~~2~~**4** Record Keeping Requirements

~~(a) In order to document the compliance status with Condition D.2.4(a)(2), the Permittee shall maintain records of the amount of fuel used in the Primary Reformer (EU-003).~~

(**a**~~b~~) In order to document the compliance status with Condition D.2.4(a)(~~3~~**2**) **and D.2.4(a)(11)**, the Permittee shall maintain monthly records of the type of fuel combusted in the Primary Reformer (EU-003).

(**b**~~c~~) **********

(**c**~~d~~) **********

(**d**~~e~~) **********

(**e**~~f~~) ~~In order to document the compliance status with Condition D.2.11, the Permittee shall maintain records of the catalyst bed inlet temperature used in conjunction with the Primary Reformer (EU-003). The Permittee shall include in its record when a catalyst bed inlet temperature is not taken and the reason for a lack of a catalyst bed inlet temperature reading (e.g. the process did not operate that day).~~**In order to document the compliance status with the emission limits in Conditions D.2.4(a)(11) and D.2.4(c)(8), (10), (12), and (14), the Permittee shall maintain records of flow monitoring data, process operational data, mass balance, or other engineering estimation methods used to determine emissions.**

(f) In order to document the compliance status with Condition D.2.4(a)(5) and Condition D.2.13, the Permittee shall maintain records of the output of the continuous emission monitoring system for NO$_x$ and shall perform the required record keeping requirements of 326 IAC 3-5-6.

(g) In order to document the compliance status with Condition D.2.4(a)(5) and Condition D.2.13, the Permittee shall maintain records of all CEMS malfunctions, out of control periods, calibration and adjustment activities, and repair of maintenance activities.

(**h**~~g~~) Section C – General Record Keeping Requirements contains the Permittee's obligations with regard to the record keeping required by this condition.

Modification No. 11: **Condition D.2.13 – Reporting Requirements**
IDEM, OAQ is revising the Section D.2 reporting condition to reflect the addition of a NOx CEMS. Revisions follow:

D.2.1~~3~~**5** Reporting Requirements

(a) A quarterly summary of the information to document the compliance status with Condition ~~D.2.4(a)(2),~~ **D.2.4(a)(12), D.**2.4(b)(1) and Condition D.2.4(c)(2) shall be submitted not later than thirty (30) days after the end of the quarter being reported. Section C – General Reporting Requirements contains the Permittee's obligation with regard to the reporting required by 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 in 326 IAC 2-7-1(35).

(b) In order to document the compliance status with Condition D.2.4(a)(5) and Condition D.2.13, the Permittee shall comply with all of the reporting requirements pursuant to 326 IAC 3-5-7.

Modification No. 12: **Condition D.3.4 – PSD BACT Limits**
The PSD BACT limits for the flares has been clarified. Revisions follow:

D.3.4 PSD Best Available Control Technology Limits [326 IAC 2-2-3]

****

(b) <u>**Back End Ammonia Process Flare (EU-006):**</u>

Common PM, PM$_{10}$, PM$_{2.5}$, NO$_x$, CO, VOC and GHG Conditions:

(1) **********

(2) **********

(3) **********

(A) Flare Use Minimization: Flare EU-006 shall be limited to flaring ammonia during high-pressure events to the extent **practicable**~~possible~~. The ammonia compressor main shall be depressurized prior to compressor maintenance. The Permittee shall limit venting ammonia rich streams to Flare EU-006 to the extent **practicable**~~possible~~ during non-emergency startup and shutdown operations;

(B) **********

(C) **********

(4) PM, PM_{10}, $PM_{2.5}$, NO_x, CO, VOC and GHG emissions from the Back End Ammonia Process Vent Flare (EU-006) shall be controlled by the use of ~~proper flare design and good combustion practices, which include the following elements~~**the following practices**:

****

(c) Ammonia Storage Flare (EU-005):
****

(3) **********

(A) Flare Use Minimization: The Permittee shall limit periods when the backup storage compressor and the ammonia refrigeration compressor are offline at the same time to the extent **practicable**~~possible~~;

****

(4) PM, PM_{10}, $PM_{2.5}$, NO_x, CO, VOC and GHG emissions shall be controlled **by the use of** ~~using proper flare design and good combustion practices, which include the following elements~~**the following practices**:

****

Modification No. 13: **A new Condition D.3.8 – Flare Emissions**
IDEM, OAQ is adding additional compliance monitoring requirements for all flares. The remaining conditions have been renumbered to allow the insertion of new conditions. Revisions follow:

D.3.8 Flare Emissions [326 IAC 2-7-6(1)][326 IAC 2-7-6(6)]

(a) In order to demonstrate compliance with the emission limits in Conditions D.3.4(b)(8), (10), (12), and (14), the Permittee shall use the following equations:

(1) For CO, VOC, and CO_2:

E = (H x EF) + PE

Where:

E= Pollutant Emissions (lb/hr)

EF_{CO} = 0.3700 lb/MMBtu

EF_{VOC} = 0.0054 lb/MMBtu

EF_{CO2} = 116.8879 lb/MMBtu

PE_{CO} = 14.158 lb/hr from pilot and purge

PE_{VOC} = 0.206 lb/hr from pilot and purge

PE_{CO2} = 4,472.60 lb/hr from pilot and purge

H = Hourly Heat Input (MMBtu/hr) = F_1 (lb/hr) x HHV_1 x 100% (portion of flare stream combusted) x 1 MMBtu/1,000,000 Btu

Where:

F_1 = Flow of flared gases from ammonia free streams (lb/hr)

HHV_1 = 9,020.7 Btu/lb or other value determined by testing

(2) For NO_x:

E = (H x EF) + PE + FE

Where:

E= Pollutant Emissions (lb/hr)

EF_{NOx} = 0.068 lb/MMBtu

PE_{NOX} = 2.60 lb/hr from pilot and purge

H = Hourly Heat Input (MMBtu/hr) = (F_1 (lb/hr) x HHV_1 x 100% (portion of flare stream combusted) x 1 MMBtu/1,000,000 Btu) + (F_2 (lb/hr) x HHV_2 x 98% (portion of flare stream combusted) x 1 MMBtu/1,000,000 Btu)

Where:
F_1 = Flow of flared gases from ammonia free streams (lb/hr)
HHV_1 = 9,020.7 Btu/lb or other value determined during testing
F_2 = Flow of flared gases from ammonia streams (lb/hr)
HHV_2 = 7,996.5 Btu/lb or other value determined by testing

FE $_{NOx}$ = F (lb/hr) x (Ammonia Combusted) x (Ammonia in Flare Gas) x (M.W. of NO_2 / M.W. of NH_3) x FN%

Where:
F = Flow of Flared Gases (lb/hr)
Ammonia Combusted = 98%
Ammonia in Flare Gas = 99.9%
M.W. of NO_2 = molecular weight of nitrogen dioxide = 46 lb/lb.mole
M.W. of NH_3 = molecular weight of ammonia = 17 lb/lb.mole
FN = Fuel NO_x factor for ammonia = 0.50%

(b) In order to demonstrate compliance with the emission limits in Conditions D.3.4(c)(8) and (11), the Permittee shall use the following equations:

(1) For NO_x and CO_2:

E = (H x EF) + PE + FE

Where:
E= Pollutant Emissions (lb/hr)
EF $_{NOx}$ = 0.068 lb/MMBtu
EF $_{CO2}$ = 0 lb/MMBtu as there are no carbon containing vent streams
PE $_{NOx}$ = 0.03 lb/hr from pilot and purge

PE_{CO2} = 52.02 lb/hr from pilot and purge

H = Hourly Heat Input (MMBtu/hr) = F (lb/hr) x HHV x 98% (portion of flare stream combusted) x 1 MMBtu/1,000,000 Btu

Where:
F = Flow of Flared Gases (lb/hr)
HHV = 7,779.7 Btu/lb or other value determined by testing

FE_{NOX} = F (lb/hr) x (Ammonia Combusted) x (Ammonia in Flare Gas) x (M.W. of NO_2 / M.W. of NH_3) x FN%

Where:
F = Flow of Flared Gases (lb/hr)
Ammonia Combusted = 98%
Ammonia in Flare Gas = 98.3%
M.W. of NO_2 = molecular weight of nitrogen dioxide = 46 lb/lb.mole
M.W. of NH_3 = molecular weight of ammonia = 17 lb/lb.mole
FN = Fuel NOx factor for ammonia = 0.50%

(c) **The Permittee shall determine flow rates used in the equations in Conditions D.3.8(a) and (b) through flow monitoring of gases sent to the flare, process operational data, mass balance, or other engineering methods.**

Modification No. 14: **Condition D.3.8 – Record Keeping Requirements**
IDEM, OAQ is adding additional record keeping requirements. In addition, both original Conditions D.3.8 and D.3.9 have been renumbered. Revisions follow:

D.3.~~8~~**9** Record Keeping Requirements

(a) **********

(g) **In order to document compliance with the emission limits in Conditions D.3.4(b)(8), (10), (12), and (14), and D.3.4(c)(8) and (11), the Permittee shall maintain records of flow monitoring data, process operational data, mass balance, or other engineering estimation methods used to determine flare emissions.**

(h) Section C – General Record Keeping Requirements contains the Permittee's obligations with regard to the record keeping required by this condition.

D.3.~~9~~**10** Reporting Requirements

****

Modification No. 15: **Condition D.4.4 – PSD BACT Limits**
IDEM, OAQ is clarifying the condition. Revisions follow:

D.4.4 PSD Best Available Control Technology Limits [326 IAC 2-2-3]

****

(d) **<u>UAN Plant Vent Flare (EU-017):</u>**

Common PM, PM_{10}, $PM_{2.5}$, NO_x, CO, VOC and GHG Conditions:

(1) **********

(2) **********

(3) **********

(A) **********

(B) **********

(C) **********.

(4) PM, PM_{10}, $PM_{2.5}$, NO_x, CO, VOC and GHG emissions shall be controlled **by the use of** ~~using proper flare design and good combustion practices, which include the following elements~~**the following practices**:

****

(h) **One DEF Truck Loadout (EU-025):**

VOC:

~~The Permittee shall use a submerged/bottom fill system at the DEF Truck Loadout (EU-025).~~**The use of submerged/bottom fill.**

****

Modification No. 16: **Revised Condition D.4.11 – Flare Emissions**
IDEM, OAQ is adding additional compliance monitoring requirements for all flares. Revisions follow:

D.4.11 Flare Emissions [326 IAC 2-7-6(1)][326 IAC 2-7-6(6)]

(a) **In order to demonstrate compliance with the emission limits in Conditions D.4.4(d)(8) and (12), the Permittee shall use the following equations:**

(1) **For NO_x:**

E = (H x EF) + PE + FE

Where:

E= Pollutant Emissions (lb/hr)

EF_{NOx} = 0.068 lb/MMBtu

PE_{NOx} = 0.44 lb/hr from pilot and purge

H = Hourly Heat Input (MMBtu/hr) = F (lb/hr) x HHV x 98% (portion of flare stream combusted) x 1 MMBtu/1,000,000 Btu

Where:

F = Flow of Flared Gases (lb/hr)
HHV = 4,605 Btu/lb or other value determined by testing

FE_{NOx} = F (lb/hr) x (Ammonia Combusted) x (Ammonia in Flare Gas) x M.W. of NO_2 / M.W. of NH_3) x FN%

Where:

F = Flow of Flares Gases (lb/hr)

Ammonia Combusted = 98%
Ammonia in Flare Gas = 72.18%
M.W. of NO_2 = molecular weight of nitrogen dioxide = 46 lb/lb.mole
M.W. of NH_3 = molecular weight of ammonia = 17 lb/lb.mole
FN = Fuel NO_x factor for ammonia = 0.50%

(2) <u>For CO_2</u>:

E = (H x EF) + PE

Where:

E = Pollutant Emissions (lb/hr)
F = Flow of Flared Gases (lb/hr)
EF CO_2 = 31%
PE CO_2 = 751.12 lb/hr from pilot and purge

(b) The Permittee shall determine flow rates used in the equations in Condition D.4.11(a)(1) and (2) through flow monitoring of gases sent to the flare, process operational data, mass balance, or other engineering methods.

Modification No. 17: **Original Condition D.4.11 – Parametric Monitoring**
IDEM, OAQ is clarifying and renumbering the condition. Revisions follow:

D.4.1~~1~~**2** Parametric Monitoring

(a) The Permittee shall record the pressure drop across the ~~scrubber with~~ particulate demisters **following the scrubbers** used in conjunction with the ammonium nitrate (AN) plants, identified as EU-002A and EU-002B at least once per day when the listed process are in operation. When for any one reading, the pressure drop is below the normal range, the Permittee shall take a reasonable response. The normal pressure drop range for these ~~scrubbers with~~ particulate demisters is 1.5 to 11 inches of water, unless a ~~new pressure drop~~**different upper-bound or lower-bound value for this** range is determined during the latest valid compliant stack test. Section C – Response to Excursions or Exceedances contains the Permittee's obligation with regard to the reasonable response steps required by this condition. A pressure drop **reading** that is outside the range mentioned above is not a deviation from this permit. Failure to take response steps shall be considered a deviation from this permit.

****

Modification No. 18: **Original Conditions D.4.12 and D.4.13 – Record Keeping and Reporting**
IDEM, OAQ is renumbering both conditions and adding additional record keeping requirements due to additional compliance monitoring of the flares. Revisions follow:

D.4.1~~2~~**3** Record Keeping Requirements

(a) **********

(e) In order to document the compliance status with Conditions D.4.4(d)(8) and (12), the Permittee shall maintain records of flow monitoring data, process operational data, mass balance, or other engineering estimation methods used to determine flare emissions.

(~~d~~**f**) Section C – General Record Keeping Requirements contains the Permittee's obligations with regard to the record keeping required by this condition.

D.4.13~~3~~**4** Reporting Requirements

****

Modification No. 19: **Condition D.5.4 – PSD BACT Limits**
IDEM, OAQ is clarifying the PSD BACT Limits. Revisions follow:

D.5.4 PSD Best Available Control Technology Limits [326 IAC 2-2-3]

****

(c) **Two (2) Cooling Towers (EU-008A through EU-008H and EU-019A through EU-019F):**

PM, PM_{10}, $PM_{2.5}$:

(1) **********

(2) The total dissolved solids in the water used in Cooling Towers (EU-008A to H and EU-019A to F) shall not exceed 2,000 mg/l**, averaged on a daily basis**.

****

(e) **Fugitive ~~NO$_x$,~~ VOC~~, and GHG~~ Emissions from Equipment Leaks:**

~~**VOC:**~~

****

Modification No. 20: **Condition D.5.11 – Parametric Monitoring**
IDEM, OAQ is clarifying the parametric monitoring condition. Revisions follow:

D.5.11 Parametric Monitoring

(a) **********

(b) **********

(c) In order to demonstrate the compliance status with Condition D.5.4(c)(2), the Permittee shall record the level of total dissolved solids in the water used in each cooling tower at least once per month when the cooling tower is in operation. When for any one reading, the level of total dissolved solids is above **2,000 ppm**~~the normal concentration~~, the Permittee shall take a reasonable response. ~~The maximum total dissolved solid in the water allowed used in the cooling towers is 2,000 ppm (mg/l)~~. Section C – Response to Excursions or Exceedances contains the Permittee's obligation with regard to the reasonable response steps required by this condition. A **single reading**~~concentration~~ in excess of the above mentioned concentration is not a deviation from this permit. Failure to take response steps shall be considered a deviation from this permit.

Modification No. 21: **Part 70 Quarterly Report – Primary Reformer (EU-003)**
IDEM, OAQ is adding a requirement to report CO2 emissions in the Primary Reformer. The header of the reporting form follows:

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

Part 70 Quarterly Report – Primary Reformer (EU-003) CO_2 Emissions

Source Name:	**Ohio Valley Resources, LLC**
Source Address:	**300-400 East CR 350 North, Rockport, Indiana 47635**
Part 70 Permit No.:	**T 147-32322-00062**
Facility:	**Primary Reformer (EU-003)**
Parameter:	**CO_2 emissions**
Limit:	**515,246 tons CO_2 per twelve consecutive month period.**

****

Modification No. 22: **Primary Reformer Emission Unit Description**
The Applicant will install a NO_x CEMS on the Primary Reformer. Because the NO_x CEMS is available NO_x testing is no longer required. In addition, the emission unit description for the Primary Reformer has been updated throughout the permit to indicate a NO_x CEMS is installed. GHG testing frequency has been increased. Revisions follow:

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

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

(a) A reformer process for production of hydrogen and nitrogen syngas consisting of the following emission units and emission control devices:

(1) One (1) primary reformer, identified as EU-003, approved for construction in 2013, with a maximum rated heat input capacity of 1,006.4 MMBtu/hr, using selective catalytic reduction for NO_x emissions control**, equipped with a NO_x CEMS**, and exhausting to the ambient atmosphere through stack EP-003. [40 CFR 63, Subpart DDDDD]

****

SECTION D.2 **EMISSIONS UNIT OPERATION CONDITIONS**

Emissions Unit Description:

(a) A reformer process for production of hydrogen and nitrogen syngas consisting of the following emission units and emission control devices:

(1) One (1) primary reformer, identified as EU-003, approved for construction in 2013, with a maximum rated heat input capacity of 1,006.4 MMBtu/hr, using selective catalytic reduction for NO_x emissions control, **equipped with a NO_x CEMS,** and exhausting to the ambient atmosphere through stack EP-003. [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.)

D.2.10 Testing Requirements [326 IAC 2-7-6(1)] [326 IAC 2-7-6(6)]

~~(a) In order to demonstrate the compliance status with Condition D.2.4(a)(6) and within sixty (60) days of reaching maximum capacity but no later than one hundred and eighty (180) days after initial startup, the Permittee shall perform~~ ~~NO_x~~ ~~testing on stack EP-003 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.~~

(**a**~~b~~) In order to demonstrate the compliance status with Condition D.2.4(a)(7) and within sixty (60) days of reaching maximum capacity but no later than one hundred and eighty (180) days after initial startup, the Permittee shall perform CO testing on stack EP-003 utilizing methods as approved by the Commissioner. Testing shall be conducted in accordance with the provisions of 326 IAC 3-6 (Source Sampling Procedures). Section C – Performance Testing contains the Permittee's obligation with regard to the performance testing required by this condition.

(**b**~~c~~) In order to demonstrate the compliance status with Condition D.2.4(a)(9) and within sixty (60) days of reaching maximum capacity but no later than one hundred and eighty (180) days after initial startup, the Permittee shall perform CO_2 testing on stack EP-003 utilizing methods as approved by the Commissioner. **This test shall be repeated at least once every five 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.

(**c**~~d~~) **********

(**d**~~e~~) **********

(**e**~~f~~) In order to demonstrate the compliance status with Condition D.2.4(b)(5) and within sixty (60) days of reaching maximum capacity but no later than one hundred and eighty (180) days after initial startup, the Permittee shall perform CO_2 testing on stack EP-004 utilizing methods as approved by the Commissioner. **This test shall be repeated at least once every five 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.

(**f**~~g~~) **In order to demonstrate the compliance status with Condition D.2.4(a)(11) – GHGs PSD BACT, and within sixty (60) days of reaching maximum capacity but no later than one hundred and eighty (180) days after initial startup, the Permittee shall perform thermal efficiency testing of the Primary Reformer (EU-003) utilizing methods as approved by the Commissioner. These tests shall be conducted once. 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.**

Recommendation

The staff recommends to the Commissioner that the PSD/Part 70 Operating Permit be approved. This recommendation is based on the following facts and conditions:

Unless otherwise stated, information used in this review was derived from the application and additional information submitted by the applicant.

An application for the purposes of this review was received on September 17, 2012.

Conclusion

The operation of this stationary nitrogenous fertilizer production plant shall be subject to the conditions of the attached PSD/Part 70 Operating Permit No. T 147-32322-00062.

IDEM Contact

(a) Questions regarding this proposed permit can be directed to David Matousek 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) 232-8253 or toll free at 1-800-451-6027 extension 2-8253.

(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

Appendix A to the Technical Support Document (TSD)

Company Name: Ohio Valley Resources, LLC
Address: 300-400 East CR 350 North
Permit Number: T 147-32322-00062
Reviewer: David Matousek
Date: October 25, 2012

Uncontrolled PTE of the Entire Source (TPY)											
Process / Emission Unit	**PM**	**PM10**	**PM2.5**	**SO2**	**VOC**	**CO**	**NOx**	**Non-Biogenic GHGs (as CO2e)**	**Biogenic GHGs (as CO2e)**	**Total HAP**	**Highest Single HAP Methanol**
Boiler (EP-011A)	1.78	7.11	7.11	0.16	5.15	34.85	28.65	111,719	0.00	1.77	0.00
Boiler (EP-011B)	1.78	7.11	7.11	0.16	5.15	34.85	28.65	111,719	0.00	1.77	0.00
Boiler (EP-011C)	1.78	7.11	7.11	0.16	5.15	34.85	28.65	111,719	0.00	1.77	0.00
Boiler (EP-11D)	1.78	7.11	7.11	0.16	5.15	34.85	28.65	111,719	0.00	1.77	0.00
Startup Heater (EP-010)	0.87	3.47	3.47	0.27	2.51	16.99	83.85	54,475	0.00	0.86	0.00
Steam Methane Reformer (EP-003)	8.21	32.84	32.84	4.85	23.77	187.78	617.12	515,751	0.00	8.15	0.00
CO2 Vent (EP-004)	0.00	0.00	0.00	0.00	28.51	5.98	0.00	1,304,033	0.00	17.99	17.99
Emergency Generator (EP-009)	0.39	0.39	0.39	2.40	0.8	6.75	11.53	1,366	0.00	0.012	0.00
Fire Water Pump (EP-016)	0.04	0.04	0.04	0.25	0.04	0.69	0.76	140	0.00	0.003	0.00
Cooling Tower A (EP-008)	2.83	1.75	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Cooling Tower B (EP-019)	1.10	0.68	0.002	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Ammonia Storage Flare (EP-005)	1.00E-03	0.004	0.004	0.0003	0.00	0.20	0.04	64	0.00	0.0012	0.00
Ammonia Backend Flare (EP-006)	2.11E-03	0.01	0.01	0.0007	0.01	0.41	0.08	130	0.00	0.0021	0.00
Ammonia Frontend Flare (EP-007)	2.11E-03	0.01	0.01	0.0007	0.01	0.41	0.08	130	0.00	0.0021	0.00
UAN Flare (EP-017)	1.57E-03	0.01	0.01	0.0005	0.004	0.31	0.06	97	0.00	0.0017	0.00
Nitric Acid Tail Gas Stack A (EP-001A)	0.00	0.00	0.00	0.00	0.00	0.00	574.88	788,186	0.00	0.00	0.00
Nitric Acid Tail Gas Stack B (EP-001B)	0.00	0.00	0.00	0.00	0.00	0.00	574.88	788,186	0.00	0.00	0.00
UAN Scrubber Vent A (EP-002A)	84.10	84.10	84.10	0.00	0.00	0.00	0.00	43,464	0.00	0.00	0.00
UAN Scrubber Vent B (EP-002B)	84.10	84.10	84.10	0.00	0.00	0.00	0.00	43,464	0.00	0.00	0.00
Product Loadout (EP-024/025)	0.00	0.00	0.00	0.00	1.95	0.00	0.00	0.00	0.00	0.00	0.00
Startup, Shutdown and Malfunctions	0.00	0.00	0.00	0.00	9.91	679.55	271.32	216,766	0.00	0.00	0.00
Miscellaneous Insignificant Activities	0.00	0.00	0.00	0.00	2.63	0.00	0.62	0.00	0.00	0.10	0.00
Process Fugitives	0.00	0.00	0.00	0.00	0.01	0.07	0.01	1,215	0.00	0.01	0.01
Haul Road Fugitives	5.82	1.11	0.28	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
PTE of Entire Source	194.59	236.95	233.70	8.41	90.75	1038.54	2,250	4,204,343	0.00	34.21	18.00
Title V Major Source Thresholds	NA	100	100	100	100	100	100	100,000	NA	25	10

Appendix A to the Technical Support Document (TSD) Controlled Potential to Emit Summary (Continued)

	Controlled PTE of the Entire Source (TPY)										
Process / Emission Unit	PM	PM10	PM2.5	SO2	VOC	CO	NOx	Non-Biogenic GHGs (as CO2e)	Biogenic GHGs (as CO2e)	Total HAP	Highest Single HAP Methanol
Boiler (EP-011A)	1.78	7.11	7.11	0.16	5.15	34.85	19.11	111,719	0.00	1.77	0.00
Boiler (EP-011B)	1.78	7.11	7.11	0.16	5.15	34.85	19.11	111,719	0.00	1.77	0.00
Boiler (EP-011C)	1.78	7.11	7.11	0.16	5.15	34.85	19.11	111,719	0.00	1.77	0.00
Boiler (EP-11D)	1.78	7.11	7.11	0.16	5.15	34.85	19.11	111,719	0.00	1.77	0.00
Startup Heater (EP-010)	0.87	3.47	3.47	0.27	2.51	16.99	83.85	54,475	0.00	0.86	0.00
Steam Methane Reformer (EP-003)	8.21	32.84	32.84	4.85	23.77	187.78	61.71	515,751	0.00	8.15	0.00
CO2 Vent (EP-004)	0.00	0.00	0.00	0.00	28.51	5.98	0.00	1,304,033	0.00	17.99	17.99
Emergency Generator (EP-009)	0.39	0.39	0.39	2.40	0.80	6.75	11.53	1,366	0.00	0.012	0.00
Fire Water Pump (EP-016)	0.04	0.04	0.04	0.25	0.04	0.69	0.76	140	0.00	0.003	0.00
Cooling Tower A (EP-008)	2.83	1.75	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Cooling Tower B (EP-019)	1.10	0.68	0.002	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Ammonia Storage Flare (EP-005)	1.00E-03	0.004	0.004	0.0003	0.00	0.20	0.04	64	0.00	0.0012	0.00
Ammonia Backend Flare (EP-006)	2.11E-03	0.01	0.01	0.0007	0.01	0.41	0.08	130	0.00	0.0021	0.00
Ammonia Frontend Flare (EP-007)	2.11E-03	0.01	0.01	0.0007	0.01	0.41	0.08	130	0.00	0.0021	0.00
UAN Flare (EP-017)	1.57E-03	0.01	0.01	0.0005	0.00	0.31	0.06	97	0.00	0.0017	0.00
Nitric Acid Tail Gas Stack A (EP-001A)	0.00	0.00	0.00	0.00	0.00	0.00	57.49	74,414	0.00	0.00	0.00
Nitric Acid Tail Gas Stack B (EP-001B)	0.00	0.00	0.00	0.00	0.00	0.00	57.49	74,414	0.00	0.00	0.00
UAN Scrubber Vent A (EP-002A)	4.21	4.21	4.21	0.00	0.00	0.00	0.00	43,464	0.00	0.00	0.00
UAN Scrubber Vent B (EP-002B)	4.21	4.21	4.21	0.00	0.00	0.00	0.00	43,464	0.00	0.00	0.00
Product Loadout (EP-024/025)	0.00	0.00	0.00	0.00	1.95	0.00	0.00	0.00	0.00	0.00	0.00
Startup, Shutdown and Malfunctions	0.00	0.00	0.00	0.00	9.91	679.55	271.32	216,766	0.00	0.00	0.00
Miscellaneous Insignificant Activities	0.00	0.00	0.00	0.00	2.63	0.00	0.62	0.00	0.00	0.10	0.00
Process Fugitives	0.00	0.00	0.00	0.00	0.01	0.07	0.01	1,215	0.00	0.01	0.01
Haul Road Fugitives	0.58	0.11	0.03	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
PTE of Entire Source	29.57	76.17	73.67	8.41	90.75	1038.54	621.47	2,776,799	0.00	34.21	18.00

Appendix A to the Technical Support Document (TSD)
Limited Potential to Emit Summary (Continued)

Limited PTE of the Entire Source (TPY)											
Process / Emission Unit	**PM**	**PM10**	**PM2.5**	**SO2**	**VOC**	**CO**	**NOx**	**Non-Biogenic GHGs (as CO2e)**	**Biogenic GHGs (as CO2e)**	**Total HAP**	**Highest Single HAP Methanol**
Boiler (EP-011A)	2.66	10.65	10.65	0.24	7.71	52.16	28.59	167,200	0.00	2.65	0.00
Boiler (EP-011B)											
Boiler (EP-011C)											
Boiler (EP-11D)											
Startup Heater (EP-010)	0.02	0.08	0.08	0.01	0.06	0.39	1.91	1,243	0.00	0.02	0.00
Steam Methane Reformer (EP-003)	8.21	32.84	32.84	4.85	23.77	187.78	61.71	515,751	0.00	8.15	0.00
CO2 Vent (EP-004)	0.00	0.00	0.00	0.00	28.51	5.98	0.00	1,304,033	0.00	17.99	17.99
Emergency Generator (EP-009)	0.16	0.16	0.16	0.96	0.32	2.70	4.61	546	0.00	0.005	0.00
Fire Water Pump (EP-016)	0.02	0.02	0.02	0.10	0.01	0.28	0.30	56	0.00	0.001	0.00
Cooling Tower A (EP-008)	2.83	1.75	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Cooling Tower B (EP-019)	1.10	0.68	0.002	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Ammonia Storage Flare (EP-005)	1.00E-03	0.00413	0.00413	0.0003	0.00297	0.2	0.03741	64	0.00	0.00115	0.000
Ammonia Backend Flare (EP-006)	2.11E-03	0.01	0.01	0.0007	0.01	0.41	0.08	130	0.00	0.00211	0.000
Ammonia Frontend Flare (EP-007)	2.11E-03	0.01	0.01	0.0007	0.01	0.41	0.08	130	0.00	0.00211	0.000
UAN Flare (EP-017)	1.58E-03	0.01	0.01	0.0005	0.00	0.31	0.06	97	0.00	0.00174	0.000
Nitric Acid Tail Gas Stack A (EP-001A)	0.00	0.00	0.00	0.00	0.00	0.00	57.49	74,414	0.00	0.00	0.00
Nitric Acid Tail Gas Stack B (EP-001B)	0.00	0.00	0.00	0.00	0.00	0.00	57.49	74,414	0.00	0.00	0.00
UAN Scrubber Vent A (EP-002A)	4.21	4.21	4.21	0.00	0.00	0.00	0.00	43,464	0.00	0.00	0.00
UAN Scrubber Vent B (EP-002B)	4.21	4.21	4.21	0.00	0.00	0.00	0.00	43,464	0.00	0.00	0.00
Product Loadout (EP-024/025)	0.00	0.00	0.00	0.00	1.95	0.00	0.00	0.00	0.00	0.00	0.00
Startup, Shutdown and Malfunctions	0.00	0.00	0.00	0.00	9.91	679.55	271.32	216,766	0.00	0.00	0.00
Miscellaneous Insignificant Activities	0.00	0.00	0.00	0.00	2.63	0.00	0.62	0.00	0.00	0.10	0.00
Process Fugitives	0.00	0.00	0.00	0.00	0.01	0.07	0.01	1,215	0.00	0.01	0.01
Haul Road Fugitives	0.58	0.11	0.03	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
PTE of Entire Source	24.01	54.74	52.24	6.16	74.90	930.24	484.29	2,442,987	0.00	28.93	18.00
PSD Significant Levels	25	15	10	40	40	100	NA	75,000	NA	NA	NA
PSD Major Source Threshold	NA	NA	NA	NA	NA	NA	100	NA	NA	NA	NA

Appendix A to the Technical Support Document (TSD)
Package Boiler - EP-011A - Natural Gas Combustion

Company Name: Ohio Valley Resources, LLC
Address: 300-400 East CR 350 North
Permit Number: T 147-32322-00062
Reviewer: David Matousek
Date: October 25, 2012

Boiler Design Data

Heat Input Capacity	218.00	MMBtu/hr
Higher Heating Value	1,020	MMBtu/MMCF
Natural Gas Usage	1,872.24	MMCF/yr
Limited Natural Gas Usage	1,872.24	MMCF/yr

Pollutant	Emission Factor		PTE (TPY)	Control Efficiency (%)	Controlled PTE (TPY)		Data Source
PM (filterable)	1.9	lb/MMCF	1.78	0.00%	1.78		AP-42, Ch 1.4, Table 1.4-2, 7/98
PM10 (filterable + condensible)	7.6	lb/MMCF	7.11	0.00%	7.11		AP-42, Ch 1.4, Table 1.4-2, 7/98
PM2.5 (filterable + condensible)	7.6	lb/MMCF	7.11	0.00%	7.11		AP-42, Ch 1.4, Table 1.4-2, 7/98
SO2	0.17	lb/MMCF	0.16	0.00%	0.16		Design Specification
Nox (Ultra-Low NOx, FGR)	30.6	lb/MMCF	28.65	33.30%	19.11		Design Specification
VOC	5.5	lb/MMCF	5.15	0.00%	5.15		AP-42, Ch 1.4, Table 1.4-2, 7/98
CO	37.23	lb/MMCF	34.85	0.00%	34.85		Design Specification
Benzene	2.10E-03	lb/MMCF	1.97E-03	0.00%	1.97E-03		AP-42, Ch 1.4, Table 1.4-3, 7/98
Dichlorobenzene	1.20E-03	lb/MMCF	1.12E-03	0.00%	1.12E-03		AP-42, Ch 1.4, Table 1.4-3, 7/98
Formaldehyde	7.50E-02	lb/MMCF	0.07	0.00%	0.07		AP-42, Ch 1.4, Table 1.4-3, 7/98
Hexane	1.8	lb/MMCF	1.69	0.00%	1.69		AP-42, Ch 1.4, Table 1.4-3, 7/98
Toluene	3.40E-03	lb/MMCF	3.18E-03	0.00%	3.18E-03		AP-42, Ch 1.4, Table 1.4-3, 7/98
Lead	5.00E-04	lb/MMCF	4.68E-04	0.00%	4.70E-04		AP-42, Ch 1.4, Table 1.4-3, 7/98
Cadmium	1.10E-03	lb/MMCF	1.03E-03	0.00%	1.03E-03		AP-42, Ch 1.4, Table 1.4-3, 7/98
Chromium	1.40E-03	lb/MMCF	1.31E-03	0.00%	1.31E-03		AP-42, Ch 1.4, Table 1.4-3, 7/98
Manganese	3.80E-04	lb/MMCF	3.56E-04	0.00%	3.60E-04		AP-42, Ch 1.4, Table 1.4-3, 7/98
Nickel	2.10E-03	lb/MMCF	1.97E-03	0.00%	1.97E-03		AP-42, Ch 1.4, Table 1.4-3, 7/98
Total HAP			1.77	0.00%	1.77		
CO_2	53.02	kg CO2/MMBtu	111,610	0.00%	111,610		40 CFR 98, Subpart C, Table C-1
CH_4	1.00E-03	kg CO2/MMBtu	2.11	0.00%	2.11		40 CFR 98, Subpart C, Table C-2
N_2O	1.00E-04	kg CO2/MMBtu	0.21	0.00%	0.21		40 CFR 98, Subpart C, Table C-2
CO_2e			111,719	0.00%	111,719		

Methodology:

1)Gas Throughput (MMCF/yr) = Heat Input (MMBtu/hr) * 8,760 hr/yr / Heating Value (MMBtu/MMCF)
2)PTE (TPY) = Gas Throughput (MMCF/yr) * Emission Factor (lb/MMCF) / 2000 lb/ton
3)PTE (TPY) = Emission Factor (kg/MMBtu) * 2.2046 lb/kg x Heating Value (MMBtu/MMCF) * Throughput (MMCF/yr) / 2000 lb/ton
4)PTE CO_2e = PTE CO_2 + (PTE CH_4 * 21) + (PTE N_2O * 310)

Appendix A to the Technical Support Document (TSD)
Package Boiler - EP-011B - Natural Gas Combustion

Company Name: Ohio Valley Resources, LLC
Address: 300-400 East CR 350 North
Permit Number: T 147-32322-00062
Reviewer: David Matousek
Date: October 25, 2012

Boiler Design Data

Heat Input Capacity	218.00	MMBtu/hr
Higher Heating Value	1,020	MMBtu/MMCF
Natural Gas Usage	1,872.24	MMCF/yr
Limited Natural Gas Usage	1,872.24	MMCF/yr

Pollutant	Emission Factor		PTE (TPY)	Control Efficiency (%)	Controlled PTE (TPY)		Data Source
PM (filterable)	1.9	lb/MMCF	1.78	0.00%	1.78		AP-42, Ch 1.4, Table 1.4-2, 7/98
PM10 (filterable + condensible)	7.6	lb/MMCF	7.11	0.00%	7.11		AP-42, Ch 1.4, Table 1.4-2, 7/98
PM2.5 (filterable + condensible)	7.6	lb/MMCF	7.11	0.00%	7.11		AP-42, Ch 1.4, Table 1.4-2, 7/98
SO2	0.17	lb/MMCF	0.16	0.00%	0.16		Design Specification
Nox (Ultra-Low NOx, FGR)	30.6	lb/MMCF	28.65	33.30%	19.11		Design Specification
VOC	5.5	lb/MMCF	5.15	0.00%	5.15		AP-42, Ch 1.4, Table 1.4-2, 7/98
CO	37.23	lb/MMCF	34.85	0.00%	34.85		Design Specification
Benzene	2.10E-03	lb/MMCF	1.97E-03	0.00%	1.97E-03		AP-42, Ch 1.4, Table 1.4-3, 7/98
Dichlorobenzene	1.20E-03	lb/MMCF	1.12E-03	0.00%	1.12E-03		AP-42, Ch 1.4, Table 1.4-3, 7/98
Formaldehyde	7.50E-02	lb/MMCF	0.07	0.00%	0.07		AP-42, Ch 1.4, Table 1.4-3, 7/98
Hexane	1.8	lb/MMCF	1.69	0.00%	1.69		AP-42, Ch 1.4, Table 1.4-3, 7/98
Toluene	3.40E-03	lb/MMCF	3.18E-03	0.00%	3.18E-03		AP-42, Ch 1.4, Table 1.4-3, 7/98
Lead	5.00E-04	lb/MMCF	4.68E-04	0.00%	4.70E-04		AP-42, Ch 1.4, Table 1.4-3, 7/98
Cadmium	1.10E-03	lb/MMCF	1.03E-03	0.00%	1.03E-03		AP-42, Ch 1.4, Table 1.4-3, 7/98
Chromium	1.40E-03	lb/MMCF	1.31E-03	0.00%	1.31E-03		AP-42, Ch 1.4, Table 1.4-3, 7/98
Manganese	3.80E-04	lb/MMCF	3.56E-04	0.00%	3.60E-04		AP-42, Ch 1.4, Table 1.4-3, 7/98
Nickel	2.10E-03	lb/MMCF	1.97E-03	0.00%	1.97E-03		AP-42, Ch 1.4, Table 1.4-3, 7/98
Total HAP			1.77	0.00%	1.77		
CO_2	53.02	kg CO2/MMBtu	111,610	0.00%	111,610		40 CFR 98, Subpart C, Table C-1
CH_4	1.00E-03	kg CO2/MMBtu	2.11	0.00%	2.11		40 CFR 98, Subpart C, Table C-2
N_2O	1.00E-04	kg CO2/MMBtu	0.21	0.00%	0.21		40 CFR 98, Subpart C, Table C-2
CO_2e			111,719	0.00%	111,719		

Methodology:

1) Gas Throughput (MMCF/yr) = Heat Input (MMBtu/hr) * 8,760 hr/yr / Heating Value (MMBtu/MMCF)
2) PTE (TPY) = Gas Throughput (MMCF/yr) * Emission Factor (lb/MMCF) / 2000 lb/ton
3) PTE (TPY) = Emission Factor (kg/MMBtu) * 2.2046 lb/kg x Heating Value (MMBtu/MMCF) * Throughput (MMCF/yr) / 2000 lb/ton
4) PTE CO_2e = PTE CO_2 + (PTE CH_4 * 21) + (PTE N_2O * 310)

Appendix A to the Technical Support Document (TSD)
Package Boiler - EP-011C - Natural Gas Combustion

Company Name: Ohio Valley Resources, LLC
Address: 300-400 East CR 350 North
Permit Number: T 147-32322-00062
Reviewer: David Matousek
Date: October 25, 2012

Boiler Design Data

Heat Input Capacity	218.00	MMBtu/hr
Higher Heating Value	1,020	MMBtu/MMCF
Natural Gas Usage	1,872.24	MMCF/yr
Limited Natural Gas Usage	1,872.24	MMCF/yr

Pollutant	Emission Factor		PTE (TPY)	Control Efficiency (%)	Controlled PTE (TPY)		Data Source
PM (filterable)	1.9	lb/MMCF	1.78	0.00%	1.78		AP-42, Ch 1.4, Table 1.4-2, 7/98
PM10 (filterable + condensible)	7.6	lb/MMCF	7.11	0.00%	7.11		AP-42, Ch 1.4, Table 1.4-2, 7/98
PM2.5 (filterable + condensible)	7.6	lb/MMCF	7.11	0.00%	7.11		AP-42, Ch 1.4, Table 1.4-2, 7/98
SO2	0.17	lb/MMCF	0.16	0.00%	0.16		Design Specification
Nox (Ultra-Low NOx, FGR)	30.6	lb/MMCF	28.65	33.30%	19.11		Design Specification
VOC	5.5	lb/MMCF	5.15	0.00%	5.15		AP-42, Ch 1.4, Table 1.4-2, 7/98
CO	37.23	lb/MMCF	34.85	0.00%	34.85		Design Specification
Benzene	2.10E-03	lb/MMCF	1.97E-03	0.00%	1.97E-03		AP-42, Ch 1.4, Table 1.4-3, 7/98
Dichlorobenzene	1.20E-03	lb/MMCF	1.12E-03	0.00%	1.12E-03		AP-42, Ch 1.4, Table 1.4-3, 7/98
Formaldehyde	7.50E-02	lb/MMCF	0.07	0.00%	0.07		AP-42, Ch 1.4, Table 1.4-3, 7/98
Hexane	1.8	lb/MMCF	1.69	0.00%	1.69		AP-42, Ch 1.4, Table 1.4-3, 7/98
Toluene	3.40E-03	lb/MMCF	3.18E-03	0.00%	3.18E-03		AP-42, Ch 1.4, Table 1.4-3, 7/98
Lead	5.00E-04	lb/MMCF	4.68E-04	0.00%	4.70E-04		AP-42, Ch 1.4, Table 1.4-3, 7/98
Cadmium	1.10E-03	lb/MMCF	1.03E-03	0.00%	1.03E-03		AP-42, Ch 1.4, Table 1.4-3, 7/98
Chromium	1.40E-03	lb/MMCF	1.31E-03	0.00%	1.31E-03		AP-42, Ch 1.4, Table 1.4-3, 7/98
Manganese	3.80E-04	lb/MMCF	3.56E-04	0.00%	3.60E-04		AP-42, Ch 1.4, Table 1.4-3, 7/98
Nickel	2.10E-03	lb/MMCF	1.97E-03	0.00%	1.97E-03		AP-42, Ch 1.4, Table 1.4-3, 7/98
Total HAP			1.77	0.00%	1.77		
CO_2	53.02	kg CO2/MMBtu	111,610	0.00%	111,610		40 CFR 98, Subpart C, Table C-1
CH_4	1.00E-03	kg CO2/MMBtu	2.11	0.00%	2.11		40 CFR 98, Subpart C, Table C-2
N_2O	1.00E-04	kg CO2/MMBtu	0.21	0.00%	0.21		40 CFR 98, Subpart C, Table C-2
CO_2e			111,719	0.00%	111,719		

Methodology:

1)Gas Throughput (MMCF/yr) = Heat Input (MMBtu/hr) * 8,760 hr/yr / Heating Value (MMBtu/MMCF)
2)PTE (TPY) = Gas Throughput (MMCF/yr) * Emission Factor (lb/MMCF) / 2000 lb/ton
3)PTE (TPY) = Emission Factor (kg/MMBtu) * 2.2046 lb/kg x Heating Value (MMBtu/MMCF) * Throughput (MMCF/yr) / 2000 lb/ton
4)PTE CO_2e = PTE CO_2 + (PTE CH_4 * 21) + (PTE N_2O * 310)

Appendix A to the Technical Support Document (TSD)
Package Boiler - EP-011D - Natural Gas Combustion

Company Name: **Ohio Valley Resources, LLC**
Address: **300-400 East CR 350 North**
Permit Number: **T 147-32322-00062**
Reviewer: **David Matousek**
Date: **October 25, 2012**

Boiler Design Data

Heat Input Capacity	218.00	MMBtu/hr
Higher Heating Value	1,020	MMBtu/MMCF
Natural Gas Usage	1,872.24	MMCF/yr
Limited Natural Gas Usage	1,872.24	MMCF/yr

Pollutant	Emission Factor		PTE (TPY)	Control Efficiency (%)	Controlled PTE (TPY)		Data Source
PM (filterable)	1.9	lb/MMCF	1.78	0.00%	1.78		AP-42, Ch 1.4, Table 1.4-2, 7/98
PM10 (filterable + condensible)	7.6	lb/MMCF	7.11	0.00%	7.11		AP-42, Ch 1.4, Table 1.4-2, 7/98
PM2.5 (filterable + condensible)	7.6	lb/MMCF	7.11	0.00%	7.11		AP-42, Ch 1.4, Table 1.4-2, 7/98
SO2	0.17	lb/MMCF	0.16	0.00%	0.16		Design Specification
Nox (Ultra-Low NOx, FGR)	30.6	lb/MMCF	28.65	33.30%	19.11		Design Specification
VOC	5.5	lb/MMCF	5.15	0.00%	5.15		AP-42, Ch 1.4, Table 1.4-2, 7/98
CO	37.23	lb/MMCF	34.85	0.00%	34.85		Design Specification
Benzene	2.10E-03	lb/MMCF	1.97E-03	0.00%	1.97E-03		AP-42, Ch 1.4, Table 1.4-3, 7/98
Dichlorobenzene	1.20E-03	lb/MMCF	1.12E-03	0.00%	1.12E-03		AP-42, Ch 1.4, Table 1.4-3, 7/98
Formaldehyde	7.50E-02	lb/MMCF	0.07	0.00%	0.07		AP-42, Ch 1.4, Table 1.4-3, 7/98
Hexane	1.8	lb/MMCF	1.69	0.00%	1.69		AP-42, Ch 1.4, Table 1.4-3, 7/98
Toluene	3.40E-03	lb/MMCF	3.18E-03	0.00%	3.18E-03		AP-42, Ch 1.4, Table 1.4-3, 7/98
Lead	5.00E-04	lb/MMCF	4.68E-04	0.00%	4.70E-04		AP-42, Ch 1.4, Table 1.4-3, 7/98
Cadmium	1.10E-03	lb/MMCF	1.03E-03	0.00%	1.03E-03		AP-42, Ch 1.4, Table 1.4-3, 7/98
Chromium	1.40E-03	lb/MMCF	1.31E-03	0.00%	1.31E-03		AP-42, Ch 1.4, Table 1.4-3, 7/98
Manganese	3.80E-04	lb/MMCF	3.56E-04	0.00%	3.60E-04		AP-42, Ch 1.4, Table 1.4-3, 7/98
Nickel	2.10E-03	lb/MMCF	1.97E-03	0.00%	1.97E-03		AP-42, Ch 1.4, Table 1.4-3, 7/98
Total HAP			1.77	0.00%	1.77		
CO_2	53.02	kg CO2/MMBtu	111,610	0.00%	111,610		40 CFR 98, Subpart C, Table C-1
CH_4	1.00E-03	kg CO2/MMBtu	2.11	0.00%	2.11		40 CFR 98, Subpart C, Table C-2
N_2O	1.00E-04	kg CO2/MMBtu	0.21	0.00%	0.21		40 CFR 98, Subpart C, Table C-2
CO_2e			111,719	0.00%	111,719		

Methodology:

1)Gas Throughput (MMCF/yr) = Heat Input (MMBtu/hr) * 8,760 hr/yr / Heating Value (MMBtu/MMCF)
2)PTE (TPY) = Gas Throughput (MMCF/yr) * Emission Factor (lb/MMCF) / 2000 lb/ton
3)PTE (TPY) = Emission Factor (kg/MMBtu) * 2.2046 lb/kg x Heating Value (MMBtu/MMCF) * Throughput (MMCF/yr) / 2000 lb/ton
4)PTE CO_2e = PTE CO_2 + (PTE CH_4 * 21) + (PTE N_2O * 310)

Appendix A to the Technical Support Document (TSD)
Package Boiler Limited Operations - EP-011A to D - Natural Gas Combustion

Company Name: Ohio Valley Resources, LLC
Address: 300-400 East CR 350 North
Permit Number: T 147-32322-00062
Reviewer: David Matousek
Date: October 25, 2012

Boiler Design Data

Heat Input Capacity	872.00	MMBtu/hr
Higher Heating Value	1,020	MMBtu/MMCF
Natural Gas Usage	7,488.94	MMCF/yr
Limited Natural Gas Usage	2,802	MMCF/yr

Pollutant	Emission Factor		PTE (TPY)	Control Efficiency (%)	Controlled PTE (TPY)	Limited PTE (TPY)	Data Source
PM (filterable)	1.9	lb/MMCF	7.11	0.00%	7.11	2.66	AP-42, Ch 1.4, Table 1.4-2, 7/98
PM10 (filterable + condensible)	7.6	lb/MMCF	28.46	0.00%	28.46	10.65	AP-42, Ch 1.4, Table 1.4-2, 7/98
PM2.5 (filterable + condensible)	7.6	lb/MMCF	28.46	0.00%	28.46	10.65	AP-42, Ch 1.4, Table 1.4-2, 7/98
SO2	0.17	lb/MMCF	0.64	0.00%	0.64	0.24	Design Specification
Nox (Ultra-Low NOx, FGR)	30.6	lb/MMCF	114.58	33.30%	76.42	28.59	Design Specification
VOC	5.5	lb/MMCF	20.59	0.00%	20.59	7.71	AP-42, Ch 1.4, Table 1.4-2, 7/98
CO	37.23	lb/MMCF	139.41	0.00%	139.41	52.16	Design Specification
Benzene	2.10E-03	lb/MMCF	7.86E-03	0.00%	7.86E-03	2.94E-03	AP-42, Ch 1.4, Table 1.4-3, 7/98
Dichlorobenzene	1.20E-03	lb/MMCF	4.49E-03	0.00%	4.49E-03	1.68E-03	AP-42, Ch 1.4, Table 1.4-3, 7/98
Formaldehyde	7.50E-02	lb/MMCF	0.28	0.00%	0.28	0.11	AP-42, Ch 1.4, Table 1.4-3, 7/98
Hexane	1.8	lb/MMCF	6.74	0.00%	6.74	2.52	AP-42, Ch 1.4, Table 1.4-3, 7/98
Toluene	3.40E-03	lb/MMCF	1.27E-02	0.00%	1.27E-02	4.76E-03	AP-42, Ch 1.4, Table 1.4-3, 7/98
Lead	5.00E-04	lb/MMCF	1.87E-03	0.00%	1.87E-03	7.00E-04	AP-42, Ch 1.4, Table 1.4-3, 7/98
Cadmium	1.10E-03	lb/MMCF	4.12E-03	0.00%	4.12E-03	1.54E-03	AP-42, Ch 1.4, Table 1.4-3, 7/98
Chromium	1.40E-03	lb/MMCF	5.24E-03	0.00%	5.24E-03	1.96E-03	AP-42, Ch 1.4, Table 1.4-3, 7/98
Manganese	3.80E-04	lb/MMCF	1.42E-03	0.00%	1.42E-03	5.30E-04	AP-42, Ch 1.4, Table 1.4-3, 7/98
Nickel	2.10E-03	lb/MMCF	7.86E-03	0.00%	7.86E-03	2.94E-03	AP-42, Ch 1.4, Table 1.4-3, 7/98
Total HAP			7.07	0.00%	7.07	2.65	
CO_2	53.02	kg CO2/MMBtu	446,437	0.00%	446,437	167,035	40 CFR 98, Subpart C, Table C-1
CH_4	1.00E-03	kg CO2/MMBtu	8.42	0.00%	8.42	3.15	40 CFR 98, Subpart C, Table C-2
N_2O	1.00E-04	kg CO2/MMBtu	0.84	0.00%	0.84	0.32	40 CFR 98, Subpart C, Table C-2
CO_2e			446,874	0.00%	446,874	167,200	

Methodology:

1)Gas Throughput (MMCF/yr) = Heat Input (MMBtu/hr) * 8,760 hr/yr / Heating Value (MMBtu/MMCF)
2)PTE (TPY) = Gas Throughput (MMCF/yr) * Emission Factor (lb/MMCF) / 2000 lb/ton
3)PTE (TPY) = Emission Factor (kg/MMBtu) * 2.2046 lb/kg x Heating Value (MMBtu/MMCF) * Throughput (MMCF/yr) / 2000 lb/ton
4)PTE CO_2e = PTE CO_2 + (PTE CH_4 * 21) + (PTE N_2O * 310)

Appendix A to the Technical Support Document (TSD)

Process Heater - EP-010 - Natural Gas Combustion

Company Name: Ohio Valley Resources, LLC
Address: 300-400 East CR 350 North
Permit Number: T 147-32322-00062
Reviewer: David Matousek
Date: October 25, 2012

Design Data

Heat Input Capacity	106.30	MMBtu/hr
Higher Heating Value	1,020	MMBtu/MMCF
Natural Gas Usage	912.93	MMCF/yr
Limited Natural Gas Usage	20.84	MMCF/yr

Pollutant	Emission Factor		PTE (TPY)	Limited PTE (TPY)	Data Source
PM (filterable)	1.9	lb/MMCF	0.87	0.02	AP-42, Ch 1.4, Table 1.4-2, 7/98
PM10 (filterable + condensible)	7.6	lb/MMCF	3.47	0.08	AP-42, Ch 1.4, Table 1.4-2, 7/98
PM2.5 (filterable + condensible)	7.6	lb/MMCF	3.47	0.08	AP-42, Ch 1.4, Table 1.4-2, 7/98
SO2	0.6	lb/MMCF	0.27	0.01	AP-42, Ch 1.4, Table 1.4-2, 7/98
NOx	183.7	lb/MMCF	83.85	1.91	Design Specification
VOC	5.5	lb/MMCF	2.51	0.06	AP-42, Ch 1.4, Table 1.4-2, 7/98
CO	37.23	lb/MMCF	16.99	0.39	AP-42, Ch 1.4, Table 1.4-1, 7/98
Benzene	2.10E-03	lb/MMCF	9.59E-04	2.19E-05	AP-42, Ch 1.4, Table 1.4-3, 7/98
Dichlorobenzene	1.20E-03	lb/MMCF	5.48E-04	1.25E-05	AP-42, Ch 1.4, Table 1.4-3, 7/98
Formaldehyde	7.50E-02	lb/MMCF	0.03	0	AP-42, Ch 1.4, Table 1.4-3, 7/98
Hexane	1.8	lb/MMCF	0.82	0.02	AP-42, Ch 1.4, Table 1.4-3, 7/98
Toluene	3.40E-03	lb/MMCF	1.55E-03	3.54E-05	AP-42, Ch 1.4, Table 1.4-3, 7/98
Lead	5.00E-04	lb/MMCF	2.28E-04	5.21E-06	AP-42, Ch 1.4, Table 1.4-3, 7/98
Cadmium	1.10E-03	lb/MMCF	5.02E-04	1.15E-05	AP-42, Ch 1.4, Table 1.4-3, 7/98
Chromium	1.40E-03	lb/MMCF	6.39E-04	1.46E-05	AP-42, Ch 1.4, Table 1.4-3, 7/98
Manganese	3.80E-04	lb/MMCF	1.73E-04	3.96E-06	AP-42, Ch 1.4, Table 1.4-3, 7/98
Nickel	2.10E-03	lb/MMCF	9.59E-04	2.19E-05	AP-42, Ch 1.4, Table 1.4-3, 7/98
Total HAP			0.86	0.02	
CO_2	53.02	kg CO2/MMBtu	54,422.34	1,242.33	40 CFR 98, Subpart C, Table C-1
CH_4	1.00E-03	kg CO2/MMBtu	1.03	0.02	40 CFR 98, Subpart C, Table C-2
N_2O	1.00E-04	kg CO2/MMBtu	0.10	2.34E-03	40 CFR 98, Subpart C, Table C-2
CO_2e			54,475	1,243	

Methodology:

1) Gas Throughput (MMCF/yr) = Heat Input (MMBtu/hr) * 8,760 hr/yr / Heating Value (MMBtu/MMCF)
2) PTE (TPY) = Gas Throughput (MMCF/yr) * Emission Factor (lb/MMCF) / 2000 lb/ton
3) PTE (TPY) = Emission Factor (kg/MMBtu) * 2.2046 lb/kg x Heating Value (MMBtu/MMCF) * Throughput (MMCF/yr) / 2000 lb/ton
4) PTE CO_2e = PTE CO_2 + (PTE CH_4 * 21) + (PTE N_2O * 310)

Appendix A to the Technical Support Document (TSD)
Steam Methane Reformer - EP-003

Company Name: Ohio Valley Resources, LLC
Address: 300-400 East CR 350 North
Permit Number: T 147-32322-00062
Reviewer: David Matousek
Date: October 29, 2012

Design Data

Heat Input Capacity	1,006.40	MMBtu/hr
Higher Heating Value	1,020	MMBtu/MMCF
Natural Gas Usage	8,643.20	MMCF/yr
Limited Natural Gas Usage	8,643.20	MMCF/yr

Pollutant	Emission Factor		PTE (TPY)	Control Efficiency %	Controlled PTE (TPY)	Limited & Controlled PTE (TPY)	Data Source
PM	1.9	lb/MMCF	8.21	0.00%	8.21	8.21	AP-42, Ch 1.4, Table 1.4-2, 7/98
PM10	7.6	lb/MMCF	32.84	0.00%	32.84	32.84	AP-42, Ch 1.4, Table 1.4-2, 7/98
PM2.5	7.6	lb/MMCF	32.84	0.00%	32.84	32.84	AP-42, Ch 1.4, Table 1.4-2, 7/98
SO2	0.0011	lb/MMBtu	4.85	0.00%	4.85	4.85	Design Specification
NOx	0.14	lb/MMBtu	617.12	90.00%	61.71	61.71	Design Specification
VOC	5.5	lb/MMCF	23.77	0.00%	23.77	23.77	AP-42, Ch 1.4, Table 1.4-2, 7/98
CO	0.0426	lb/MMBtu	187.78	0.00%	187.78	187.78	Design Specification
Benzene	2.10E-03	lb/MMCF	9.08E-03	0.00%	9.08E-03	9.08E-03	AP-42, Ch 1.4, Table 1.4-3, 7/98
Dichlorobenzene	1.20E-03	lb/MMCF	5.19E-03	0.00%	5.19E-03	5.19E-03	AP-42, Ch 1.4, Table 1.4-3, 7/98
Formaldehyde	7.50E-02	lb/MMCF	0.32	0.00%	0.32	0.32	AP-42, Ch 1.4, Table 1.4-3, 7/98
Hexane	1.8	lb/MMCF	7.78	0.00%	7.78	7.78	AP-42, Ch 1.4, Table 1.4-3, 7/98
Toluene	3.40E-03	lb/MMCF	1.47E-02	0.00%	0.015	0.015	AP-42, Ch 1.4, Table 1.4-3, 7/98
Lead	5.00E-04	lb/MMCF	2.16E-03	0.00%	2.16E-03	2.16E-03	AP-42, Ch 1.4, Table 1.4-3, 7/98
Cadmium	1.10E-03	lb/MMCF	4.75E-03	0.00%	4.75E-03	4.75E-03	AP-42, Ch 1.4, Table 1.4-3, 7/98
Chromium	1.40E-03	lb/MMCF	6.05E-03	0.00%	6.05E-03	6.05E-03	AP-42, Ch 1.4, Table 1.4-3, 7/98
Manganese	3.80E-04	lb/MMCF	1.64E-03	0.00%	1.64E-03	1.64E-03	AP-42, Ch 1.4, Table 1.4-3, 7/98
Nickel	2.10E-03	lb/MMCF	9.08E-03	0.00%	9.08E-03	9.08E-03	AP-42, Ch 1.4, Table 1.4-3, 7/98
Total HAP			8.15	0.00%	8.15	8.15	
CO_2	53.02	kg CO2/MMBtu	515,246	0.00%	515,246	515,246	40 CFR 98, Subpart C, Table C-1
CH_4	1.00E-03	kg CO2/MMBtu	9.72	0.00%	9.72	9.72	40 CFR 98, Subpart C, Table C-2
N_2O	1.00E-04	kg CO2/MMBtu	0.97	0.00%	0.97	0.97	40 CFR 98, Subpart C, Table C-2
CO_2e			515,751		515,751	515,751	

Methodology:

1) Gas Throughput (MMCF/yr) = Heat Input (MMBtu/hr) * 8,760 hr/yr / Heating Value (MMBtu/MMCF)
2) PTE (TPY) = Gas Throughput (MMCF/yr) * Emission Factor (lb/MMCF) / 2000 lb/ton
3) PTE (TPY) = Emission Factor (kg/MMBtu) * 2.2046 lb/kg x Heating Value (MMBtu/MMCF) * Throughput (MMCF/yr) / 2000 lb/ton
4) PTE CO_2e = PTE CO_2 + (PTE CH_4 * 21) + (PTE N_2O * 310)

Appendix A to the Technical Support Document (TSD)
CO_2 Purification Vent - EP-004

Company Name: Ohio Valley Resources, LLC
Address: 300-400 East CR 350 North
Permit Number: T 147-32322-00062
Reviewer: David Matousek
Date: October 29, 2012

Design Data

Ammonia Production Capacity	116.67 tons ammonia / hr
	1,022,000.00 tons ammonia / year

Scenario 1

Pollutant	Emission Factor		PTE (TPY)	% Vented to Atmosphere	Vented Emissisons (TPY)	Data Source
VOC	0.0558	lb/ton ammonia	28.51	100.00%	28.51	Engineering Estimate
CO	0.0117	lb/ton ammonia	5.98	100.00%	5.98	Engineering Estimate
Methanol	0.0352	lb/ton ammonia	17.99	100.00%	17.99	Engineering Estimate
Total HAP			17.99	100.00%	17.99	
CO_2	2,550.00	lb/ton ammonia	1,303,050	77.60%	1,011,167	Engineering Estimate
Methane	0.0916	lb/ton ammonia	46.81	77.60%	36.32	Engineering Estimate
CO_2e			1,304,033		1,011,930	

Scenario 2

Pollutant	Emission Factor		PTE (TPY)	% Vented to Atmosphere	Vented Emissisons (TPY)	Data Source
VOC	0.0558	lb/ton ammonia	28.51	100.00%	28.51	Engineering Estimate
CO	0.0117	lb/ton ammonia	5.98	100.00%	5.98	Engineering Estimate
Methanol	0.0352	lb/ton ammonia	17.99	100.00%	17.99	Engineering Estimate
Total HAP			17.99	100.00%	17.99	
CO_2	2,550.00	lb/ton ammonia	1,303,050	100.00%	1,303,050	Engineering Estimate
Methane	0.0916	lb/ton ammonia	46.81	100.00%	46.81	Engineering Estimate
CO_2e			1,304,033		1,304,033	

Methodology:

1) PTE (TPY) = Emission Factor (lb/ton ammonia) * Ammonia Production (tons ammonia/yr) / 2000 lb/ton
2) PTE CO_2e = PTE CO_2 + (PTE CH_4 * 21): No N2O is expected.
3) Vented Emissions (TPY) = PTE (TPY) * % Vented

Appendix A to the Technical Support Document (TSD)
Potential to Emit - Diesel Fired Emergency Generator EP-009

Company Name: Ohio Valley Resources, LLC
Address: 300-400 East CR 350 North
Permit Number: T 147-32322-00062
Reviewer: David Matousek
Date: October 25, 2012

Operating Parameters - Diesel Combustion

Engine Output	4,690 Hp			
Brake Specific Fuel Consumption	7,117 Btu/Hp.hr			
Heat Input	33.38 MMBtu/hr			
Diesel Heat Content	140.00 MMBtu/Kgallon			
Hours for Emergency PTE	500 hours/yr	or	119.214	Kgal/yr
Limited Hours	200 hours/yr	or	47.686	Kgal/yr

Pollutant	Emission Factor		PTE (TPY)	Limited PTE (TPY)	Emission Factor Source
PM	0.15	g/hp-hr	0.39	0.16	Design Specification
PM10	0.15	g/hp-hr	0.39	0.16	Design Specification
PM2.5	0.15	g/hp-hr	0.39	0.16	Design Specification
SO2	0.93	g/hp-hr	2.40	0.96	Design Specification
VOC	0.31	g/hp-hr	0.8	0.32	Design Specification
CO	2.61	g/hp-hr	6.75	2.70	Design Specification
NOx	4.46	g/hp-hr	11.53	4.61	Design Specification
Benzene	7.76E-04	lb/MMBtu	6.48E-03	2.59E-03	AP-42, Ch 3.4, Table 3.4-3 and 3.4-4
Toluene	2.81E-04	lb/MMBtu	2.34E-03	9.38E-04	AP-42, Ch 3.4, Table 3.4-3 and 3.4-4
Xylene	1.93E-04	lb/MMBtu	1.61E-03	6.44E-04	AP-42, Ch 3.4, Table 3.4-3 and 3.4-4
Formaldehyde	7.89E-05	lb/MMBtu	6.58E-04	2.63E-04	AP-42, Ch 3.4, Table 3.4-3 and 3.4-4
Acetaldehyde	2.52E-05	lb/MMBtu	2.10E-04	8.41E-05	AP-42, Ch 3.4, Table 3.4-3 and 3.4-4
Acrolein	7.88E-06	lb/MMBtu	6.58E-05	2.63E-05	AP-42, Ch 3.4, Table 3.4-3 and 3.4-4
Naphthalene	1.30E-04	lb/MMBtu	1.08E-03	4.34E-04	AP-42, Ch 3.4, Table 3.4-3 and 3.4-4
Total HAP			1.20E-02	5.00E-03	
CO2	73.96	kg/MMBtu	1,361	544	40 CFR 98, Subpart C, Table C-1
CH4	3.00E-03	kg/MMBtu	0.055	0.022	40 CFR 98, Subpart C, Table C-2
N2O	6.00E-04	kg/MMBtu	0.011	0.004	40 CFR 98, Subpart C, Table C-2
CO2e			1,366	546	

Methodology:
(a) PTE (TPY) = Engine Output (Hp) x Hours Operated (Hr/yr) x Emission Factor (lb/Hp-Hr) x 1 ton / 2,000 lb
(b) PTE (TPY) = Heat Input (MMBtu/hr) x Emission Factor (lb/MMBtu) x Hours Operated (hr/yr) x 1 ton / 2,000 lb
(c) CO2e (ton/yr) = CO2 (ton/yr) + CH4 (ton/yr) x 21 + N2O (ton/yr) x 310
(d) Emission Factor (lb/MMBtu) = Emission Factor (kg/MMBtu) x 2.2046 lb/kg

Appendix A to the Technical Support Document (TSD)
Potential to Emit - Diesel Fired Emergency Fire Pump EP-016

Company Name: Ohio Valley Resources, LLC
Address: 300-400 East CR 350 North
Permit Number: T 147-32322-00062
Reviewer: David Matousek
Date: October 25, 2012

Operating Parameters - Diesel Combustion

Engine Output	481 Hp			
Brake Specific Fuel Consumption	7,131 Btu/Hp.hr			
Heat Input	3.43 MMBtu/hr			
Diesel Heat Content	140.00 MMBtu/Kgallon			
Hours for Emergency PTE	500 hours/yr	or	12.250	Kgal/yr
Limited Hours	200 hours/yr	or	4.900	Kgal/yr

Pollutant	Emission Factor		PTE (TPY)	Limited PTE (TPY)	Emission Factor Source
PM	0.15	g/hp-hr	0.04	0.02	Design Specification
PM10	0.15	g/hp-hr	0.04	0.02	Design Specification
PM2.5	0.15	g/hp-hr	0.04	0.02	Design Specification
SO2	0.93	g/hp-hr	0.25	0.10	Design Specification
VOC	0.14	g/hp-hr	0.04	0.01	Design Specification
CO	2.60	g/hp-hr	0.69	0.28	Design Specification
NOx	2.859	g/hp-hr	0.76	0.30	Design Specification
Benzene	9.33E-04	lb/MMBtu	8.00E-04	3.20E-04	AP-42, Ch 3.3, Table 3.3-2
Toluene	4.09E-04	lb/MMBtu	3.51E-04	1.40E-04	AP-42, Ch 3.3, Table 3.3-2
Xylene	2.85E-04	lb/MMBtu	2.44E-04	9.78E-05	AP-42, Ch 3.3, Table 3.3-2
Formaldehyde	1.18E-03	lb/MMBtu	1.01E-03	4.05E-04	AP-42, Ch 3.3, Table 3.3-2
Acetaldehyde	7.67E-04	lb/MMBtu	6.58E-04	2.63E-04	AP-42, Ch 3.3, Table 3.3-2
Naphthalene	8.48E-05	lb/MMBtu	7.27E-05	2.91E-05	AP-42, Ch 3.3, Table 3.3-2
Total HAP			3.00E-03	1.25E-03	
CO2	73.96	kg/MMBtu	140	56	40 CFR 98, Subpart C, Table C-1
CH4	3.00E-03	kg/MMBtu	0.006	0.002	40 CFR 98, Subpart C, Table C-2
N2O	6.00E-04	kg/MMBtu	0.001	4.50E-04	40 CFR 98, Subpart C, Table C-2
CO2e			140	56	

Methodology:
(a) PTE (TPY) = Engine Output (Hp) x Hours Operated (Hr/yr) x Emission Factor (lb/Hp-Hr) x 1 ton / 2,000 lb
(b) PTE (TPY) = Heat Input (MMBtu/hr) x Emission Factor (lb/MMBtu) x Hours Operated (hr/yr) x 1 ton / 2,000 lb
(c) CO2e (ton/yr) = CO2 (ton/yr) + CH4 (ton/yr) x 21 + N2O (ton/yr) x 310
(d) Emission Factor (lb/MMBtu) = Emission Factor (kg/MMBtu) x 2.2046 lb/kg

Appendix A to the Technical Support Document (TSD)

Cooling Tower A - EP-008
Cooling Tower B - EP-019

Company Name: Ohio Valley Resources, LLC
Address: 300-400 East CR 350 North
Permit Number: T 147-32322-00062
Reviewer: David Matousek
Date: October 25, 2012

Cooling Tower - Potential to Emit							
Emission Unit	**Description**	**Circulation Rate (GPM)**	**Drift Factor (%)**	**Solids Content (mg/l)**	**Pollutant**	**Mass Fraction (%)**	**Annual Emissions (TPY)**
EP-008	Cooling Tower A	129,320	0.0005	2,000	PM	100.00%	2.83
					PM_{10}	62.00%	1.75
					$PM_{2.5}$	0.22%	0.01
EP-019	Cooling Tower B	50,400	0.0005	2,000	PM	100.00%	1.10
					PM_{10}	62.00%	0.68
					$PM_{2.5}$	0.22%	0.002

Methodology:

1) PM10 and PM2.5 mass fractions were estimated using, "Calculating Realistic PM10 Emissions from Cooling Towers," by Reisman, J. and Frisbie, G.

2) PM Emissions (lb/hr) = Q (GPM) * 60 min/hr * 8.34 lb/gallon x (Solids Con. (mg/l) /1.0E06) * (Drift Factor/100) * 1ton/2,000 lb

3) PM Emissions (TPY) = PM Emissions (lb/hr) * 4.38 ton-hr/lb-yr

Appendix A to the Technical Support Document (TSD)

Ammonia Storage Flare - EP-005 - Natural Gas Combustion with Purge Gas

Company Name: Ohio Valley Resources, LLC
Address: 300-400 East CR 350 North
Permit Number: T 147-32322-00062
Reviewer: David Matousek
Date: October 25, 2012

Design Data

Heat Input Capacity	0.126	MMBtu/hr
Higher Heating Value	902	MMBtu/MMCF (Natural Gas Pilot + Purge Process CH_4)
Natural Gas Usage	1.22	MMCF/yr
Limited Natural Gas Usage	1.22	MMCF/yr

Pollutant	Emission Factor		PTE (TPY)	Limited PTE (TPY)	Data Source
PM	0.0019	lb/MMBtu	0.001	0.001	AP-42, Ch 1.4, 1,020 MMBtu/MMCF
PM10 (filterable + condensible)	0.0075	lb/MMBtu	0.004	0.004	AP-42, Ch 1.4, Table 1.4-2
PM2.5 (filterable + condensible)	0.0075	lb/MMBtu	0.004	0.004	AP-42, Ch 1.4, Table 1.4-2
SO2	0.0006	lb/MMBtu	0.0003	0.0003	AP-42, Ch 1.4, Table 1.4-2
NOx	0.068	lb/MMBtu	0.038	0.037	AP-42, Ch 13.5, Table 13.5-1
VOC	0.0054	lb/MMBtu	0.003	0.003	AP-42, Ch 1.4, Table 1.4-2
CO	0.37	lb/MMBtu	0.20	0.20	AP-42, Ch 13.5, Table 13.5-1
Benzene	2.10E-03	lb/MMCF	1.28E-06	1.28E-06	AP-42, Ch 1.4, Table 1.4-3
Dichlorobenzene	1.20E-03	lb/MMCF	7.32E-07	7.32E-07	AP-42, Ch 1.4, Table 1.4-3
Formaldehyde	7.50E-02	lb/MMCF	4.58E-05	4.58E-05	AP-42, Ch 1.4, Table 1.4-3
Hexane	1.8	lb/MMCF	1.10E-03	1.10E-03	AP-42, Ch 1.4, Table 1.4-3
Toluene	3.40E-03	lb/MMCF	2.07E-06	2.07E-06	AP-42, Ch 1.4, Table 1.4-3
Lead	4.90E-07	lb/MMCF	2.99E-10	2.99E-10	AP-42, Ch 1.4, Table 1.4-2
Cadmium	1.10E-03	lb/MMCF	6.71E-07	6.71E-07	AP-42, Ch 1.4, Table 1.4-4
Chromium	1.40E-03	lb/MMCF	8.54E-07	8.54E-07	AP-42, Ch 1.4, Table 1.4-4
Manganese	3.80E-04	lb/MMCF	2.32E-07	2.32E-07	AP-42, Ch 1.4, Table 1.4-4
Nickel	2.10E-03	lb/MMCF	1.28E-06	1.28E-06	AP-42, Ch 1.4, Table 1.4-4
Total HAP			1.15E-03	1.15E-03	
CO_2	53.02	kg CO2/MMBtu	64.31	64.31	40 CFR 98, Subpart C, Table C-1
CH_4	1.00E-03	kg CO2/MMBtu	1.21E-03	1.21E-03	40 CFR 98, Subpart C, Table C-2
N_2O	1.00E-04	kg CO2/MMBtu	1.20E-04	1.20E-04	40 CFR 98, Subpart C, Table C-2
CO_2e			64	64	

Methodology:

1) Gas Throughput (MMCF/yr) = Heat Input (MMBtu/hr) * 8,760 hr/yr / Heating Value (MMBtu/MMCF)
2) PTE (TPY) = Gas Throughput (MMCF/yr) * Emission Factor (lb/MMCF) / 2000 lb/ton
3) PTE (TPY) = Emission Factor (kg/MMBtu) * 2.2046 lb/kg x Heating Value (MMBtu/MMCF) * Throughput (MMCF/yr) / 2000 lb/ton
4) PTE CO_2e = PTE CO_2 + (PTE CH_4 * 21) + (PTE N_2O * 310)

Appendix A to the Technical Support Document (TSD)

Ammonia Process Backend Flare - EP-006 - Natural Gas Combustion with Purge Gas

Company Name: Ohio Valley Resources, LLC
Address: 300-400 East CR 350 North
Permit Number: T 147-32322-00062
Reviewer: David Matousek
Date: October 25, 2012

Design Data

Heat Input Capacity	0.253	MMBtu/hr
Higher Heating Value	902	MMBtu/MMCF (Natural Gas Pilot + Purge Process CH_4)
Natural Gas Usage	2.46	MMCF/yr
Limited Natural Gas Usage	2.46	MMCF/yr

Pollutant	Emission Factor		PTE (TPY)	Limited PTE (TPY)	Data Source
PM	0.0019	lb/MMBtu	2.11E-03	2.11E-03	AP-42, Ch 1.4, 1,020 MMBtu/MMCF
PM10 (filterable + condensible)	0.0075	lb/MMBtu	0.01	0.01	AP-42, Ch 1.4, Table 1.4-2
PM2.5 (filterable + condensible)	0.0075	lb/MMBtu	0.01	0.01	AP-42, Ch 1.4, Table 1.4-2
SO2	0.0006	lb/MMBtu	0.0007	0.0007	AP-42, Ch 1.4, Table 1.4-2
NOx	0.068	lb/MMBtu	0.08	0.08	AP-42, Ch 13.5, Table 13.5-1
VOC	0.0054	lb/MMBtu	0.01	0.01	AP-42, Ch 1.4, Table 1.4-2
CO	0.37	lb/MMBtu	0.41	0.41	AP-42, Ch 13.5, Table 13.5-1
Benzene	2.10E-03	lb/MMCF	2.58E-06	2.58E-06	AP-42, Ch 1.4, Table 1.4-3
Dichlorobenzene	1.20E-03	lb/MMCF	1.48E-06	1.48E-06	AP-42, Ch 1.4, Table 1.4-3
Formaldehyde	7.50E-02	lb/MMCF	9.23E-05	9.23E-05	AP-42, Ch 1.4, Table 1.4-3
Hexane	1.8	lb/MMCF	0.002	0.002	AP-42, Ch 1.4, Table 1.4-3
Toluene	3.40E-03	lb/MMCF	4.18E-06	4.18E-06	AP-42, Ch 1.4, Table 1.4-3
Lead	4.90E-07	lb/MMCF	1.00E-09	1.00E-09	AP-42, Ch 1.4, Table 1.4-2
Cadmium	1.10E-03	lb/MMCF	1.35E-06	1.35E-06	AP-42, Ch 1.4, Table 1.4-4
Chromium	1.40E-03	lb/MMCF	1.72E-06	1.72E-06	AP-42, Ch 1.4, Table 1.4-4
Manganese	3.80E-04	lb/MMCF	4.67E-07	4.67E-07	AP-42, Ch 1.4, Table 1.4-4
Nickel	2.10E-03	lb/MMCF	2.58E-06	2.58E-06	AP-42, Ch 1.4, Table 1.4-4
Total HAP			2.11E-03	2.11E-03	
CO_2	53.02	kg CO2/MMBtu	129.68	129.68	40 CFR 98, Subpart C, Table C-1
CH_4	1.00E-03	kg CO2/MMBtu	0.00	0.00	40 CFR 98, Subpart C, Table C-2
N_2O	1.00E-04	kg CO2/MMBtu	0.00	0.00	40 CFR 98, Subpart C, Table C-2
CO_2e			130	130	

Methodology:

1) Gas Throughput (MMCF/yr) = Heat Input (MMBtu/hr) * 8,760 hr/yr / Heating Value (MMBtu/MMCF)
2) PTE (TPY) = Gas Throughput (MMCF/yr) * Emission Factor (lb/MMCF) / 2000 lb/ton
3) PTE (TPY) = Emission Factor (kg/MMBtu) * 2.2046 lb/kg x Heating Value (MMBtu/MMCF) * Throughput (MMCF/yr) / 2000 lb/ton
4) PTE CO_2e = PTE CO_2 + (PTE CH_4 * 21) + (PTE N_2O * 310)

Appendix A to the Technical Support Document (TSD)

Ammonia Process Frontend Flare - EP-007 - Natural Gas Combustion with Purge Gas

Company Name: Ohio Valley Resources, LLC
Address: 300-400 East CR 350 North
Permit Number: T 147-32322-00062
Reviewer: David Matousek
Date: October 25, 2012

Design Data

Heat Input Capacity	0.253	MMBtu/hr
Higher Heating Value	902	MMBtu/MMCF (Natural Gas Pilot + Purge Process CH_4)
Natural Gas Usage	2.46	MMCF/yr
Limited Natural Gas Usage	2.46	MMCF/yr

Pollutant	Emission Factor		PTE (TPY)	Limited PTE (TPY)	Data Source
PM	0.0019	lb/MMBtu	2.11E-03	2.11E-03	AP-42, Ch 1.4, 1,020 MMBtu/MMCF
PM10 (filterable + condensible)	0.0075	lb/MMBtu	0.01	0.01	AP-42, Ch 1.4, Table 1.4-2
PM2.5 (filterable + condensible)	0.0075	lb/MMBtu	0.01	0.01	AP-42, Ch 1.4, Table 1.4-2
SO2	0.0006	lb/MMBtu	0.0007	0.0007	AP-42, Ch 1.4, Table 1.4-2
NOx	0.068	lb/MMBtu	0.08	0.08	AP-42, Ch 13.5, Table 13.5-1
VOC	0.0054	lb/MMBtu	0.01	0.01	AP-42, Ch 1.4, Table 1.4-2
CO	0.37	lb/MMBtu	0.41	0.41	AP-42, Ch 13.5, Table 13.5-1
Benzene	2.10E-03	lb/MMCF	2.58E-06	2.58E-06	AP-42, Ch 1.4, Table 1.4-3
Dichlorobenzene	1.20E-03	lb/MMCF	1.48E-06	1.48E-06	AP-42, Ch 1.4, Table 1.4-3
Formaldehyde	7.50E-02	lb/MMCF	9.225E-05	9.225E-05	AP-42, Ch 1.4, Table 1.4-3
Hexane	1.8	lb/MMCF	0.002	0.002	AP-42, Ch 1.4, Table 1.4-3
Toluene	3.40E-03	lb/MMCF	4.18E-06	4.18E-06	AP-42, Ch 1.4, Table 1.4-3
Lead	4.90E-07	lb/MMCF	1.00E-09	1.00E-09	AP-42, Ch 1.4, Table 1.4-2
Cadmium	1.10E-03	lb/MMCF	1.35E-06	1.35E-06	AP-42, Ch 1.4, Table 1.4-4
Chromium	1.40E-03	lb/MMCF	1.72E-06	1.72E-06	AP-42, Ch 1.4, Table 1.4-4
Manganese	3.80E-04	lb/MMCF	4.67E-07	4.67E-07	AP-42, Ch 1.4, Table 1.4-4
Nickel	2.10E-03	lb/MMCF	2.58E-06	2.58E-06	AP-42, Ch 1.4, Table 1.4-4
Total HAP			2.11E-03	2.11E-03	
CO_2	53.02	kg CO2/MMBtu	129.68	129.68	40 CFR 98, Subpart C, Table C-1
CH_4	1.00E-03	kg CO2/MMBtu	0.00	0.00	40 CFR 98, Subpart C, Table C-2
N_2O	1.00E-04	kg CO2/MMBtu	0.00	0.00	40 CFR 98, Subpart C, Table C-2
CO_2e			130	130	

Methodology:

1) Gas Throughput (MMCF/yr) = Heat Input (MMBtu/hr) * 8,760 hr/yr / Heating Value (MMBtu/MMCF)
2) PTE (TPY) = Gas Throughput (MMCF/yr) * Emission Factor (lb/MMCF) / 2000 lb/ton
3) PTE (TPY) = Emission Factor (kg/MMBtu) * 2.2046 lb/kg x Heating Value (MMBtu/MMCF) * Throughput (MMCF/yr) / 2000 lb/ton
4) PTE CO_2e = PTE CO_2 + (PTE CH_4 * 21) + (PTE N_2O * 310)

Appendix A to the Technical Support Document (TSD)

UAN Flare - EP-017 - Natural Gas Combustion with Purge Gas

Company Name: Ohio Valley Resources, LLC
Address: 300-400 East CR 350 North
Permit Number: T 147-32322-00062
Reviewer: David Matousek
Date: October 25, 2012

Design Data

Heat Input Capacity	0.189	MMBtu/hr
Higher Heating Value	902	MMBtu/MMCF (Natural Gas Pilot + Purge Process CH_4)
Natural Gas Usage	1.84	MMCF/yr
Limited Natural Gas Usage	1.84	MMCF/yr

Pollutant	Emission Factor		PTE (TPY)	Limited PTE (TPY)	Data Source
PM	0.0019	lb/MMBtu	1.57E-03	1.58E-03	AP-42, Ch 1.4, 1,020 MMBtu/MMCF
PM10 (filterable + condensible)	0.0075	lb/MMBtu	0.01	0.01	AP-42, Ch 1.4, Table 1.4-2
PM2.5 (filterable + condensible)	0.0075	lb/MMBtu	0.01	0.01	AP-42, Ch 1.4, Table 1.4-2
SO2	0.0006	lb/MMBtu	0.0005	0.0005	AP-42, Ch 1.4, Table 1.4-2
NOx	0.068	lb/MMBtu	0.06	0.06	AP-42, Ch 13.5, Table 13.5-1
VOC	0.0054	lb/MMBtu	0.0045	0.0045	AP-42, Ch 1.4, Table 1.4-2
CO	0.37	lb/MMBtu	0.31	0.31	AP-42, Ch 13.5, Table 13.5-1
Benzene	2.10E-03	lb/MMCF	1.93E-06	1.93E-06	AP-42, Ch 1.4, Table 1.4-3
Dichlorobenzene	1.20E-03	lb/MMCF	1.10E-06	1.10E-06	AP-42, Ch 1.4, Table 1.4-3
Formaldehyde	7.50E-02	lb/MMCF	6.90E-05	6.90E-05	AP-42, Ch 1.4, Table 1.4-3
Hexane	1.8	lb/MMCF	1.66E-03	1.66E-03	AP-42, Ch 1.4, Table 1.4-3
Toluene	3.40E-03	lb/MMCF	3.13E-06	3.13E-06	AP-42, Ch 1.4, Table 1.4-3
Lead	4.90E-07	lb/MMCF	0.00E+00	0.00E+00	AP-42, Ch 1.4, Table 1.4-2
Cadmium	1.10E-03	lb/MMCF	1.01E-06	1.01E-06	AP-42, Ch 1.4, Table 1.4-4
Chromium	1.40E-03	lb/MMCF	1.29E-06	1.29E-06	AP-42, Ch 1.4, Table 1.4-4
Manganese	3.80E-04	lb/MMCF	3.50E-07	3.50E-07	AP-42, Ch 1.4, Table 1.4-4
Nickel	2.10E-03	lb/MMCF	1.93E-06	1.93E-06	AP-42, Ch 1.4, Table 1.4-4
Total HAP			0.0017	0.0017	
CO_2	53.02	kg CO2/MMBtu	97	97	40 CFR 98, Subpart C, Table C-1
CH_4	1.00E-03	kg CO2/MMBtu	1.83E-03	1.83E-03	40 CFR 98, Subpart C, Table C-2
N_2O	1.00E-04	kg CO2/MMBtu	1.80E-04	1.80E-04	40 CFR 98, Subpart C, Table C-2
CO_2e			97	97	

Methodology:

1) Gas Throughput (MMCF/yr) = Heat Input (MMBtu/hr) * 8,760 hr/yr / Heating Value (MMBtu/MMCF)
2) PTE (TPY) = Gas Throughput (MMCF/yr) * Emission Factor (lb/MMCF) / 2000 lb/ton
3) PTE (TPY) = Emission Factor (kg/MMBtu) * 2.2046 lb/kg x Heating Value (MMBtu/MMCF) * Throughput (MMCF/yr) / 2000 lb/ton
4) PTE CO_2e = PTE CO_2 + (PTE CH_4 * 21) + (PTE N_2O * 310)

Appendix A to the Technical Support Document (TSD)
Nitric Acid Tail Gas Units - EP-001A/B
UAN Process Scrubber Vents - EP-002A/B

Company Name: Ohio Valley Resources, LLC
Address: 300-400 East CR 350 North
Permit Number: T 147-32322-00062
Reviewer: David Matousek
Date: October 25, 2012

Process Description	Emission Point	Product Throughput (TPY)	Pollutant	Emission Factor		PTE (TPY)	Overall Control Efficiency	Controlled PTE (TPY)	Limited PTE (TPY)	Emission Factor Source
Nitric Acid Unit A Tail Gas Stack (Product is Nitric Acid)	EP-001A	229,950	NOx	5.00	lb/ton Nitric Acid	574.88	90.00%	57.49	57.49	Design Specification
			CO_2	320.49		36,848	0.00%	36,848	36,848	
			N_2O	21.08		2,423.67	95.00%	121.18	121.18	
			CO_2e			788,186		74,414	74,414	
Nitric Acid Unit B Tail Gas Stack (Product is Nitric Acid)	EP-001B	229,950	NOx	5.00	lb/ton Nitric Acid	574.88	90.00%	57.49	57.49	
			CO_2	320.49		36,848	0.00%	36,848	36,848	
			N_2O	21.08		2,423.67	95.00%	121.18	121.18	
			CO_2e			788,186		74,414	74,414	
UAN Process Scrubber Vent A (Product is Urea Ammonium Nitrate)	EP-002A	657,000	PM	0.256	lb/ton UAN	84.10	95.00%	4.21	4.21	
			PM_{10}	0.256		84.10	95.00%	4.21	4.21	
			$PM_{2.5}$	0.256		84.10	95.00%	4.21	4.21	
			CO_2 / CO_2e	132.31		43,464	0.00%	43,464	43,464	
UAN Process Scrubber Vent B (Product is Urea Ammonium Nitrate)	EP-002B	657,000	PM	0.256	lb/ton UAN	84.10	95.00%	4.21	4.21	
			PM_{10}	0.256		84.10	95.00%	4.21	4.21	
			$PM_{2.5}$	0.256		84.10	95.00%	4.21	4.21	
			CO_2 / CO_2e	132.31		43,464	0.00%	43,464	43,464	

Methodology:

1) PTE (TPY) = Product Throughput (ton/yr) * Emission Factor (lb/ton product) * 1 ton /2,000 lb
2) Controlled PTE (TPY) = PTE (TPY) * (1 - Control Efficiency)

Appendix A to the Technical Support Document (TSD)
Product Loadout
UAN Truck and Rail Loading (EP-024)
DEF Truck Loading (EP-025)

Company Name: Ohio Valley Resources, LLC
Address: 300-400 East CR 350 North
Permit Number: T 147-32322-00062
Reviewer: David Matousek
Date: October 31, 2012

Maximum Annual Pumping

UAN Truck	237,184	kgal/yr
UAN Railcar	237,184	kgal/yr
DEF Truck	11,888	kgal/yr

Molecular Weight of the Vapor 60.06 lb/lb.mole (Assume Pure Urea)

Description	Emission Point	Maximum Hourly Pumping Rate (kgal/hr)	Urea Vapor Pressure (psia)	Bulk Temp of Fluid (Rankine)	Saturation Factor	Emission Factor (lb/kgal)	Annual VOC Emissions (TPY)
UAN Truck Loading	EP-024A	158	0.01	560	0.6	0.0080	0.95
UAN Railcar Loading	EP-024B	158	0.01	560	0.6	0.0080	0.95
DEF Truck Loading	EP-025	7.9	0.01	560	0.6	0.0080	0.05
					Loadout Total		1.95

Appendix A to the Technical Support Document (TSD)

Startup, Shutdown and Maintenance Emissions

Company Name: Ohio Valley Resources, LLC
Address: 300-400 East CR 350 North
Permit Number: T 147-32322-00062
Reviewer: David Matousek
Date: October 25, 2012

1) Storage - Ammonia Bullet Tanks and Loadout - Flare EP-005

Loadout

2 Storage Tanks	(EP-013)
4 Ammonia Bullet Tanks	(EP-023)

Flare Heat Input	69.18	MMBtu/hr
Ammonia Feed Rate	9,075	lb ammonia per hour
SSM Allowance	168	hrs of venting per year

Pollutant	Emission Factor		PTE (TPY)	Data Source
NOx - Thermal	0.068	lb/MMBtu	0.40	AP-42, Ch 13.5, Table 13.5-1
NOx - Fuel	0.01325	lb NOx / lb NH_3	10.10	Design Specification
Total NOx Emissions			10.50	
N_2O	1.00E-04	kg CO2/MMBtu	1.28E-03	40 CFR 98, Subpart C, Table C-2
CO_2e			0.40	

2) Ammonia Unit - Ammonia Back End Flare (EP-006)

Refrigeration Compressor
Ammonia Unit Compressor

Flare Heat Input	2,175.07	MMBtu/hr
Ammonia Feed Rate	36,000	lb ammonia per hour
SSM Allowance	336	hrs of venting per year

Pollutant	Emission Factor		PTE (TPY)	Data Source
NOx - Thermal	0.068	lb/MMBtu	24.85	AP-42, Ch 13.5, Table 13.5-1
NOx - Fuel	0.01325	lb NOx / lb NH_3	80.14	Design Specification
NOx - Total			104.99	
VOC	0.0054	lb/MMBtu	1.97	AP-42, Ch 1.4, Table 1.4-2
CO	0.37	lb/MMBtu	135.20	AP-42, Ch 13.5, Table 13.5-1
CO_2	53.02	kg CO2/MMBtu	42,712	40 CFR 98, Subpart C, Table C-1
CH_4	1.00E-03	kg CO2/MMBtu	0.81	40 CFR 98, Subpart C, Table C-2
N_2O	1.00E-04	kg CO2/MMBtu	0.08	40 CFR 98, Subpart C, Table C-2
CO_2e			42,754	

Methodology:

1) PTE (TPY) = Emission Factor (lb/MMBtu) * Heat Input (MMBtu/hr) * hours/yr * (1 ton / 2,000 lb)
2) PTE (TPY) = Emission Factor (kg/MMBtu) * 2.2046 lb/kg * Heat Input (MMBtu/hr) * hours/yr * (1 Ton / 2,000 lb)
3) PTE CO_2e = PTE CO_2 + (PTE CH_4 * 21) + (PTE N_2O * 310)

Appendix A to the Technical Support Document (TSD)

Startup, Shutdown and Maintenance Emissions (Continued)

3) Steam Methane Reforming Process - Front End Flare EP-007

Reformer (EP-003)
Shift Reactor
CO_2 Purification (EP-004)

Flare Heat Input 8,757.20 MMBtu/hr
SSM Allowance 336 hrs of venting per year

Pollutant	Emission Factor		PTE (TPY)	Data Source
NOx	0.068	lb/MMBtu	100.04	AP-42, Ch 13.5, Table 13.5-1
VOC	0.0054	lb/MMBtu	7.94	AP-42, Ch 1.4, Table 1.4-2
CO	0.37	lb/MMBtu	544.35	AP-42, Ch 13.5, Table 13.5-1
CO_2	53.02	kg CO2/MMBtu	171,967	40 CFR 98, Subpart C, Table C-1
CH_4	1.00E-03	kg CO2/MMBtu	3.24	40 CFR 98, Subpart C, Table C-2
N_2O	1.00E-04	kg CO2/MMBtu	0.32	40 CFR 98, Subpart C, Table C-2
CO_2e			172,134	

4) Urea Units - UAN Flare (EP-017)

NH_3 Scrubber
Decomposer #1

Flare Heat Input 154.73 MMBtu/hr
Ammonia Feed Rate 33,600 lb ammonia per hour
SSM Allowance 336 hrs of venting per year

Pollutant	Emission Factor		PTE (TPY)	Data Source
NOx - Thermal	0.068	lb/MMBtu	1.77	AP-42, Ch 13.5, Table 13.5-1
NOx - Fuel	0.00957	lb NOx / lb NH_3	54.02	Design Specification
Total NOx Emissions			55.79	
CO_2	72.19	lb CO2 / MMBtu	1876.63	Design Specification
N_2O	1.00E-04	kg CO2/MMBtu	5.73E-03	40 CFR 98, Subpart C, Table C-2
CO_2e			1,878	

SSM Summary	
Pollutant	(TPY)
NOx	271.32
VOC	9.91
CO	679.55
CO_2e	216,766

Appendix A to the Technical Support Document (TSD)
Miscellaneous Insignificant Activities

Company Name: Ohio Valley Resources, LLC
Address: 300-400 East CR 350 North
Permit Number: T 147-32322-00062
Reviewer: David Matousek
Date: October 25, 2012

	Potential to Emit (TPY)									
Emission Unit	**PM**	**PM10**	**PM2.5**	**SO2**	**VOC**	**CO**	**NOx**	**GHG**	**Total HAP**	**Worst Case HAP Methanol**
UAN Storage Tank A (EP-012A)	0.00	0.00	0.00	0.00	0.694	0.00	0.00	0.00	0.00	0.00
UAN Storage Tank A (EP-012B)	0.00	0.00	0.00	0.00	0.694	0.00	0.00	0.00	0.00	0.00
DEF Tank EP-021	0.00	0.00	0.00	0.00	0.01	0.00	0.00	0.00	0.00	0.00
Diesel Storage Tank EP-014	0.00	0.00	0.00	0.00	1.77E-03	0.00	0.00	0.00	3.53E-05	0.00
Gasoline Storage Tank EP-015	0.00	0.00	0.00	0.00	0.45	0.00	0.00	0.00	0.10	0.00
UAN Day Tank A (EP-020A)	0.00	0.00	0.00	0.00	0.26	0.00	0.00	0.00	0.00	0.00
UAN Day Tank B (EP-020B)	0.00	0.00	0.00	0.00	0.26	0.00	0.00	0.00	0.00	0.00
UAN Day Tank C (EP-020C)	0.00	0.00	0.00	0.00	0.26	0.00	0.00	0.00	0.00	0.00
Nitric Acid Surge Tank Plant A (EP-022)	0.00	0.00	0.00	0.00	0.00	0.00	0.31	0.00	0.00	0.00
Nitric Acid Surge Tank Plant B (EP-022)	0.00	0.00	0.00	0.00	0.00	0.00	0.31	0.00	0.00	0.00
Total for Misc. Insignificant	0.00	0.00	0.00	0.00	2.63	0.00	0.62	0.00	0.10	0.00

Appendix A to the Technical Support Document (TSD)
Fugitive Emissions from Process Units (F-200a/b/c-1/c-2/d)

Company Name: **Ohio Valley Resources, LLC**
Address: **300-400 East CR 350 North**
Permit Number: **T 147-32322-00062**
Reviewer: **David Matousek**
Date:

1) Reformer and Ammonia Units (F-200a)

Component	Service	# of Components	Uncontrolled Emission Factor (lb/hr-component)	Uncontrolled PTE (lb/hr)	Uncontrolled PTE (TPY)
Valves	Gas/Vapor	169	0.01316	2.2240	9.7411
	Light Liquid	211	0.00888	1.8737	8.2068
	Heavy Liquid	0	0.00051	0.0000	0.0000
Pumps	Light Liquid	8	0.04387	0.3510	1.5374
	Light Liquid Double Seals	0	0.04387	0.0000	0.0000
	Light Liquid Single Seals	0	0.04387	0.0000	0.0000
	Heavy Liquid Single Seals	0	0.019	0.0000	0.0000
Flanges	Gas/Vapor	292	0.00086	0.2511	1.0998
	Light Liquid	35	0.00024	0.0084	0.0368
	Heavy Liquid	0	0.000001	0.0000	0.0000
Compressors	Gas/Vapor	2	0.50265	1.0053	4.4032
Relief Valves	Rupture Disk	18	0.22928	4.1270	18.0763
	Gas/Vapor	2	0.22928	0.4586	2.0087
Open Ended Lines		111	0.00375	0.4163	1.8234
Sampling Points		0	0.03307	0.0000	0.0000
		Total Fugitives (lb/hr and TPY)		**10.7154**	**46.9335**

Emission Summary - Reformer and Ammonia Units			
Component	**Component Description**	**% by Mass of Total Fugitive**	**Potential to Emit (TPY)**
CO	Criteria Pollutant	0.14%	0.07
NOx		0.00%	0.00
Methanol	VOC / Worst Case HAP	0.02%	0.01
Urea	VOC	0.00%	0.00
aMDEA	VOC	0.00%	0.00
Total VOC	VOC		0.01
Total HAP	HAP		0.01
CO_2	Greenhouse Gas	84.51%	39.66
N_2O		0.00%	0.00
CH_4		15.34%	7.2
CO_2e			191

Appendix A to the Technical Support Document (TSD)
Fugitive Emissions from Process Units (Continued)

2) aMDEA Area (F-200b)

Component	Service	# of Components	Uncontrolled Emission Factor (lb/hr-component)	Uncontrolled PTE (lb/hr)	Uncontrolled PTE (TPY)
Valves	Gas/Vapor	0	0.01316	0.0000	0.0000
	Light Liquid	0	0.00888	0.0000	0.0000
	Heavy Liquid	152	0.00051	0.0775	0.3395
Pumps	Light Liquid Sealless	0	0.04387	0.0000	0.0000
	Light Liquid Double Seals	0	0.04387	0.0000	0.0000
	Light Liquid Single Seals	0	0.04387	0.0000	0.0000
	Heavy Liquid Single Seals	9	0.019	0.1710	0.7490
Flanges	Gas/Vapor	0	0.00086	0.0000	0.0000
	Light Liquid	0	0.00024	0.0000	0.0000
	Heavy Liquid	750	0.000001	0.0008	0.0035
Compressors	Gas/Vapor	0	0.50265	0.0000	0.0000
Relief Valves	Rupture Disk	0	0.22928	0.0000	0.0000
	Gas/Vapor	2	0.22928	0.4586	2.0087
Open Ended Lines		8	0.00375	0.0300	0.1314
Sampling Points		28	0.03307	0.9260	4.0559
		Total Fugitives (lb/hr and TPY)		**1.6639**	**7.2880**

Emission Summary - aMDEA Area			
Component	**Component Description**	**% by Mass of Total Fugitive**	**Potential to Emit (TPY)**
CO	Criteria Pollutant	0.00%	0
NOx		0.00%	0
Methanol	VOC / Worst Case HAP	0.00%	0
Urea	VOC	0.00%	0
aMDEA	VOC	100.00%	7.29
Total VOC	VOC	▨	0
Total HAP	HAP	▨	0
CO_2	Greenhouse Gas	0.00%	0
N_2O		0.00%	0
CH_4		0.00%	0
CO_2e		▨	0

Appendix A to the Technical Support Document (TSD)
Fugitive Emissions from Process Units (Continued)

3) UAN Plant / CO_2 (F-200c-1)

Component	Service	# of Components	Uncontrolled Emission Factor (lb/hr-component)	Uncontrolled PTE (lb/hr)	Uncontrolled PTE (TPY)
Valves	Gas/Vapor	82	0.01316	1.0791	4.7265
	Light Liquid	196	0.00888	1.7405	7.6234
	Heavy Liquid	0	0.00051	0.0000	0.0000
Pumps	Light Liquid Sealless	0	0.04387	0.0000	0.0000
	Light Liquid Double Seals	0	0.04387	0.0000	0.0000
	Light Liquid Single Seals	6	0.04387	0.2632	1.1528
	Heavy Liquid Single Seals	0	0.019	0.0000	0.0000
Flanges	Gas/Vapor	132	0.00086	0.1135	0.4971
	Light Liquid	238	0.00024	0.0571	0.2501
	Heavy Liquid	0	0.000001	0.0000	0.0000
Compressors	Gas/Vapor	0	0.50265	0.0000	0.0000
Relief Valves	Rupture Disk	0	0.22928	0.0000	0.0000
	Gas/Vapor	6	0.22928	1.3757	6.0256
Open Ended Lines		0	0.00375	0.0000	0.0000
Sampling Points		2	0.03307	0.0661	0.2895
			Total Fugitives (lb/hr and TPY)	**4.6952**	**20.5650**

Emission Summary - UAN Plant /CO_2			
Component	**Component Description**	**% by Mass of Total Fugitive**	**Potential to Emit (TPY)**
CO	Criteria Pollutant	0.00%	0.00
NOx		0.00%	0.00
Methanol	VOC / Worst Case HAP	0.00%	0.00
Urea	VOC	43.00%	8.84
aMDEA	VOC	0.00%	0.00
Total VOC	VOC		0
Total HAP	HAP		0.00
CO_2	Greenhouse Gas	19.00%	3.91
N_2O		0.00%	0.00
CH_4		0.00%	0.00
CO_2e			4

Appendix A to the Technical Support Document (TSD)
Fugitive Emissions from Process Units (Continued)

4) UAN Plant NOx/N_2O (F-200c-2)

Component	Service	# of Components	Uncontrolled Emission Factor (lb/hr-component)	Uncontrolled PTE (lb/hr)	Uncontrolled PTE (TPY)
Valves	Gas/Vapor	82	0.01316	1.0791	4.7265
	Light Liquid	196	0.00888	1.7405	7.6234
	Heavy Liquid	0	0.00051	0.0000	0.0000
Pumps	Light Liquid Sealless	0	0.04387	0.0000	0.0000
	Light Liquid Double Seals	0	0.04387	0.0000	0.0000
	Light Liquid Single Seals	6	0.04387	0.2632	1.1528
	Heavy Liquid Single Seals	0	0.019	0.0000	0.0000
Flanges	Gas/Vapor	132	0.00086	0.1135	0.4971
	Light Liquid	238	0.00024	0.0571	0.2501
	Heavy Liquid	0	0.000001	0.0000	0.0000
Compressors	Gas/Vapor	0	0.50265	0.0000	0.0000
Relief Valves	Rupture Disk	0	0.22928	0.0000	0.0000
	Gas/Vapor	6	0.22928	1.3757	6.0256
Open Ended Lines		0	0.00375	0.0000	0.0000
Sampling Points		2	0.03307	0.0661	0.2895
		Total Fugitives	**(lb/hr and TPY)**	**4.6952**	**20.5650**

Emission Summary - UAN Plant /CO_2			
Component	**Component Description**	**% by Mass of Total Fugitive**	**Potential to Emit (TPY)**
CO	Criteria Pollutant	0.00%	0.00
NOx		0.04%	0.01
Methanol	VOC / Worst Case HAP	0.00%	0.00
Urea	VOC	0.00%	0
aMDEA	VOC	0.00%	0.00
Total VOC	VOC	▨	0
Total HAP	HAP	▨	0.00
CO_2	Greenhouse Gas	2.39%	0.49
N_2O		16.00%	3.29
CH_4		0.00%	0.00
CO_2e		▨	1,020

Appendix A to the Technical Support Document (TSD)
Fugitive Emissions from Process Units (Continued)

5) UAN Product Storage Area (F-200d)

Component	Service	# of Components	Uncontrolled Emission Factor (lb/hr-component)	Uncontrolled PTE (lb/hr)	Uncontrolled PTE (TPY)
Valves	Gas/Vapor	0	0.01316	0.0000	0.0000
	Light Liquid	110	0.00888	0.9768	4.2784
	Heavy Liquid	0	0.00051	0.0000	0.0000
Pumps	Light Liquid Sealless	0	0.04387	0.0000	0.0000
	Light Liquid Double Seals	0	0.04387	0.0000	0.0000
	Light Liquid Single Seals	2	0.04387	0.0877	0.3841
	Heavy Liquid Single Seals	0	0.019	0.0000	0.0000
Flanges	Gas/Vapor	0	0.00086	0.0000	0.0000
	Light Liquid	260	0.00024	0.0624	0.2733
	Heavy Liquid	0	0.000001	0.0000	0.0000
Compressors	Gas/Vapor	0	0.50265	0.0000	0.0000
Relief Valves	Rupture Disk	0	0.22928	0.0000	0.0000
	Gas/Vapor	0	0.22928	0.0000	0.0000
Open Ended Lines		22	0.00375	0.0825	0.3614
Sampling Points		0	0.03307	0.0000	0.0000
		Total Fugitives (lb/hr and TPY)		**1.2094**	**5.2972**

Emission Summary - UAN Product Storage Area

Component	Component Description	% by Mass of Total Fugitive	Potential to Emit (TPY)
CO	Criteria Pollutant	0.00%	0.00
NOx		0.00%	0.00
Methanol	VOC / Worst Case HAP	0.00%	0.00
Urea	VOC	36.00%	1.91
aMDEA	VOC	0.00%	0.00
Total VOC	VOC		0
Total HAP	HAP		0.00
CO_2	Greenhouse Gas	0.00%	0
N_2O		0.00%	0.00
CH_4		0.00%	0.00
CO_2e			0

Appendix A to the Technical Support Document (TSD)
Fugitive Emissions from Process Units (Continued)

Process Fugitive Emission Summary

Pollutant	F-200a (TPY)	F-200b (TPY)	F-200c-1 (TPY)	F-200c-2 (TPY)	F-200d (TPY)	Total (TPY)
CO	0.07	0	0.00	0.00	0.00	0.07
NOx	0	0	0.00	0.01	0.00	0.01
Methanol	0.01	0	0.00	0.00	0.00	0.01
Urea	0	0	8.84	0.00	1.91	10.75
aMDEA	0	7.29	0.00	0.00	0.00	7.29
Total VOC	0.01	0	0.00	0.00	0.00	0.01
Total HAP	0.01	0	0.00	0.00	0.00	0.01
CO_2	39.66	0	3.91	0.49	0.00	44.06
N_2O	0	0	0.00	3.29	0.00	3.29
CH_4	7.2	0	0.00	0.00	0.00	7.2
CO_2e	191	0	4	1,020	0	1,215

Appendix A to the Technical Support Document (TSD)
Paved Road Emissions - Haul Roads (F-100)

Company Name: Ohio Valley Resources, LLC
Address: 300-400 East CR 350 North
Permit Number: T 147-32322-00062
Reviewer: David Matousek
Date: October 25, 2012

Average Vehicle Weight Calculation

Vehicle Type	Trucks/Day	Average Weight (tons)	Total Trips per Year	Miles per Trip	Vehicle Miles Traveled (miles per year)	Traffic Component (%)	Component Weight (tons)
DEF Tanker	6	27.5	2,190	0.4053	888	5.17%	1.42
Ammonia Tanker	110	27.5	40,150	0.4053	16,273	94.83%	26.08
				Total VMT	17,160		
				Average Vehicle Weight (tons) - W			27.50

Site Constants

Value Name	Symbol	Value	Units	Source
Emission Factor	E	—	g/VMT	Calculated
Particle Size Multiplier	k for PM	5.24	g/VMT	AP-42 Table 13.2.1-1, January 2011
Particle Size Multiplier	k for PM10	1.00	g/VMT	AP-42 Table 13.2.1-1, January 2011
Particle Size Multiplier	k for PM2.5	0.25	g/VMT	AP-42 Table 13.2.1-1, January 2011
Silt Loading	sL	2.35	g/m^2	Estimated by IDEM (Higher than AP-42 default)
Days >0.01" of rain	P	119	days	AP-42, Figure 13.2.1-2, January 2011
Mean Vehicle Weight	W	27.50	tons	Calculated above

Emission Factor Calculations

E = [k * (sL)^0.91 * (W)^1.02] * [1 - P/(4 * N)] AP-42, Chapter 13.2.1-5, January 2011, Eq. 2

E for PM =	307.75	g/VMT	0.6785	lb/VMT
E for PM10 =	58.73	g/VMT	0.1295	lb/VMT
E for PM2.5 =	14.68	g/VMT	0.0324	lb/VMT

Potential to Emit

PM Emissions (TPY) = [Annual Average E for PM (lb/VMT) * Total VMT/yr * 1 ton / 2,000 lb]	5.82	TPY
PM10 Emissions (TPY) = [Annual Average E for PM10 (lb/VMT) * Total VMT/yr * 1 ton / 2,000 lb]	1.11	TPY
PM2.5 Emissions (TPY) = [Annual Average E for PM2.5 (lb/VMT) * Total VMT/yr * 1 ton / 2,000 lb]	0.28	TPY

Limited Potential to Emit

Control Efficiency 90.00%

Limited PM Emissions (TPY) = Potential to Emit PM * (1 - Control Efficiency)	0.58	TPY
Limited PM10 Emissions (TPY) = Potential to Emit PM10 * (1 - Control Efficiency)	0.11	TPY
Limited PM2.5 Emissions (TPY) = Potential to Emit PM2.5 * (1 - Control Efficiency)	0.03	TPY

Indiana Department of Environmental Management
Office of Air Quality

Appendix B to the Technical Support Document (TSD)
BACT Analysis

Source Background and Description

Source Name:	Ohio Valley Resources, LLC
Source Location:	300-400 East CR 350 North, Rockport, Indiana 47635
County:	Spencer
SIC Code:	2873
Permit No.:	T 147-32322-00062
Permit Reviewer:	David Matousek

Proposed Construction

On September 17, 2012, Ohio Valley Resources LLC submitted an air permit application to the Indiana Department of Environmental Management (IDEM), Office of Air Quality (OAQ). The application proposed the construction of a greenfield ammonia and urea ammonium nitrate (UAN) fertilizer facility, referred to as the Spencer County Fertilizer Plant. This facility will be located in Spencer County, Indiana approximately three miles north of Rockport, Indiana. The facility will have a maximum capacity of 2,800 tons per day of anhydrous ammonia, 3,600 tons per day of UAN and 150 tons per day of diesel exhaust fluid (DEF) which is a blend of 32.5% urea and water. During normal operation, approximately 50% of the ammonia will be placed in storage with the ability to loadout as a final product and 50% will be used for UAN production. The facility can operate under an alternate scenario where only anhydrous ammonia is produced.

Requirement for Best Available Control Technology (BACT)

326 IAC 2-2 (Prevention of Significant Deterioration) requires a Best Available Technology (BACT) review to be performed on emission units, one of which exceeds the PSD threshold and others, which exceed the significant levels because the Ohio Valley Resources, LLC fertilizer plant is in one of 28 listed source categories and has the potential to emit of CO in excess of 100 tons per year and the potential to emit Greenhouse Gases (GHG) over 75,000 tons per year as CO_2e; for the potential to emit of VOC, NOx, PM, PM_{10} and $PM_{2.5}$ are more than 40, 40, 25, 10, and 2.5 respectively. BACT analyses have been performed for VOC, CO, NOx, GHG, PM, PM_{10} and $PM_{2.5}$.

Proposed Emission Units

326 IAC 2-2 (Prevention of Significant Deterioration) requires a BACT analysis for the following emission units:

(a) A reformer process for production of hydrogen and nitrogen syngas consisting of the following emission units and emission control devices:

  (1) One (1) primary reformer, identified as EU-003, approved for construction in 2013, with a maximum rated heat input capacity of 1,006.4 MMBtu/hr, using selective catalytic reduction for NO_x emissions control, equipped with NO_x CEMS, and exhausting to the ambient atmosphere through stack EP-003. [40 CFR 63, Subpart DDDDD]

  (2) One (1) CO_2 purification process, identified as EU-004, with a maximum rated CO_2 production of 3,570 ton per day, approved for construction in 2013, and exhausting to the ambient atmosphere through stack EP-004.
  [40 CFR 63, Subpart FFFF]

(3) One (1) front end process flare for combusting intermittent process gas emissions from maintenance, startup, shutdown, and malfunctions, identified as EU-007, with a pilot nominally rated at 0.253 MMBtu/hr, approved for construction in 2013, utilizing proper flare design and operation minimization practices, and exhausting to the ambient atmosphere through the emission point EP-007.

(b) An ammonia unit with a maximum throughput capacity of 2,800 ton/day of ammonia consisting of the following emission units and emission control devices:

(1) One (1) ammonia catalyst startup heater, identified as EU-010, approved for construction in 2013, with a maximum rated heat input capacity of 106.3 MMBtu/hr, utilizing no control devices, and exhausting to the ambient atmosphere through stack EP-010. [40 CFR 63, Subpart DDDDD]

(2) One (1) back end ammonia process vent flare for combusting intermittent process gas emissions from maintenance, startup, shutdown, and malfunctions, identified as EU-006, approved for construction in 2013, with pilot capacity of 0.253 MMBtu per hour, utilizing proper flare design and operation minimization practices, and exhausting to the ambient atmosphere through emission point EP-006.

(3) One (1) ammonia storage flare, identified as EU-005, approved for construction in 2013, with pilot capacity of 0.126 MMBtu per hour, utilizing proper flare design and operation minimization practices, and exhausting to the ambient atmosphere through emission point EP-005.

(c) Two (2) urea ammonium nitrate (UAN) plants, including the production of urea, nitric acid, ammonium nitrate, and diesel exhaust fluid (DEF), consisting of the following emission units and emission control devices:

(1) Two (2) nitric acid units, identified as EU-001A and EU-001B, with a maximum throughput capacity of 630 ton/day of 100% nitric acid each, approved for construction in 2013, equipped with selective catalytic reduction for NO_x control, catalytic decomposition for N_2O control, and a NO_x CEMS, and exhausting to the ambient atmosphere through tailgas stacks EP-001A and EP-001B.
[40 CFR 60, Subpart Ga]

(2) Two (2) nitric acid storage tanks, identified as EU-022A and EU-022B, approved for construction in 2013, with a maximum throughput of 1,105 ton/day of 57% nitric acid each, and exhausting to the ambient atmosphere through the UAN process vent stacks EP-002A and EP-002B.

(3) Two (2) ammonium nitrate (AN) plants, identified as EU-002A and EU-002B, approved for construction in 2013, with a maximum throughput capacity of 798 ton/day of ammonium nitrate each, utilizing a scrubber with particulate demister for particulate matter control, and exhausting to the ambient atmosphere through stacks EP-002A and EP-002B. [40 CFR 60, Subpart VVa]

(4) Two (2) UAN Storage Tanks, identified as EU-012A and EU-012B, approved for construction in 2013, with a maximum rated capacity of 30,000 tons each, and exhausting to the ambient atmosphere through vents EP-012A and EP-012B.
[40 CFR 60, Subpart VVa]

(5) Three (3) UAN Day Tanks, identified as EU-020A, EU-020B, and EU-020C, approved for construction in 2013, with a maximum rated capacity of 750 tons each, and exhausting to the ambient atmosphere through vents EP-020A, EP-020B, and EP-020C. [40 CFR 60, Subpart VVa]

(6) Two (2) UAN loadout facilities (one (1) truck and one (1) for rail), identified as EU-024A and EU-024B, approved for construction in 2013, and exhausting to the ambient atmosphere as fugitive emission sources EP-024A and EP-024B.
[40 CFR 60, Subpart VVa]

(7) One (1) UAN plant vent flare for combusting intermittent process gas emissions from maintenance, startup, shutdown, and malfunctions, identified as EU-017, approved for construction in 2013, with a pilot capacity of 0.189 MMBtu per hour, utilizing proper flare design and operation minimization practices, and exhausting to the ambient atmosphere through emission point EP-017.
[40 CFR 60, Subpart VVa]

(8) One (1) DEF tank, identified as EU-021, approved for construction in 2013, with capacity of 100 tons, and exhausting to the ambient atmosphere through vent EP-021.
[40 CFR 60, Subpart VVa]

(9) One (1) DEF truck loadout facility, identified as EU-025, approved for construction in 2013, and exhausting to the ambient atmosphere as fugitive emission source EP-025.
[40 CFR 60, Subpart VVa]

(d) Four (4) natural gas-fired boilers, identified as EU-011A, EU-011B, EU-011C, and EU-011D, approved for construction in 2013, with a maximum rated heat input capacity of 218 MMBtu/hr each, using ultra low NO_x burners and flue gas recirculation for NO_x emissions control, equipped with NO_x CEMS, and exhausting to the ambient atmosphere through stacks EP-011A, EP-011B, EP-011C, and EP-011D. [40 CFR 60, Subpart Db]
[40 CFR 63, Subpart DDDDD]

(e) One (1) diesel-fired emergency generator, identified as EU-009, approved for construction in 2013, with a maximum rated capacity of 4,690 horsepower, utilizing no control devices, and exhausting to the ambient atmosphere through stack EP-009.
[40 CFR 60, Subpart IIII] [40 CFR 63, Subpart ZZZZ]

(f) Fugitive NO_x, VOC, and GHG Emissions from Equipment Leaks
[326 IAC 2-2] [40 CFR 60, Subpart VVa]

(g) Paved roadways and parking lots with public access. [326 IAC 6-4] [326 IAC 2-2]

(h) One (1) diesel-fired emergency firewater pump, identified as EU-016, approved for construction in 2013, with a maximum rated capacity of 481 horsepower, utilizing no control devices, and exhausting to the ambient atmosphere through stack EP-016.
[40 CFR 60, Subpart IIII] [40 CFR 63, Subpart ZZZZ] [326 IAC 2-2]

(i) Two (2) cooling towers, with a total of fourteen (14) cells, identified as EU-008A through EU-008H and EU-019A through EU-019F, approved for construction in 2013, with a combined maximum rated capacity of 179,720 gallons per minute, utilizing high efficiency drift eliminators for particulate matter control, and exhausting to the ambient atmosphere through cells EP-008A through EP-008H and EP-019A through EP-019F. [326 IAC 2-2]

(j) Fuel dispensing activities, including the gasoline fuel transfer dispensing operation, identified as EU-015, approved for construction in 2013, handling less than or equal to one thousand three hundred (1,300) gallons per day and filling storage tanks having a capacity equal to or less than ten thousand five hundred (10,500) gallons. Such storage tanks may be in a fixed location or on mobile equipment. [326 IAC 2-2]

(k) Fuel dispensing activities, including a petroleum fuel other than gasoline dispensing facility, identified as EU-014, approved for construction in 2013, having a storage tank capacity less than or equal to ten thousand five hundred (10,500) gallons, and dispensing three thousand five hundred (3,500) gallons per day or less. [326 IAC 2-2]

Summary of the Best Available Control Technology (BACT) Process

BACT is an emission limitation based on the maximum degree of pollution reduction of emissions, which is achievable on a case-by-case basis. BACT analysis takes into account the energy, environmental, and economic impacts on the source. These reductions may be determined through the application of available control techniques, process design, work practices, and operational limitations. There will still be air pollution from this project; however, Ohio Valley Resources, LLC will be required to demonstrate that the emissions will be reduced to the maximum extent.

Federal EPA generally requires an evaluation that follows a “top down” process. In this approach, the applicant identifies the best controlled similar source on the basis of controls required by regulation or permit, or controls achieved in practice. The highest level of control is then evaluated for technical feasibility. IDEM evaluates BACT based on a "top down" approach.

The five (5) basic steps of a top-down BACT analysis used by the Office of Air Quality (OAQ) to make BACT determinations are listed below:

Step 1: Identify Potential Control Technologies

The first step is to identify potentially “available” control options for each emission unit and for each pollutant under review. Available options should consist of a comprehensive list of those technologies with a potentially practical application to the emissions unit in question. The list should include lowest achievable emission rate (LAER) technologies and controls applied to similar source categories.

Step 2: Eliminate Technically Infeasible Options

The second step is to eliminate technically infeasible options from further consideration. To be considered feasible, a technology must be both available and applicable. It is important in this step that any presentation of a technical argument for eliminating a technology from further consideration be clearly documented based on physical, chemical, engineering, and source specific factors related to safe and successful use of the controls. Innovative control means a control that has not been demonstrated in a commercial application on similar units. Innovative controls are normally given a waiver from the BACT requirements due to the uncertainty of actual control efficiency. IDEM evaluates any innovative controls if proposed by the source. Ohio Valley Resources, LLC has not submitted any innovative control technology. Only available and proven control technologies are evaluated. A control technology is considered available when there are sufficient data indicating that the technology results in a reduction in emissions of regulated pollutants.

Step 3: Rank the Remaining Control Technologies by Control Effectiveness

The third step is to rank the technologies not eliminated in Step 2 in order of descending control effectiveness for each pollutant of concern. The ranked alternatives are reviewed in terms of control effectiveness (percent pollutant removed). If the highest ranked technology is proposed as BACT, it is not necessary to perform any further technical or economic evaluation, except, for the environmental analyses and any more stringent limits established from other RBLC Permits.

Step 4: Evaluate the Most Effective Controls and Document the Results

The fourth step begins with an evaluation of the remaining technologies under consideration for each pollutant of concern in regards to energy, environmental, and economic impacts for determining a final control technology. The highest ranked alternative is evaluated for environmental, energy and economic impacts specific to the proposed modification. If the analysis determines that the highest ranked control is not appropriate as BACT, due to any of the energy, environmental, and economic impacts, then the next most effective control is evaluated.

The evaluation continues until a technology under consideration cannot be eliminated based on adverse energy, environmental, or economic impacts. If the highest ranked technology is proposed as BACT, it is not necessary to perform any further economic or environmental analysis. In no case can the selected BACT be less stringent than any New Source Performance Standard (NSPS), National Emission Standards for Hazardous Air Pollutants (NESHAP) or Reasonably Available Control Technologies (RACT) standard or emission limit.

Step 5: Select BACT

The fifth and final step is to select as BACT the most effective of the remaining technologies under consideration for each pollutant of concern. For the technologies determined to be feasible, there may be several different limits that have been set as BACT for the same control technology. The permitting agency has to choose the most stringent limit as BACT unless the applicant demonstrates in a convincing manner why that limit is not feasible. The final BACT determination would be the technology with the most stringent corresponding limit that is economically feasible. BACT must, at a minimum, be no less stringent than the level of control required by any applicable New Source Performance Standard (NSPS) and National Emissions Standard for Hazardous Air Pollutants (NESHAP) or state regulatory standards applicable to the emission units included in the permits.

Particulate (PM, PM_{10} and $PM_{2.5}$) BACT Determinations

(1) Particulate BACT - Primary Reformer (EU-003)

Step 1: Identify Potential Control Technologies

Emissions of particulate matter (PM), particulate matter with an aerodynamic diameter less than or equal to ten (10) micrometers (PM_{10}) and particulate matter with an aerodynamic diameter less than or equal to 2.5 micrometers ($PM_{2.5}$) are generally controlled with add-on control equipment designed to capture the emissions prior to the time they are exhausted to the atmosphere. The available technologies include:

(1) Cyclones;

(2) Wet Scrubbers;

(3) Electrostatic Precipitators (ESP); and

(4) Fabric Filter Dust Collectors (Baghouses).

The choice of which technology is most appropriate for a specific application depends upon several factors, including particle size to be collected, particle loading, stack gas flow rate, stack gas physical characteristics (e.g., temperature, moisture content, presence of reactive materials), and desired collection efficiency. If add-on control technology is not feasible, an alternate method of control may be implemented.

Alternate Control Methods:

One or more alternate methods of control may be considered when they are more cost-effective than add-on controls or when add-on control technology may not be feasible. For this source, the following alternate control methods were evaluated:

(1) Fuel Specifications – Clean Burning Fuel; and

(2) Good Combustion Practices.

Step 2: Eliminate Technically Infeasible Options

(a) **Cyclone**
Cyclones mechanically separate particulates through centrifugal and inertial forces, by forcing a particulate-laden stream to change direction, with the particles falling out as they hit the walls of a typically cone-shaped cyclone. Cyclones are used in applications with waste gas pollutant loadings of 1 – 100 gr/scf. Since the concentration of PM/PM_{10} in the Primary Reformer (EU-003) exhaust is very low (~0.005 gr/cf), a cyclone is not a technically feasible control option for the Primary Reformer (EU-003) at this source.

(b) **Wet Scrubber**
Wet scrubbers use a flow or spray of liquid in a tower to contact particulate-laden exhaust gas stream and absorb particles in the liquid, either physically, or in combination with a chemical reaction. Wet scrubbing towers are not typically used for fine particulate applications because high liquid to gas ratios are required, and typical pollutant loadings are 250-10,000 ppmv. (EPA-452/F-03-016, Air Pollution Control Technology Fact Sheet for Spray Tower Wet Scrubber). For fine particulate control, a venturi scrubber can be used but typical loadings for such a scrubber are 0.1-50 grains/scf (EPA-452/F-03-017, Air Pollution Control Technology Fact Sheet for Venturi Scrubber). Since the concentration of this stream (0.005 gr/cf) is already orders of magnitude lower, a wet scrubber would not achieve any appreciable particulate control. A wet scrubber is not a technically feasible control option for the Primary Reformer (EU-003) at this source.

(c) **Electrostatic Precipitators**
An electrostatic precipitator is a particulate control device that uses electrical forces to move particles entrained in an exhaust stream onto collector plates. The design inlet pollutant loadings for an ESP typically range from 0.5 – 50 gr/ft^3. Since the pollutant concentration of the Primary Reformer (EU-003) exhaust is already orders of magnitude lower, an ESP would not achieve any appreciable additional particulate control. An electrostatic precipitator is not a technically feasible control option for the Primary Reformer (EU-003) at this source.

(d) **Fabric Filter Dust Collectors (Baghouse)**
A baghouse uses a fabric filter to capture particles as the gas stream flows through the fabric. A typical baghouse outlet design concentration is 0.005 gr/cf and relies, in part on the filtering properties of a layer of particulate that first accumulates on the filter media. Since the emission concentration from this source is already extremely low, a baghouse would not be effective in providing further particulate control. Therefore, a baghouse is rejected as an ineffective control device for this source. A fabric filter dust collector is not a technically feasible control option for the Primary Reformer (EU-003) at this source.

(e) **Fuel Specifications – Clean Burning Fuel**
Clean burning natural gas has a very low potential for generating PM, PM_{10} and $PM_{2.5}$ emissions. Fuel specifications are a technically feasible control option for the Primary Reformer (EU-003) at this source.

(f) **Good Combustion Practices / Combustion Controls**
Good combustion practices as well as operation and maintenance of the Primary Reformer to keep it in good working order per the manufacturer's specifications will minimize PM, PM_{10} and $PM_{2.5}$ emissions. Good combustion practices and combustion controls are a technically feasible control option for the Primary Reformer (EU-003) at this source.

Step 3: Rank the Remaining Control Technologies by Control Effectiveness

The following measures have been identified for control of PM, PM_{10} and $PM_{2.5}$ resulting from the operation of the Primary Reformer (EU-003).

(1) Fuel Specifications – Clean Burning Fuel

(2) Good Combustion Practices

The applicant has accepted top BACT.

Step 4: Evaluate the Most Effective Controls and Document the Results

The following table lists the proposed PM, PM_{10} and $PM_{2.5}$ BACT determinations for similar sources. All data in the table is based on the information obtained from the permit application submitted by Ohio Valley Resources, LLC, the U.S. EPA RACT/BACT/LAER Clearinghouse (RBLC), Indiana issued permits, and electronic versions of permits available at the websites of other permitting agencies.

RACT/BACT/LEAR CLEARINGHOUSE DATA
Primary Reformer (EU-003) – Particulate (PM, PM_{10} and $PM_{2.5}$)

RBLC ID	Facility	Issued Date	Process Description	Capacity	Limitation	Control Method
IA-0105	Iowa Fertilizer Company	10/26/12	Syngas Primary Reformer	1.13 MMCF/hr natural gas	0.0024 lb/MMBtu 11.9 TPY	None
147-32322-00062	**Ohio Valley Resources**	**Proposed**	**Methane Primary Reformer**	**1,006.40 MMBtu/hr**	**1.9, 7.6 and 7.6 lb/MMCF, respectively, 3 hr avg.**	**Good Combustion Practices, Fuel Usage Limit**
LA-0211	Garyville Refinery	12/27/06	Hydrogen Reformer Furnace Flue Gas	1,412 MMBtu/hr	0.0075 lb/MMBtu	Proper Design, Operation, and Good Engineering Practices
NM-0050	Artesia Refinery	12/14/07	Steam Methane Reformer Heater	337 MMBtu/hr	0.0075 lb/MMBtu 2.52 lb/hr	Combust Gaseous Fuel Only
OK-0134	Pryor Plant Chemical Company	02/23/09	Reformer EUID #101, EUG#1	700 ton ammonia/day	1.26 lb/hr	None, permit indicates 225 MMBtu/hr using 7.6 lb/MMCF
OK-0135	Pryor Plant Chemical Company	02/23/09	Primary Reformer	700 ton ammonia/day	1.26 lb/hr	None, permit indicates 225 MMBtu/hr using 7.6 lb/MMCF

RBLC Review

PM, PM_{10} and $PM_{2.5}$ emissions from the Primary Reformer (EU-003) result from the combustion of natural gas. The potential to emit $PM/PM_{10}/PM_{2.5}$ from the reformer is estimated to be 8.21 tons/yr for PM and 32.84 tons/yr for PM_{10} and $PM_{2.5}$ with the particulate concentration in the exhaust of 0.005 grains/dscf or less. This low concentration renders add-on controls infeasible. Generally, add-on controls for PM, PM_{10} and $PM_{2.5}$ are not applied to a combustion source firing only clean gaseous fuel. This is because PM, PM_{10} and $PM_{2.5}$ emissions are already extremely low (~0.005 gr/dscf), and are below levels that would be feasible for effective use of conventional particulate control devices.

A search of the USEPA's RACT/BACT/LAER Clearinghouse database did not indicate any source is using add-on control technologies for PM/ $PM_{10}/PM_{2.5}$ emissions from natural gas-fired reformers or furnaces. The combustion of clean gaseous fuel is inherently low in particulate (PM, PM_{10} and $PM_{2.5}$) emissions and add-on controls are not feasible. IDEM, OAQ anticipates the lowest uncontrolled emission rate for PM will be 1.9 lb/MMCF and 7.6 lb/MMCF for $PM_{10}/PM_{2.5}$ from a natural gas fired reformer.

Applicant Proposal
The applicant proposed the following as BACT:

(a) The use of good combustion practices; and

(c) A BACT limit for PM, PM_{10} and $PM_{2.5}$ of 0.0075 lb/MMBtu.

The applicant's proposal is consistent with a majority of the entries in the RBLC for PM, PM_{10}, and $PM_{2.5}$. These emission limits are based on the uncontrolled emission factors found in AP-42. A permit for the Iowa Fertilizer Company (IFC) was recently issued by the Iowa Department of Natural Resources (IDNR) with a proposed emission rate of 0.0024 lb/MMBtu. The IFC permit limit is lower than the limit proposed by the applicant. IDNR established this limit based on two stack tests at a single boiler. IDEM believes the emission rate proposed by the applicant is appropriate for BACT based on the following factors:

1. Add-on emission controls have been demonstrated to be infeasible or not cost-effective.

2. The majority of the entries in the RBLC for uncontrolled natural gas-fired combustion units are derived from the AP-42 emission factors, which are based on stack tests on a large sample size of natural gas-burning facilities.

3. The emission limits in the IFC permit set by IDNR are based on two stack tests at the same facility – a 429 MMBtu/hr auxiliary boiler located at the Walter Scott Generating Plant in Council Bluffs, Iowa. These test results do not establish BACT for the Primary Reformer at Ohio Valley Resources.

    a. Two stack test results at the same facility are not representative of the emission rate achievable at a large range of natural gas facility types and sizes. The AP-42 emission factor for natural gas combustion is a better reflection of what is achievable for an uncontrolled natural gas unit.

    b. IFC's facilities have not yet begun operations, and consequently the achievability of the IFC BACT limits have not been demonstrated in practice.

IDEM is proposing an emission rate of 0.0019 lb/MMBtu for PM and 0.0075 lb/MMBtu which is equivalent to 1.9, 7.6 and 7.6 lb/MMCF, respectively.

Step 5: Select BACT
IDEM has established the following as BACT for PM, PM_{10} and $PM_{2.5}$ for Primary Reformer (EU-003):

(1) PM, PM_{10}, and $PM_{2.5}$ emissions from the operation of Primary Reformer (EU-003) shall be controlled through the use of good combustion practices.

(2) The Primary Reformer (EU-003) shall combust natural gas and/or process off gas streams.

(3) PM, PM_{10} and $PM_{2.5}$ emissions from the operation of Primary Reformer (EU-003) shall not exceed 1.9, 7.6 and 7.6 lb/MMCF respectively, based on a three-hour average. PM includes filterable particulate matter, while, PM_{10} and $PM_{2.5}$ include both filterable and condensible particulate matter.

(2) Particulate BACT – Front End Process Flare (EU-007)

Step 1: Identify Potential Control Technologies

In evaluating BACT for flare PM, PM_{10} and $PM_{2.5}$ emissions, there are limited process and/or add-on control alternatives available. Based on a review of the RBLC, as well as other permits and sources, the list of potential control and process alternatives includes the following:

(1) Flare design and good combustion practices;

(2) Process flaring minimization practices; and

(3) Flare gas recovery.

Add-on PM, PM_{10} and $PM_{2.5}$ controls that may be used on other types of sources, such as cyclones, baghouses, ESPs, or scrubbers are not utilized on flares.

Step 2: Eliminate Technically Infeasible Options

Each option listed above is evaluated as follows:

(a) **Flare design and good combustion practices**

Flare design and operation are key elements in the emissions performance of flares. The Front End Process Flare (EU-007) will be designed and operated to be smoke-free, thereby minimizing emissions. The fact that all gases vented to the flare will be low molecular weight helps assure low particulate creation. The use of flare design and good combustion practices is a technically feasible control option for the Front End Process Flare (EU-007) at this source.

(b) **Process flaring minimization practices**

To the extent actions can be taken to minimize the volume of gas going to the flare, emissions of PM, PM_{10} and $PM_{2.5}$ will be less. The use of process flaring minimizing practices is a technically feasible control option for the Front End Process Flare (EU-007) at this source.

(c) **Flare gas recovery**

Flare gas recovery has been implemented at certain types of facilities that produce and use internally generated fuel gas streams such as petroleum refineries. However, flare gas recovery for this facility is not feasible for the following reasons.

(1) First, unlike a refinery's nearly continuous supply of flared gases, flaring at the proposed Ohio Valley Resources, LLC facility will be an infrequent occurrence.

(2) Another difference is that the Ohio Valley Resources, LLC flaring events, the flared material may not be suitable for use as a fuel gas.

The use of a flare gas recovery system is not a technically feasible control option for the Front End Process Flare (EU-007) at this source.

Step 3: Rank the Remaining Control Technologies by Control Effectiveness

The remaining technically feasible control technologies for flares are:

(1) Proper flare design and good combustion practices; and

(2) Process flaring minimization practices.

Both controls listed above are proposed to be implemented by the source; therefore, no ranking of control technologies is needed.

Step 4: Evaluate the Most Effective Controls and Document the Results

The following table lists the proposed PM, PM_{10} and $PM_{2.5}$ BACT determinations for similar emission units. All data in the table is based on the information obtained from the permit application submitted by Ohio Valley Resources, LLC, the U.S. EPA RACT/BACT/LAER Clearinghouse (RBLC), Indiana issued permits, and electronic versions of permits available at the websites of other permitting agencies.

RACT/BACT/LEAR CLEARINGHOUSE DATA

Front End Process Flare (EU-007) – Particulate (PM, PM_{10} and $PM_{2.5}$)

RBLC ID	Facility	Issued Date	Process Description	Capacity	Limitation	Control Method
T147-32322-00062	**Ohio Valley Resources, LLC**	**Proposed**	**Flare EU-007**	**0.253 MMBtu/hr**	**PM–0.0019 lb/MMBtu** **$PM_{10/2.5}$-0.0075 lb/MMBtu**	**Proper design and operation, low carbon fuel, flare minimization practices**
ID-0017	Southeast Idaho Energy, LLC	02/10/09	Process Flare SRC21	1.5 MMBtu/hr pilot	No emissions from the process, no limit on pilot emissions	None
IA-0105	Iowa Fertilizer Company	10/26/12	Ammonia Flare	0.40 MMBtu/hr	None	Work Practice, Good Combustion Practices

RBLC Review

The potential to emit $PM/PM_{10}/PM_{2.5}$ of this flare is 0.002 tons per year for PM and 0.01 tons per year for PM_{10} and $PM_{2.5}$. A review of the $PM/PM_{10}/PM_{2.5}$ control strategies from the RBLC indicates no add-on controls are used. The most recent entry indicates PM, PM_{10} and $PM_{2.5}$ are normally controlled by work practice standards, good design and good combustion practices. IDEM, OAQ believes the lowest emission rate from a natural gas-fired flare for PM is 1.9 lb/MMCF and 7.6 lb/MMCF for PM_{10} and $PM_{2.5}$, using the AP-42 emission factor. There are additional entries for natural gas flares in the RBLC; however, these entries are for flares using landfill gas or are flares in continuous use. This flare normally does not control emissions. It is used during process venting operations that occur during process upsets, startups and shutdowns.

Applicant Proposal

The applicant proposed:

(a) Proper flare design and good combustion practices;

(b) The use of natural gas;

(c) The use of flare minimization practices; and

(d) Venting for Startup, Shutdown and Malfunction shall not exceed 336 hours per twelve consecutive month period with compliance determined at the end of each month.

The applicant's proposal is consistent with the RBLC entries shown in the table above for emergency flares that are not in continuous service. The source requested a limit on the number of hours the flare can be used to flare process gases during startup, shutdown and malfunction to ensure emissions from this source do not cause an increment violation or a violation of the National Ambient Air Quality Standard for PM, PM_{10} and $PM_{2.5}$. IDEM, OAQ is adding pounds per hour limits for PM, PM_{10} and $PM_{2.5}$ based on the standard emission rates in AP-42, Chapter 1.4 and a heating value of 1,020 MMBtu/MMCF.

Step 5: Select BACT

IDEM has established the following as BACT for PM, PM_{10} and $PM_{2.5}$ for Front End Process Flare (EU-007):

(1) In order to control PM, PM_{10} and $PM_{2.5}$ emissions, the pilot and purge gas fuels used in the flare shall be natural gas.

(2) Venting in the Front End Process Flare (EU-007) shall not exceed 336 hours per twelve consecutive month period with compliance determined at the end of each month.

(3) Comply with the following flare minimization practices to reduce emissions during startups, shutdowns, and other flaring events:

(A) Flare Use Minimization: Process syngas streams to flare EU-007 shall not contain ammonia. During the startup of the sequential reformer, only one process stream at a time shall be sent to the flare to the extent practicable. Maximize the use of process syngas during the startup of the Ammonia Unit;

(B) The Permittee shall train all operators responsible for the day-to-day operation of the flares on the flare minimization practices and the specific procedures to follow during process startup, shutdown, and other flaring events; and

(C) The Permittee shall investigate the "root cause" of malfunction events that cause flaring events other than at startup or shutdown. This root cause analysis shall identify the apparent cause of unanticipated flaring event and shall recommend additional preventive measures that will minimize the chance of a repeat event. The Permittee shall implement the recommended preventive measures.

(4) PM, PM_{10} and $PM_{2.5}$ emissions shall be controlled by use of the following practices:

(A) Flares shall be designed for and operated with no visible emissions, except for periods not to exceed 5 minutes during any two consecutive hours;

(B) Flares shall be operated with a flame present at all times; and

(C) Flares shall be continuously monitored to assure the presence of a pilot flame with a thermocouple, infrared monitor, or other approved device.

(5) PM emissions shall not exceed 0.0019 lb/MMBtu, based on a three-hour average.

(6) PM_{10} and $PM_{2.5}$ emissions shall not exceed 0.0075 lb/MMBtu, based on a three-hour average.

(3) Particulate BACT – Ammonia Catalyst Startup Heater (EU-010)

Step 1: Identify Potential Control Technologies

Emissions of particulate matter (PM), particulate matter with an aerodynamic diameter less than or equal to ten (10) micrometers (PM_{10}) and particulate matter with an aerodynamic diameter less than or equal to 2.5 micrometers ($PM_{2.5}$) are generally controlled with add-on control equipment designed to capture the emissions prior to the time they are exhausted to the atmosphere. The available technologies include:

(1) Cyclones;

(2) Wet Scrubbers;

(3) Electrostatic Precipitators (ESP); and

(4) Fabric Filter Dust Collectors (Baghouses).

The choice of which technology is most appropriate for a specific application depends upon several factors, including particle size to be collected, particle loading, stack gas flow rate, stack gas physical characteristics (e.g., temperature, moisture content, presence of reactive materials), and desired collection efficiency. If add-on control technology is not feasible, an alternate method of control may be implemented.

Alternate Control Methods:

One or more alternate methods of control may be considered when they are more cost-effective than add-on controls or when add-on control technology may not be feasible. For this source, the following alternate control methods were evaluated:

(1) Fuel Specifications – Clean Burning Fuel; and

(2) Good Combustion Practices.

Step 2: Eliminate Technically Infeasible Options

(a) **Cyclone**

Cyclones mechanically separate particulates through centrifugal and inertial forces, by forcing a particulate-laden stream to change direction, with the particles falling out as they hit the walls of a typically cone-shaped cyclone. Cyclones are used in applications with waste gas pollutant loadings of 1 – 100 gr/scf. Since the concentration of $PM/PM_{10}/PM_{2.5}$ in the Ammonia Catalyst Startup Heater (EU-010) exhaust is very low (~0.005 gr/cf), a cyclone would not be effective at this source. The cyclone is not a technically feasible control option for the Ammonia Catalyst Startup Heater (EU-010) at this source.

(b) **Wet Scrubber**

Wet scrubbers use a flow or spray of liquid in a tower to contact particulate-laden exhaust gas stream and absorb particles in the liquid, either physically, or in combination with a chemical reaction. Wet scrubbing towers are not typically used for fine particulate applications because high liquid to gas ratios are required, and typical pollutant loadings are 250-10,000 ppmv. (EPA-452/F-03-016, Air Pollution Control Technology Fact Sheet for Spray Tower Wet Scrubber). For fine particulate control, a venturi scrubber can be used but typical loadings for such a scrubber are 0.1-50 grains/scf (EPA-452/F-03-017, Air Pollution Control Technology Fact Sheet for Venturi Scrubber). Since the concentration of this stream (0.005 gr/cf) is already orders of magnitude lower, a wet scrubber would not achieve any appreciable particulate control. The wet scrubber is not a technically feasible control option for the Ammonia Catalyst Startup Heater (EU-010) at this source.

(c) **Electrostatic Precipitators**
An electrostatic precipitator is a particulate control device that uses electrical forces to move particles entrained in an exhaust stream onto collector plates. The design inlet pollutant loadings for an ESP typically range from 0.5 – 50 gr/ft^3. Since the pollutant concentration of the Ammonia Catalyst Startup Heater (EU-010) exhaust is already orders of magnitude lower, an ESP would not achieve any appreciable additional particulate control. The electrostatic precipitator is not a technically feasible control option for the Ammonia Catalyst Startup Heater (EU-010) at this source.

(d) **Fabric Filter Dust Collectors (Baghouse)**
A baghouse uses a fabric filter to capture particles as the gas stream flows through the fabric. A typical baghouse outlet design concentration is 0.005 gr/cf and relies, in part on the filtering properties of a layer of particulate that first accumulates on the filter media. Since the emission concentration from this source is already extremely low, a baghouse would not be effective in providing further particulate control. Therefore, a baghouse is rejected as an ineffective and not technically feasible control device for the Ammonia Catalyst Startup Heater (EU-010).

(e) **Fuel Specifications – Clean Burning Fuel**
Clean burning natural gas has a very low potential for generating PM, PM_{10} and $PM_{2.5}$ emissions. Fuel specifications are a technically feasible control option for the Ammonia Catalyst Startup Heater (EU-010) at this source.

(f) **Good Combustion Practices / Combustion Controls**
Good combustion practices as well as operation and maintenance of the Ammonia Catalyst Startup Heater (EU-010) to keep it in good working order per the manufacturer's specifications will minimize PM, PM_{10} and $PM_{2.5}$ emissions. Good combustion practices are a technically feasible control option for the Ammonia Catalyst Startup Heater (EU-010) at this source.

<u>Step 3: Rank the Remaining Control Technologies by Control Effectiveness</u>

The following measures have been identified for control of PM, PM_{10} and $PM_{2.5}$ resulting from the operation of the Ammonia Catalyst Startup Heater (EU-010).

(1) Fuel Specifications – Clean Burning Fuel

(2) Good Combustion Practices / Combustion Controls

The applicant selected all control measures; therefore, a ranking is not required.

<u>Step 4: Evaluate the Most Effective Controls and Document the Results</u>

The following table lists the proposed PM, PM_{10} and $PM_{2.5}$ BACT determinations for similar emission units. All data in the table is based on the information obtained from the permit application submitted by Ohio Valley Resources, LLC, the U.S. EPA RACT/BACT/LAER Clearinghouse (RBLC), Indiana issued permits, and electronic versions of permits available at the websites of other permitting agencies.

RACT/BACT/LEAR CLEARINGHOUSE DATA Ammonia Catalyst Start Up Heater (EU-010) – Particulate (PM, PM_{10} and $PM_{2.5}$)						
RBLC ID	**Facility**	**Issued Date**	**Process Description**	**Capacity**	**Limitation**	**Control Method**
IA-0105	Iowa Fertilizer Company	10/26/12	Startup Heater	110.12 MMBtu/hr	0.0024 lb/MMBtu 0.01 TPY	Good combustion practices
T 147-32322-00062	**Ohio Valley Resources, LLC**	**Proposed**	**Ammonia Catalyst Heater (EU-010)**	**106.3 MMBtu/hr**	**1.9, 7.6, 7.6 lb/MMCF, respectively, 3 hr avg.**	**Good design and combustion, use low carbon fuel, limit use**
LA-0231	Lake Charles Cogeneration	06/22/09	Methanator Startup Heater	56.90 MMBtu/hr	0.42 lb/hr	None, 0.0075 lb/MMBtu estimated by IDEM
TN-0153	Williams Refining & Marketing	04/03/02	No. 2 N/S ECU Heaters	166.5 MMBtu/hr	0.005 lb/MMBtu (filterable)	None
TN-0153	Williams Refining & Marketing	04/03/02	WCR Heater	209.0 MMBtu/hr	0.005 lb/MMBtu (filterable)	None

RBLC Review

The PM, PM_{10} and $PM_{2.5}$ emissions from the Ammonia Catalyst Startup Heater (EU-010) result from the combustion of natural gas. The potential to emit PM/PM_{10}/$PM_{2.5}$ from the Ammonia Catalyst Startup Heater (EU-010) is estimated to be 0.87 TPY for PM and 3.47 tons/yr for PM_{10} and $PM_{2.5}$, with the particulate concentration in the exhaust of 0.005 grains/dscf or less. This low concentration renders add-on controls infeasible. Generally add-on controls for PM, PM_{10} and $PM_{2.5}$ are not applied to a combustion source firing only clean gaseous fuel. This is because the PM, PM_{10} and $PM_{2.5}$ emissions are already extremely low (~0.005 gr/dscf), and are below levels that would be feasible for effective use of conventional particulate control devices.

A search of the USEPA's RACT/BACT/LAER Clearinghouse database did not indicate control technologies for PM/ PM_{10}/$PM_{2.5}$ emissions from natural gas-fired heaters are used. The combustion of clean gaseous fuel is inherently low in particulate (PM, PM_{10} and $PM_{2.5}$) emissions and add-on controls are not feasible. IDEM, OAQ anticipates the lowest uncontrolled emission rate of a natural gas fired heater will be 7.6 lb/MMSCF for PM10 and PM2.5 and 1.9 lb/MMCF for PM. The Williams Refining & Marketing, LLC has an emission limit of 0.005 lb/MMBtu but only includes filterable PM_{10} and $PM_{2.5}$ only. When condensible emissions are considered, the emission rate is identical to the Ohio Valley Resources, LLC proposal. The startup heater in the Iowa Fertilizer Company permit has the lowest emission rate for a natural gas-fired startup heater.

Applicant Proposal

The applicant proposed the following as BACT:

(a) The use of natural gas;

(b) PM, PM_{10} and $PM_{2.5}$ emissions from the Ammonia Catalyst Startup Heater (EU-010) not to exceed 0.0075 lb/MMBtu;

(c) Fuel usage not to exceed 20.84 MMCF per year; and

(d) Good heater design and good combustion practices.

The applicant's proposal is consistent with a majority of the entries in the RBLC for PM, PM_{10}, and $PM_{2.5}$. These emission limits are based on the uncontrolled emission factors found in AP-42. A permit for the Iowa Fertilizer Company (IFC) was recently issued by the Iowa Department of Natural Resources (IDNR) with a proposed emission rate of 0.0024 lb/MMBtu. The IFC permit limit is lower than the limit proposed by the applicant. IDNR established this limit based on two stack tests at a single boiler. IDEM believes the emission rate proposed by the applicant is appropriate for BACT based on the following factors:

1. Add-on emission controls have been demonstrated to be infeasible or not cost-effective.

2. The majority of the entries in the RBLC for uncontrolled natural gas-fired combustion units are derived from the AP-42 emission factors, which are based on stack tests on a large sample size of natural gas-burning facilities.

3. The emission limits in the IFC permit set by IDNR are based on two stack tests at the same facility – a 429 MMBtu/hr auxiliary boiler located at the Walter Scott Generating Plant in Council Bluffs, Iowa. These test results do not establish BACT for the Ammonia Catalyst Startup Heater at Ohio Valley Resources.

    a. Two stack test results at the same facility are not representative of the emission rate achievable at a large range of natural gas facility types and sizes. The AP-42 emission factor for natural gas combustion is a better reflection of what is achievable for an uncontrolled natural gas unit.

    b. IFC's facilities have not yet begun operations, and consequently the achievability of the IFC BACT limits have not been demonstrated in practice.

IDEM is proposing an emission rate of 0.0019 lb/MMBtu for PM and 0.0075 lb/MMBtu which is equivalent to 1.9, 7.6 and 7.6 lb/MMCF, respectively

Step 5: Select BACT
IDEM has established the following as BACT for PM, PM_{10} and $PM_{2.5}$ for Ammonia Catalyst Startup Heater (EU-010).

(1) In order to control PM, PM_{10} and $PM_{2.5}$, the Ammonia Catalyst Startup Heater (EU-010) shall combust natural gas.

(2) In order to control PM, PM_{10} and $PM_{2.5}$, the Ammonia Catalyst Startup Heater (EU-010) shall be controlled by good heater design and good combustion practices.

(3) Fuel usage in the Ammonia Catalyst Startup Heater (EU-010) shall not exceed 20.84 MMCF per twelve consecutive month period with compliance determined at the end of each month.

(4) PM, PM_{10} and $PM_{2.5}$ emissions from the Ammonia Catalyst Startup Heater (EU-010) shall not exceed 1.9, 7.6, and 7.6 lb/MMCF respectively, based on a three-hour average. PM includes filterable particulate matter, while, PM_{10} and $PM_{2.5}$ include both filterable and condensible particulate matter.

(4) Particulate BACT – Back End Ammonia Process Vent Flare (EU-006)

Step 1: Identify Potential Control Technologies

In evaluating BACT for flare PM, PM_{10} and $PM_{2.5}$ emissions, there are limited process and/or add-on control alternatives available. Based on a review of the RBLC, as well as other permits and sources, the list of potential control and process alternatives includes the following:

(1) Flare design and good combustion practices;

(2) Process flaring minimization practices; and

(3) Flare gas recovery.

Add-on PM, PM_{10} and $PM_{2.5}$ controls that may be used on other types of sources, such as cyclones, baghouses, ESPs, or scrubbers are not applicable to flares because the outlet exhaust of an elevated process flare is not enclosed or contained. Therefore, the emissions or flue gases cannot be routed to an add-on control device, and such add-on controls have not been utilized on flares.

Step 2: Eliminate Technically Infeasible Options

Each option listed above is evaluated as follows:

(a) **Flare design and good combustion practices**
Flare design and operation are key elements in the emissions performance of flares. The Back End Ammonia Process Vent Flare (EU-006) will be designed and operated to be smoke-free, thereby minimizing emissions. The fact that all gases vented to the flare will be low molecular weight helps assure low particulate creation. The use of flare design and good combustion practices is a technically feasible control option for the Back End Ammonia Process Vent Flare (EU-006) at this source.

(b) **Process flaring minimization practices**
To the extent actions can be taken to minimize the volume of gas going to the flare, emissions of PM, PM_{10} and $PM_{2.5}$ will be less. Flaring minimization practices are feasible and are evaluated in the analysis of BACT. The use of process flaring minimization practices is a technically feasible control option for the Back End Ammonia Process Vent Flare (EU-006) at this source.

(c) **Flare gas recovery**
Flare gas recovery has been implemented at certain types of facilities that produce and use internally generated fuel gas streams such as petroleum refineries. However, flare gas recovery for this facility is not feasible for the following reasons.

(1) First, unlike a refinery's nearly continuous supply of flared gases, flaring at the proposed Ohio Valley Resources, LLC facility will be an infrequent occurrence.

(2) Another difference is that the Ohio Valley Resources, LLC flaring events, the flared material may not be suitable for use as a fuel gas.

The use of a flare gas recovery system is not a technically feasible control option for the Back End Ammonia Process Vent Flare (EU-006) at this source.

Step 3: Rank the Remaining Control Technologies by Control Effectiveness

The remaining technically feasible control technologies for flares are:

(1) Proper flare design and good combustion practices;

(2) Process flaring minimization practices.

Both controls listed above are proposed to be implemented by the source, therefore, no ranking of control technologies is needed.

Step 4: Evaluate the Most Effective Controls and Document the Results

The following table lists the proposed PM, PM_{10} and $PM_{2.5}$ BACT determinations for similar emission units. All data in the table is based on the information obtained from the permit application submitted by Ohio Valley Resources, LLC, the U.S. EPA RACT/BACT/LAER Clearinghouse (RBLC), Indiana issued permits, and electronic versions of permits available at the websites of other permitting agencies.

RACT/BACT/LEAR CLEARINGHOUSE DATA
Back End Ammonia Process Vent Flare (EU-006) – Particulate (PM, PM_{10} and $PM_{2.5}$)

RBLC ID	Facility	Issued Date	Process Description	Capacity	Limitation	Control Method
T147-32322-00062	**Ohio Valley Resources, LLC**	**Proposed**	**Back End Ammonia Process Flare EU-006**	**0.253 MMBtu/hr**	**PM - 0.0019 lb/MMBtu** **$PM_{10/2.5}$-0.0075 lb/MMBtu**	**Use low carbon fuel, good design and operation, flare minimization practices**
ID-0017	Southeast Idaho Energy, LLC	02/10/09	Process Flare SRC21	1.5 MMBtu/hr pilot	No emissions from the process, no limit on pilot emissions	None
IA-0105	Iowa Fertilizer Company	10/26/12	Ammonia Flare	0.40 MMBtu/hr	None	Work Practice, Good Combustion Practices

RBLC Review

The potential to emit $PM/PM_{10}/PM_{2.5}$ of this flare is 0.002 tons per year for PM and 0.01 tons per year for PM_{10} and $PM_{2.5}$. A review of the $PM/PM_{10}/PM_{2.5}$ control strategies from the RBLC indicates no add-on controls are used. The most recent entry indicates $PM/PM_{10}/PM_{2.5}$ emissions are normally controlled by work practice standards, good design and good combustion practices. There are other RBLC entries for flares; however, these flares are in continuous service and do not combust a clean burning fuel. The entries from Iowa and Idaho indicate limits are not established for the pilot and the only control methods include good combustion practices and good work practices. IDEM, OAQ is adding pounds per hour limits for PM, PM_{10} and $PM_{2.5}$ based on the standard emission rates in AP-42, Chapter 1.4 and a heating value of 1,020 MMBtu/MMCF.

Applicant Proposal

The applicant proposed:

(a) Proper flare design and good combustion practices;

(b) The use of natural gas;

(c) The use of flare minimization practices; and

(d) Venting for Startup, Shutdown and Malfunction shall not exceed 168 hours per twelve consecutive month period with compliance determined at the end of each month.

The applicant's proposal is consistent with other flares in intermittent service and represents top BACT. The limitation on the hours of operation is intended to ensure the use of the flare during startup, shutdown and malfunction does not cause a violation of the National Ambient Air Quality Standards as demonstrated in the modeling submitted with this application.

Step 5: Select BACT

IDEM has established the following as BACT for PM, PM_{10} and $PM_{2.5}$ for Back End Ammonia Process Flare (EU-006):

(1) In order to control PM, PM_{10} and $PM_{2.5}$, the pilot and purge gas fuels used in the flare shall be natural gas.

(2) Venting in the Back End Ammonia Process Flare (EU-006) shall not exceed 336 hours per twelve consecutive month period with compliance determined at the end of each month.

(3) Comply with the following flare minimization practices to reduce emissions during startups, shutdowns, and other flaring events:

(A) Flare Use Minimization: Flare EU-006 shall be limited to flaring ammonia during high-pressure events to the extent practicable. The ammonia compressor main shall be depressurized prior to compressor maintenance. The Permittee shall limit venting ammonia rich streams to Flare EU-006 to the extent practicable during non-emergency startup and shutdown operations;

(B) The Permittee shall train all operators responsible for the day-to-day operation of the flares on the flare minimization practices and the specific procedures to follow during process startup, shutdown, and other flaring events; and

(C) The Permittee shall investigate the "root cause" of malfunction events that cause flaring events other than at startup or shutdown. This root cause analysis shall identify the apparent cause of unanticipated flaring event and shall recommend additional preventive measures that will minimize the chance of a repeat event. The Permittee shall implement the recommended preventive measures.

(4) PM, PM_{10} and $PM_{2.5}$ emissions from the Back End Ammonia Process Vent Flare (EU-006) shall be controlled by the use of the following practices:

(A) Flares shall be designed for and operated with no visible emissions, except for periods not to exceed 5 minutes during any two consecutive hours;

(B) Flares shall be operated with a flame present at all times; and

(C) Flares shall be continuously monitored to assure the presence of a pilot flame with a thermocouple, infrared monitor, or other approved device.

(5) PM emissions in the Back End Ammonia Process Flare (EU-006) shall not exceed 0.0019 lb/MMBtu, based on a three-hour average.

(6) PM_{10} and $PM_{2.5}$ emissions in the Back End Ammonia Process Flare (EU-006) shall not exceed 0.0075 lb/MMBtu, based on a three-hour average.

(5) Particulate BACT – Ammonia Storage Flare (EU-005)

Step 1: Identify Potential Control Technologies

In evaluating BACT for flare PM, PM_{10} and $PM_{2.5}$ emissions, there are limited process and/or add-on control alternatives available. Based on a review of the RBLC, as well as other permits and sources, the list of potential control and process alternatives includes the following:

(1) Flare design and good combustion practices;

(2) Process flaring minimization practices; and

(3) Flare gas recovery.

Add-on PM, PM_{10} and $PM_{2.5}$ controls that may be used on other types of sources, such as cyclones, baghouses, ESPs, or scrubbers are not applicable to flares because the outlet exhaust of an elevated process flare is not enclosed or contained. Therefore, the emissions or flue gases cannot be routed to an add-on control device, and such add-on controls have not been utilized on flares.

Step 2: Eliminate Technically Infeasible Options

Each option listed above is evaluated as follows:

(a) **Flare design and good combustion practices**
Flare design and operation are key elements in the emissions performance of flares. The Ammonia Storage Flare (EU-005) will be designed and operated to be smoke-free, thereby minimizing emissions. The fact that all gases vented to the flare will be low molecular weight helps assure low particulate creation. The use of flare design and good combustion practices is a technically feasible control option for the Ammonia Storage Flare (EU-005) at this source.

(b) **Process flaring minimization practices**
To the extent actions can be taken to minimize the volume of gas going to the flare, emissions of PM, PM_{10} and $PM_{2.5}$ will be less. The use of process flaring minimization practices is a technically feasible control option for the Ammonia Storage Flare (EU-005) at this source.

(c) **Flare gas recovery**
Flare gas recovery has been implemented at certain types of facilities that produce and use internally generated fuel gas streams such as petroleum refineries. However, flare gas recovery for this facility is not feasible for the following reasons.

(1) First, unlike a refinery's nearly continuous supply of flared gases, flaring at the proposed Ohio Valley Resources, LLC facility will be an infrequent occurrence.

(2) Another difference is that the Ohio Valley Resources, LLC flaring events, the flared material may not be suitable for use as a fuel gas.

The use of a flare gas recovery system is not a technically feasible control option for the Ammonia Storage Flare (EU-005) at this source.

Step 3: Rank the Remaining Control Technologies by Control Effectiveness

The remaining technically feasible control technologies for flares are:

(1) Proper flare design and good combustion practices; and

(2) Process flaring minimization practices.

Both controls listed above are proposed to be implemented by the source, therefore, no ranking of control technologies or further analysis is needed.

Step 4: Evaluate the Most Effective Controls and Document the Results

The following table lists the proposed PM, PM_{10} and $PM_{2.5}$ BACT determinations for similar emission units. All data in the table is based on the information obtained from the permit application submitted by Ohio Valley Resources, LLC, the U.S. EPA RACT/BACT/LAER Clearinghouse (RBLC), Indiana issued permits, and electronic versions of permits available at the websites of other permitting agencies.

RACT/BACT/LEAR CLEARINGHOUSE DATA
Ammonia Storage Flare (EU-005) – Particulate (PM, PM_{10} and $PM_{2.5}$)

RBLC ID	Facility	Issued Date	Process Description	Capacity	Limitation	Control Method
T147-32322-00062	**Ohio Valley Resources, LLC**	**Proposed**	**Flare EU-005**	**0.126 MMBtu/hr**	**PM - 0.0019 lb/MMBtu, $PM_{10/2.5}$ - 0.0075 lb/MMBtu**	**natural gas, FMP, good design and combustion, limit operation**
ID-0017	Southeast Idaho Energy, LLC	02/10/09	Process Flare SRC21	1.5 MMBtu/hr pilot	No emissions from the process, no limit on pilot emissions	None
IA-0105	Iowa Fertilizer Company	10/26/12	Ammonia Flare	0.40 MMBtu/hr	None	Work Practice, Good Combustion Practices

RBLC Review

The potential to emit of PM is 0.001 and PM_{10} and $PM_{2.5}$ are 0.004 tons per year for this flare. A review of the PM, PM_{10}, $PM_{2.5}$ control strategies from the RBLC indicates no add-on controls are used. The most recent entry indicates PM, PM_{10} and $PM_{2.5}$ are normally controlled by work practice standards, good design and good combustion practices. There are other RBLC entries for flares; however, these flares are in continuous service and do not combust a clean burning fuel. IDEM, OAQ is adding pounds per hour limits for PM, PM_{10} and $PM_{2.5}$ based on the standard emission rates in AP-42, Chapter 1.4 and a heating value of 1,020 MMBtu/MMCF.

Applicant Proposal

The applicant proposed:

(a) Proper flare design and good combustion practices;

(b) The use of natural gas;

(c) The use of flare minimization practices; and

(d) Venting for Startup, Shutdown and Malfunction shall not exceed 168 hours per twelve consecutive month period with compliance determined at the end of each month.

The applicant's proposal is consistent with other RBLC entries and represents top BACT.

Step 5: Select BACT

IDEM has established the following as BACT for PM, PM_{10} and $PM_{2.5}$ for Ammonia Storage Flare (EU-005):

(1) In order to control PM, PM_{10} and $PM_{2.5}$, the pilot and purge gas fuels used in the flare shall be natural gas.

(2) Venting for Startup, Shutdown and Malfunction shall not exceed 168 hours per twelve consecutive month period with compliance determined at the end of each month.

(3) Comply with the following flare minimization practices to reduce emissions during startups, shutdowns, and other flaring events:

  (A) Flare Use Minimization: The Permittee shall limit periods when the backup storage compressor and the ammonia refrigeration compressor are offline at the same time to the extent practicable;

  (B) The Permittee shall train all operators responsible for the day-to-day operation of the flares on the flare minimization practices and the specific procedures to follow during process startup, shutdown, and other flaring events; and

  (C) The Permittee shall investigate the “root cause” of malfunction events that cause flaring events other than at startup or shutdown. This root cause analysis shall identify the apparent cause of unanticipated flaring event and shall recommend additional preventive measures that will minimize the chance of a repeat event. The Permittee shall implement the recommended preventive measures.

(4) PM, PM_{10} and $PM_{2.5}$ emissions shall be controlled by use of the following practices:

  (A) Flares shall be designed for and operated with no visible emissions, except for periods not to exceed 5 minutes during any two consecutive hours;

  (B) Flares shall be operated with a flame present at all times; and

  (C) Flares shall be continuously monitored to assure the presence of a pilot flame with a thermocouple, infrared monitor, or other approved device.

(5) PM emissions from the Ammonia Storage Flare (EU-005) shall not exceed 0.0019 lb/MMBtu, based on a three-hour average.

(6) PM_{10} and $PM_{2.5}$ emissions Ammonia Storage Flare (EU-005) shall not exceed 0.0075 lb/MMBtu, based on a three-hour average.

(6) Particulate BACT – Two Identical Ammonium Nitrate Plants (EU-002A and EU-002B)

Step 1: Identify Potential Control Technologies

Emissions of particulate matter (PM), particulate matter with an aerodynamic diameter less than or equal to ten (10) micrometers (PM_{10}) and particulate matter with an aerodynamic diameter less than or equal to 2.5 micrometers ($PM_{2.5}$) are generally controlled with add-on control equipment designed to capture the emissions prior to the time they are exhausted to the atmosphere. The available technologies include:

(1) Cyclones;

(2) Wet Scrubbers;

(3) Electrostatic Precipitators (ESP);

(4) Fabric Filter Dust Collectors (Baghouses); and

(5) In-Stack Condensers.

The choice of which technology is most appropriate for a specific application depends upon several factors, including particle size to be collected, particle loading, stack gas flow rate, stack gas physical characteristics (e.g., temperature, moisture content, presence of reactive materials), and desired collection efficiency.

Alternate Control Methods:
One or more alternate methods of control may be considered when they are more cost-effective than add-on controls or when add-on control technology may not be feasible. For this source, the following alternate control methods were evaluated:

(1) Good Operation Practices

Step 2: Eliminate Technically Infeasible Options

(a) **Cyclone**
Cyclones mechanically separate particulates through centrifugal and inertial forces, by forcing a particulate-laden stream to change direction, with the particles falling out as they hit the walls of a typically cone-shaped cyclone. Cyclones are used in applications with waste gas pollutant loadings of 1 – 100 gr/scf. Particulate emissions from the Ammonium Nitrate Plants (EU-002A and EU-002B) will consist of ammonium nitrate as condensible PM. Cyclones cannot control condensible particulate matter. A cyclone is not a technically feasible control option for the Ammonium Nitrate Plants (EU-002A and EU-002B) at this source.

(b) **Wet Scrubber**
Wet scrubbers use a flow or spray of liquid in a tower to contact particulate-laden exhaust gas stream and absorb particles in the liquid, either physically, or in combination with a chemical reaction. A wet scrubber is capable of efficiently removing condensible PM from a gas stream. A wet scrubber is a technically feasible control option for the Ammonium Nitrate Plants (EU-002A and EU-002B) at this source.

(c) **Electrostatic Precipitators**
An electrostatic precipitator is a particulate control device that uses electrical forces to move particles entrained in an exhaust stream onto collector plates. The design inlet pollutant loadings for an ESP typically range from 0.5 – 50 gr/ft^3. Particulate matter emissions from Ammonium Nitrate Plants (EU-002A and EU-002B) consists of ammonium nitrate as condensible PM. Electrostatic precipitators cannot control condensible particulate matter. An electrostatic precipitator is not a technically feasible control option for the Ammonium Nitrate Plants (EU-002A and EU-002B) at this source.

(d) **Fabric Filter Dust Collectors (Baghouse)**
A baghouse uses a fabric filter to capture particles as the gas stream flows through the fabric. A typical baghouse outlet design concentration is 0.005 gr/cf and relies, in part on the filtering properties of a layer of particulate that first accumulates on the filter media. Particulate matter emissions from Ammonium Nitrate Plants (EU-002A and EU-

002B) consists of ammonium nitrate as condensible PM. Fabric filter dust collectors cannot control condensible particulate matter. A fabric filter dust collector is not a technically feasible control option for the Ammonium Nitrate Plants (EU-002A and EU-002B) at this source.

(e) **In-Stack Condensers**
An in-stack condenser is typically used on emissions streams containing high concentrations of volatile organic compounds. They are less effective on dilute streams. A refrigerated condenser is normally a viable option for any source of evaporative organic emissions if:

(1) there is minimal air flow carrying the organic emissions (i.e., the air stream is saturated with the organic compound);

(2) the organic vapor containment system limits air flow;

(3) the required air flow does not overload a refrigeration system with heat; and

(4) only one organic compound is emitted.

Ammonium nitrate is a solid at standard temperature and pressure and has a melting point of 337 °F at standard pressure. The ammonium nitrate units each exhaust at 3,340 ACFM, 180 °F at standard pressure. The use of a refrigerated condenser would require significant energy input to reduce the exhaust from the reaction temperature to final exhaust temperature. The use of an inline condenser is not a technically feasible control option for the Ammonium Nitrate Plants (EU-002A and EU-002B) at this source.

(f) **Demister**
A demister is a control device used to separate liquid droplets from a vapor stream. The demister consists of a containment vessel, a packing and a storage area for the material collected. The packing used in each system is specifically designed to separate the liquid droplet from the gas stream based on the diameter of the droplet. A demister has the highest collection efficiencies for droplets with a diameter of 20 micron and higher. Droplets with diameters below 2 micron have near zero collection efficiencies. A demister is a technically feasible control option for the Ammonium Nitrate Plants (EU-002A and EU-002B) at this source.

(g) **Good Operation Practices**
Good operation practices involve optimizing operation to minimize the creation and emission of particulate matter. Operation practices can include monitoring of system parametric readings to indicate when the process is operating out of established ranges. Good operation practices are a technically feasible control option for the Ammonium Nitrate Plants (EU-002A and EU-002B) at this source.

Step 3: Rank the Remaining Control Technologies by Control Effectiveness
The following measures have been identified for control of PM, PM_{10} and $PM_{2.5}$ resulting from the operation of the Ammonium Nitrate Plants (EU-002A and EU-002B):

(1) Wet Scrubber with Demister (95%)

(2) Good Operation Practices (80%)

The source has selected the use of a wet scrubber with a demister as BACT. Since top BACT has been selected, no ranking is required.

Step 4: Evaluate the Most Effective Controls and Document the Results

The following table lists the proposed PM, PM_{10} and $PM_{2.5}$ BACT determinations for similar emission units. All data in the table is based on the information obtained from the permit application submitted by Ohio Valley Resources, LLC, the U.S. EPA RACT/BACT/LAER Clearinghouse (RBLC), Indiana issued permits, and electronic versions of permits available at the websites of other permitting agencies.

RACT/BACT/LEAR CLEARINGHOUSE DATA
Ammonium Nitrate Plants (EU-002A and EU-002B) – Particulate (PM, PM_{10} and $PM_{2.5}$)

RBLC ID	Facility	Issued Date	Process Description	Capacity	Limitation	Control Method
T147-32322-00062	**Ohio Valley Resources**	**Proposed**	**UAN Plants EU-002A/B**	**798 tons/day**	**0.0128 lb/ton AN, 3 hr avg.**	**Wet Scrubber, with 95% Control, Throughput Limit**
OK-0135	Pryor Plant Chemical Company	02/23/09	Ammonium Nitrate Plants #1 and #2	23.8 tons AN per hour	0.1 lb $PM_{2.5}$/hr, PM/PM_{10}-0.05 lb/ton AN, $PM_{2.5}$-0.038 lb/ton AN	In-Stack Condensers, Good Operation Practices, 80% control
OK-0135	Pryor Plant Chemical Company	02/23/09	Granulator Scrubbers #1, #2 and #3	16.7 tons AN per hour	0.7 lb/hr	Good Operation Practices, 80% Control
ID-0017	Southeast Idaho Energy	02/05/10	Ammonium Nitrate Vent	715 ton AN per day	0.05 lb/ton AN	Wet Scrubber
AR-0117	El Dorado Chemical Company	11/24/10	Ammonium Nitrate Manufacturing	61.5 tons AN per hour	0.0540 lb/ton AN (30 Day) 0.2230 lb/ton AN (24 Hr)	Wet Scrubber
IA-0105	Iowa Fertilizer Company	10/26/12	Urea Granulator	1,500 Metric Tons AN/day	0.025 kg/MT	Wet Scrubber, 0.06 lb/ton AN

RBLC Review

The potential to emit PM, PM_{10} and $PM_{2.5}$ of each plant is 84.1 tons per year. A review of RBLC entries for Ammonium Nitrate Plants indicates PM, PM_{10} and $PM_{2.5}$ emissions are controlled by wet scrubbers, in-stack condensers and good operation practices. The applicant has proposed the best level of control and lowest emission rate of any facility indicated in the above table.

Applicant Proposal

The applicant proposed the following as BACT:

(a) PM, PM_{10} and $PM_{2.5}$ emissions from each ammonium nitrate plant shall be controlled with a wet scrubber containing a particulate demister.

(b) PM, PM_{10} and $PM_{2.5}$ emissions shall not exceed 0.96 lb/hr.

Because OVR is capable of achieving higher control efficiency with less energy input, IDEM, OAQ has excluded the in-line condenser from consideration as BACT. Finally, IDEM, OAQ prefers to use a production limit in place of a pound per hour limit to facilitate compliance determinations. Because the proposed emission control technology and emission limits for OVR represent the top level BACT for an ammonium nitrate plant, no further analysis of other technologies is required.

Step 5: Select BACT

IDEM has established the following as BACT for PM, PM_{10} and $PM_{2.5}$ for Ammonium Nitrate Plants (EU-002A and EU-002B):

(1) The maximum combined production of urea ammonium nitrate (UAN) for the Ammonium Nitrate Plants (EU-002A and EU-002B) shall not exceed 1,314,000 tons per year.

(2) The PM, PM_{10} and $PM_{2.5}$ emissions from the operation of each Ammonium Nitrate Plants (EU-002A and EU-002B) shall not exceed 0.0128 lb per ton of urea ammonium nitrate (UAN), based on a three-hour average, through the use of a wet scrubber with demister.

(7) Particulate BACT – UAN Plant Vent Flare (EU-017)

Step 1: Identify Potential Control Technologies

In evaluating BACT for flare PM, PM_{10} and $PM_{2.5}$ emissions, there are limited process and/or add-on control alternatives available. Based on a review of the RBLC, as well as other permits and sources, the list of potential control and process alternatives includes the following:

(1) Flare design and good combustion practices;

(2) Process flaring minimization practices; and

(3) Flare gas recovery.

Add-on PM, PM_{10} and $PM_{2.5}$ controls that may be used on other types of sources, such as cyclones, baghouses, ESPs, or scrubbers are not applicable to flares because the outlet exhaust of an elevated process flare is not enclosed or contained. Therefore, the emissions or flue gases cannot be routed to an add-on control device, and such add-on controls have not been utilized on flares.

Step 2: Eliminate Technically Infeasible Options

Each option listed above is evaluated as follows:

(a) **Flare design and good combustion practices**
Flare design and operation are key elements in the emissions performance of flares. The UAN Plant Vent Flare (EU-017) will be designed and operated to be smoke-free, thereby minimizing emissions. The fact that all gases vented to the flare will be low molecular weight helps assure low particulate creation. The use of flare design and good combustion practices is a technically feasible control option for the UAN Plant Vent Flare (EU-017) at this source.

(b) **Process flaring minimization practices**
To the extent actions can be taken to minimize the volume of gas going to the flare, emissions of PM, PM_{10} and $PM_{2.5}$ will be less. The use of process flaring minimization practices is a technically feasible control option for the UAN Plant Vent Flare (EU-017) at this source.

(c) **Flare gas recovery**

Flare gas recovery has been implemented at certain types of facilities that produce and use internally generated fuel gas streams such as petroleum refineries. However, flare gas recovery for this facility is not feasible for the following reasons.

(1) First, unlike a refinery's nearly continuous supply of flared gases, flaring at the proposed Ohio Valley Resources, LLC facility will be an infrequent occurrence.

(2) Another difference is that the Ohio Valley Resources, LLC flaring events, the flared material may not be suitable for use as a fuel gas.

The use of a flare gas recovery system is not a technically feasible control option for the UAN Plant Vent Flare (EU-017) at this source.

Step 3: Rank the Remaining Control Technologies by Control Effectiveness

The remaining technically feasible control technologies for flares are:

(1) Proper flare design and good combustion practices;

(2) Process flaring minimization practices.

Both controls listed above are proposed to be implemented by the source, therefore, no ranking of control technologies or further analysis is needed.

Step 4: Evaluate the Most Effective Controls and Document the Results

The following table lists the proposed PM, PM_{10} and $PM_{2.5}$ BACT determinations for similar emission units. All data in the table is based on the information obtained from the permit application submitted by Ohio Valley Resources, LLC, the U.S. EPA RACT/BACT/LAER Clearinghouse (RBLC), Indiana issued permits, and electronic versions of permits available at the websites of other permitting agencies.

RACT/BACT/LEAR CLEARINGHOUSE DATA
UAN Plant Vent Flare (EU-017) – Particulate (PM, PM_{10} and $PM_{2.5}$)

RBLC ID	Facility	Issued Date	Process Description	Capacity	Limitation	Control Method
T147-32322-00062	**Ohio Valley Resources, LLC**	**Proposed**	**UAN Plant Vent Flare EU-017**	**0.189 MMBtu/hr**	**PM – 0.0019 lb/MMBtu** **$PM_{10/2.5}$ – 0.0075 lb/MMBtu**	**natural gas, flare minimization practices, good design and combustion, limit operation**
ID-0017	Southeast Idaho Energy, LLC	02/10/09	Process Flare SRC21	1.5 MMBtu/hr pilot	No emissions from the process, no limit on pilot emissions	None
IA-0105	Iowa Fertilizer Company	10/26/12	Ammonia Flare	0.40 MMBtu/hr	None	Work Practice, Good Combustion Practices

RBLC Review
The potential to emit PM/PM_{10}/$PM_{2.5}$ of this flare is 0.001 tons per year for PM and 0.01 tons per year for PM_{10} and $PM_{2.5}$. A review of the PM/PM_{10}/$PM_{2.5}$ control strategies from the RBLC indicates no add-on controls are used. The most recent entry indicates PM/PM_{10}/$PM_{2.5}$ are normally controlled by work practice standards, good design and good combustion practices. There are other flares listed in the RBLC; however, these flares are in continuous service and do not combust a clean burning fuel. IDEM, OAQ is adding a pound per hour limit for PM, PM_{10} and $PM_{2.5}$ based on the standard emission rates in AP-42, Chapter 1.4 and a heating value of 1,020 MMBtu/MMCF.

Applicant Proposal
The applicant proposed:

(a) Proper flare design and good combustion practices;

(b) The use of natural gas;

(c) The use of flare minimization practices; and

(d) Venting for Startup, Shutdown and Malfunction shall not exceed 336 hours per twelve consecutive month period with compliance determined at the end of each month.

Step 5: Select BACT
IDEM has established the following as BACT for PM, PM_{10} and $PM_{2.5}$ for UAN Plant Vent Flare (EU-017):

(1) In order to control PM, PM_{10}, and $PM_{2.5}$ emissions, the pilot and purge gas fuels used in the flare shall be natural gas.

(2) Venting for Startup, Shutdown and Malfunction shall not exceed 336 hours per twelve consecutive month period with compliance determined at the end of each month.

(3) Comply with the following flare minimization practices to reduce emissions during startups, shutdowns, and other flaring events:

  (A) Flare Use Minimization: The UAN process shall be properly operated to avoid emergency upsets. Startup time of the Nitric Acid Units shall be minimized. During emergency upsets of the Nitric Acid Units, the Permittee shall return some of the high and low-pressure off-gas back to the urea process as soon as urea production is reduced to a level that safely allows this;

  (B) The Permittee shall train all operators responsible for the day-to-day operation of the flares on the flare minimization practices and the specific procedures to follow during process startup, shutdown, and other flaring events; and

  (C) The Permittee shall investigate the “root cause” of malfunction events that cause flaring events other than at startup or shutdown. This root cause analysis shall identify the apparent cause of unanticipated flaring event and shall recommend additional preventive measures that will minimize the chance of a repeat event. The Permittee shall implement the recommended preventive measures.

(4) PM, PM_{10}, and $PM_{2.5}$ emissions shall be controlled by use of the following practices:

  (A) Flares shall be designed for and operated with no visible emissions, except for periods not to exceed 5 minutes during any two consecutive hours;

  (B) Flares shall be operated with a flame present at all times; and

  (C) Flares shall be continuously monitored to assure the presence of a pilot flame with a thermocouple, infrared monitor, or other approved device.

(5) PM emissions from the UAN Plant Vent Flare (EU-017) shall not exceed 0.0019 lb/MMBtu, based on a three-hour average.

(6) PM_{10} and $PM_{2.5}$ emissions from the UAN Plant Vent Flare (EU-017) shall not exceed 0.0075 lb/MMBtu, based on a three-hour average.

(8) Particulate BACT – Four (4) Identical 218 MMBtu/hr Natural Gas Fired Boilers (EU-011A, EU-011B, EU-011C and EU-011D)

Step 1: Identify Potential Control Technologies

Emissions of particulate matter (PM), particulate matter with an aerodynamic diameter less than or equal to ten (10) micrometers (PM_{10}) and particulate matter with an aerodynamic diameter less than or equal to 2.5 micrometers ($PM_{2.5}$) are generally controlled with add-on control equipment designed to capture the emissions prior to the time they are exhausted to the atmosphere. The available technologies include:

(1) Cyclones;

(2) Wet Scrubbers;

(3) Electrostatic Precipitators (ESP); and

(4) Fabric Filter Dust Collectors (Baghouses).

The choice of which technology is most appropriate for a specific application depends upon several factors, including particle size to be collected, particle loading, stack gas flow rate, stack gas physical characteristics (e.g., temperature, moisture content, presence of reactive materials), and desired collection efficiency. If add-on control technology is not feasible, an alternate method of control may be implemented.

Alternate Control Methods:

One or more alternate methods of control may be considered when they are more cost-effective than add-on controls or when add-on control technology may not be feasible. For this source, the following alternate control methods were evaluated:

(1) Fuel Specifications – Clean Burning Fuel; and

(2) Good Combustion Practices / Combustion Controls.

Step 2: Eliminate Technically Infeasible Options

(a) **Cyclone**

Cyclones mechanically separate particulates through centrifugal and inertial forces, by forcing a particulate-laden stream to change direction, with the particles falling out as they hit the walls of a typically cone-shaped cyclone. Cyclones are used in applications with waste gas pollutant loadings of 1 – 100 gr/scf. Since the concentration of $PM/PM_{10}/PM_{2.5}$ in the natural gas-fired boilers (EU-011A, EU-011B, EU-011C and EU-011D) exhaust is very low (~0.005 gr/cf), a cyclone would not be effective at this source. A cyclone is not a technically feasible control option for the natural gas-fired boilers (EU-011A, EU-011B, EU-011C and EU-011D) at this source.

(b) **Wet Scrubber**

Wet scrubbers use a flow or spray of liquid in a tower to contact particulate-laden exhaust gas stream and absorb particles in the liquid, either physically, or in combination with a chemical reaction. Wet scrubbing towers are not typically used for fine particulate applications because high liquid to gas ratios are required, and typical pollutant loadings are 250-10,000 ppmv. (EPA-452/F-03-016, Air Pollution Control Technology Fact Sheet for Spray Tower Wet Scrubber). For fine particulate control, a venturi scrubber can be used but typical loadings for such a scrubber are 0.1-50 grains/scf (EPA-452/F-03-017, Air Pollution Control Technology Fact Sheet for Venturi Scrubber). Since the concentration of this stream (0.005 gr/cf) is already orders of magnitude lower, a wet scrubber would not achieve any appreciable particulate control. A wet scrubber is not a technically feasible control option.

(c) **Electrostatic Precipitators**

An electrostatic precipitator is a particulate control device that uses electrical forces to move particles entrained in an exhaust stream onto collector plates. The design inlet pollutant loadings for an ESP typically range from 0.5 – 50 gr/ft^3. Since the pollutant concentration of the natural gas-fired boilers (EU-011A, EU-011B, EU-011C and EU-011D) exhaust is already orders of magnitude lower, an ESP would not achieve any appreciable additional particulate control. The electrostatic precipitator is not a technically feasible control option for the natural gas-fired boilers (EU-011A, EU-011B, EU-011C and EU-011D) at this source.

(d) **Fabric Filter Dust Collectors (Baghouse)**

A baghouse uses a fabric filter to capture particles as the gas stream flows through the fabric. A typical baghouse outlet design concentration is 0.005 gr/cf and relies, in part on the filtering properties of a layer of particulate that first accumulates on the filter media. Since the emission concentration from this source is already extremely low, a baghouse would not be effective in providing further particulate control. The fabric filter dust collector is not a technically feasible control option for the natural gas-fired boilers (EU-011A, EU-011B, EU-011C and EU-011D) at this source.

(e) **Fuel Specifications – Clean Burning Fuel**

Clean burning natural gas has a very low potential for generating PM, PM_{10} and $PM_{2.5}$ emissions. Fuel specifications are a technically feasible control option for the natural gas-fired boilers (EU-011A, EU-011B, EU-011C and EU-011D) at this source.

(f) **Good Combustion Practices**

Good combustion practices as well as operation and maintenance of the boiler to keep it in good working order per the manufacturer's specifications will minimize PM, PM_{10} and $PM_{2.5}$ emissions. Good combustion practices are a technically feasible control option for the natural gas-fired boilers (EU-011A, EU-011B, EU-011C and EU-011D) at this source.

Step 3: Rank the Remaining Control Technologies by Control Effectiveness

The following measures have been identified for control of PM, PM_{10} and $PM_{2.5}$ resulting from the operation of the natural gas-fired boilers (EU-011A, EU-011B, EU-011C and EU-011D).

(1) Fuel Specifications – Clean Burning Fuel

(2) Good Combustion Practices

Both controls listed above are proposed to be implemented by the source, therefore, no ranking of control technologies or further analysis is needed.

Step 4: Evaluate the Most Effective Controls and Document the Results

The following table lists the proposed PM, PM_{10} and $PM_{2.5}$ BACT determinations for similar sources. All data in the table is based on the information obtained from the permit application submitted by Ohio Valley Resources, LLC, the U.S. EPA RACT/BACT/LAER Clearinghouse (RBLC), Indiana issued permits, and electronic versions of permits available at the websites of other permitting agencies.

RACT/BACT/LEAR CLEARINGHOUSE DATA

Boilers (EU-011A, EU-011B, EU-011C and EU-011D) – Particulate (PM, PM_{10} and $PM_{2.5}$)

RBLC ID	Facility	Issued Date	Process Description	Capacity	Limitation	Control Method
IA-0105	Iowa Fertilizer Company	10/26/12	Auxiliary Boiler	472.4 MMBtu/hr	0.0024 lb/MMBtu	Work Practice, Good Combustion Practices
T147-32322-00062	**Ohio Valley Resources, LLC**	**Proposed**	**Boilers (EU-011A, B, C and D)**	**218 MMBtu/hr, each**	**1.9, 7.6, 7.6 lb/MMCF, respectively, 3 hr avg.**	**Proper Design, Good Combustion Practices**
LA-0231	Lake Charles Cogeneration, LLC	06/22/09	Auxiliary Boiler	938.3 MMBtu/hr	6.99 lb PM_{10}/hr, filterable and condensible	None, lb/hr rate is 0.0075 lb/MMBtu
OH-0307	Biomass Energy South Point	04/04/06	Auxiliary Boiler	247 MMBtu/hr	0.0075 lb/MMBtu	None
TX-0371	Corpus Cristi Energy Center	02/04/00	Auxiliary Boilers 1 to 3	315 MMBtu/hr	0.005 lb/MMBtu, filterable	None
NC-0101	Forsyth Energy Plant	09/29/05	Auxiliary Boiler	110.20 MMBtu/hr	0.82 lb/hr, PM_{10} filterable	Good Combustion Practices, Burn Low Sulfur Fuel
PA-0187	Gray’s Ferry Cogen Partnership	03/21/01	Auxiliary Boiler	1,119 MMBtu/hr	0.005 lb/MMBtu, filterable	Good Combustion Practices

RBLC Review

The PM, PM_{10} and $PM_{2.5}$ emissions from the natural gas-fired boilers (EU-011A, EU-011B, EU-011C and EU-011D) result from the combustion of natural gas. Uncontrolled PM/PM_{10}/$PM_{2.5}$ emissions from each of the natural gas-fired boilers (EU-011A, EU-011B, EU-011C and EU-011D) are estimated to be 1.78 tons per year for PM and 7.11 tons per year for PM_{10} and $PM_{2.5}$ with the particulate concentration in the exhaust of 0.005 grains/dscf or less. This low concentration renders add-on controls infeasible. Generally add-on controls for PM, PM_{10} and $PM_{2.5}$ are not applied to a combustion source firing only clean gaseous fuel. This is because the PM, PM_{10} and $PM_{2.5}$ emissions are already extremely low (~0.005 gr/dscf), and are below levels that would be feasible for effective use of conventional particulate control devices.

A search of the USEPA's RACT/BACT/LAER Clearinghouse database did not indicate the use of control technologies for PM/ PM_{10}/$PM_{2.5}$ emissions from natural gas-fired boilers. The combustion of clean gaseous fuel is inherently low in particulate (PM, PM_{10} and $PM_{2.5}$) emissions and add-on controls are not feasible. The emission limits for the Corpus Christi Energy Center and Gray's Ferry Cogen. Partnership appear to be lower emission rates; however, the emission rates shown only include filterable particulate matter. Once condensible particulate matter is included, the emission rates are identical to the applicant's proposal. The particulate matter limits for an auxiliary boiler at the Iowa Fertilizer Company were the lowest emission rates found.

Applicant Proposal

The applicant proposed the following as BACT:

(a) Good boiler design and good combustion practices;

(b) Scheduled maintenance;

(c) Natural gas usage in three boilers is limited to 468 MMCF/yr each, while the fourth boiler is limited to 1,404 MMCF/yr.

(d) A BACT limit for PM, PM_{10} and $PM_{2.5}$ 7.6 lb/MMCF.

The applicant's proposal is consistent with a majority of the entries in the RBLC for PM, PM_{10}, and $PM_{2.5}$. These emission limits are based on the uncontrolled emission factors found in AP-42. A permit for the Iowa Fertilizer Company (IFC) was recently issued by the Iowa Department of Natural Resources (IDNR) with a proposed emission rate of 0.0024 lb/MMBtu. The IFC permit limit is lower than the limit proposed by the applicant. IDNR established this limit based on two stack tests at a single boiler. IDEM believes the emission rate proposed by the applicant is appropriate for BACT based on the following factors:

1. Add-on emission controls have been demonstrated to be infeasible or not cost-effective.
2. The majority of the entries in the RBLC for uncontrolled natural gas-fired combustion units are derived from the AP-42 emission factors, which are based on stack tests on a large sample size of natural gas-burning facilities.
3. The emission limits in the IFC permit set by IDNR are based on two stack tests at the same facility – a 429 MMBtu/hr auxiliary boiler located at the Walter Scott Generating Plant in Council Bluffs, Iowa. These test results do not establish BACT for the boilers at Ohio Valley Resources.
    a. Two stack test results at the same facility are not representative of the emission rate achievable at a large range of natural gas facility types and sizes. The AP-42 emission factor for natural gas combustion is a better reflection of what is achievable for an uncontrolled natural gas unit.

b. IFC's facilities have not yet begun operations, and consequently the achievability of the IFC BACT limits have not been demonstrated in practice.

Step 5: Select BACT
IDEM has established the following as BACT for PM, PM_{10} and $PM_{2.5}$ for natural gas-fired boilers (EU-011A, EU-011B, EU-011C and EU-011D).

(a) PM, PM_{10}, and $PM_{2.5}$ emissions from the boilers (EU-011A, EU-011B, EU-011C and EU-011D) shall be controlled through the use of proper boiler design and good combustion practices.

(b) Combined fuel usage in the boilers (EU-011A, EU-011B, EU-011C and EU-011D) shall not exceed 2,802 MMCF per twelve consecutive month period with compliance determined at the end of each month.

(c) The boilers (EU-011A, EU-011B, EU-011C, and EU-011D) shall combust natural gas.

(d) PM, PM_{10} and $PM_{2.5}$ emissions from each of the boilers (EU-011A, EU-011B, EU-011C and EU-011D) shall not exceed 1.9, 7.6 and 7.6 lb/MMCF, respectively, based on a three-hour average. PM includes filterable particulate matter, while, PM_{10} and $PM_{2.5}$ include both filterable and condensible particulate matter.

(9) Particulate BACT – Diesel-Fired Emergency Generator (EU-009)

Step 1: Identify Potential Control Technologies
Today's stationary diesel-fired emergency compression ignition internal combustion engines are sold as package units with an engineering design tailored to meet the emission limitations of 40 CFR 60, Subpart IIII and 40 CFR 63, Subpart ZZZZ. The manufacturer provides an engine that is in compliance with the applicable NSPS and NESHAP and the owner/operator is expected to maintain and operate the unit to guarantee compliance with applicable emission limitations.

Step 2: Eliminate Technically Infeasible Options
(a) **Catalyzed Diesel Particulate Filter (CDPF)**
Particulate matter emissions in the exhaust gas of the engine is trapped by a ceramic fixed filter and oxidized using a metallic catalyst or a base. The operating temperature range is between 480 °F and 570 °F. The exhaust gas temperature must be high enough over an extended period of time to allow the filter to regenerate. This type of control is not included in the RBLC for the control of particulate emissions from emergency engines. EPA determined that add-on controls were economically infeasible for emergency internal combustion engines during the development of 40 CFR 60, Subpart IIII. Therefore, CDPF is not a technically feasible option.

(b) **Good Combustion Practices**
Organic particulate matter in the exhaust of internal combustion engines are caused by incomplete combustion. When fuel and air are not well mixed in the combustion zone, low oxygen regions form and cause unburned fuel to pyrolize at high temperatures to form soot. Soot formation can be minimized by improving the fuel/air mixture in the combustion zone through enhanced fuel injection systems, air management systems, combustion system designs, and pre-mixed diesel combustion. This type of emission control is included in the RBLC for particulate matter control from emergency internal combustion engines. Good combustion practices are a technically feasible control option.

(c) **Usage Limitations**
Usage limitations restrict the number of hours the internal combustion engine can operate and result in lower overall emissions of all pollutants. This method of emission control is listed in the RBLC for internal combustion engines and is a technically feasible control option.

Step 3: Rank the Remaining Control Technologies by Control Effectiveness
The applicant has accepted good combustion practices and usage limitations; therefore, ranking is not required.

Step 4: Evaluate the Most Effective Controls and Document the Results
The following table lists the proposed PM, PM_{10} and $PM_{2.5}$ BACT determinations for similar emission units. All data in the table is based on the information obtained from the permit application submitted by Ohio Valley Resources, LLC, the U.S. EPA RACT/BACT/LAER Clearinghouse (RBLC), Indiana issued permits, and electronic versions of permits available at the websites of other permitting agencies.

RACT/BACT/LEAR CLEARINGHOUSE DATA
Diesel-Fired Emergency Generator (EU-009) – Particulate (PM, PM_{10} and $PM_{2.5}$)

RBLC ID	Facility	Issued Date	Process Description	Capacity	Limitation	Control Method
NV-0050	MGM Mirage	11/30/09	Diesel Emergency Generators CC09 - CC015	3,622 HP	0.0001 lb/hp-hr, PM_{10}, filterable only	Good Combustion Practice, 0.05 g/hp-hr filterable
NV-0050	MGM Mirage	11/30/09	Diesel Emergency Generators LX024–LX025	2,206 HP	0.0001 lb/hp-hr, PM_{10}, filterable only	Good Combustion Practice, 0.05 g/hp-hr filterable
T147-32322-00062	**Ohio Valley Resources, LLC**	**Proposed**	**Emergency Generator EU-009**	**4,690 HP**	**0.15 g/hp-hr**	**Good Combustion Practices, 200 hrs of operation**
IA-0105	Iowa Fertilizer Company	10/26/12	Emergency Generator	2,000 KW	0.2 g/KW-hr	Good Combustion Practices, 0.27 g/hp-hr
FL-0322	Southeast Renewable Fuels, LLC	12/23/10	Emergency Generator	2,000 KW	0.2 g/KW-hr, filterable and condensible	Comply with 40 CFR 60, Subpart IIII, 0.27 g/hp-hr
ID-0018	Idaho Power Company, Langley Gulch	06/25/10	Emergency Generator	750 KW 1,005 HP	0.2 g/KW-hr	None, 0.27 g/hp-hr

RBLC Review
All of the entries listed above, except for the MGM Mirage generators, show emission limitations in compliance with 40 CFR 60, Subpart IIII. The Permittee contacted the permitting agency and the MGM Mirage units were constructed but were never tested.

Applicant Proposal

The applicant proposed the following as BACT:

(a) PM, PM_{10} and $PM_{2.5}$ emissions shall not exceed 0.15 g/hp-hr;

(b) PM, PM_{10} and $PM_{2.5}$ emissions shall be controlled by exercising good combustion practices; and

(c) Hours of operation in the diesel-fired emergency generator (EU-009) shall not exceed 200 hours per year.

The applicant is proposing an emission rate for PM, PM_{10} and $PM_{2.5}$ that is 0.15 g/hp-hr. This is significantly higher than the MGM Mirage emission rate of 0.05 g/hp-hr. The applicant performed an economic analysis for the lower emission rate. This analysis is shown in the table below:

Control Alternative	**Captured Emissions (TPY)**	**Emission Reduction (TPY)**	**Capital Cost ($)**	**Operating Cost ($/yr)**	**Total Annualized Costs ($/yr)** (b)	**Cost Effectiveness ($/ton)**	**Energy and Environmental Impacts**
0.05 g/hp-hr, PTE at 500 hours	0.13	0.03	45,000	(a)	$6,407	$213,567	lower overall emissions, units have same HP requirements
Baseline, 200 Hours, 0.15 g/hp-hr	0.16	---	---	---	---	---	---

Notes:
(a) The annual operating costs and salvage value are assumed identical for both engine designs.
(b) Capital Recovery Factor – 0.14238 (7%, 10 year lifecycle)

The emergency generator will operate 200 hours annually regardless of the generator selected. The emission reduction attributable to the lower emitting generator is only 0.03 tons per year and costs $213,567 dollars per ton of emission reduction achieved. IDEM, OAQ concurs with the applicant's assessment. The lower emitting generator cannot be justified using a cost effectiveness analysis in this specific application.

Step 5: Select BACT

IDEM has established the following as BACT for PM, PM_{10} and $PM_{2.5}$ for the diesel-fired emergency generator (EU-009):

(1) The hours of operation of the diesel-fired emergency generator (EU-009) shall not exceed 200 hours per twelve consecutive month period with compliance determined at the end of each month.

(2) PM, PM_{10}, and $PM_{2.5}$ emissions shall be controlled by the use of good combustion practices.

(3) The PM, PM_{10} and $PM_{2.5}$ emissions from the operation of the diesel-fired emergency generator (EU-009) shall not exceed 0.15 g/hp-hr, based on a three-hour average.

(10) Particulate BACT – Paved Roadways and Parking Lots

Step 1: Identify Potential Control Technologies

Emissions of particulate matter (PM), particulate matter with an aerodynamic diameter less than or equal to ten (10) micrometers (PM_{10}) and $PM_{2.5}$ from fugitive sources are generally controlled with measures to prevent the emissions from occurring. Generally, fugitive PM, PM_{10} and $PM_{2.5}$ emissions from roadways are controlled through one of the following mechanisms:

(1) Paving of Roadways;

(2) Wet Suppression or Chemical suppression; and

(3) Good Housekeeping (cleanup spilled material).

Add-on particulate control devices such as cyclones, scrubbers, baghouses or ESP's are not possible alternatives because the roadways cannot be enclosed and vented to a point source control device.

Step 2: Eliminate Technically Infeasible Options

(a) **Add-on Control Technology:**
Add-on particulate control devices such as cyclones, scrubbers, baghouses or ESP's are not possible alternatives because the roadways cannot be enclosed and vented to a point source control device. The use of add-on controls is not a technically feasible control option for the paved roadways and parking lots with public access at this source.

(b) **Wet Suppression or Chemical Suppression:**
Wet suppression systems use liquid sprays or foam to suppress the formation of airborne dust. The primary control mechanisms are those that prevent emissions through agglomerate formation by combining small dust particles with larger aggregate or with liquid droplets. The key factors affecting the degree of agglomeration and the performance of the system are the coverage of the material by the liquid and the ability of the liquid to wet small particles. There are two types of wet suppression systems: liquid sprays which use water or a water/surfactant mix and foams. Wet suppression systems typically achieve PM control efficiencies of greater than 85%. The use of a wet suppression or chemical suppression is a technically feasible control option for the paved roadways and parking lots with public access at this source.

(c) **Paving Roadways and Good Housekeeping**
Paving all haul roads and prompt cleanup of any spilled or eroded materials are effective at minimizing dust emissions from vehicle traffic. The use of paving roadways and good housekeeping is a technically feasible control option for the paved roadways and parking lots with public access at this source.

Step 3: Rank the Remaining Control Technologies by Control Effectiveness

The following measures have been identified for control of PM, PM_{10} and $PM_{2.5}$ resulting from the paved roadways and parking lots with public access.

(1) Paving haul roads reduces vehicle dust emissions versus unpaved surfaces and is feasible.

(2) Wet or chemical suppression (frequent use of water or chemical surfactants) can significantly reduce airborne dust emissions from both paved and unpaved roadways.

(3) Particulate emission from paved roadways can also be minimized with good housekeeping (i.e., cleaning up spills of solid material or dirt eroded onto the road surfaces).

The applicant has accepted all feasible control measures therefore no ranking or additional analysis is required.

Step 4: Evaluate the Most Effective Controls and Document the Results

The following table lists the proposed PM, PM_{10} and $PM_{2.5}$ BACT determinations for similar emission units. All data in the table is based on the information obtained from the permit application submitted by Ohio Valley Resources, LLC, the U.S. EPA RACT/BACT/LAER Clearinghouse (RBLC), Indiana issued permits, and electronic versions of permits available at the websites of other permitting agencies.

RACT/BACT/LEAR CLEARINGHOUSE DATA
Paved Roadways and Parking Lots with Public Access – Particulate (PM, PM_{10} and $PM_{2.5}$)

RBLC ID	Facility	Issued Date	Process Description	Capacity	Limitation	Control Method
T147-32322-00062	**Ohio Valley Resources, LLC**	**Proposed**	**Paved Roads and Parking Lots**	**17,160 VMT/yr**	**90% Control**	**Paving, Speed Limits, sweeping, wet suppression**
T147-30464-00060	Indiana Gasification, LLC	06/27/12	Haul Roads	Not indicated	90% Control	Paving, wet suppression, prompt cleanup
OH-0317	Ohio River Clean Fuels	11/20/08	Paved Roads	736,205 VMT/yr	PM – 79.00 TPY PM_{10} – 15.69 TPY 90% Control	Watering, Sweeping, Speed Limit
OH-0297	FDS Coke Company	06/14/04	Roadways	Unknown	PM – 24.88 TPY PM_{10} – 4.85 TPY	Watering
OH-0328	V & M Star	04/10/09	Roadways	Unknown	PM_{10} – 12.4 TPY (AP-42 Emission Factors)	Control Measures to Minimize Emissions
IA-0105	Iowa Fertilizer Company	10/26/12	Paved Roads	2 miles of road	No numeric limit	Water Flushing, Sweeping

RBLC Review

The table above shows recent entries in the RACT/BACT/LEAR Clearinghouse (RBLC database for haul roads. Control measures include watering, sweeping, speed limits and good housekeeping. The highest emission reduction appearing in the RBLC is 90% control.

Applicant Proposal

The applicant proposed the following as BACT:

(a) All roadways will be paved;

(b) The source will use speed limits; and

(c) The source will use daily sweeping with wet suppression.

Step 5: Select BACT

The PM, PM_{10}, and $PM_{2.5}$ emissions from paved haul roads shall be controlled to an overall control efficiency of 90% by employing the following work practices:

(1) Paving all plant haul roads;

(2) Daily sweeping with wet suppression; and

(3) Prompt cleanup of any spilled materials.

(11) Particulate BACT – Diesel-Fired Emergency Fire Water Pump (EU-016)

Step 1: Identify Potential Control Technologies

Today's stationary diesel-fired emergency compression ignition internal combustion engines are sold as package units with an engineering design tailored to meet the emission limitations of 40 CFR 60, Subpart IIII and 40 CFR 63, Subpart ZZZZ. The manufacturer provides an engine that is in compliance with the applicable NSPS and NESHAP and the owner/operator is expected to maintain and operate the unit to guarantee compliance with applicable emission limitations.

Step 2: Eliminate Technically Infeasible Options

(a) **Catalyzed Diesel Particulate Filter (CDPF)**

Particulate matter emissions in the exhaust gas of the engine is trapped by a ceramic fixed filter and oxidized using a metallic catalyst or a base. The operating temperature range is between 480 °F and 570 °F. The exhaust gas temperature must be high enough over an extended period of time to allow the filter to regenerate. This type of control is not included in the RBLC for the control of particulate emissions from emergency engines. EPA determined that add-on controls were economically infeasible for emergency internal combustion engines during the development of 40 CFR 60, Subpart IIII. Therefore, CDPF is not a technically feasible option.

(b) **Good Combustion Practices**

Organic particulate matter in the exhaust of internal combustion engines are caused by incomplete combustion. When fuel and air are not well mixed in the combustion zone, low oxygen regions form and cause unburned fuel to pyrolize at high temperatures to form soot. Soot formation can be minimized by improving the fuel/air mixture in the combustion zone through enhanced fuel injection systems, air management systems, combustion system designs, and pre-mixed diesel combustion. This type of emission control is included in the RBLC for particulate matter control from emergency internal combustion engines. Good combustion practices are a technically feasible control option.

(c) **Usage Limitations**

Usage limitations restrict the number of hours the internal combustion engine can operate and result in lower overall emissions of all pollutants. This method of emission control is listed in the RBLC for internal combustion engines and is a technically feasible control option.

Step 3: Rank the Remaining Control Technologies by Control Effectiveness

The applicant has accepted both control technologies; therefore, no ranking is necessary.

Step 4: Evaluate the Most Effective Controls and Document the Results

The following table lists the proposed PM, PM_{10} and $PM_{2.5}$ BACT determinations for similar emission units. All data in the table is based on the information obtained from the permit application submitted by Ohio Valley Resources, LLC, the U.S. EPA RACT/BACT/LAER Clearinghouse (RBLC), Indiana issued permits, and electronic versions of permits available at the websites of other permitting agencies.

RACT/BACT/LEAR CLEARINGHOUSE DATA
Diesel-Fired Emergency Fire Water Pump (EU-016) – Particulate (PM, PM_{10} and $PM_{2.5}$)

RBLC ID	Facility	Issued Date	Process Description	Capacity	Limitation	Control Method
T147-32322-00062	**Ohio Valley Resources, LLC**	**Proposed**	**Emergency Fire Water Pump**	**481 HP**	**0.15 g/hp-hr, 3 hr avg.**	**Good Combustion Practices, Usage Limit**
LA-0254	Ninemile Point Electric Generating Plant	08/16/11	Emergency Fire Pump	350 HP	0.15 g/Hp-hr	Ultra-Low Sulfur Diesel, Good Combustion Practices
IA-0088	Archer Daniels Midland – Cedar Rapids	06/29/07	Fire Pump	540 HP	0.15 g/Hp-hr	None
IA-0094	Tate & Lyle Ingredients, Inc.	09/19/08	Fire Pump	575 HP	0.20 g/HP-hr	None
AZ-0046	Arizona Clean Fuels, Yuma LLC	04/14/05	Fire Water Pump	5.46 MMBtu/hr 780 HP	0.2 g/KW-hr 0.27 g/HP-hr	None
IA-0105	Iowa Fertilizer Company	10/26/12	Diesel Fire Pump	235 KW 315 HP	0.2 g/KW-hr 0.0006 lb/Hp-hr 0.27 g/Hp-hr	Good Combustion Practice

RBLC Review
The potential to emit of $PM/PM_{10}/PM_{2.5}$ is 0.04 TPY. Review of the RBLC data shows the common methods of control for emergency diesel-fired RICE is the use of good combustion practices with a $PM/PM_{10}/PM_{2.5}$ emission rate of 0.15 g/Hp-hr. This emission rate is consistent with the requirements of 40 CFR 60, Subpart IIII. The applicant proposed top BACT.

Applicant Proposal
The applicant proposed the following as BACT:

(a) Good Combustion Practices;

(b) PM, PM_{10} and $PM_{2.5}$ emissions shall not exceed 0.15 g/hp-hr; and

(c) Operation of the diesel-fired emergency fire water pump (EU-016) shall not exceed 200 hours per year.

Step 5: Select BACT
IDEM has established the following as BACT for PM, PM_{10} and $PM_{2.5}$ for the diesel-fired emergency fire water pump (EU-016):

(1) Operation of the Diesel-Fired Emergency Firewater Pump (EU-016) shall not exceed 200 hours per twelve consecutive month period with compliance determined at the end of each month.

(2) PM, PM_{10}, and $PM_{2.5}$ emissions from the Diesel-Fired Emergency Firewater Pump (EU-016) shall be controlled by the use of good combustion practices.

(3) The PM, PM_{10} and $PM_{2.5}$ emissions from the operation of the Diesel-Fired Emergency Firewater Pump (EU-016) shall not exceed 0.15 g/hp-hr, based on a three-hour average.

(12) Particulate BACT – Two Cooling Towers (EU-008A to H and EU-019A to F)

Step 1: Identify Potential Control Technologies

Emissions from cooling towers are generally controlled by a drift elimination system.

Step 2: Eliminate Technically Infeasible Options

(a) **High Efficiency Drift Eliminators**

Cooling towers are a source of particulate matter ($PM/PM_{10}/PM_{2.5}$) emissions from the small amount of water mist that is entrained with the cooling air as “drift”. The cooling water contains small amounts of dissolved solids which become particulate ($PM/PM_{10}/PM_{2.5}$) emissions once the water mist evaporates. To reduce the drift from cooling towers, drift eliminators are typically incorporated into the tower design to remove as many droplets as practical from the air stream before exiting the tower.

Particulate matter emissions occur from cooling towers when suspended solids contained in the water used in the cooling tower becomes airborne as the water is circulated and cooled. Drift eliminators contain packing which is used to limit the amount of this particulate matter which becomes airborne during the cooling process. As mist passes through the packing, the particles in the air contact and adhere to the surface of the packing. As condensed water flows down this packing, these particles are removed.

The use of a drift elimination system is technically feasible control option for the Cooling Towers (EU-008A to H and EU-019A to F) at this source.

(b) **Dissolved Solids Management**

A cooling tower is a device intended to remove heat from a process through the evaporation of water. The minerals contained in the vaporized water remain in the recirculated cooling water and form scale or increase the total dissolved solids. Operators remove water from the system (blowdown) and replace it with makeup water to maintain a desired total dissolved solids concentration and a constant volume of recirculated water. The blowdown process is automated and the system normally contains a conductivity sensor and a solenoid valve to automatically remove solids from the system. The proper management of the total dissolved solids concentration of the recirculation water is a technologically feasible control method.

Step 3: Rank the Remaining Control Technologies by Control Effectiveness

The applicant has accepted both control strategies. Therefore, a ranking of control efficiencies is not required.

Step 4: Evaluate the Most Effective Controls and Document the Results

The following table lists the proposed PM, PM_{10} and $PM_{2.5}$ BACT determinations for similar emission units. All data in the table is based on the information obtained from the permit application submitted by Ohio Valley Resources, LLC, the U.S. EPA RACT/BACT/LAER Clearinghouse (RBLC), Indiana issued permits, and electronic versions of permits available at the websites of other permitting agencies.

RACT/BACT/LEAR CLEARINGHOUSE DATA

Cooling Towers (EU-008A to H and EU-019A to F) – Particulate (PM, PM_{10} and $PM_{2.5}$)

RBLC ID	Facility	Issued Date	Process Description	Capacity	Limitation	Control Method
LA-0248	Nucor, Direct Reduction Plant	01/27/11	Cooling Tower DRI-113	26,857 GPM	0.0005% Drift, 1,000 mg/l TDS	Drift Eliminators
LA-0248	Nucor, Direct Reduction Plant	01/27/11	Cooling Tower DRI-213	26,857 GPM	0.0005% Drift, 1,000 mg/l TDS	Drift Eliminators
LA-0248	Nucor, Direct Reduction Plant	01/27/11	Cooling Tower DRI-114	17,611 GPM	0.0005% Drift, 1,000 mg/l TDS	Drift Eliminators
T147-32322-00062	**Ohio Valley Resources, LLC**	**Proposed**	**Cooling Towers EU-008A-H EU-019A-F**	**179,720 GPM combined**	**0.0005% Drift 2,000 mg/l TDS**	**High Efficiency Drift Eliminators**
T147-30464-00060	Indiana Gasification	06/27/12	ASU and Main Cooling Tower EU-016A/B	55,000 GPM–A 405,000 GPM-B	0.0005% Drift 1,500 mg/l	High Efficiency Drift Eliminators
LA-0254	Ninemile Point Electric	08/16/11	Unit 6 Cooling Tower	115,847 GPM	0.0005% Drift	High Efficiency Mist Eliminator

RBLC Review

USEPA's RACT/BACT/LAER Clearinghouse shows BACT determinations specifying the use of drift/mist eliminators for controlling PM, PM_{10} and $PM_{2.5}$ emissions, with drift rates ranging from 0.003% – 0.0005%. A design drift rate of 0.0005% appears in the most recent permit determinations and it represents the best performing control measure. The total dissolved solids concentration in the recirculated cooling tower water is listed in a handful of permits and can range from a low of 1,000 ppm (mg/l) up to 5,000 mg/l (IA-0017). The majority of permits do not list a TDS limit.

Applicant Proposal

The applicant proposed the following as BACT:

(a) The use of high efficiency drift eliminators with a maximum drift rate of 0.0005%; and

(b) The maximum total dissolved solids (TDS) of the cooling tower water shall not exceed 2,000 mg/l.

Data from the RBLC clearly indicates the use of high efficiency drift eliminators with a maximum drift rate of 0.0005% is BACT for cooling tower water. It is less clear that BACT is 1,000 ppm (1,000 mg/l) for the total dissolved solids (TDS) concentration. The three lowest BACT entries in terms of TDS are all from the same facility and use the same water source. The most recent cooling water BACT in the State of Indiana was for the Indiana Gasification (IG) permit. The IG facility is located adjacent to the proposed Ohio Valley Resources facility. IDEM, OAQ approved a TDS concentration of 1,500 mg/l for the IG facility.

The operation of the cooling tower system is based on the evaporation of water to cool a process stream. As water evaporates, the TDS concentration of the water will increase, because the dissolved solids remain behind in the cooling water. The cooling tower requires additional water, makeup water, to keep the total volume of cooling water constant and to limit the TDS contained in the cooling water. These systems typically recycle water five to seven times before it is removed from the system. In the OVR facility, this recycle rate will result in an estimated TDS concentration that ranges from 1,500 to 2,000 mg/l.

The three lowest entries do not directly correspond to the cooling towers at OVR. The Nucor cooling water towers are much smaller and will use less water. The Indiana Gasification cooling towers use water from the Ohio River while OVR uses well water. River water is naturally lower in dissolved solids than well water. Ground water travels slowly from the recharge point and the water is in direct contact with the ions that contribute to TDS. These ions include chloride, sodium, nitrate, calcium, magnesium, bicarbonate, sulfate, boron, bromide and iron.

The applicant provided an economic analysis for the option of reducing the TDS concentration from 2,000 mg/l to 1,500 mg/l. The analysis is shown in the table below and is for particulate matter (PM) emissions only. PM_{10} and $PM_{2.5}$ will have much higher costs per ton of emission reduction.

Control Alternative (c)	**Captured Emissions (TPY)**	**Emission Reduction (TPY)**	**Capital Cost ($)**	**Operating Cost ($/yr)** (d)	**Total Annualized Costs ($/yr)**	**Cost Effectiveness ($/ton)**	**Energy and Environmental Impacts**
1,500 mg/l	2.96	0.98	0	$4,500	$4,500	$4,592	An additional 0.53 MGD of makeup water that is discharged to the Ohio River.
Baseline, 2,000 mg/l	3.94	---	---	---	---	---	---

Notes:
(a) The annual operating costs and salvage value are assumed identical for both engine designs.
(b) The analysis shown above is for PM. Cost per ton of reduction will increase from this point.
(c) Only electrical costs are considered. There will be additional chemical treatment cost.

The table above indicates the source will incur an additional $4,500 per year in operating costs as a result in pumping an additional 0.53 MGD of makeup water. The emission reduction achieved at 1,500 mg/l results in significant additional electrical costs and adverse environmental costs. Environmental effects include the use of an additional 0.53 million gallons per day of ground water and an equivalent additional discharge to the Ohio River. The reduction in PM, PM_{10}, and $PM_{2.5}$ cannot be justified on economic or environmental terms.

Step 5: Select BACT

IDEM, OAQ has established PM, PM_{10} and $PM_{2.5}$ BACT for the Cooling Towers (EU-008A to H and EU-019A to F).

(1) The PM, PM_{10} and $PM_{2.5}$ emissions from the Cooling Towers (EU-008A to H and EU-019A to F) shall be controlled by high efficiency drift eliminators designed with a drift loss rate of less than 0.0005%.

(2) The total dissolved solids in the water used in Cooling Towers (EU-008A to H and EU-019A to F) shall not exceed 2,000 mg/l, averaged on a daily basis.

NOx BACT Determinations

(1) NOx BACT – Primary Reformer (EU-003)

Step 1: Identify Potential Control Technologies

NOx emissions from the primary reformer (EU-003) can be controlled with the following control technologies:

(1) Selective Catalytic Reduction (SCR)
(2) Selective Non-Catalytic Reduction (SNCR)
(3) Low NOx Burner (LNB)

These add-on control technologies and combustion control approaches are discussed below.

Step 2: Eliminate Technically Infeasible Options

(a) **Selective Catalytic Reduction**

Selective Catalytic Reduction (SCR) process involves the mixing of anhydrous or aqueous ammonia vapor with flue gas and passing the mixture through a catalytic reactor to reduce NO_X to nitrogen and water. Under optimal conditions, SCR has removal efficiencies up to 90% when used on steady state processes. The efficiency of removal will be reduced for processes that are not stable or require frequent changes in the mode of operation.

The most important factor affecting SCR efficiency is temperature. SCR typically operates in a flue gas window ranging from 500°F to 1100°F, although the optimum temperature range depends on the type of catalyst and the flue gas composition. Temperatures below the optimum decrease catalyst activity and allow NH_3 to slip through. Until the system reaches the minimum temperature, the SCR operates without ammonia injection. Above the optimum range, ammonia will oxidize to form additional NO_x. SCR efficiency is also largely dependent on the stoichiometric molar ratio of NH_3: NOx; variation of the ideal 1:1 ratio to 0.5:1 ratio can reduce the removal efficiency to 50%. Selective catalytic reduction (SCR) is a technically feasible control option for the Primary Reformer (EU-003) at this source.

(b) **Selective Non-Catalytic Reduction (SNCR)**

With selective non-catalytic reduction (SNCR), NO_X is selectively removed by the injection of ammonia or urea into the flue gas at an appropriate temperature window of 1600°F to 2000°F, without employing a catalyst. Similar to SCR without a catalyst bed, the injected chemicals selectively reduce the NO_X to molecular nitrogen and water. This approach avoids the problem related to catalyst fouling but the temperature window and reagent mixing residence time is critical for conducting the necessary chemical reaction. At the proper temperature, urea decomposes to produce ammonia which is responsible for NO_X reduction. At a higher temperature, the rate of competing reactions for the direct oxidation of ammonia that forms NOx becomes significant. At a lower temperature, the rates of NO_X reduction reactions become too slow resulting in urea slip (i.e. emissions of unreacted urea).

Optimal implementation of SNCR requires the employment of an injection system that can accomplish thorough reagent/gas mixing within the temperature window while accommodating spatial and production rate temperature variability in the gas stream. The attainment of maximum NO_x control performance requires that the furnace exhibit a favorable opportunity for the application of this technology relative to the location of the reaction temperature range and steady operation within that temperature window. The exhaust gases from the primary reformer are used to preheat the influent streams to the reformer in its convection section. This reduces the reformer exhaust to 325 °F which is well below the activation temperature necessary for the reaction to begin and move to completion. The relatively low temperature of the primary reformer flue gas renders the use of SNCR technically infeasible.

(c) **Low NOx Burners (LNB)**

Using LNB can reduce formation of NOx through careful control of the fuel-air mixture during combustion. Control techniques used in LNBs includes staged air, and staged fuel, as well as other methods that effectively lower the flame temperature.

Experience suggests that significant reduction in NOx emissions can be realized using LNBs. The U.S. EPA reports that LNBs have achieved reduction up to 80%, but actual reduction depends on the type of fuel and varies considerably from one installation to another. Typical reductions range from 40% - 50% but under certain conditions, higher reductions are possible.

The use of a low NOx burner is a technically feasible control option for the Primary Reformer (EU-003) at this source.

Step 3: Rank the Remaining Control Technologies by Control Effectiveness

The following control technologies have been identified and ranked for the control of NOx from the Primary Reformer (EU-003).

(1) SCR (90% Control)
(2) Low NOx Burners (40% Control)

The applicant proposes the use of SCR to control NOx emissions from the Primary Reformer (EU-003). This is top BACT; therefore, no further review is necessary.

Step 4: Evaluate the Most Effective Controls and Document the Results

The following table lists the proposed NOx BACT determination for Ohio Valley Resources, LLC along with the existing NOx BACT determinations for similar emission units. All data in the table is based on the information obtained from the permit application submitted by Ohio Valley Resources, LLC, the U.S. EPA RACT/BACT/LAER Clearinghouse (RBLC), Indiana issued permits, and electronic versions of permits available at the websites of other permitting agencies.

RACT/BACT/LEAR CLEARINGHOUSE DATA
Primary Reformer (EU-003) – NOx

RBLC ID	Facility	Issued Date	Process Description	Capacity	Limitation	Control Method
LA-0211	Garyville Refinery	12/27/06	Hydrogen Reformer Furnace Vent	1,412.5 MMBtu/hr	0.0125 lb/MMBtu	Ultra-Low NOx Burner
T147-32322-00062	**Ohio Valley Resources, LLC**	**Proposed**	**Methane Primary Reformer**	**1,006.4 MMBtu/hr**	**9 ppm$_{vd}$ on a 30 day rolling average**	**SCR, 90% Control**
IA-0105	Iowa Fertilizer Company	10/26/12	Syngas Primary Reformer	1.13 MMCF/hr, 1,152.6 MMBtu/hr	9 ppmv on a 30 day rolling average, 56 TPY (12-mo.)	SCR
NM-0050	Artesia Refinery	12/14/07	Steam Methane Reformer Heater	337 MMBtu/hr	0.0125 lb/MMBtu, 4.21 lb/hr 3-hr avg. @ 3% O_2	SCR, 70% Control
OK-0134	Pryor Plant Chemical	02/23/09	Primary Reformer EUID #101, EUG#1	700 ton ammonia per day	0.2 lb/MMBtu, 11.93 lb/hr (3-hr over 168-hr)	Low NOx Burner, Good Combustion
OK-0135	Pryor Plant Chemical	02/23/09	Primary Reformer	700 ton ammonia per day	0.2 lb/MMBtu, 11.93 lb/hr (3-hr over 168-hr)	Low NOx Burner, Good Combustion

RBLC Review

The applicant proposes the use of SCR to control emissions of NOx to 9 ppmv. RBLC entries for reformers at fertilizer plants are limited and not all of the units listed directly correspond to the process used by Ohio Valley Resources, LLC. The Garyville Refinery reformer is based on hydrogen as a primary fuel, while Ohio Valley Resources' reformer will primarily combust natural gas. Hydrogen reformers have a cleaner fuel with lower emissions. The control efficiency for the SCR unit at the Artesia refinery is significantly less than the applicant's proposed 90% control efficiency. For methane steam reformers at fertilizer plants, Ohio Valley Resources has proposed top BACT.

Applicant Proposal

The applicant proposes the following as BACT:

(a) NOx emissions from the Primary Reformer (EU-003) shall be controlled by selective catalytic reduction (SCR) at all times the reformer is in operation; and

(b) NOx emissions from the Primary Reformer (EU-003) shall not exceed 14.09 lb/hr.

IDEM is not requiring the applicant to achieve 0.0125 lb/MMBtu in accordance with the BACT determination for the Artesia Refinery and the Garyville Refinery because significant design differences exist. The Garyville Refinery is a hydrogen reformer and not a methane reformer. Hydrogen is a cleaner burning fuel and can achieve lower emission levels. The Ohio Valley Resources, LLC reformer cannot combust hydrogen without a change in process design. In addition, Ohio Valley Resource was unable to obtain a performance guarantee for a steam methane reformer at the emission rates of the Garyville Refinery. The proposed 9 ppm NOx limit on a 30 day rolling average basis for Ohio Valley Resources is the lowest emission rate for a steam methane reformer at a Fertilizer plant.

Step 5: Select BACT

IDEM, OAQ has established NOx BACT for Primary Reformer (EU-003) as:

(1) NO_x emissions from the operation of Primary Reformer (EU-003) shall be controlled through the use of good combustion practices.

(2) The Primary Reformer (EU-003) shall combust natural gas and/or process off gas streams.

(3) NO_x emissions from the Primary Reformer (EU-003) shall be controlled by selective catalytic reduction (SCR) at all times the reformer is in operation.

(4) NO_x emissions from the Primary Reformer (EU-003) shall not exceed 9 ppm_{vd}, based on a thirty-day rolling average.

(2) NOx BACT – Front End Process Flare (EU-007)

Step 1: Identify Potential Control Technologies

The following control technologies have been identified for the control of NOx in the Front End Process Flare (EU-007):

(1) Flare design and good combustion practices;

(2) Process flaring minimization practices; and

(3) Flare Gas Recovery.

Certain NOx controls that may be used on other types of sources, such as selective catalytic reduction (SCR), selective non-catalytic reduction (SNCR), and flue gas recirculation (FGR) are not applicable to flares because the outlet exhaust of an elevated process flare is not enclosed or contained. Therefore, the emissions or flue gases cannot be routed to an add-on control device, and such add-on controls have not been utilized on flares.

Step 2: Eliminate Technically Infeasible Options

(a) **Flare design and good combustion practices**
Flare design and good combustion practices – flare design and monitoring are key elements in emissions performance of flares. The flare must be properly operated and maintained in order to achieve the anticipated emission rates guaranteed by the flare manufacturer. The use of proper flare design and good combustion practices are technically feasible control options for the Front End Process Flare (EU-007) at this source.

(b) **Process flaring minimization practices**
Process flaring minimization practices – to the extent actions can be taken to minimize the volume of gas going to the flare, emissions of NOx will be less. The use of process flaring minimization practices is a technically feasible control option for the Front End Process Flare (EU-007) at this source.

(c) **Flare gas recovery**
Flare gas recovery – flare gas recovery has been implemented at some facilities that produce and use internally generated fuel gas streams such as petroleum refineries. However, flare gas recovery for the Ohio Valley Resources, LLC facility is not feasible for the following reasons.

  (1) First, unlike a refinery’s nearly continuous supply of flared gases, flaring at the proposed Ohio Valley Resources, LLC facility will be an infrequent occurrence.

(2) Another difference is that the Ohio Valley Resources, LLC flaring events, the flared material may not be suitable for use as a fuel gas.

The use of a flare gas recovery system is not a technically feasible control option for the Front End Process Flare (EU-007) at this source.

Step 3: Rank the Remaining Control Technologies by Control Effectiveness
The applicant proposed both proper flare design and operation along with flare minimization practices as BACT for NOx. Therefore, no ranking or further analysis is required.

Step 4: Evaluate the Most Effective Controls and Document the Results
The following table lists the proposed NOx BACT determination for Ohio Valley Resources, LLC along with the existing NOx BACT determinations for similar emission units. All data in the table is based on the information obtained from the permit application submitted by Ohio Valley Resources, LLC, the U.S. EPA RACT/BACT/LAER Clearinghouse (RBLC), Indiana issued permits, and electronic versions of permits available at the websites of other permitting agencies.

RACT/BACT/LEAR CLEARINGHOUSE DATA
Front End Process Flare (EU-007) – NOx

RBLC ID	Facility	Issued Date	Process Description	Capacity	Limitation	Control Method
T147-32322-00062	**Ohio Valley Resources, LLC**	**Proposed**	**Process Flare EU-007**	**0.253 MMBtu/hr**	**0.068 lb/MMBtu, pilot and 595.47 lb/hr venting**	**Combustion / design, FMP, nat. gas, limit use**
AK-0076	Exxon, Point Thomson Production	08/20/12	Combustion Flares	35 MMCF/yr	0.068 lb/MMBtu	None
TX-0436	Borger Carbon Black Plant	10/03/02	Dryers, Boilers, Flare	Unspecified	0.1 lb/MMBtu	Good Combustion Practices and Design
ID-0017	Southeast Idaho Energy, LLC	02/10/09	Process Flare SRC21	1.5 MMBtu/hr pilot	No emissions from the process, no limit on pilot emissions	None
IA-0105	Iowa Fertilizer Company	10/26/12	Ammonia Flare	0.4 MMBtu/hr	No Numeric Limit	Work Practice, Good Combustion Practices

RBLC Review
The requirements of BACT listed in the RBLC for flares mostly involve the proper design and operation of the flare to achieve a manufacturer performance guarantee. The lowest emission rate achievable does not vary significantly for similar flares in similar service. The applicant is proposing an emission limitation of 0.068 lb/MMBtu for the flare pilot and purge gas. During scheduled flaring events such as process startup and shutdown, the emission of NOx increases to 595.47 lb/hr.

Applicant Proposal
The applicant proposes the following as BACT:

(a) Proper design and good combustion practices;

(b) The use of natural gas;

(c) The use of flare minimization practices;

(d) Venting for Startup, Shutdown and Malfunction shall not exceed 168 hours per twelve consecutive month period with compliance determined at the end of each month; and

(e) The NOx emission rate from the Front End Process Flare (EU-007) shall not exceed 0.068 lb/MMBtu for the pilot and purge gas.

The applicant proposed top BACT.

Step 5: Select BACT

IDEM, OAQ has established NOx BACT for the Front End Process Flare (EU-007) as:

(1) In order to control NO_x emissions, the pilot and purge gas fuels used in the flare shall be natural gas.

(2) Venting in the Front End Process Flare (EU-007) shall not exceed 336 hours per twelve consecutive month period with compliance determined at the end of each month.

(3) Comply with the following flare minimization practices to reduce emissions during startups, shutdowns, and other flaring events:

(A) Flare Use Minimization: Process syngas streams to flare EU-007 shall not contain ammonia. During the startup of the sequential reformer, only one process stream at a time shall be sent to the flare to the extent practicable. Maximize the use of process syngas during the startup of the Ammonia Unit;

(B) The Permittee shall train all operators responsible for the day-to-day operation of the flares on the flare minimization practices and the specific procedures to follow during process startup, shutdown, and other flaring events; and

(C) The Permittee shall investigate the “root cause” of malfunction events that cause flaring events other than at startup or shutdown. This root cause analysis shall identify the apparent cause of unanticipated flaring event and shall recommend additional preventive measures that will minimize the chance of a repeat event. The Permittee shall implement the recommended preventive measures.

(4) NO_x emissions shall be controlled by use of the following practices:

(A) Flares shall be designed for and operated with no visible emissions, except for periods not to exceed 5 minutes during any two consecutive hours;

(B) Flares shall be operated with a flame present at all times; and

(C) Flares shall be continuously monitored to assure the presence of a pilot flame with a thermocouple, infrared monitor, or other approved device.

(5) NO_x emissions from the Front End Process Flare (EU-007) shall not exceed 0.068 lb/MMBtu, based on a three-hour average, during normal operation, non-venting periods.

(6) NO_x emissions from the Front End Process Flare (EU-007) shall not exceed 595.47 lb/hr, based on a three-hour average, during venting events.

(3) NOx BACT – Ammonia Catalyst Startup Heater (EU-010)

Step 1: Identify Potential Control Technologies

IDEM, OAQ has identified the following NOx control technologies for the Ammonia Catalyst Startup Heater (EU-010):

(1) Selective Catalytic Reduction (SCR)
(2) Selective Non-Catalytic Reduction (SNCR)
(3) Low NOx Burner (LNB)
(4) Flue Gas Recirculation (FGR)
(5) Low NOx Burner (LNB) with Flue Gas Recirculation (FGR)

NOx add-on control technologies are discussed below:

Step 2: Eliminate Technically Infeasible Options

(a) **Selective Catalytic Reduction**

Selective Catalytic Reduction (SCR) process involves the mixing of anhydrous or aqueous ammonia vapor with flue gas and passing the mixture through a catalytic reactor to reduce NO_X to nitrogen and water. Under optimal conditions, SCR has removal efficiencies up to 90% when used on steady state processes. The efficiency of removal will be reduced for processes that are not stable or require frequent changes in the mode of operation.

The most important factor affecting SCR efficiency is temperature. SCR typically operates in a flue gas window ranging from 500°F to 1100°F, although the optimum temperature range depends on the type of catalyst and the flue gas composition. Temperatures below the optimum decrease catalyst activity and allow NH_3 to slip through. Until the system reaches the minimum temperature, the SCR operates without ammonia injection. Above the optimum range, ammonia will oxidize to form additional NO_x. SCR efficiency is also largely dependent on the stoichiometric molar ratio of NH_3:NOx; variation of the ideal 1:1 ratio to 0.5:1 ratio can reduce the removal efficiency to 50%.

Selective catalytic reduction (SCR) is a technically feasible control option for the Ammonia Catalyst Startup Heater (EU-010) at this source.

(b) **Selective Non-Catalytic Reduction (SNCR)**

With selective non-catalytic reduction (SNCR), NO_X is selectively removed by the injection of ammonia or urea into the flue gas at an appropriate temperature window of 1600°F to 2000°F and without employing a catalyst. Similar to SCR without a catalyst bed, the injected chemicals selectively reduce the NO_X to molecular nitrogen and water. This approach avoids the problem related to catalyst fouling but the temperature window and reagent mixing residence time is critical for conducting the necessary chemical reaction.

At the proper temperature, urea decomposes to produce ammonia which is responsible for NO_X reduction. At a higher temperature, the rate of competing reactions for the direct oxidation of ammonia that actually forms NOx becomes significant. At a lower temperature, the rates of NO_X reduction reactions become too slow resulting in urea slip (i.e. emissions of unreacted urea).

Optimal implementation of SNCR requires the employment of an injection system that can accomplish thorough reagent/gas mixing within the temperature window while accommodating spatial and production rate temperature variability in the gas stream. The attainment of maximum NO_x control performance therefore requires that the boiler exhibit a favorable opportunity for the application of this technology relative to the location of the reaction temperature range and steady operation within that temperature window. Given the standby nature of the operation of these boilers, steady-state operation cannot be expected and makes SNCR technically infeasible.

Selective non-catalytic reduction (SNCR) is not a technically feasible control option for the Ammonia Catalyst Startup Heater (EU-010) at this source.

(c) **Low NOx Burners (LNB)**
Using LNB can reduce formation of NOx through careful control of the fuel-air mixture during combustion. Control techniques used in LNBs includes staged air, and staged fuel, as well as other methods that effectively lower the flame temperature.

Experience suggests that significant reduction in NOx emissions can be realized using LNBs. The U.S. EPA reports that LNBs have achieved reduction of up to 80%, but actual reduction depends on the type of fuel and varies considerably from one installation to another. Typical reductions range from 40% - 50% but under certain conditions, higher reductions are possible.

The use of a low NOx burner is a technically feasible control option for the Ammonia Catalyst Startup Heater (EU-010) at this source.

(d) **Flue Gas Recirculation (FGR)**
Recirculating a portion of the flue gas to the combustion zone can lower the peak flame temperature and result in reduced thermal NOx production. Flue gas recirculation (FGR) can be highly effective technique for lowering NOx emissions from burners and it's relatively inexpensive to apply. Most of the early FGR work was done on boilers, and investigators found that recirculating up to 25% of the flue gases through the burner could lower NOx emissions to as little as 25% of their normal levels. FGR lowers NOx emissions in two ways; the cooler, relatively inert, recirculated flue gases act as a heat sink, absorbing heat from the flame and lowering peak flame temperatures and when mixed with the combustion air, recirculated flue gases lower the average oxygen content of the air, starving the NOx-forming reactions for one of the needed ingredients.

The use of Flue Gas Recirculation (FGR) is a technically feasible control option for the Ammonia Catalyst Startup Heater (EU-010) at this source.

(e) **Flue Gas Recirculation (FGR) and Low NOx Burners (LNB)**
Flue gas recirculation and low NOx burners can be used in conjunction to achieve higher overall emission reductions.

The use of Flue Gas Recirculation (FGR) with Low NOx Burners (LNB) is a technically feasible control option for the Ammonia Catalyst Startup Heater (EU-010) at this source.

(f) **No Control**
The no control option is where no add-on controls are proposed to control NOx from the Ammonia Catalyst Startup Heater (EU-010). This option is usually feasible in the case of emission units that have extremely low emissions or extremely low hours of operation that make the use of add-on controls impractical.

The use of the no control option is a technically feasible control option for the Ammonia Catalyst Startup Heater (EU-010) at this source.

Step 3: Rank the Remaining Control Technologies by Control Effectiveness

The following control technologies are available for NOx control for the Ammonia Catalyst Startup Heater (EU-010). They are ranked in order of control efficiency:

(1) Selective Catalytic Reduction (90% control)
(2) Low NOx Burners with Flue Gas Recirculation (55% to 60% control)
(3) Low NOx Burners (50% control)
(4) Flue Gas Recirculation (25%)
(5) No Control Option (0% control)

The applicant has selected a no control option as BACT. As such, a technical, environmental and economic analysis is normally performed. In this case, IDEM, OAQ is not requiring further analysis because this emission unit will only operate 200 hours a year and it is clear add-on controls are inappropriate for this specific installation.

Step 4: Evaluate the Most Effective Controls and Document the Results

The following table lists the proposed NOx BACT determination for Ohio Valley Resources, LLC along with the existing NOx BACT determinations for similar emission units. All data in the table is based on the information obtained from the permit application submitted by Ohio Valley Resources, LLC, the U.S. EPA RACT/BACT/LAER Clearinghouse (RBLC), Indiana issued permits, and electronic versions of permits available at the websites of other permitting agencies.

RACT/BACT/LEAR CLEARINGHOUSE DATA
Ammonia Catalyst Startup Heater (EU-010) – NOx

RBLC ID	Facility	Issued Date	Process Description	Capacity	Limitation	Control Method
T147-32322-00062	**Ohio Valley Resources, LLC**	**Proposed**	**Ammonia Catalyst Startup Heater**	**106.3 MMBtu/hr**	**183.7 lb/MMCF, 3 hr avg., 200 hr of operations**	**Good Combustion Practices, Usage Limit**
LA-0244	Sasol N.A., Inc.	11/29/10	Natural Gas Charge Heater	87.3 MMBtu/hr	7.15 lb/hr	None, 0.08 lb/MMBtu
IA-0105	Iowa Fertilizer Company	10/26/12	Startup Heater	110 MMBtu/hr	0.119 lb/MMBtu	Good Combustion Practices
LA-0244	Sasol, N.A., Inc.	11/29/10	Oil Heater	170 MMBtu/hr	19.69 lb/hr	None, 0.12 lb/MMBtu
LA-0262	Cornerstone Chemical Company	05/03/12	Stack Heater	61 MMBtu/hr	10.15 lb/hr	None, 0.17 lb/MMBtu

RBLC Review

The Ammonia Catalyst Startup Heater (EU-010) is intended to be used by the source for a maximum of 200 hours per year for plant startup. The limited amount of use of this heater makes the use of add-on controls impractical. The unrestricted potential to emit of the Ammonia Catalyst Startup Heater (EU-010) is 83.85 TPY. The limited potential to emit based on 200 hours of operation is 1.91 TPY. NOx emissions from these units are controlled by engine design and good combustion practices.

Applicant Proposal

The applicant proposed the following as BACT:

(a) Good design and good combustion practices;

(b) The use of natural gas;

(c) The Ammonia Catalyst Startup Heater (EU-010) shall not operate more than 200 hours per year; and

(d) NOx emissions from the Ammonia Catalyst Startup Heater (EU-010) shall not exceed 183.7 lb/MMCF and 0.18 lb/MMBtu.

The lowest emission rate indicated in the RBLC is 0.08 lb/MMBtu. Ohio Valley Resources is proposing an emission rate of 0.18 lb/MMBtu and an annual limit of 200 hours of operation. If the Ohio Valley Resources unit was to accept a BACT limit of 0.08 lb/MMBtu without a limit on the hours of operation, the startup heater would emit 37.25 tons of NOx per year. If the applicant's proposal is accepted, the startup heater would emit 1.91 tons of NOx per year. So while the emissions on an hourly rate are higher, the annual rate is much lower and represents a higher level of control.

Step 5: Select BACT

IDEM, OAQ has established NOx BACT for the Ammonia Catalyst Startup Heater (EU-010) as:

(1) In order to control NO_x emissions, the Ammonia Catalyst Startup Heater (EU-010) shall combust natural gas.

(2) In order to control NO_x emissions, the Ammonia Catalyst Startup Heater (EU-010) shall be controlled by good heater design and good combustion practices.

(3) Fuel usage in the Ammonia Catalyst Startup Heater (EU-010) shall not exceed 20.84 MMCF per twelve consecutive month period with compliance determined at the end of each month.

(4) NO_x emissions from the Ammonia Catalyst Startup Heater (EU-010) shall not exceed 183.70 lb/MMCF, based on a three-hour average.

(4) NOx BACT – Back End Ammonia Process Vent Flare (EU-006)

Step 1: Identify Potential Control Technologies

The following control technologies have been identified for the control of NOx in the Back End Ammonia Process Vent Flare (EU-006):

(1) Flare design and good combustion practices;

(2) Process flaring minimization practices; and

(3) Flare Gas Recovery.

Certain NOx controls that may be used on other types of sources, such as selective catalytic reduction (SCR), selective non-catalytic reduction (SNCR), and flue gas recirculation (FGR) are not applicable to flares because the outlet exhaust of an elevated process flare is not enclosed or contained. Therefore, the emissions or flue gases cannot be routed to an add-on control device, and such add-on controls have not been utilized on flares.

Flare design and good combustion practices

Flare design and good combustion practices – Flare design and monitoring are key elements in emissions performance of flares. The flare must be properly operated and maintained in order to achieve the anticipated emission rates guaranteed by the flare manufacturer.

The use of proper flare design and good combustion practices is a technically feasible control option for the Back End Ammonia Process Vent Flare (EU-006) at this source.

Process flaring minimization practices

Process flaring minimization practices – To the extent actions can be taken to minimize the volume of gas going to the flare, emissions of NOx will be less. Flaring minimization practices are feasible and are evaluated in the analysis of BACT.

The use of process flaring minimization practices is a technically feasible control option for the Back End Ammonia Process Vent Flare (EU-006) at this source.

Flare gas recovery

Flare gas recovery – Flare gas recovery has been implemented at some facilities that produce and use internally generated fuel gas streams such as petroleum refineries. However, flare gas recovery for the Ohio Valley Resources, LLC facility is not feasible for the following reasons.

(1) First, unlike a refinery's nearly continuous supply of flared gases, flaring at the proposed Ohio Valley Resources, LLC facility will be an infrequent occurrence.

(2) Another difference is that the Ohio Valley Resources, LLC flaring events, the flared material may not be suitable for use as a fuel gas.

The use of a flare gas recovery system is not a technically feasible control option for the Back End Ammonia Process Vent Flare (EU-006) at this source.

<u>Step 3: Rank the Remaining Control Technologies by Control Effectiveness</u>

The applicant proposed both proper flare design and operation along with flare minimization practices as BACT for NOx. Therefore, no ranking or further analysis is required.

<u>Step 4: Evaluate the Most Effective Controls and Document the Results</u>

The following table lists the proposed NOx BACT determination for Ohio Valley Resources, LLC along with the existing NOx BACT determinations for similar emission units. All data in the table is based on the information obtained from the permit application submitted by Ohio Valley Resources, LLC, the U.S. EPA RACT/BACT/LAER Clearinghouse (RBLC), Indiana issued permits, and electronic versions of permits available at the websites of other permitting agencies.

RACT/BACT/LEAR CLEARINGHOUSE DATA
Back End Ammonia Process Flare (EU-006) – NOx

RBLC ID	Facility	Issued Date	Process Description	Capacity	Limitation	Control Method
T147-32322-00062	**Ohio Valley Resources, LLC**	**Proposed**	**Ammonia Process Flare EU-006**	**0.253 MMBtu/hr**	**0.068 lb/MMBtu, pilot and 624.94 lb/hr, venting**	**Combustion / design, FMP, nat. gas, limit use**
AK-0076	Exxon, Point Thomson Production	08/20/12	Combustion Flares	35 MMCF/yr	0.068 lb/MMBtu	None
TX-0436	Borger Carbon Black Plant	10/03/02	Dryers, Boilers, Flare	Unspecified	0.1 lb/MMBtu	Good Combustion Practices and Design
ID-0017	Southeast Idaho Energy, LLC	02/10/09	Process Flare SRC21	1.5 MMBtu/hr pilot	No emissions from the process, no limit on pilot emissions	None
IA-0105	Iowa Fertilizer Company	11/02/12	Ammonia Flare	0.4 MMBtu/hr	No Numeric Limit	Work Practice, Good Combustion Practices

RBLC Review
The requirements of BACT listed in the RBLC for flares mostly involve the proper design and operation of the flare to achieve a manufacturer performance guarantee. The lowest emission rate achievable does not vary significantly for similar flares in similar service.

Applicant Proposal
The applicant proposes the following as BACT:

(a) Proper design and good combustion practices;

(b) The use of natural gas;

(c) The use of flare minimization practices;

(d) Venting for Startup, Shutdown and Malfunction shall not exceed 336 hours per twelve consecutive month period with compliance determined at the end of each month; and

(e) The NOx emission rate from the Back End Ammonia Process Flare (EU-006) shall not exceed 0.068 lb/MMBtu.

The applicant proposed top BACT. IDEM, OAQ is adding an emission limitation to make startup, shutdown and malfunction emissions enforceable.

Step 5: Select BACT
IDEM, OAQ has established NOx BACT for the Back End Ammonia Process Vent Flare (EU-006) as:

(1) In order to control NO_x emissions, the pilot and purge gas fuels used in the flare shall be natural gas.

(2) Venting in the Back End Ammonia Process Flare (EU-006) shall not exceed 336 hours per twelve consecutive month period with compliance determined at the end of each month.

(3) Comply with the following flare minimization practices to reduce emissions during startups, shutdowns, and other flaring events:

(A) Flare Use Minimization: Flare EU-006 shall be limited to flaring ammonia during high-pressure events to the extent practicable. The ammonia compressor main shall be depressurized prior to compressor maintenance. The Permittee shall limit venting ammonia rich streams to Flare EU-006 to the extent practicable during non-emergency startup and shutdown operations;

(B) The Permittee shall train all operators responsible for the day-to-day operation of the flares on the flare minimization practices and the specific procedures to follow during process startup, shutdown, and other flaring events; and

(C) The Permittee shall investigate the “root cause” of malfunction events that cause flaring events other than at startup or shutdown. This root cause analysis shall identify the apparent cause of unanticipated flaring event and shall recommend additional preventive measures that will minimize the chance of a repeat event. The Permittee shall implement the recommended preventive measures.

(4) NO_x emissions from the Back End Ammonia Process Vent Flare (EU-006) shall be controlled by the use of the following practices:

(A) Flares shall be designed for and operated with no visible emissions, except for periods not to exceed 5 minutes during any two consecutive hours;

(B) Flares shall be operated with a flame present at all times; and

(C) Flares shall be continuously monitored to assure the presence of a pilot flame with a thermocouple, infrared monitor, or other approved device.

(5) NO_x emissions from the Back End Ammonia Process Vent Flare (EU-006) shall not exceed 0.068 lb/MMBtu, based on a three-hour average, during normal operation, non-venting periods.

(6) NO_x emissions from the Back End Ammonia Process Vent Flare (EU-006) shall not exceed 624.94 lb/hr, based on a three-hour average, during venting events.

(5) NOx BACT – Ammonia Storage Flare (EU-005)

Step 1: Identify Potential Control Technologies

The following control technologies have been identified for the control of NOx in the Ammonia Storage Flare (EU-005):

(1) Flare design and good combustion practices;

(2) Process flaring minimization practices; and

(3) Flare Gas Recovery.

Certain NOx controls that may be used on other types of sources, such as selective catalytic reduction (SCR), selective non-catalytic reduction (SNCR), and flue gas recirculation (FGR) are not applicable to flares because the outlet exhaust of an elevated process flare is not enclosed or contained. Therefore, the emissions or flue gases cannot be routed to an add-on control device, and such add-on controls have not been utilized on flares.

Flare design and good combustion practices
Flare design and good combustion practices – Flare design and monitoring are key elements in emissions performance of flares. The flare must be properly operated and maintained in order to achieve the anticipated emission rates guaranteed by the flare manufacturer.

The use of proper flare design and good combustion practices is a technically feasible control option for the Ammonia Storage Flare (EU-005) at this source.

Process flaring minimization practices
Process flaring minimization practices – To the extent actions can be taken to minimize the volume of gas going to the flare, emissions of NOx will be less. Flaring minimization practices are feasible and are evaluated in the analysis of BACT.

The use of process flaring minimization practices is a technically feasible control option for the Ammonia Storage Flare (EU-005) at this source.

Flare gas recovery
Flare gas recovery – Flare gas recovery has been implemented at some facilities that produce and use internally generated fuel gas streams such as petroleum refineries. However, flare gas recovery for the Ohio Valley Resources, LLC facility is not feasible for the following reasons.

(1) First, unlike a refinery's nearly continuous supply of flared gases, flaring at the proposed Ohio Valley Resources, LLC facility will be an infrequent occurrence.

(2) Another difference is that the Ohio Valley Resources, LLC flaring events, the flared material may not be suitable for use as a fuel gas.

The use of a flare gas recovery system is not a technically feasible control option for the Ammonia Storage Flare (EU-005) at this source.

<u>Step 3: Rank the Remaining Control Technologies by Control Effectiveness</u>
The applicant proposed both proper flare design and operation along with flare minimization practices as BACT for NOx. Therefore, no ranking is required.

<u>Step 4: Evaluate the Most Effective Controls and Document the Results</u>
The following table lists the proposed NOx BACT determination for Ohio Valley Resources, LLC along with the existing NOx BACT determinations for similar emission units. All data in the table is based on the information obtained from the permit application submitted by Ohio Valley Resources, LLC, the U.S. EPA RACT/BACT/LAER Clearinghouse (RBLC), Indiana issued permits, and electronic versions of permits available at the websites of other permitting agencies.

RACT/BACT/LEAR CLEARINGHOUSE DATA Ammonia Storage Flare (EU-005) – NOx						
RBLC ID	**Facility**	**Issued Date**	**Process Description**	**Capacity**	**Limitation**	**Control Method**
T147-32322-00062	**Ohio Valley Resources, LLC**	**Proposed**	**Ammonia Storage Flare EU-005**	**0.126 MMBtu/hr**	**0.068 lb/MMBtu, pilot and 125.0 lb/hr, venting**	**Combustion / design, FMP, nat. gas, limit use**
AK-0076	Exxon, Point Thomson Production	08/20/12	Combustion Flares	35 MMCF/yr	0.068 lb/MMBtu	None
TX-0436	Borger Carbon Black Plant	10/03/02	Dryers, Boilers, Flare	Unspecified	0.1 lb/MMBtu	Good Combustion Practices and Design
ID-0017	Southeast Idaho Energy, LLC	02/10/09	Process Flare SRC21	1.5 MMBtu/hr pilot	No emissions from the process, no limit on pilot emissions	None
IA-0105	Iowa Fertilizer Company	11/02/12	Ammonia Flare	0.4 MMBtu/hr	No Numeric Limit	Work Practice, Good Combustion Practices

RBLC Review
The requirements of BACT listed in the RBLC for flares mostly involve the proper design and operation of the flare to achieve a manufacturer performance guarantee. The lowest emission rate achievable does not vary significantly for similar flares in similar service.

Applicant Proposal
The applicant proposes the following as BACT:

(a) Proper design and good combustion practices;

(b) The use of natural gas; and

(c) The use of flare minimization practices.

The applicant proposed top BACT. IDEM, OAQ is adding an emission limitation to make startup, shutdown and malfunction emissions enforceable.

Step 5: Select BACT
IDEM, OAQ has established NOx BACT for the Ammonia Storage Flare (EU-005) as:

(1) In order to control NO_x emissions, the pilot and purge gas fuels used in the flare shall be natural gas.

(2) Venting for Startup, Shutdown and Malfunction shall not exceed 168 hours per twelve consecutive month period with compliance determined at the end of each month.

(3) Comply with the following flare minimization practices to reduce emissions during startups, shutdowns, and other flaring events:

(A) Flare Use Minimization: The Permittee shall limit periods when the backup storage compressor and the ammonia refrigeration compressor are offline at the same time to the extent practicable;

(B) The Permittee shall train all operators responsible for the day-to-day operation of the flares on the flare minimization practices and the specific procedures to follow during process startup, shutdown, and other flaring events; and

(C) The Permittee shall investigate the “root cause” of malfunction events that cause flaring events other than at startup or shutdown. This root cause analysis shall identify the apparent cause of unanticipated flaring event and shall recommend additional preventive measures that will minimize the chance of a repeat event. The Permittee shall implement the recommended preventive measures.

(4) NO_x emissions shall be controlled by use of the following practices:

(A) Flares shall be designed for and operated with no visible emissions, except for periods not to exceed 5 minutes during any two consecutive hours;

(B) Flares shall be operated with a flame present at all times; and

(C) Flares shall be continuously monitored to assure the presence of a pilot flame with a thermocouple, infrared monitor, or other approved device.

(5) NO_x emissions from the Ammonia Storage Flare (EU-005) shall not exceed 0.068 lb/MMBtu, based on a three-hour average, during normal operation, non-venting periods.

(6) NO_x emissions from the Ammonia Storage Flare (EU-005) shall not exceed 125.0 lb/hour, based on a three-hour average, during venting events.

(6) NOx BACT – Two Identical Nitric Acid Plants (EU-001A and EU-001B)

Step 1: Identify Potential Control Technologies

IDEM, OAQ has identified the following control technologies for NOx for Nitric Acid Plants (EU-001A and EU-001B) as follows:

(1) Selective Catalytic Reduction (SCR);

(2) Hydrogen Peroxide Injection; and

(3) Selective Noncatalytic Reduction (SNCR) or EnviNOx System.

The add-on control technologies are discussed below.

Step 2: Eliminate Technically Infeasible Options

(a) **Selective Catalytic Reduction**
Selective Catalytic Reduction (SCR) process involves the mixing of anhydrous or aqueous ammonia vapor with flue gas and passing the mixture through a catalytic reactor to reduce NO_X to nitrogen and water. Under optimal conditions, SCR has a removal efficiency of up to 90% when used on steady state processes. The efficiency of removal will be reduced for processes that are not stable or require frequent changes in the mode of operation.

The most important factor affecting SCR efficiency is temperature. SCR typically operates in a flue gas window ranging from 500°F to 1100°F, although the optimum temperature range depends on the type of catalyst and the flue gas composition. Temperatures below the optimum decrease catalyst activity and allow NH_3 to slip through. Until the system reaches the minimum temperature, the SCR operates without ammonia injection. Above the optimum range, ammonia will oxidize to form additional NO_x. SCR efficiency is also largely dependent on the stoichiometric molar ratio of NH_3:NOx; variation of the ideal 1:1 ratio to 0.5:1 ratio can reduce the removal efficiency to 50%.

Selective catalytic reduction (SCR) is a technically feasible control option for the Nitric Acid Plants (EU-001A and EU-001B) at this source.

(b) **Selective Non-Catalytic Reduction (SNCR)**

With selective non-catalytic reduction (SNCR), NO_X is selectively removed by the injection of ammonia or urea into the flue gas at an appropriate temperature window of 1600°F to 2000°F and without employing a catalyst. Similar to SCR without a catalyst bed, the injected chemicals selectively reduce the NO_X to molecular nitrogen and water. This approach avoids the problem related to catalyst fouling but the temperature window and reagent mixing residence time is critical for conducting the necessary chemical reaction.

At the proper temperature, urea decomposes to produce ammonia which is responsible for NO_X reduction. At a higher temperature, the rate of competing reactions for the direct oxidation of ammonia that actually forms NOx becomes significant. At a lower temperature, the rates of NO_X reduction reactions become too slow resulting in urea slip (i.e. emissions of unreacted urea).

Optimal implementation of SNCR requires the employment of an injection system that can accomplish thorough reagent/gas mixing within the temperature window while accommodating spatial and production rate temperature variability in the gas stream. The attainment of maximum NO_x control performance therefore requires that the furnace exhibit a favorable opportunity for the application of this technology relative to the location of the reaction temperature range and steady operation within that temperature window.

Selective non-catalytic reduction (SNCR) in general is a technically feasible control option for the Nitric Acid Plants (EU-001A and EU-001B) at this source.

(c) **Hydrogen Peroxide Injection**

Hydrogen peroxide injection was identified in the RBLC for the Kennewick Fertilizer Operation in the State of Washington. The project was granted an innovative control waiver under 40 CFR 52.21(v). After construction and operation, the BACT limit was reassessed to be 0.6 lb NOx / ton acid. This emission rate is greater than the emission limitation required by 40 CFR 60, Subpart Ga and no other facility is using this technology.

Hydrogen peroxide injection is not a technically feasible control option for the Nitric Acid Plants (EU-001A and EU-001B) at this source.

(d) **Uhde EnviNOx System**
The EnviNOx system is a patented system capable of reducing both NOx and N_2O emissions from waste industrial gases. The system was developed by Uhde GmbH in Germany and uses a new type of catalyst to convert N_2O and NOx to N_2, O_2 and H_2O in a two stage reactor. This technology has been commercially available since September 2003 for nitric acid plants designed by Uhde. The OVR facility was not designed by Uhde and the patented technology is unavailable. The Uhde EnviNOx system is not a technically feasible option.

Step 3: Rank the Remaining Control Technologies by Control Effectiveness

IDEM, OAQ has ranked the remaining control technologies in order of their NOx control efficiency and listed them below:

(1) Selective Catalytic Reduction (98% + control)

(2) Selective Noncatalytic Reduction (93% control)

The applicant has selected Selective Catalytic Reduction which is top BACT; therefore, no further ranking is required.

Step 4: Evaluate the Most Effective Controls and Document the Results

The following table lists the proposed NOx BACT determination for Ohio Valley Resources, LLC along with the existing NOx BACT determinations for similar emission units. All data in the table is based on the information obtained from the permit application submitted by Ohio Valley Resources, LLC, the U.S. EPA RACT/BACT/LAER Clearinghouse (RBLC), Indiana issued permits, and electronic versions of permits available at the websites of other permitting agencies.

RACT/BACT/LEAR CLEARINGHOUSE DATA
Two Identical Nitric Acid Plants (EU-001A and EU-001B) – NOx

RBLC ID	Facility	Issued Date	Process Description	Capacity	Limitation	Control Method
T147-32322-00062	**Ohio Valley Resources, LLC**	**Proposed**	**Nitric Acid Units EU-001A EU-001B**	**630 tons/day, each**	**0.5 lb/ton nitric acid, 30 day average.**	**SCR / Catalytic Decomposition, 90% Control Throughput limit**
IA-0105	Iowa Fertilizer Company	10/26/12	Nitric Acid Plant	1,905 MT/day	5 ppmv, 30 day rolling and 30 TPY, 12 month rolling	Uhde EnviNOx 2,100 ton NA/day, 0.5 lb/ton Nitric Acid
WA-0318	Kennewick Fertilizer Operations	07/11/08	Plant 7 Nitric Acid Plant	76,300 TPY Nitric Acid	0.524 lb/ton nitric acid 27 TPY	SCR, 98% Control, 209 ton NA/day
WA-0318	Kennewick Fertilizer Operations	07/11/08	Plant 9 Nitric Acid Plant	270,000 TPY Nitric Acid	0.6 lb/ton 400 lb/day 47 TPY	Hydrogen Peroxide Injection, 98% Control
GA-0109	PCS Nitrogen Fertilizer – Augusta Plant	05/10/05	Nitric Acid Plant	Unspecified	3 lb/ton nitric acid 297 tons/yr	NSCR, 93% Control
OK-0135	Pryor Plant Chemical Company	02/23/09	Nitric Acid Plant #1	8.3 lb/hr	1.6 lb/ton, 3 lb/ton for a 7 day maximum	Extended Absorption with NSCR

RBLC Review

RBLC entries for NOx emissions from nitric acid plants indicate SCR, NSCR and EnviNOx are viable control technologies. The lowest NOx emission rates achieved are 0.5 lb NOx per ton of nitric acid produced. Control efficiencies are not directly comparable due to design differences in each individual facility.

Applicant Proposal

The applicant proposed the following as BACT:

(a) NOx emissions from the Nitric Acid Plants (EU-001A and EU-001B) shall be controlled by a selective catalytic reduction system (SCR) at all times the process is in operation.

(b) NOx emissions from the nitric acid stacks shall not exceed 0.5 lb NOx per ton of nitric acid produced, based on a 30-day average.

The applicant has accepted top BACT.

Step 5: Select BACT

IDEM, OAQ has established NOx BACT for the Nitric Acid Plants (EU-001A and EU-001B) as:

(1) The combined nitric acid production from Nitric Acid Plants (EU-001A and EU-001B) shall not exceed 459,900 tons of 100% nitric acid per twelve consecutive month period with compliance determined at the end of each month.

(2) NO_x emissions from the Nitric Acid Plants (EU-001A and EU-001B) shall not exceed 0.5 lb NO_x per ton acid, based on a thirty day average, each, using Selective Catalytic Reduction (SCR).

(7) NOx BACT – Two Identical Nitric Acid Storage Tanks (EU-022A and EU-022B)

Step 1: Identify Potential Control Technologies

The following control technologies have been identified for the control of NOx from the nitric acid storage tanks.

(a) **Add-on Control Technologies:** The following add on control technologies are available for controlling NOx from the nitric acid storage tanks;

(1) Scrubber with water, sodium hydroxide, or a dilute acid
(2) Nitrogen Blanket
(3) Vapor Recovery System

Each of the Nitric Acid Storage Tanks (EU-022A and EU-022B) have the potential to emit NOx of less than one ton per year. Therefore, add-on controls are obviously impractical on a dollar per ton removed basis. The use of add-on controls is not considered a viable control option for the nitric acid storage tanks.

(b) **Submerged Fill:** Loading losses occur when a storage tank is filled because the vapor space above the liquid is displaced as the liquid level in the tank increases. One method of lowering the amount of emissions is minimizing the overall concentration of a pollutant in this vapor space. For a storage tank, the use of splash loading results in a high level of turbulence at the liquid/water interface. This turbulence results in higher levels of mass transfer between the liquid and vapor phases, resulting in a higher concentration of pollutant in the vapor space. The use of a submerged fill pipe in the storage tank results in the liquid being introduced far enough below the liquid/vapor interface that mass transfer of the pollutant is minimized. The use of a submerged fill pipe is an available NOx control method for storage tanks.

(c) **Temperature Control:** Another method of controlling the concentration of a pollutant in the vapor space above a liquid in a storage tank is to maintain the temperature of the liquid at the lowest temperature physically and economically feasible. Lower liquid temperatures result in lower vapor pressures and slower mass transfer of the pollutant. Unless the process requires the liquid to be stored at a constant temperature, this is not a practical emission control method for tanks with low emissions.

Step 2: Eliminate Technically Infeasible Options

Each of the Nitric Acid Storage Tanks (EU-022A and EU-022B) has a potential to emit NOx below one ton per year (0.31 TPY, each). This extremely low emission rate makes the use of add-on controls impractical due to high capital and annual operational costs relative to the emission reduction obtained. IDEM, OAQ has determined that no cost effective add-on control measures exist for the Nitric Acid Storage Tanks. However, the use of a submerged fill pipe is a technologically feasible NOx control method.

Step 3: Rank the Remaining Control Technologies by Control Effectiveness

IDEM, OAQ has determined that no add-on control technologies are available to the Nitric Acid Storage Tanks. The use of a submerged fill pipe is the only NOx control method available. Therefore, a ranking is not necessary.

Step 4: Evaluate the Most Effective Controls and Document the Results

The following table lists the proposed NOx BACT determination for Ohio Valley Resources, LLC along with the existing NOx BACT determinations for similar emission units. All data in the table is based on the information obtained from the permit application submitted by Ohio Valley Resources, LLC, the U.S. EPA RACT/BACT/LAER Clearinghouse (RBLC), Indiana issued permits, and electronic versions of permits available at the websites of other permitting agencies.

RACT/BACT/LEAR CLEARINGHOUSE DATA
Nitric Acid Storage Tanks (EU-022A and EU-022B) – NOx

RBLC ID	Facility	Issued Date	Process Description	Capacity	Limitation	Control Method
T147-32322-00062	**Ohio Valley Resources, LLC**	**Proposed**	**Nitric Acid Storage Tanks**	**1,105 ton/day of 57% Nitric Acid, each**	**0.0015 lb/ton**	**Submerged Fill, Throughput limit**
IA-0105	Iowa Fertilizer Company	11/02/12	Nitric Acid Storage Tank	1,935,773 gallons	0.72 TPY	Acid/Water Lock

RBLC Review

The only entry in the RBLC for NOx emissions from a nitric acid storage tank is from the Iowa Fertilizer Company. This tank has an emission limitation based the design throughput of nitric acid. The control method listed is really a design feature of the tank based on a tank seal method. The Ohio Valley Resources, LLC nitric acid tanks are half the size and are more process tanks than storage tanks. As such, they do not employ the same tank seal designs.

Applicant Proposal

The applicant proposed the following as BACT:

(1) Operate tanks at a constant process temperature of 122 °F

(2) Submerged Fill

(3) NOx emissions shall not exceed 0.62 TPY

The applicant proposes to operate the process tanks at the same temperature as the process. In this case, the nitric acid is maintained at an elevated temperature because follow on process equipment requires the elevated temperature. Nitric acid would have to be stored at reduced temperatures to see a significant reduction in NOx emissions. This is because the freezing point of 57% nitric acid is 0.4 °F. Meaningful control can be achieved by using submerged fill in the storage tanks.

Step 5: Select BACT

IDEM, OAQ has established the NOx BACT for the Nitric Acid Storage Tanks (EU-022A and EE-022B) is as follows:

(1) NO_x emissions from each of the Nitric Acid Storage Tanks (EU-022A and EU-022B) shall be controlled by the use of submerged/bottom fill.

(2) Combined throughput of the Nitric Acid Storage Tanks (EU-022A and EU-022B) shall not exceed 806,842 tons of 57% nitric acid per twelve consecutive month period with compliance determined at the end of each month.

(3) NO_x emissions from each of the Nitric Acid Storage Tanks (EU-022A and EU-022B) shall not exceed 0.0015 lb NO_x per ton of 57% nitric acid.

(8) NOx BACT – UAN Plant Vent Flare (EU-017)

Step 1: Identify Potential Control Technologies

The following control technologies have been identified for the control of NOx in UAN Plant Vent Flare (EU-017):

(1) Flare design and good combustion practices;

(2) Process flaring minimization practices; and

(3) Flare Gas Recovery.

Certain NOx controls that may be used on other types of sources, such as selective catalytic reduction (SCR), selective non-catalytic reduction (SNCR), and flue gas recirculation (FGR) are not applicable to flares because the outlet exhaust of an elevated process flare is not enclosed or contained. Therefore, the emissions or flue gases cannot be routed to an add-on control device, and such add-on controls have not been utilized on flares.

Flare design and good combustion practices

Flare design and good combustion practices – Flare design and monitoring are key elements in emissions performance of flares. The flare must be properly operated and maintained in order to achieve the anticipated emission rates guaranteed by the flare manufacturer. The use of proper flare design and good combustion practices is a technically feasible control option for the UAN Plant Vent Flare (EU-017) at this source.

Process flaring minimization practices

Process flaring minimization practices – To the extent actions can be taken to minimize the volume of gas going to the flare, emissions of NOx will be less. Flaring minimization practices are feasible and are evaluated in the analysis of BACT. The use of process flaring minimization practices is a technically feasible control option for the UAN Plant Vent Flare (EU-017) at this source.

Flare gas recovery

Flare gas recovery – Flare gas recovery has been implemented at some facilities that produce and use internally generated fuel gas streams such as petroleum refineries. However, flare gas recovery for the Ohio Valley Resources, LLC facility is not feasible for the following reasons.

(1) First, unlike a refinery's nearly continuous supply of flared gases, flaring at the proposed Ohio Valley Resources, LLC facility will be an infrequent occurrence.

(2) Another difference is that the Ohio Valley Resources, LLC flaring events, the flared material may not be suitable for use as a fuel gas.

The use of a flare gas recovery system is not a technically feasible control option for the UAN Plant Vent Flare (EU-017) at this source.

Step 3: Rank the Remaining Control Technologies by Control Effectiveness

The applicant proposed both proper flare design and operation along with flare minimization practices as BACT for NOx. Therefore, no ranking is required.

Step 4: Evaluate the Most Effective Controls and Document the Results

The following table lists the proposed NOx BACT determination for Ohio Valley Resources, LLC along with the existing NOx BACT determinations for similar emission units. All data in the table is based on the information obtained from the permit application submitted by Ohio Valley Resources, LLC, the U.S. EPA RACT/BACT/LAER Clearinghouse (RBLC), Indiana issued permits, and electronic versions of permits available from other permitting agencies.

RACT/BACT/LEAR CLEARINGHOUSE DATA
UAN Plant Vent Flare (EU-017) – NOx

RBLC ID	Facility	Issued Date	Process Description	Capacity	Limitation	Control Method
T147-32322-00062	**Ohio Valley Resources**	**Proposed**	**UAN Plant Flare**	**0.189 MMBtu/hr**	**0.068 lb/MMBtu, pilot and 332.08 lb/hr, venting**	**Combustion / design, FMP, nat. gas, limit use**
AK-0076	Exxon, Point Thomson Production	08/20/12	Combustion Flares	35 MMCF/yr	0.068 lb/MMBtu	None
TX-0436	Borger Carbon Black Plant	10/03/02	Dryers, Boilers, Flare	Unspecified	0.1 lb/MMBtu	Good Combustion Practices and Design
ID-0017	Southeast Idaho Energy	02/10/09	Process Flare SRC21	1.5 MMBtu/hr pilot	No emissions from process, no limit on pilot	None
IA-0105	Iowa Fertilizer Company	11/02/12	Ammonia Flare	0.4 MMBtu/hr	No Numeric Limit	Work Practice, Good Combustion Practices

RBLC Review

The requirements of BACT listed in the RBLC for flares mostly involve the proper design and operation of the flare to achieve a manufacturer performance guarantee. The lowest emission rate achievable does not vary significantly for similar flares in similar service.

Applicant Proposal

The applicant proposes the following as BACT:

(a) Proper design and good combustion practices;

(b) The use of natural gas; and

(c) The use of flare minimization practices.

The applicant has accepted top BACT. IDEM, OAQ is adding an emission limitation to make startup, shutdown and malfunction flaring enforceable.

Step 5: Select BACT

IDEM, OAQ has established NOx BACT for the UAN Plant Vent Flare (EU-017) as:

(1) In order to control NO_x emissions, the pilot and purge gas fuels used in the flare shall be natural gas.

(2) Venting for Startup, Shutdown and Malfunction shall not exceed 336 hours per twelve consecutive month period with compliance determined at the end of each month.

(3) Comply with the following flare minimization practices to reduce emissions during startups, shutdowns, and other flaring events:

(A) Flare Use Minimization: The UAN process shall be properly operated to avoid emergency upsets. Startup time of the Nitric Acid Units shall be minimized. During emergency upsets of the Nitric Acid Units, the Permittee shall return some of the high and low-pressure off-gas back to the urea process as soon as urea production is reduced to a level that safely allows this;

(B) The Permittee shall train all operators responsible for the day-to-day operation of the flares on the flare minimization practices and the specific procedures to follow during process startup, shutdown, and other flaring events; and

(C) The Permittee shall investigate the “root cause” of malfunction events that cause flaring events other than at startup or shutdown. This root cause analysis shall identify the apparent cause of unanticipated flaring event and shall recommend additional preventive measures that will minimize the chance of a repeat event. The Permittee shall implement the recommended preventive measures.

(4) NO_x emissions shall be controlled by use of the following practices:

(A) Flares shall be designed for and operated with no visible emissions, except for periods not to exceed 5 minutes during any two consecutive hours;

(B) Flares shall be operated with a flame present at all times; and

(C) Flares shall be continuously monitored to assure the presence of a pilot flame with a thermocouple, infrared monitor, or other approved device.

(5) NO_x emissions from the UAN Plant Vent Flare (EU-017) shall not exceed 0.068 lb/MMBtu, based on a three-hour average, during normal operation, non-venting periods.

(6) NO_x emissions from the UAN Plant Vent Flare (EU-017) shall not exceed 332.08 lb/hr, based on a three-hour average, during venting events.

(9) NOx BACT – Four (4) Identical 218 MMBtu/hr Natural Gas Fired Boilers (EU-011A, EU-011B, EU-011C and EU-011D)

Step 1: Identify Potential Control Technologies

IDEM, OAQ has identified the following NOx control technologies for the four (4) natural gas-fired boilers (EU-011A, EU-011B, EU-011C and EU-011D):

(1) Selective Catalytic Reduction (SCR)
(2) Selective Non-Catalytic Reduction (SNCR)
(3) Low NOx Burner (LNB)
(4) Flue Gas Recirculation (FGR)
(5) Low NOx Burner (LNB) with Flue Gas Recirculation (FGR)

NOx add-on control technologies are discussed below:

Step 2: Eliminate Technically Infeasible Options

(a) **Selective Catalytic Reduction**

Selective Catalytic Reduction (SCR) process involves the mixing of anhydrous or aqueous ammonia vapor with flue gas and passing the mixture through a catalytic reactor to reduce NO_X to nitrogen and water. Under optimal conditions, SCR has removal efficiencies up to 90% when used on steady state processes. The efficiency of removal will be reduced for processes that are not stable or require frequent changes in the mode of operation.

The most important factor affecting SCR efficiency is temperature. SCR typically operates in a flue gas window ranging from 500°F to 1100°F, although the optimum temperature range depends on the type of catalyst and the flue gas composition. Temperatures below the optimum decrease catalyst activity and allow NH_3 to slip through. Until the system reaches the minimum temperature, the SCR operates without ammonia injection. Above the optimum range, ammonia will oxidize to form additional NO_x. SCR efficiency is also largely dependent on the stoichiometric molar ratio of NH_3:NOx; variation of the ideal 1:1 ratio to 0.5:1 ratio can reduce the removal efficiency to 50%.

The four (4) natural gas-fired boilers (EU-011A, EU-011B, EU-011C and EU-011D) are limited use boilers. These boilers are used at plant startup and upsets. These boilers will have a difficult time achieving steady state operation in a reasonable time period to make SCR an effective NOx control method. Selective catalytic reduction (SCR) is not a technically feasible control option for the four (4) natural gas-fired boilers (EU-011A, EU-011B, EU-011C and EU-011D) at this source.

(b) **Selective Non-Catalytic Reduction (SNCR)**

With selective non-catalytic reduction (SNCR), NO_X is selectively removed by the injection of ammonia or urea into the flue gas at an appropriate temperature window of 1600°F to 2000°F and without employing a catalyst. Similar to SCR without a catalyst bed, the injected chemicals selectively reduce the NO_X to molecular nitrogen and water. This approach avoids the problem related to catalyst fouling but the temperature window and reagent mixing residence time is critical for conducting the necessary chemical reaction.

At the proper temperature, urea decomposes to produce ammonia which is responsible for NO_X reduction. At a higher temperature, the rate of competing reactions for the direct oxidation of ammonia that actually forms NOx becomes significant. At a lower temperature, the rates of NO_X reduction reactions become too slow resulting in urea slip (i.e. emissions of unreacted urea).

Optimal implementation of SNCR requires the employment of an injection system that can accomplish thorough reagent/gas mixing within the temperature window while accommodating spatial and production rate temperature variability in the gas stream. The attainment of maximum NO_x control performance therefore requires that the furnace exhibit a favorable opportunity for the application of this technology relative to the location of the reaction temperature range and steady operation within that temperature window. Given the standby nature of the operation of these boilers, steady-state operation cannot be expected and makes SNCR technically infeasible.

Selective non-catalytic reduction (SNCR) is not a technically feasible control option for the four (4) natural gas-fired boilers (EU-011A, EU-011B, EU-011C and EU-011D) at this source.

(c) **Low NOx Burners (LNB)**
Using LNB can reduce formation of NOx through careful control of the fuel-air mixture during combustion. Control techniques used in LNBs includes staged air, and staged fuel, as well as other methods that effectively lower the flame temperature.

Experience suggests that significant reduction in NOx emissions can be realized using LNBs. The U.S. EPA reports that LNBs have achieved reduction up to 80%, but actual reduction depends on the type of fuel and varies considerably from one installation to another. Typical reductions range from 40% - 50% but under certain conditions, higher reductions are possible. The use of a low NOx burner is a technically feasible control option for the four (4) natural gas-fired boilers (EU-011A, EU-011B, EU-011C and EU-011D) at this source.

(d) **Flue Gas Recirculation (FGR)**
Recirculating a portion of the flue gas to the combustion zone can lower the peak flame temperature and result in reduced thermal NOx production. Flue gas recirculation (FGR) can be highly effective technique for lowering NOx emissions from burners and it's relatively inexpensive to apply. Most of the early FGR work was done on boilers, and investigators found that recirculating up to 25% of the flue gases through the burner could lower NOx emissions to as little as 25% of their normal levels. FGR lowers NOx emissions in two ways; the cooler, relatively inert, recirculated flue gases act as a heat sink, absorbing heat from the flame and lowering peak flame temperatures and when mixed with the combustion air, recirculated flue gases lower the average oxygen content of the air, starving the NOx-forming reactions for one of the needed ingredients. The use of a Flue Gas Recirculation (FGR) is a technically feasible control option for the four (4) natural gas-fired boilers (EU-011A, EU-011B, EU-011C and EU-011D).

(e) **Flue Gas Recirculation (FGR) and Low NOx Burners (LNB)**
Flue gas recirculation and low NOx burners can be used in conjunction to achieve higher overall emission reductions.

The use of a Flue Gas Recirculation (FGR) with Low NOx Burners (LNB) is a technically feasible control option for the four (4) natural gas-fired boilers (EU-011A, EU-011B, EU-011C and EU-011D) at this source.

Step 3: Rank the Remaining Control Technologies by Control Effectiveness
The following control technologies are available for NOx control for the four (4) natural gas-fired Boilers (EU-011A, EU-011B, EU-011C and EU-011D) and IDEM, OAQ has ranked them in order of control efficiency:

(1) Low NOx Burners with Flue Gas Recirculation (55% to 60% control)

(2) Low NOx Burners (50% control)

(3) Flue Gas Recirculation (25%)

The applicant has selected the top BACT.

Step 4: Evaluate the Most Effective Controls and Document the Results

The following table lists the proposed NOx BACT determination for Ohio Valley Resources, LLC along with the existing NOx BACT determinations for similar emission units. All data in the table is based on the information obtained from the permit application submitted by Ohio Valley Resources, LLC, the U.S. EPA RACT/BACT/LAER Clearinghouse (RBLC), Indiana issued permits, and electronic versions of permits available at the websites of other permitting agencies.

RACT/BACT/LEAR CLEARINGHOUSE DATA
Boilers (EU-011A, EU-011B, EU-011C and EU-011D) – NOx

RBLC ID	Facility	Issued Date	Process Description	Capacity	Limitation	Control Method
IA-0105	Iowa Fertilizer Co	10/26/2012	Auxiliary Boiler	472.4 MMBtu/hr	0.0125 lb/MMBtu 5.52 ton/yr	Low NO_x Burner
T147-32322-00062	**Ohio Valley Resources**	**Proposed**	**Boilers EU-011A to EU-011D**	**218 MMBtu/hr Each**	**20.40 lb/MMCF, 24 hr avg.**	**Low NOx Burner, FGR, Usage Limit**
NJ-0043	Liberty Gen. Station	03/28/02	Auxiliary Boiler	200 MMBtu/hr	0.036 lb/MMBtu at STP (7.2 lb/hr)	SCR
CO-0052	Rocky Mountain Energy Ctr.	08/11/02	Natural Gas Fired Boiler (Aux. Boiler)	129 MMBtu/hr	0.038 lb/MMBtu	Low NOx Burner
TX-0386	Amella Energy Ctr.	03/26/02	Auxiliary Boiler	155 MMBtu/hr	0.04 lb/MMBtu	None
TX-0411	Amella Energy Ctr,	03/26/02	Auxiliary Boiler	155 MMBtu/hr	0.04 lb/MMBtu	None

RBLC Review

The RBLC entries shown in the table above indicates most add-on controls for NOx used in auxiliary boilers is SCR and Low NOx Burners. Two of the determinations did not require the use of add-on control devices.

Applicant Proposal

The applicant proposes the following as BACT:

(a) NOx emissions from the four (4) natural gas-fired boilers (EU-011A, EU-011B, EU-011C and EU-011D) shall be controlled by the use of Low NOx Burners and Flue Gas Recirculation (FGR).

(b) Combined natural gas usage from the four (4) natural gas-fired boilers (EU-011A, EU-011B, EU-011C and EU-011D) shall not exceed 2,802 MMCF per twelve consecutive month period with compliance determined at the end of each month.

(c) NOx emissions from the four (4) natural gas-fired boilers (EU-011A, EU-011B, EU-011C and EU-011D) shall not exceed 20.40 lb/MMCF.

The applicant's proposed emission rate is lower than the majority of the entries in the RBLC for NOx. A permit for the Iowa Fertilizer Company (IFC) was recently issued by the Iowa Department of Natural Resources (IDNR) with a proposed emission rate of 0.0125 lb/MMBtu. The IFC permit limit is lower than the limit proposed by the applicant. IDNR established this limit based on two stack tests at a single boiler. IDEM believes the emission rate proposed by the applicant is appropriate for BACT based on the following factors:

1. Low NOx burners and flue-gas recirculation technologies are the most effective NOx reduction systems for emission units that operate under limited circumstances such as those found at a fertilizer plant.

2. Add-on emission controls have been demonstrated to be infeasible or not cost-effective for units that operate under limited circumstances.

3. The emission limits in the IFC permit set by IDNR are based on two stack tests at the same facility – a 429 MMBtu/hr auxiliary boiler located at the Walter Scott Generating Plant in Council Bluffs, Iowa. These test results do not establish BACT for the boilers at Ohio Valley Resources.

    a. Two stack test results at the same facility are not representative of the emission rate achievable at a large range of natural gas facility types and sizes.

    b. IFC's facilities have not yet begun operations, and consequently the achievability of the IFC BACT limits have not been demonstrated in practice.

Step 5: Select BACT
IDEM, OAQ has established NOx BACT for the four (4) natural gas-fired Boilers (EU-011A, EU-011B, EU-011C and EU-011D) as:

(a) NO_x emissions from the boilers (EU-011A, EU-011B, EU-011C and EU-011D) shall be controlled through the use of proper boiler design and good combustion practices.

(b) Combined fuel usage in the boilers (EU-011A, EU-011B, EU-011C and EU-011D) shall not exceed 2,802 MMCF per twelve consecutive month period with compliance determined at the end of each month.

(c) The boilers (EU-011A, EU-011B, EU-011C, and EU-011D) shall combust natural gas.

(d) NO_x emissions from the boilers (EU-011A, EU-011B, EU-011C, and EU-011D) shall be controlled by the use of Ultra Low NO_x Burners and Flue Gas Recirculation (FGR).

(e) NO_x emissions from each of the boilers (EU-011A, EU-011B, EU-011C, and EU-011D) shall not exceed 20.40 lb/MMCF, based on a twenty-four hour average.

(10) NOx BACT – Diesel-Fired Emergency Generator (EU-009)

Step 1: Identify Potential Control Technologies
Today's stationary diesel-fired emergency compression ignition internal combustion engines are sold as package units with an engineering design tailored to meet the emission limitations of 40 CFR 60, Subpart IIII and 40 CFR 63, Subpart ZZZZ. The manufacturer provides an engine that is in compliance with the applicable NSPS and NESHAP and the owner/operator is expected to maintain and operate the unit to guarantee compliance with applicable emission limitations. Based on the review of information for this BACT, IDEM has determined that no add-on controls are practical.

Step 2: Eliminate Technically Infeasible Options
The test for technical feasibility of any control option is whether it is both available and applicable to reducing the target pollutant. IDEM, OAQ has not identified any technically feasible add-on control options for the diesel-fired emergency generator (EU-009).

Step 3: Rank the Remaining Control Technologies by Control Effectiveness
IDEM, OAQ has not identified any technically feasible add-on control options for the diesel-fired emergency generator (EU-009).

Step 4: Evaluate the Most Effective Controls and Document the Results

The following table lists the proposed NOx BACT determination for Ohio Valley Resources, LLC along with the existing NOx BACT determinations for similar emission units. All data in the table is based on the information obtained from the permit application submitted by Ohio Valley Resources, LLC, the U.S. EPA RACT/BACT/LAER Clearinghouse (RBLC), Indiana issued permits, and electronic versions of permits available at the websites of other permitting agencies.

RACT/BACT/LEAR CLEARINGHOUSE DATA
Diesel-Fired Emergency Generator (EU-009) – NOx

RBLC ID	Facility	Issued Date	Process Description	Capacity	Limitation	Control Method
T147-32322-00062	**Ohio Valley Resources**	**Proposed**	**Emergency Generator EU-009**	**4,690 HP**	**4.46 g/hp-hr, 3 hr avg.**	**Good Combustion Practices**
NV-0050	MGM Mirage	11/30/09	Emergency Generators CC009 – CC015	3,622 HP	0.01 lb/Hp-hr 37.4 lb/hr	None, 4.54 g/hp-hr
NV-0050	MGM Mirage	11/30/09	Emergency Generators LX024 – LX025	2,206 HP	0.0131 lb/Hp-hr 28.98 lb/hr	None, 5.94 g/hp-hr
IA-0105	Iowa Fertilizer Company	10/26/12	Emergency Generator	2,680 HP	6.0 g/KW-hr (0.018 lb/Hp-hr)	Good Combustion Practices
FL-0322	Southeast Renewable Fuels, LLC	12/23/10	Emergency Generator	2,682 HP	6.4 g/KW-hr (0.018 lb/Hp-hr)	None
AK-0071	Chugach Electric, International Station Power	12/20/10	Caterpillar Black-Start Generator	2,010 HP	6.4 g/KW-hr (0.018 lb/Hp-hr)	None

RBLC Review

The potential to emit NOx for this generator is 11.53 TPY based on 500 hours of operation. The applicant proposed a 200 hour limit on annual operation. This limit reduces emissions to 4.61 tons per year. The RBLC table above indicates add-on control technology is not used for NOx reduction. NOx emissions are reduced by good combustion practice and maintenance.

Applicant Proposal

The applicant proposed the following as BACT:

(a) NOx emissions shall not exceed 4.46 g/hp-hr.

(c) NOx emissions shall be controlled by exercising good combustion practices; and

(d) Hours of operation in the diesel-fired emergency generator (EU-009) shall not exceed 200 hours per year.

The emission rate for the emergency generator proposed by the applicant represents top BACT.

Step 5: Select BACT

IDEM, OAQ has established NOx BACT for the diesel-fired emergency generator (EU-009) as:

(1) The hours of operation of the diesel-fired emergency generator (EU-009) shall not exceed 200 hours per twelve consecutive month period with compliance determined at the end of each month.

(2) NO_x emissions shall be controlled by the use of good combustion practices.

(3) NO_x emissions from the diesel-fired emergency generator (EU-009) shall not exceed 4.46 g/hp-hr, based on a three-hour average.

(11) NOx BACT – Fugitive Emissions from Equipment Leaks

Step 1: Identify Potential Control Technologies

Fugitive emissions from equipment leaks have the potential to emit NOx of less than 0.01 ton per year. NOx emissions from these units are insignificant and no additional add-on controls or operational practices are required.

Step 2: Eliminate Technically Infeasible Options

This step is not required.

Step 3: Rank the Remaining Control Technologies by Control Effectiveness

IDEM has determined that NOx emissions from fugitive sources are insignificant and control is not practical. Ranking is not necessary. The level fugitive NOx emissions are below the permitting exemption level and are environmentally insignificant.

Step 4: Evaluate the Most Effective Controls and Document the Results

This step is not required.

Step 5: Select BACT

This step is not required.

(12) NOx BACT – Diesel-Fired Emergency Fire Water Pump (EU-016)

Step 1: Identify Potential Control Technologies

Today's stationary diesel-fired emergency compression ignition internal combustion engines are sold as package units with an engineering design tailored to meet the emission limitations of 40 CFR 60, Subpart IIII and 40 CFR 63, Subpart ZZZZ. The manufacturer provides an engine that is in compliance with the applicable NSPS and NESHAP and the owner/operator is expected to maintain and operate the unit to guarantee compliance with applicable emission limitations. Based on the review of information for this BACT, IDEM has determined that no add-on controls are practical.

Step 2: Eliminate Technically Infeasible Options

The test for technical feasibility of any control option is whether it is both available and applicable to reducing the target pollutant. IDEM, OAQ has not identified any technically feasible add-on control options for the diesel-fired emergency fire pump (EU-016).

Step 3: Rank the Remaining Control Technologies by Control Effectiveness
IDEM, OAQ has not identified any technically feasible add-on control options for the diesel-fired emergency fire pump (EU-016).

Step 4: Evaluate the Most Effective Controls and Document the Results
The following table lists the proposed NOx BACT determination for Ohio Valley Resources, LLC along with the existing NOx BACT determinations for similar emission units. All data in the table is based on the information obtained from the permit application submitted by Ohio Valley Resources, LLC, the U.S. EPA RACT/BACT/LAER Clearinghouse (RBLC), Indiana issued permits, and electronic versions of permits available at the websites of other permitting agencies.

RACT/BACT/LEAR CLEARINGHOUSE DATA
Fire Water Pump (EU-016) – NOx

RBLC ID	Facility	Issued Date	Process Description	Capacity	Limitation	Control Method
T147-32322-00062	**Ohio Valley Resources, LLC**	**Proposed**	**Fire Pump EU-016**	**481 HP**	**2.86 g/hp-hr, 3 hr avg.**	**Good Combustion, Usage Limit**
IA-0105	Iowa Fertilizer Company	10/26/12	Fire Pump	300 HP	3.75 g/KW-hr 0.49 TPY	Good Combustion Practices, 2.80 g/hp-hr
LA-0251	Flopam, Inc.	04/26/11	Fire Pump	444 HP	3.0 g/KW-hr	None, 2.99 g/hp-hr
ID-0018	Idaho Power Company	06/25/10	Fire Pump	267 HP	4.0 g/KW-hr	None, 2.99 g/hp-hr
SC-0113	Pyramax Ceramics, LLC	02/08/12	Fire Pump	500 HP	4.0 g/KW-hr	None, 2.99 g/hp-hr
OH-0254	Duke Energy Washington County, LLC	08/14/03	Fire Pump	400 HP	14.5 g/Hp-hr 12.8 lb/hr 3.2 TPY	Combustion Control

RBLC Review
The potential to emit NOx for this fire water pump is 0.76 TPY based on 500 hours of operation. The applicant proposed a 200 hour limit on annual operation. This limit reduces emissions to 0.30 tons per year. The RBLC table above indicates add-on control technology is not used for NOx reduction. NOx emissions are reduced by good combustion practice and maintenance.

Applicant Proposal
The applicant proposed the following as BACT:

(a) NOx emissions from the diesel-fired emergency fire water pump (EU-016) shall be minimized by compliance with 40 CFR 60, Subpart IIII;

(b) NOx emissions shall not exceed 2.86 g/hp-hr;

(c) NOx emissions shall be controlled by exercising good combustion practices; and

(d) Hours of operation of the diesel-fired emergency fire water pump (EU-016) shall not exceed 200 hours per year.

The applicant proposed top BACT.

Step 5: Select BACT

IDEM, OAQ has established NOx BACT for the diesel-fired emergency fire water pump (EU-016) as:

(1) Operation of the Diesel-Fired Emergency Firewater Pump (EU-016) shall not exceed 200 hours per twelve consecutive month period with compliance determined at the end of each month.

(2) NO_x emissions from the Diesel-Fired Emergency Firewater Pump (EU-016) shall be controlled by the use of good combustion practices.

(3) NO_x emissions from the diesel-fired emergency firewater pump (EU-016) shall not exceed 2.86 g/hp-hr, based on a three-hour average.

CO BACT Determinations

(1) CO BACT - Primary Reformer (EU-003)

Step 1: Identify Potential Control Technologies

IDEM, OAQ has identified the following CO control technologies for the Primary Reformer (EU-003):

(1) Regenerative Thermal Oxidation;

(2) Catalytic Oxidation;

(3) Flares; and

(4) Combustion Control.

Each of the control technologies is discussed below.

Step 2: Eliminate Technically Infeasible Options

(a) **Thermal Oxidizers**

The thermal oxidizer has a stabilized flame maintained by a combination of auxiliary fuel, waste gas compounds, and supplemental air added when necessary. This technology is typically applied for destruction of organic vapors, nevertheless it is also considered as a technology for controlling CO emissions. Upon passing through the flame, the gas containing CO is heated from its inlet temperature to its ignition temperature (It is the temperature at which the combustion reaction rate (and consequently the energy production rate) exceeds the rate of heat losses, thereby raising the temperature of the gases to some higher value). Thus, any CO/air mixture will ignite if its temperature is raised to a sufficiently high level. The CO-containing mixture ignites at some temperature between the preheat temperature and the reaction temperature. The ignition occurs at some point during the heating of a waste stream. The mixture continues to react as it flows through the combustion chamber.

Most thermal units are designed to provide no more than 1 second of residence time to the waste gas with typical temperatures of 1,200 to 2,000°F. Once the unit is designed and built, the residence time is not easily changed, so that the required reaction temperature becomes a function of the particular gaseous species and the level of control. Regenerative Thermal Oxidizers consists of direct contact heat exchangers constructed of a ceramic material that can tolerate the high temperatures needed to achieve ignition of the waste stream.

The inlet gas first passes through a hot ceramic bed thereby heating the stream (and cooling the bed) to its ignition temperature. The hot gases then react (releasing energy) in the combustion chamber and while passing through another ceramic bed, thereby heating it to the combustion chamber outlet temperature. The process flows are then switched, feeding the inlet stream to the hot bed. This cyclic process affords high energy recovery (up to 95%). The higher capital costs associated with these high-performance heat exchangers and combustion chambers may be offset by the auxiliary fuel savings to make such a system economical.

The use of a regenerative thermal oxidizer is not a technically feasible control option for the Primary Reformer at this source; because, the exhaust stream is comprised of natural gas combustion products with extremely low heating value. Thermal oxidizers have not been installed on natural gas combustion sources to control CO.

(b) **Catalytic Oxidizers**

Catalytic oxidation is also a widely used control technology to control pollutants where the waste gas is passed through a flame area and then through a catalyst bed for complete combustion of the waste in the gas. This technology is typically applied for destruction of organic vapors, nevertheless it is considered a technology for controlling CO emissions. A catalyst is an element or compound that speeds up a reaction at lower temperatures (compared to thermal oxidation) without the catalyst undergoing change itself. Catalytic oxidizers operate at 650°F to 1000°F and require approximately 1.5 to 2.0 ft^3 of catalyst per 1000 standard ft^3 gas flow.

Emissions from some emission units may contain significant amount of particulates. These particulates can poison the catalyst resulting in the failure of catalytic oxidation. For some fuels, such as coal and residual oil, contaminants would likely be present in such concentrations so as to foul catalysts quickly thereby making such systems infeasible due to the need to constantly replace catalyst materials. In addition, the use of oxidation catalysts on units with high sulfur fuels can also result in the creation of sulfuric acid mist through the conversion of SO_2 to SO_3 and subsequent combination with moisture in the exhaust gas. The use of an oxidation catalyst to control carbon monoxide emissions is feasible for gas fired units because the fuel is a low sulfur fuel with relatively low concentrations of other contaminants, such as metals.

The use of a catalytic oxidizer is a technically feasible control option for the Primary Reformer (EU-003) at this source. Catalytic oxidizers utilize a catalyst (either an element or a compound) that can oxidize CO at a lower temperature than thermal oxidation.

(c) **Flare**

The low heating value of the Primary Reformer (EU-003) exhaust is too low for flaring. As there are insufficient organics in this vent stream to support combustion, use of a flare would require a significant addition of supplementary fuel. Therefore, a secondary impact of the use of a flare for this stream would be the creation of additional emissions from burning supplemental fuel, including NO_x. Flares have not been utilized or demonstrated as a control device for CO from this type of high-volume process stream. The use of a flare is not a technically feasible option for the Primary Reformer at this source.

(d) **Combustion Control**
Because CO is essentially a by-product of incomplete or inefficient combustion, combustion control constitutes the primary mode of reduction of CO emissions. This type of control is appropriate for any type of fuel combustion source. Combustion process controls involve combustion chamber designs and operating practices that improve the oxidation process and minimize incomplete combustion. CO emissions result from the incomplete combustion of carbon and organic compounds. Factors affecting CO emissions include firing temperatures, residence time in the combustion zone and combustion chamber mixing characteristics. Combustion control is a technically feasible control option for the Auxiliary Boilers.

Step 3: Rank the Remaining Control Technologies by Control Effectiveness

(1) Oxidation Catalyst – 75% destruction efficiency

(2) Combustion Control

Step 4: Evaluate the Most Effective Controls and Document the Results
The following table lists the proposed CO BACT determination for Ohio Valley Resources, LLC along with the existing CO BACT determinations for similar emission units. All data in the table is based on the information obtained from the permit application submitted by Ohio Valley Resources, LLC, the U.S. EPA RACT/BACT/LAER Clearinghouse (RBLC), Indiana issued permits, and electronic versions of permits available at the websites of other permitting agencies.

RACT/BACT/LEAR CLEARINGHOUSE DATA

Primary Reformer (EU-003) – CO

RBLC ID	Facility	Issued Date	Process Description	Capacity	Limitation	Control Method
IA-0105	Iowa Fertilizer Company	10/26/12	Primary Reformer	1.13 MMCF/hr 1,152.6 MMBtu/hr	0.0194 lb/MMBtu 96.3 TPY	Good Combustion
T147-32322-00062	**Ohio Valley Resources, LLC**	**Proposed**	**Primary Reformer EU-003**	**1,006.4 MMBtu/hr**	**43.45 lb/MMCF, 3 hr avg.**	**Good Combustion Practices, Usage Limit**
LA-0211	Garyville Refinery	12/27/06	Hydrogen Reformer Furnace Flue	1,412.5 MMBtu/hr	0.04 lb/MMBtu 30 day rolling avg. (56.5 lb/hr)	Proper Design, Operation and Good Engineering Practices
NM-0050	Artesia Refinery	12/14/07	Steam Methane Reformer Heater	337 MMBtu/hr	0.06 lb/MMBtu 30 day rolling avg, 22.22 lb/hr 3 hr average	Combust Gaseous Fuel Only
OK-0134	Pryor Plant Chemical Company	02/23/09	Primary Reformer EUID #101	700 ton ammonia per day	18.53 lb/hr	Good Combustion, 225 MMBtu/hr reformer, 0.08 lb/MMBtu
OK-0135	Pryor Plant Chemical Company	02/23/09	Primary Reformer	700 ton ammonia per day	18.5 lb/hr	Good Combustion, 225 MMBtu/hr reformer, 0.08 lb/MMBtu

RBLC Review

The Primary Reformer (EU-003) has a potential to emit CO of 187.78 tons per year. A review of the RBLC entries for reformer units indicates no add-on control technology for CO is cost-effective for these units. OVR presented information that a catalytic oxidizer is economically infeasible. This is because of the large exhaust flow rate from its stack. The cost is estimated at $40,000 per ton. No other facilities in the RBLC utilize catalytic oxidation to reduce CO emissions. In addition, the use of a thermal or catalytic oxidizer for CO control would require the use of a significant amount of supplemental fuel (to heat the exhaust gas to the required operating temperature to achieve destruction). This supplemental fuel firing will create additional combustion pollutant emissions (particularly NOx) which will at least partially offset any benefits of additional CO control. CO is exclusively controlled by proper design and good combustion practice.

Applicant Proposal

The applicant proposed the following as BACT:

(a) CO emissions shall be controlled by the use of good combustion practices;

(b) The Primary Reformer (EU-003) shall combust natural gas; and

(b) CO emissions shall not exceed 42.87 lb/hr.

The applicant's proposal is consistent with a majority of the entries in the RBLC for CO. These emission limits are based on the uncontrolled emission factors found in AP-42. A permit for the Iowa Fertilizer Company (IFC) was recently issued by the Iowa Department of Natural Resources (IDNR) with a proposed emission rate of 0.0194 lb/MMBtu. The IFC permit limit is lower than the limit proposed by the applicant. IDNR established this limit based on two stack tests at a single boiler. IDEM believes the emission rate proposed by the applicant is appropriate for BACT based on the following factors:

1. Add-on emission controls have been demonstrated to be infeasible or not cost-effective.

2. The majority of the entries in the RBLC for uncontrolled natural gas-fired combustion units are derived from the AP-42 emission factors, which are based on stack tests on a large sample size of natural gas-burning facilities.

3. The emission limits in the IFC permit set by IDNR are based on two stack tests at the same facility – a 429 MMBtu/hr auxiliary boiler located at the Walter Scott Generating Plant in Council Bluffs, Iowa. These test results do not establish BACT for the Primary Reformer at Ohio Valley Resources.

    a. Two stack test results at the same facility are not representative of the emission rate achievable at a large range of natural gas facility types and sizes. The AP-42 emission factor for natural gas combustion is a better reflection of what is achievable for an uncontrolled natural gas unit.

    b. IFC's facilities have not yet begun operations, and consequently the achievability of the IFC BACT limits have not been demonstrated in practice.

IDEM is proposing an emission rate of 43.45 lb/MMSCF for CO.

Step 5: Select BACT

IDEM, OAQ has established CO BACT for the Primary Reformer (EU-003) as:

(1) CO emissions from the operation of Primary Reformer (EU-003) shall be controlled through the use of good combustion practices.

(2) The Primary Reformer (EU-003) shall combust natural gas and/or process off gas streams.

(3) CO emissions from the Primary Reformer (EU-003) shall not exceed 43.45 lb/MMCF, based on a three-hour average.

(2) CO BACT - CO_2 Purification Process (EU-004)

Step 1: Identify Potential Control Technologies

IDEM, OAQ has identified the following CO control technologies for the CO_2 Purification Process (EU-004):

(1) Optimum conversion from CO to CO_2 by use of a catalyst and good operational practices.

Only one control technology was identified in the RBLC. Optimum conversion is discussed below.

Step 2: Eliminate Technically Infeasible Options

Optimum CO Conversion

CO emissions can be minimized by optimum catalytic conversion of CO to CO_2 in the high end and low end shift converters. The use of an efficient process catalyst and good operational procedures are technically feasible control options.

Step 3: Rank the Remaining Control Technologies by Control Effectiveness

The only control technology available to the CO_2 Purification Process (EU-004) is the use of an efficient catalyst and good operational procedures.

The applicant has accepted the only feasible control technology. Therefore, no ranking is required.

Step 4: Evaluate the Most Effective Controls and Document the Results

The following table lists the proposed CO BACT determination for Ohio Valley Resources, LLC along with the existing CO BACT determinations for similar emission units. All data in the table is based on the information obtained from the permit application submitted by Ohio Valley Resources, LLC, the U.S. EPA RACT/BACT/LAER Clearinghouse (RBLC), Indiana issued permits, and electronic versions of permits available at the websites of other permitting agencies.

RACT/BACT/LEAR CLEARINGHOUSE DATA

CO_2 Purification Process (EU-004) – CO

RBLC ID	Facility	Issued Date	Process Description	Capacity	Limitation	Control Method
T147-32322-00062	**Ohio Valley Resources, LLC**	**Proposed**	**CO_2 Purification Process EU-004**	**3,570 tons of CO_2 per day**	**0.0117 lb/ton ammonia, 3 hr avg.**	**Use catalyst, Throughput Limit**
LA-0236	Donaldson Nitrogen Complex	03/03/09	#1 to #4 Carbon Dioxide Vents	Tons Ammonia/day #1/#2–1,620 each #3/#4–1,785 each 283.75 ton/hr total	#1 - 5.59 lb/hr #2 – 5.59 lb/hr #3 – 5.08 lb/hr #4 – 5.95 lb/hr 0.08 lb/ton total	Optimum Catalytic Conversion of CO to CO_2
IA-0105	Iowa Fertilizer Company	10/26/12	CO_2 Regenerator	3,300 ton/day Ammonia	0.02 lb/ton ammonia	Good Operational Practices

RBLC Review
The CO_2 Purification Process Vent (EU-004) has a potential to emit CO of 5.98 tons per year. Entries in the RBLC table above indicate add-on control devices are not included in the BACT determinations. The entries show BACT as the optimum conversion of CO to CO_2 by use of a catalyst and good operational practices.

Applicant Proposal
The applicant proposed the following as BACT:

(a) CO emissions in the CO_2 Purification Process (EU-004) shall be controlled by the use of good operational procedures including the selection of an optimal process catalyst;

(b) CO emissions shall not exceed 1.37 lb/hr; and

(c) Ammonia production shall not exceed 1,022,000 tons per twelve consecutive month period with compliance determined at the end of each month.

The applicant has proposed top BACT.

Step 5: Select BACT
IDEM, OAQ has established CO BACT for the CO_2 Purification Process Vent (EU-004) as:

(1) Ammonia production shall not exceed 1,022,000 tons per twelve consecutive month period with compliance determined at the end of each month.

(2) CO emissions from the CO_2 Purification Process Vent (EU-004) shall be controlled by the use of good operational procedures and the use of a process catalyst.

(3) The CO emission rate shall not exceed 0.0117 lb/ton of ammonia produced, based on a three-hour average.

(3) CO BACT – Front End Process Flare (EU-007)

Step 1: Identify Potential Control Technologies

The following control technologies have been identified for the control of CO in the Front End Process Flare (EU-007):

(1) Flare design and good combustion practices;

(2) Process flaring minimization practices; and

(3) Flare Gas Recovery.

Certain CO controls that may be used on other types of sources, such as thermal or catalytic oxidation are not applicable to flares because the outlet exhaust of an elevated process flare is not enclosed or contained. Therefore, the emissions or flue gases cannot be routed to an add-on control device, and such add-on controls have not been utilized on flares.

Step 2: Eliminate Technically Infeasible Options

(a) **Flare design and good combustion practices**

Flare design and good combustion practices – Flare design and monitoring are key elements in emissions performance of flares. The flare must be properly operated and maintained in order to achieve the anticipated emission rates guaranteed by the flare manufacturer.

The use of proper flare design and good combustion practices is a technically feasible control option for the Front End Process Flare (EU-007) at this source.

(b) **Process flaring minimization practices**

Process flaring minimization practices – To the extent actions can be taken to minimize the volume of gas going to the flare, emissions of CO will be less. Flaring minimization practices are feasible and are evaluated in the analysis of BACT.

The use of process flaring minimization practices is a technically feasible control option for the Front End Process Flare (EU-007) at this source.

(c) **Flare gas recovery**

Flare gas recovery – Flare gas recovery has been implemented at some facilities that produce and use internally generated fuel gas streams such as petroleum refineries. However, flare gas recovery for the Ohio Valley Resources, LLC facility is not feasible for the following reasons.

(1) First, unlike a refinery’s nearly continuous supply of flared gases, flaring at the proposed Ohio Valley Resources, LLC facility will be an infrequent occurrence.

(2) Another difference is that the Ohio Valley Resources, LLC flaring events, the flared material may not be suitable for use as a fuel gas.

The use of a flare gas recovery system is not a technically feasible control option for the Front End Process Flare (EU-007) at this source.

Step 3: Rank the Remaining Control Technologies by Control Effectiveness

The applicant proposed both proper flare design and operation along with flare minimization practices as BACT for CO. Therefore, no ranking is required.

Step 4: Evaluate the Most Effective Controls and Document the Results

The following table lists the proposed CO BACT determination for Ohio Valley Resources, LLC along with the existing CO BACT determinations for similar emission units. All data in the table is based on the information obtained from the permit application submitted by Ohio Valley Resources, LLC, the U.S. EPA RACT/BACT/LAER Clearinghouse (RBLC), Indiana issued permits, and electronic versions of permits available from other permitting agencies.

RACT/BACT/LEAR CLEARINGHOUSE DATA
Front End Process Flare (EU-007) – CO

RBLC ID	Facility	Issued Date	Process Description	Capacity	Limitation	Control Method
T147-32322-00062	**Ohio Valley Resources, LLC**	**Proposed**	**Process Flare EU-007**	**0.253 MMBtu/hr**	**0.37 lb/MMBtu, pilot and 3,240.16 lb/hr, venting**	**Combustion Practices, FMP, Limit Hours**
AK-0076	Exxon, Point Thomson Production	08/20/12	Combustion Flares	35 MMCF/yr	0.37 lb/MMBtu	None
IA-0105	Iowa Fertilizer Company	10/26/12	Ammonia Flare	0.4 MMBtu/hr	None	Work Practice, Good Combustion
ID-0017	Southeast Idaho Energy, LLC	02/10/09	Process Flare SRC21	1.5 MMBtu/hr pilot	No emissions from the process, no limit on pilot emissions	None

RBLC Review

The requirements of BACT listed in the RBLC for flares mostly involve the proper design and operation of the flare to achieve a manufacturer performance guarantee.

Applicant Proposal

The applicant proposed the following as BACT:

(a) CO emissions from the Front End Process Flare (EU-007) shall be controlled by good combustion practices;

(b) CO emissions shall be controlled by the use of flare minimization practices (FMP);

(c) CO emissions from the Front End Process Flare (EU-007) shall not exceed 0.37 lb/MMBtu; and

(d) Venting for Startup, Shutdown and Malfunction shall not exceed 336 hours per twelve consecutive month period with compliance determined at the end of each month.

The applicant proposed top BACT.

Step 5: Select BACT

IDEM, OAQ has established CO BACT for the Front End Process Flare (EU-007) as:

(1) In order to control CO emissions, the pilot and purge gas fuels used in the flare shall be natural gas.

(2) Venting in the Front End Process Flare (EU-007) shall not exceed 336 hours per twelve consecutive month period with compliance determined at the end of each month.

(3) Comply with the following flare minimization practices to reduce emissions during startups, shutdowns, and other flaring events:

  (A) Flare Use Minimization: Process syngas streams to flare EU-007 shall not contain ammonia. During the startup of the sequential reformer, only one process stream at a time shall be sent to the flare to the extent practicable. Maximize the use of process syngas during the startup of the Ammonia Unit;

  (B) The Permittee shall train all operators responsible for the day-to-day operation of the flares on the flare minimization practices and the specific procedures to follow during process startup, shutdown, and other flaring events; and

  (C) The Permittee shall investigate the "root cause" of malfunction events that cause flaring events other than at startup or shutdown. This root cause analysis shall identify the apparent cause of unanticipated flaring event and shall recommend additional preventive measures that will minimize the chance of a repeat event. The Permittee shall implement the recommended preventive measures.

(4) CO emissions shall be controlled by the use of the following practices:

  (A) Flares shall be designed for and operated with no visible emissions, except for periods not to exceed 5 minutes during any two consecutive hours;

  (B) Flares shall be operated with a flame present at all times; and

  (C) Flares shall be continuously monitored to assure the presence of a pilot flame with a thermocouple, infrared monitor, or other approved device.

(5) CO emissions from the Front End Process Flare (EU-007) shall not exceed 0.37 lb/MMBtu, based on a three-hour average, during normal operations, non-venting periods.

(6) CO emissions from the Front End Process Flare (EU-007) shall not exceed 3,240.16 lb/hr, based on a three-hour average, during venting events.

(4) CO BACT – Ammonia Catalyst Startup Heater (EU-010)

Step 1: Identify Potential Control Technologies

IDEM, OAQ has identified the following CO control technologies for the Ammonia Catalyst Startup Heater (EU-010):

(1) Regenerative Thermal Oxidation;

(2) Catalytic Oxidation;

(3) Flares; and

(4) Combustion Control.

Each of the control technologies is discussed below.

Step 2: Eliminate Technically Infeasible Options

(a) **Regenerative Thermal Oxidizers**
The thermal oxidizer has a stabilized flame maintained by a combination of auxiliary fuel, waste gas compounds, and supplemental air added when necessary. This technology is typically applied for destruction of organic vapors, nevertheless it is also considered as a technology for controlling CO emissions. Upon passing through the flame, the gas containing CO is heated from its inlet temperature to its ignition temperature (It is the temperature at which the combustion reaction rate (and consequently the energy production rate) exceeds the rate of heat losses, thereby raising the temperature of the gases to some higher value). Thus, any CO/air mixture will ignite if its temperature is raised to a sufficiently high level. The CO-containing mixture ignites at some temperature between the preheat temperature and the reaction temperature. The ignition occurs at some point during the heating of a waste stream. The mixture continues to react as it flows through the combustion chamber.

Most thermal units are designed to provide no more than 1 second of residence time to the waste gas with typical temperatures of 1,200 to 2,000 °F. Once the unit is designed and built, the residence time is not easily changed, so that the required reaction temperature becomes a function of the particular gaseous species and the level of control. Regenerative Thermal Oxidizers consists of direct contact heat exchangers constructed of a ceramic material that can tolerate the high temperatures needed to achieve ignition of the waste stream.

The inlet gas first passes through a hot ceramic bed thereby heating the stream (and cooling the bed) to its ignition temperature. The hot gases then react (releasing energy) in the combustion chamber and while passing through another ceramic bed, thereby heating it to the combustion chamber outlet temperature. The process flows are then switched, feeding the inlet stream to the hot bed. This cyclic process affords high energy recovery (up to 95%). The higher capital costs associated with these high-performance heat exchangers and combustion chambers may be offset by the auxiliary fuel savings to make such a system economical.

The use of a regenerative thermal oxidizer is not a technically feasible control option for the Ammonia Catalyst Startup Heater (EU-010) at this source. Thermal oxidation is not normally used to control CO in the exhaust streams of natural gas combustion. The combustion products have a low heating value that makes the use of a thermal oxidizer impractical.

(b) **Catalytic Oxidizers**
Catalytic oxidation is also a widely used control technology to control pollutants where the waste gas is passed through a flame area and then through a catalyst bed for complete combustion of the waste in the gas. This technology is typically applied for destruction of organic vapors, nevertheless it is considered as a technology for controlling CO emissions. A catalyst is an element or compound that speeds up a reaction at lower temperatures (compared to thermal oxidation) without the catalyst undergoing change itself. Catalytic oxidizers operate at 650°F to 1000°F and require approximately 1.5 to 2.0 ft^3 of catalyst per 1000 standard ft^3 gas flow. Emissions from some emission units may contain significant amount of particulates. These particulates can poison the catalyst resulting in the failure of catalytic oxidation.

For some fuels, such as coal and residual oil, contaminants would likely be present in such concentrations so as to foul catalysts quickly thereby making such systems infeasible due to the need to constantly replace catalyst materials. In addition, the use of oxidation catalysts on units with high sulfur fuels can also result in the creation of sulfuric acid mist through the conversion of SO_2 to SO_3 and subsequent combination with moisture in the exhaust gas. The use of an oxidation catalyst to control carbon monoxide emissions is feasible for gas fired units because the fuel is a low sulfur fuel with relatively low concentrations of other contaminants, such as metals.

The use of a catalytic oxidizer is a technically feasible control option for the Ammonia Catalyst Startup Heater (EU-010) at this source. Catalytic oxidizers utilize a catalyst (either an element or a compound) that can oxidize CO at a lower temperature than thermal oxidation.

(c) **Flare**

The low heating value of the Ammonia Catalyst Startup Heater (EU-010) exhaust is too low for flaring. As there are insufficient organics in this vent stream to support combustion, use of a flare would require a significant addition of supplementary fuel. Therefore, a secondary impact of the use of a flare for this stream would be the creation of additional emissions from burning supplemental fuel, including NO_x. Flares have not been utilized or demonstrated as a control device for CO from this type of high-volume process stream. The use of a flare is a technically infeasible option for the Ammonia Catalyst Startup Heater (EU-010) at this source.

(d) **Combustion Control**

Because CO is essentially a by-product of incomplete or inefficient combustion, combustion control constitutes the primary mode of reduction of CO emissions. This type of control is appropriate for any type of fuel combustion source. Combustion process controls involve combustion chamber designs and operating practices that improve the oxidation process and minimize incomplete combustion. CO emissions result from the incomplete combustion of carbon and organic compounds. Factors affecting CO emissions include firing temperatures, residence time in the combustion zone and combustion chamber mixing characteristics. Combustion control is a technically feasible control option for the Auxiliary Boilers.

Step 3: Rank the Remaining Control Technologies by Control Effectiveness

(1) Oxidation Catalyst – 75% destruction efficiency

(2) Combustion Control

Step 4: Evaluate the Most Effective Controls and Document the Results

The following table lists the proposed CO BACT determination for Ohio Valley Resources, LLC along with the existing CO BACT determinations for similar emission units. All data in the table is based on the information obtained from the permit application submitted by Ohio Valley Resources, LLC, the U.S. EPA RACT/BACT/LAER Clearinghouse (RBLC), Indiana issued permits, and electronic versions of permits available at the websites of other permitting agencies.

RACT/BACT/LEAR CLEARINGHOUSE DATA Ammonia Catalyst Startup Heater (EU-010) – CO						
RBLC ID	**Facility**	**Issued Date**	**Process Description**	**Capacity**	**Limitation**	**Control Method**
IA-0105	Iowa Fertilizer Company	10/26/2012	Startup Heater	110.12 MMBtu/hr	0.0194 lb/MMBtu	Good Combustion
WY-0067	Williams Field Services	04/01/09	Hot Oil Heater	84 MMBtu/hr	0.02 lb/MMBtu	None
MD-0035	Dominion Cove Pt	08/12/05	Vaporization Heater	88.4 MMBtu/hr	0.03 lb/MMBtu	None
T147-32322-00062	**Ohio Valley Resources, LLC**	**Proposed**	**Ammonia Catalyst Heater EU-010**	**106.3 MMBtu/hr**	**37.23 lb/MMCF, 3 hr avg.**	**Good Combustion, Usage Limit**
OK-0136	Conoco Phillips	02/09/09	Crude Heater	125 MMBtu/hr	0.04 lb/MMBtu	None
MN-0070	Minnesota Steel Industries	09/07/07	Process Heaters	606 MMBtu/hr	0.08 lb/MMBtu	None

RBLC Review

The Ammonia Catalyst Startup Heater (EU-010) has a potential to emit CO of 16.99 tons per year. Actual CO emissions are limited to less than 0.4 ton/year. A review of the RBLC entries for auxiliary boiler units indicates CO emissions are normally uncontrolled and emissions are dictated by fuel type and process design. None of the RBLC entries above utilized any add-on emission control systems for CO. As noted earlier in this Technical Support Document, catalytic oxidation is not a cost-effective CO emission control system for the primary reformer. Because of the lower utilization of the Ammonia Catalyst Startup Heater and significantly lower actual CO emissions, is even less cost-effective to use catalytic oxidation for the Ammonia Catalyst Startup Heater. In addition, the use of a thermal or catalytic oxidizer for CO control would require the use of a significant amount of supplemental fuel (to heat the exhaust gas to the required operating temperature to achieve destruction). This supplemental fuel firing will create additional combustion pollutant emissions (particularly NOx) which will at least partially offset any benefits of additional CO control.

Applicant Proposal

The applicant proposed the following for BACT:

(a) Ammonia Catalyst Startup Heater (EU-010) shall combust natural gas;

(b) Fuel usage shall not exceed 20.84 MMCF per year (200 hrs per year); and

(c) CO emissions shall be controlled by good design and combustion practices.

The applicant's proposal is consistent with or lower than a majority of the entries in the RBLC for CO emissions. Ohio Valley Resources' emission limits are based on the uncontrolled emission factors found in AP-42. A permit for the Iowa Fertilizer Company (IFC) was recently issued by the Iowa Department of Natural Resources (IDNR) with a proposed emission rate of 0.0194 lb/MMBtu. The IFC permit limit is lower than the limit proposed by the applicant. IDNR established this limit based on two stack tests at a single boiler. IDEM believes the emission rate proposed by the applicant is appropriate for BACT based on the following factors:

1. Add-on emission controls have been demonstrated to be infeasible or not cost-effective.

2. The emission limits in the IFC permit set by IDNR are based on two stack tests at the same facility – a 429 MMBtu/hr auxiliary boiler located at the Walter Scott Generating Plant in Council Bluffs, Iowa. These test results do not establish BACT for the Ammonia Catalyst Startup Heater at Ohio Valley Resources.

    a. Two stack test results at the same facility are not representative of the emission rate achievable at a large range of natural gas facility types and sizes. The AP-42 emission factor for natural gas combustion is a better reflection of what is achievable for an uncontrolled natural gas unit.

    b. IFC's facilities have not yet begun operations, and consequently the achievability of the IFC BACT limits have not been demonstrated in practice.

The next lowest entry in the RBLC for CO from a startup heater is 0.02 lb/MMBtu from the Williams Field Services Oil Heater in Wyoming. If Ohio Valley Resources accepted the lower emission rate without the limit on the hours of operation, the startup heater would emit 9.33 tons CO per year. If the applicant's proposal of 0.0365 lb/MMBtu with a 200 hour per year operational limit is accepted, the startup heater would emit 0.39 tons of CO per year. With 0.39 ton/year of CO emissions, add-on controls needed to achieve 0.02 lb CO/MMBtu would not be cost effective. While the hourly emission rate would be lower at 0.02 lb CO/MMBtu, the applicant's proposal represents an overall lower annual emission rate and represents BACT for this unit.

Step 5: Select BACT
IDEM, OAQ has established CO BACT for the Ammonia Catalyst Startup Heater (EU-010) as:

(1) In order to control CO emissions, the Ammonia Catalyst Startup Heater (EU-010) shall combust natural gas.

(2) In order to control CO emissions, the Ammonia Catalyst Startup Heater (EU-010) shall be controlled by good heater design and good combustion practices.

(3) Fuel usage in the Ammonia Catalyst Startup Heater (EU-010) shall not exceed 20.84 MMCF per twelve consecutive month period with compliance determined at the end of each month.

(4) CO emissions from the Ammonia Catalyst Startup Heater (EU-010) shall not exceed 37.23 lb/MMCF, based on a three-hour average.

(5) CO BACT – Back End Ammonia Process Flare (EU-006)

Step 1: Identify Potential Control Technologies
The following control technologies have been identified for the control of CO in the Back End Ammonia Process Flare (EU-006):

(1) Flare design and good combustion practices;

(2) Process flaring minimization practices; and

(3) Flare Gas Recovery.

Certain CO controls that may be used on other types of sources, such as thermal or catalytic oxidation are not applicable to flares because the outlet exhaust of an elevated process flare is not enclosed or contained. Therefore, the emissions or flue gases cannot be routed to an add-on control device, and such add-on controls have not been utilized on flares.

Step 2: Eliminate Technically Infeasible Options

(a) **Flare design and good combustion practices**
Flare design and good combustion practices – Flare design and monitoring are key elements in emissions performance of flares. The flare must be properly operated and maintained in order to achieve the anticipated emission rates guaranteed by the flare manufacturer. The use of proper flare design and good combustion practices is a technically feasible control option for the Back End Ammonia Process Flare (EU-006) at this source.

(b) **Process flaring minimization practices**
Process flaring minimization practices – To the extent actions can be taken to minimize the volume of gas going to the flare, emissions of CO will be less. Flaring minimization practices are feasible and are evaluated in the analysis of BACT. The use of process flaring minimization practices is a technically feasible control option for the Back End Ammonia Process Flare (EU-006) at this source.

(c) **Flare gas recovery**
Flare gas recovery – Flare gas recovery has been implemented at some facilities that produce and use internally generated fuel gas streams such as petroleum refineries. However, flare gas recovery for the Ohio Valley Resources, LLC facility is not feasible for the following reasons.

(1) First, unlike a refinery's nearly continuous supply of flared gases, flaring at the proposed Ohio Valley Resources, LLC facility will be an infrequent occurrence.

(2) Another difference is that the Ohio Valley Resources, LLC flaring events, the flared material may not be suitable for use as a fuel gas.

The use of a flare gas recovery system is not a technically feasible control option for the Back End Ammonia Process Flare (EU-006) at this source.

Step 3: Rank the Remaining Control Technologies by Control Effectiveness
The applicant proposed both proper flare design and operation along with flare minimization practices as BACT for CO. Therefore, no ranking is required.

Step 4: Evaluate the Most Effective Controls and Document the Results
The following table lists the proposed CO BACT determination for Ohio Valley Resources, LLC along with the existing CO BACT determinations for similar emission units. All data in the table is based on the information obtained from the permit application submitted by Ohio Valley Resources, LLC, the U.S. EPA RACT/BACT/LAER Clearinghouse (RBLC), Indiana issued permits, and electronic versions of permits available at the websites of other permitting agencies.

RACT/BACT/LEAR CLEARINGHOUSE DATA
Back End Ammonia Process Flare (EU-006) – CO

RBLC ID	Facility	Issued Date	Process Description	Capacity	Limitation	Control Method
T147-32322-00062	**Ohio Valley Resources, LLC**	**Proposed**	**Process Flare EU-006**	**0.253 MMBtu/hr**	**0.37 lb/MMBtu, pilot and 804.76 lb/hr, venting**	**Combustion Practices, FMP, Limit Hours**
AK-0076	Exxon, Point Thomson Production	08/20/12	Combustion Flares	35 MMCF/yr	0.37 lb/MMBtu	None
IA-0105	Iowa Fertilizer Company	10/26/12	Ammonia Flare	0.4 MMBtu/hr	None	Work Practice, Good Combustion
ID-0017	Southeast Idaho Energy, LLC	02/10/09	Process Flare SRC21	1.5 MMBtu/hr pilot	No emissions from the process, no limit on pilot emissions	None

RBLC Review
The requirements of BACT listed in the RBLC for flares mostly involve the proper design and operation of the flare to achieve a manufacturer performance guarantee.

Applicant Proposal
The applicant proposed the following as BACT:

(a) CO emissions from the Back End Ammonia Process Flare (EU-006) shall be controlled by proper flare design and good combustion practices;

(b) CO emissions from the Back End Ammonia Process Flare (EU-006) shall be controlled by the use of flare minimization practices;

(c) Venting for Startup, Shutdown and Malfunction shall not exceed 336 hours per twelve consecutive month period with compliance determined at the end of each month; and

(d) CO emissions shall not exceed 0.37 lb/MMBtu.

The applicant proposed top BACT.

Step 5: Select BACT

IDEM, OAQ has established CO BACT for the Back End Ammonia Process Flare (EU-006) as:

(1) In order to control CO emissions, the pilot and purge gas fuels used in the flare shall be natural gas.

(2) Venting in the Back End Ammonia Process Flare (EU-006) shall not exceed 336 hours per twelve consecutive month period with compliance determined at the end of each month.

(3) Comply with the following flare minimization practices to reduce emissions during startups, shutdowns, and other flaring events:

(A) Flare Use Minimization: Flare EU-006 shall be limited to flaring ammonia during high-pressure events to the extent practicable. The ammonia compressor main shall be depressurized prior to compressor maintenance. The Permittee shall limit venting ammonia rich streams to Flare EU-006 to the extent practicable during non-emergency startup and shutdown operations;

(B) The Permittee shall train all operators responsible for the day-to-day operation of the flares on the flare minimization practices and the specific procedures to follow during process startup, shutdown, and other flaring events; and

(C) The Permittee shall investigate the “root cause” of malfunction events that cause flaring events other than at startup or shutdown. This root cause analysis shall identify the apparent cause of unanticipated flaring event and shall recommend additional preventive measures that will minimize the chance of a repeat event. The Permittee shall implement the recommended preventive measures.

(4) CO emissions from the Back End Ammonia Process Vent Flare (EU-006) shall be controlled by the use of the following practices

(A) Flares shall be designed for and operated with no visible emissions, except for periods not to exceed 5 minutes during any two consecutive hours;

(B) Flares shall be operated with a flame present at all times; and

(C) Flares shall be continuously monitored to assure the presence of a pilot flame with a thermocouple, infrared monitor, or other approved device.

(5) CO emissions from the Back End Ammonia Process Flare (EU-006) shall not exceed 0.37 lb/MMBtu, based on a three-hour average, during normal operations, non-venting periods.

(6) CO emissions from the Back End Ammonia Process Flare (EU-006) shall not exceed 804.76 lb/hr, based on a three-hour average, during venting events.

(6) CO BACT – Ammonia Storage Flare (EU-005)

Step 1: Identify Potential Control Technologies

The following control technologies have been identified for the control of CO in the Ammonia Storage Flare (EU-005):

(1) Flare design and good combustion practices;

(2) Process flaring minimization practices; and

(3) Flare Gas Recovery.

Certain CO controls that may be used on other types of sources, such as thermal or catalytic oxidation are not applicable to flares because the outlet exhaust of an elevated process flare is not enclosed or contained. Therefore, the emissions or flue gases cannot be routed to an add-on control device, and such add-on controls have not been utilized on flares.

Step 2: Eliminate Technically Infeasible Options

(a) **Flare design and good combustion practices**

Flare design and good combustion practices – Flare design and monitoring are key elements in emissions performance of flares. The flare must be properly operated and maintained in order to achieve the anticipated emission rates guaranteed by the flare manufacturer.

The use of proper flare design and good combustion practices is a technically feasible control option for the Ammonia Storage Flare (EU-005) at this source.

(b) **Process flaring minimization practices**

Process flaring minimization practices – To the extent actions can be taken to minimize the volume of gas going to the flare, emissions of CO will be less. Flaring minimization practices are feasible and are evaluated in the analysis of BACT.

The use of process flaring minimization practices is a technically feasible control option for the Ammonia Storage Flare (EU-005) at this source.

(c) **Flare gas recovery**

Flare gas recovery – Flare gas recovery has been implemented at some facilities that produce and use internally generated fuel gas streams such as petroleum refineries. However, flare gas recovery for the Ohio Valley Resources, LLC facility is not feasible for the following reasons.

(1) First, unlike a refinery's nearly continuous supply of flared gases, flaring at the proposed Ohio Valley Resources, LLC facility will be an infrequent occurrence.

(2) Another difference is that the Ohio Valley Resources, LLC flaring events, the flared material may not be suitable for use as a fuel gas.

The use of a flare gas recovery system is not a technically feasible control option for the Ammonia Storage Flare (EU-005) at this source.

Step 3: Rank the Remaining Control Technologies by Control Effectiveness

The applicant proposed both proper flare design and operation along with flare minimization practices as BACT for CO. Therefore, ranking is not required.

Step 4: Evaluate the Most Effective Controls and Document the Results

The following table lists the proposed CO BACT determination for Ohio Valley Resources, LLC along with the existing CO BACT determinations for similar emission units. All data in the table is based on the information obtained from the permit application submitted by Ohio Valley Resources, LLC, the U.S. EPA RACT/BACT/LAER Clearinghouse (RBLC), Indiana issued permits, and electronic versions of permits available at the websites of other permitting agencies.

RACT/BACT/LEAR CLEARINGHOUSE DATA
Ammonia Storage Flare (EU-005) – CO

RBLC ID	Facility	Issued Date	Process Description	Capacity	Limitation	Control Method
T147-32322-00062	**Ohio Valley Resources, LLC**	**Proposed**	**Process Flare EU-005**	**0.126 MMBtu/hr**	**0.37 lb/MMBtu, pilot**	**Good Combustion Practices, FMP, Limit Hours**
AK-0076	Exxon, Point Thomson Production	08/20/12	Combustion Flares	35 MMCF/yr	0.37 lb/MMBtu	None
IA-0105	Iowa Fertilizer Company	10/26/12	Ammonia Flare	0.4 MMBtu/hr	None	Work Practice, Good Combustion
ID-0017	Southeast Idaho Energy, LLC	02/10/09	Process Flare SRC21	1.5 MMBtu/hr pilot	No emissions from the process, no limit on pilot emissions	None

RBLC Review
The requirements of BACT listed in the RBLC for flares mostly involve the proper design and operation of the flare to achieve a manufacturer performance guarantee.

Applicant Proposal
The applicant proposes the following as BACT:

(a) Proper design and good combustion practices;

(b) The use of natural gas; and

(c) The use of flare minimization practices (FMP).

The applicant proposed top BACT.

Step 5: Select BACT
IDEM, OAQ has established CO BACT for the Ammonia Storage Flare (EU-005) as:

(1) In order to control CO emissions, the pilot and purge gas fuels used in the flare shall be natural gas.

(2) Venting for Startup, Shutdown and Malfunction shall not exceed 168 hours per twelve consecutive month period with compliance determined at the end of each month.

(3) Comply with the following flare minimization practices to reduce emissions during startups, shutdowns, and other flaring events:

  (A) Flare Use Minimization: The Permittee shall limit periods when the backup storage compressor and the ammonia refrigeration compressor are offline at the same time to the extent practicable;

(B) The Permittee shall train all operators responsible for the day-to-day operation of the flares on the flare minimization practices and the specific procedures to follow during process startup, shutdown, and other flaring events; and

(C) The Permittee shall investigate the “root cause” of malfunction events that cause flaring events other than at startup or shutdown. This root cause analysis shall identify the apparent cause of unanticipated flaring event and shall recommend additional preventive measures that will minimize the chance of a repeat event. The Permittee shall implement the recommended preventive measures.

(4) CO emissions shall be controlled by use of the following practices:

(A) Flares shall be designed for and operated with no visible emissions, except for periods not to exceed 5 minutes during any two consecutive hours;

(B) Flares shall be operated with a flame present at all times; and

(C) Flares shall be continuously monitored to assure the presence of a pilot flame with a thermocouple, infrared monitor, or other approved device.

(5) CO emissions from the Ammonia Storage Flare (EU-005) shall not exceed 0.37 lb/MMBtu, based on a three-hour average.

(7) CO BACT – UAN Plant Vent Flare (EU-017)

Step 1: Identify Potential Control Technologies

The following control technologies have been identified for the control of CO in the UAN Plant Vent Flare (EU-017):

(1) Flare design and good combustion practices;

(2) Process flaring minimization practices; and

(3) Flare Gas Recovery.

Certain CO controls that may be used on other types of sources, such as thermal or catalytic oxidation are not applicable to flares because the outlet exhaust of an elevated process flare is not enclosed or contained. Therefore, the emissions or flue gases cannot be routed to an add-on control device, and such add-on controls have not been utilized on flares.

Step 2: Eliminate Technically Infeasible Options

(a) **Flare design and good combustion practices**

Flare design and good combustion practices – Flare design and monitoring are key elements in emissions performance of flares. The flare must be properly operated and maintained in order to achieve the anticipated emission rates guaranteed by the flare manufacturer.

The use of proper flare design and good combustion practices is a technically feasible control option for the UAN Plant Vent Flare (EU-017) at this source.

(b) **Process flaring minimization practices**
Process flaring minimization practices – To the extent actions can be taken to minimize the volume of gas going to the flare, emissions of CO will be less. Flaring minimization practices are feasible and are evaluated in the analysis of BACT.

The use of process flaring minimization practices is a technically feasible control option for the UAN Plant Vent Flare (EU-017) at this source.

(c) **Flare gas recovery**
Flare gas recovery – Flare gas recovery has been implemented at some facilities that produce and use internally generated fuel gas streams such as petroleum refineries. However, flare gas recovery for the Ohio Valley Resources, LLC facility is not feasible for the following reasons.

(1) First, unlike a refinery's nearly continuous supply of flared gases, flaring at the proposed Ohio Valley Resources, LLC facility will be an infrequent occurrence.

(2) Another difference is that the Ohio Valley Resources, LLC flaring events, the flared material may not be suitable for use as a fuel gas.

The use of a flare gas recovery system is not a technically feasible control option for the UAN Plant Vent Flare (EU-017) at this source.

Step 3: Rank the Remaining Control Technologies by Control Effectiveness
The applicant proposed both proper flare design and operation along with flare minimization practices as BACT for CO. Therefore, no ranking is required.

Step 4: Evaluate the Most Effective Controls and Document the Results
The following table lists the proposed CO BACT determination for Ohio Valley Resources, LLC along with the existing CO BACT determinations for similar emission units. All data in the table is based on the information obtained from the permit application submitted by Ohio Valley Resources, LLC, the U.S. EPA RACT/BACT/LAER Clearinghouse (RBLC), Indiana issued permits, and electronic versions of permits available at the websites of other permitting agencies.

RACT/BACT/LEAR CLEARINGHOUSE DATA
UAN Plant Vent Flare (EU-017) – CO

RBLC ID	Facility	Issued Date	Process Description	Capacity	Limitation	Control Method
T147-32322-00062	**Ohio Valley Resources, LLC**	**Proposed**	**Process Flare EU-017**	**0.189 MMBtu/hr**	**0.37 lb/MMBtu, pilot**	**Combustion Practices, FMP, Limit Hours**
AK-0076	Exxon, Point Thomson Production	08/20/12	Combustion Flares	35 MMCF/yr	0.37 lb/MMBtu	None
IA-0105	Iowa Fertilizer Company	10/26/12	Ammonia Flare	0.4 MMBtu/hr	None	Work Practice, Good Combustion
ID-0017	Southeast Idaho Energy, LLC	02/10/09	Process Flare SRC21	1.5 MMBtu/hr pilot	No emissions from the process, no limit on pilot emissions	None

RBLC Review
The requirements of BACT listed in the RBLC for flares mostly involve the proper design and operation of the flare to achieve a manufacturer performance guarantee.

Applicant Proposal
The applicant proposed the following for BACT:

(a) CO emissions from the UAN Plant Vent Flare (EU-017) shall be controlled by good design and good combustion practices;

(b) UAN Plant Vent Flare (EU-017) shall combust natural gas; and

(c) CO emissions from the UAN Plant Vent Flare (EU-017) shall be controlled by flare minimization practices (FMP).

The applicant proposed top BACT.

Step 5: Select BACT
IDEM, OAQ has established CO BACT for UAN Plant Vent Flare (EU-017) as:

(1) In order to control CO emissions, the pilot and purge gas fuels used in the flare shall be natural gas.

(2) Venting for Startup, Shutdown and Malfunction shall not exceed 336 hours per twelve consecutive month period with compliance determined at the end of each month.

(3) Comply with the following flare minimization practices to reduce emissions during startups, shutdowns, and other flaring events:

    (A) Flare Use Minimization: The UAN process shall be properly operated to avoid emergency upsets. Startup time of the Nitric Acid Units shall be minimized. During emergency upsets of the Nitric Acid Units, the Permittee shall return some of the high and low-pressure off-gas back to the urea process as soon as urea production is reduced to a level that safely allows this;

    (B) The Permittee shall train all operators responsible for the day-to-day operation of the flares on the flare minimization practices and the specific procedures to follow during process startup, shutdown, and other flaring events; and

    (C) The Permittee shall investigate the “root cause” of malfunction events that cause flaring events other than at startup or shutdown. This root cause analysis shall identify the apparent cause of unanticipated flaring event and shall recommend additional preventive measures that will minimize the chance of a repeat event. The Permittee shall implement the recommended preventive measures.

(4) CO emissions shall be controlled use of the following practices:

    (A) Flares shall be designed for and operated with no visible emissions, except for periods not to exceed 5 minutes during any two consecutive hours;

(B) Flares shall be operated with a flame present at all times; and

(C) Flares shall be continuously monitored to assure the presence of a pilot flame with a thermocouple, infrared monitor, or other approved device.

(5) CO emissions from the UAN Plant Vent Flare (EU-017) shall not exceed 0.37 lb/MMBtu, based on a three-hour average.

(8) CO BACT – Four (4) Identical 218 MMBtu/hr Natural Gas-Fired Boilers (EU-011A, EU-011B, EU-011C and EU-011D)

Step 1: Identify Potential Control Technologies

IDEM, OAQ has identified the following CO control technologies for the natural gas-fired boilers (EU-011A, EU-011B, EU-011C and EU-011D):

(1) Regenerative Thermal Oxidation;

(2) Catalytic Oxidation;

(3) Flares; and

(4) Combustion Control.

Each of the control technologies is discussed below.

Step 2: Eliminate Technically Infeasible Options

(a) **Regenerative Thermal Oxidizers**

The thermal oxidizer has a stabilized flame maintained by a combination of auxiliary fuel, waste gas compounds, and supplemental air added when necessary. This technology is typically applied for destruction of organic vapors, nevertheless it is also considered a technology for controlling CO emissions. Upon passing through the flame, the gas containing CO is heated from its inlet temperature to its ignition temperature (It is the temperature at which the combustion reaction rate (and consequently the energy production rate) exceeds the rate of heat losses, thereby raising the temperature of the gases to some higher value). Thus, any CO/air mixture will ignite if its temperature is raised to a sufficiently high level. The CO-containing mixture ignites at some temperature between the preheat temperature and the reaction temperature. The ignition occurs at some point during the heating of a waste stream. The mixture continues to react as it flows through the combustion chamber.

Most thermal units are designed to provide no more than 1 second of residence time to the waste gas with typical temperatures of 1,200 to 2,000°F. Once the unit is designed and built, the residence time is not easily changed, so that the required reaction temperature becomes a function of the particular gaseous species and the level of control. Regenerative Thermal Oxidizers consists of direct contact heat exchangers constructed of a ceramic material that can tolerate the high temperatures needed to achieve ignition of the waste stream.

The inlet gas first passes through a hot ceramic bed thereby heating the stream (and cooling the bed) to its ignition temperature. The hot gases then react (releasing energy) in the combustion chamber and while passing through another ceramic bed, thereby heating it to the combustion chamber outlet temperature. The process flows are then switched, feeding the inlet stream to the hot bed. This cyclic process affords high energy recovery (up to 95%). The higher capital costs associated with these high-performance heat exchangers and combustion chambers may be offset by the auxiliary fuel savings to make such a system economical.

The use of a regenerative thermal oxidizer is not a technically feasible control option for the natural gas-fired boilers (EU-011A, EU-011B, EU-011C and EU-011D) at this source. The relatively low heat content of the exhaust gas from the natural gas boilers will require a large amount of makeup fuel to increase the temperature of the gas to cause CO/air combustion.

(b) **Catalytic Oxidizers**

Catalytic oxidation is also a widely used control technology to control pollutants where the waste gas is passed through a flame area and then through a catalyst bed for complete combustion of the waste in the gas. This technology is typically applied for destruction of organic vapors, nevertheless it is considered as a technology for controlling CO emissions. A catalyst is an element or compound that speeds up a reaction at lower temperatures (compared to thermal oxidation) without the catalyst undergoing change itself. Catalytic oxidizers operate at 650°F to 1000°F and require approximately 1.5 to 2.0 ft^3 of catalyst per 1000 standard ft^3 gas flow. Emissions from some emission units may contain significant amount of particulates. These particulates can poison the catalyst resulting in the failure of catalytic oxidation.

For some fuels, such as coal and residual oil, contaminants would likely be present in such concentrations so as to foul catalysts quickly thereby making such systems infeasible due to the need to constantly replace catalyst materials. In addition, the use of oxidation catalysts on units with high sulfur fuels can also result in the creation of sulfuric acid mist through the conversion of SO2 to SO3 and subsequent combination with moisture in the exhaust gas. The use of an oxidation catalyst to control carbon monoxide emissions is feasible for gas fired units because the fuel is a low sulfur fuel with relatively low concentrations of other contaminants, such as metals.

The use of a catalytic oxidizer is a technically feasible control option for the natural gas-fired boilers (EU-011A, EU-011B, EU-011C and EU-011D) at this source. Catalytic oxidizers utilize a catalyst (either an element or a compound) that can oxidize CO at a lower temperature than thermal oxidation.

(c) **Flare**

The low heating value of the natural gas-fired boilers (EU-011A, EU-011B, EU-011C and EU-011D) exhaust is too low for flaring. As there are insufficient organics in this vent stream to support combustion, use of a flare would require a significant addition of supplementary fuel. Therefore, a secondary impact of the use of a flare for this stream would be the creation of additional emissions from burning supplemental fuel, including NO_x. Flares have not been utilized or demonstrated as a control device for CO from this type of high-volume process stream. In addition, the flare would have no additional control versus the thermal oxidizers. The use of a flare is a technically infeasible option for the natural gas-fired boilers (EU-011A, EU-011B, EU-011C and EU-011D) at this source.

(d) **Combustion Control**

Because CO is essentially a by-product of incomplete or inefficient combustion, combustion control constitutes the primary mode of reduction of CO emissions. This type of control is appropriate for any type of fuel combustion source. Combustion process controls involve combustion chamber designs and operating practices that improve the oxidation process and minimize incomplete combustion. CO emissions result from the incomplete combustion of carbon and organic compounds. Factors affecting CO emissions include firing temperatures, residence time in the combustion zone and combustion chamber mixing characteristics. Combustion control is a technically feasible control option for the Auxiliary Boilers.

Step 3: Rank the Remaining Control Technologies by Control Effectiveness

(1) Oxidation Catalyst – 75% destruction efficiency

(2) Combustion Control

Step 4: Evaluate the Most Effective Controls and Document the Results

The following table lists the proposed CO BACT determination for Ohio Valley Resources, LLC along with the existing CO BACT determinations for similar emission units. All data in the table is based on the information obtained from the permit application submitted by Ohio Valley Resources, LLC, the U.S. EPA RACT/BACT/LAER Clearinghouse (RBLC), Indiana issued permits, and electronic versions of permits available at the websites of other permitting agencies.

RACT/BACT/LEAR CLEARINGHOUSE DATA
Boilers (EU-011A, EU-011B, EU-011C and EU-011D) – CO

RBLC ID	Facility	Issued Date	Process Description	Capacity	Limitation	Control Method
IA-0105	Iowa Fertilizer Company	10/26/2012	Auxiliary Boiler	472.4 MMBtu/hr	0.0013 lb/MMBtu	Good Combustion Practices
T147-32322-00062	**Ohio Valley Resources, LLC**	**Proposed**	**4 Package Boilers EU-011A to EU-011D**	**218 MMBtu/hr Each**	**37.22 lb/MMCF, 3 hr avg.**	**Good Combustion Practices, Usage Limit**
CA-1212	City of Palmdale Hybrid Power	12/20/12	Auxiliary Boiler	110 MMBtu/hr	50 ppmvd @ 3% O2	None
MI-0389	Consumers Energy	12/29/09	Auxiliary Boiler	220 MMBtu/hr	0.0350 lb/MMBtu	None
GA-0127	Southern Company	01/07/08	Auxiliary Boilers	200 MMBtu/hr	0.0370 lb/MMBtu	None
OH-0310	American Municipal Power	10/08/09	Auxiliary Boiler	150 MMBtu/hr	12.6 lb/hr	None, 0.084 lb/MMBtu

RBLC Review

The natural gas-fired boilers (EU-011A, EU-011B, EU-011C and EU-011D) have a potential to emit CO of 34.85 tons per year, each. With fuel usage limits in place, actual CO emissions are effectively limited to approximately 50 ton/year for all four boilers combined. A review of the RBLC entries for auxiliary boiler units indicates most emissions are uncontrolled and good combustion controls are utilized as BACT. None of the RBLC entries above utilized any add-on emission control systems for CO. As noted earlier in this Technical Support Document, catalytic oxidation is not a cost-effective CO emission control system for the primary reformer. Because of the lower utilization of the natural gas-fired boilers, and significantly lower actual CO emissions, is even less cost-effective to use catalytic oxidation for the natural gas fired boilers. In addition, the use of a thermal or catalytic oxidizer for CO control would require the use of a significant amount of supplemental fuel (to heat the exhaust gas to the required operating temperature to achieve destruction). This supplemental fuel firing will create additional combustion pollutant emissions (particularly NOx) which will at least partially offset any benefits of additional CO control.

Applicant Proposal

The applicant proposed the following as BACT:

(a) Proper design and good combustion practices;

(b) Use of natural gas; and

(c) Natural gas usage in three boilers is limited to 468 MMCF/yr each, while the fourth boiler is limited to 1,404 MMCF/yr.

The applicant's proposal is consistent with a majority of the entries in the RBLC for CO emissions. These emission limits are based on the uncontrolled emission factors found in AP-42. A permit for the Iowa Fertilizer Company (IFC) was recently issued by the Iowa Department of Natural Resources (IDNR) with a proposed emission rate of 0.0013 lb/MMBtu. The IFC permit limit is lower than the limit proposed by the applicant. IDNR established this limit based on two stack tests at a single boiler. IDEM believes the emission rate proposed by the applicant is appropriate for BACT based on the following factors:

1. Add-on emission controls have been demonstrated to be infeasible or not cost-effective.
2. The majority of the entries in the RBLC for uncontrolled natural gas-fired combustion units are derived from the AP-42 emission factors, which are based on stack tests on a large sample size of natural gas-burning facilities.
3. The emission limits in the IFC permit set by IDNR are based on two stack tests at the same facility – a 429 MMBtu/hr auxiliary boiler located at the Walter Scott Generating Plant in Council Bluffs, Iowa. These test results do not establish BACT for the boilers at Ohio Valley Resources.
    a. Two stack test results at the same facility are not representative of the emission rate achievable at a large range of natural gas facility types and sizes. The AP-42 emission factor for natural gas combustion is a better reflection of what is achievable for an uncontrolled natural gas unit.
    b. IFC's facilities have not yet begun operations, and consequently the achievability of the IFC BACT limits have not been demonstrated in practice.

<u>Step 5: Select BACT</u>

IDEM, OAQ has established CO BACT for the natural gas-fired boilers (EU-011A, EU-011B, EU-011C and EU-011D) as:

(a) CO emissions from the boilers (EU-011A, EU-011B, EU-011C and EU-011D) shall be controlled through the use of proper boiler design and good combustion practices.

(b) Combined fuel usage in the boilers (EU-011A, EU-011B, EU-011C and EU-011D) shall not exceed 2,802 MMCF per twelve consecutive month period with compliance determined at the end of each month.

(c) The boilers (EU-011A, EU-011B, EU-011C, and EU-011D) shall combust natural gas.

(d) CO emissions from each of the boilers (EU-011A, EU-011B, EU-011C, and EU-011D) shall not exceed 37.22 lb/MMCF, based on a three-hour average.

(9) CO BACT – Diesel-Fired Emergency Generator (EU-009)

Step 1: Identify Potential Control Technologies

Today's stationary diesel-fired emergency compression ignition internal combustion engines are sold as package units with an engineering design tailored to meet the emission limitations of 40 CFR 60, Subpart IIII and 40 CFR 63, Subpart ZZZZ. The manufacturer provides an engine that is in compliance with the applicable NSPS and NESHAP and the owner/operator is expected to maintain and operate the unit to guarantee compliance with applicable emission limitations. Based on the review of information for this BACT, IDEM has determined that add-on control technologies are not practical.

Step 2: Eliminate Technically Infeasible Options

The test for technical feasibility of any control option is whether it is both available and applicable to reducing the target pollutant. IDEM, OAQ has not identified any technically feasible add-on control options for the diesel-fired emergency generator (EU-009).

Step 3: Rank the Remaining Control Technologies by Control Effectiveness

IDEM, OAQ has not identified any technically feasible add-on control options for the diesel-fired emergency generator (EU-009).

Step 4: Evaluate the Most Effective Controls and Document the Results

The following table lists the proposed CO BACT determination for Ohio Valley Resources, LLC along with the existing CO BACT determinations for similar emission units. All data in the table is based on the information obtained from the permit application submitted by Ohio Valley Resources, LLC, the U.S. EPA RACT/BACT/LAER Clearinghouse (RBLC), Indiana issued permits, and electronic versions of permits available at the websites of other permitting agencies.

RACT/BACT/LEAR CLEARINGHOUSE DATA
Diesel-Fired Emergency Generator (EU-009) – CO

RBLC ID	Facility	Issued Date	Process Description	Capacity	Limitation	Control Method
NV-0050	MGM Mirage	11/30/09	Emergency Generators CC009 to CC015	3,622 HP	0.0017 lb/Hp-hr 6.05 lb/hr	Good Combustion Practices, 0.77 g/hp-hr
NV-0050	MGM Mirage	11/30/09	Emergency Generators LX024 and LX025	2,206 Hp	0.0018 lb/HP-hr 3.95 lb/hr	Good Combustion Practices, 0.82 g/hp-hr
T 147-32322-00062	**Ohio Valley Resources, LLC**	**Proposed**	**Emergency Generator EU-009**	**4,690**	**2.61 g/hp-hr, 3 hr avg.**	**Good Combustion Practices, Usage Limit**
AK-0076	Exxon-Port Thomson Production Facility	08/20/12	Diesel-Fired Generators	2,314 HP	3.5 g/KW-hr 0.01 lb/Hp-hr	None, 4.69 g/hp-hr
IA-0105	Iowa Fertilizer Company	10/26/12	Emergency Generator	2,682 HP	3.5 g/KW-hr 3.86 TPY 0.01 lb/Hp-hr	Good Combustion Practices, 4.69 g/hp-hr
FL-0332	Highlands Biorefinery and Cogeneration	09/23/11	2000 KW Emergency Equipment	2,682 HP	3.5 g/KW-hr 0.01 lb/Hp-hr	Comply with 40 CFR 60, Subpart IIII, 4.69 g/hp-hr

RBLC Review
The potential to emit CO for this generator is 6.75 TPY based on 500 hours of operation. The applicant proposed a 200 hour limit on annual operation. This limit reduces emissions to 2.70 tons per year. The RBLC table above indicates add-on control technology is not used for CO reduction. CO emissions are reduced by good combustion practice and maintenance.

Applicant Proposal
The applicant proposed the following for BACT:

(a) The diesel-fired emergency generator (EU-009) shall not operate more than 200 hours per year;

(b) CO emissions shall be controlled by good combustion practices and compliance with 40 CFR 60, Subpart IIII; and

(c) CO emissions shall not exceed 2.61 g/hp-hr.

Control Alternative	**Captured Emissions (TPY)**	**Emission Reduction (TPY)**	**Capital Cost ($)**	**Operating Cost ($/yr)**	**Total Annualized Costs ($/yr)** (b), (c)	**Cost Effectiveness ($/ton)**	**Energy and Environmental Impacts**
500 Hours, 0.77 g/hp-hr	1.99	0.71	45,000	(a)	$6,407	$9,024	lower overall emissions, units have same HP requirements
Baseline, 200 Hours, 2.61 g/hp-hr	2.70	Baseline	Baseline	Baseline	Baseline	Baseline	Baseline

Notes:
(a) IDEM, OAQ assumed the annual operating costs and salvage value are identical for both engine designs.
(b) Capital Recovery Factor – IDEM, OAQ assumed 0.142378 (7%, 10 year lifecycle)

The emergency generator will operate 200 hours annually regardless of the generator selected. The emission reduction attributable to the lower emitting generator is only 2.09 tons per year and costs $9,024 dollars per ton of emission reduction achieved. IDEM, OAQ concurs with the applicant's assessment. The lower emitting generator cannot be justified using a cost effectiveness analysis in this specific application because of the low hours of operation proposed.

Step 5: Select BACT
IDEM, OAQ has established CO BACT for the diesel-fired emergency generator (EU-009) as:

(1) The hours of operation of the diesel-fired emergency generator (EU-009) shall not exceed 200 hours per twelve consecutive month period with compliance determined at the end of each month.

(2) CO emissions shall be controlled by the use of good combustion practices.

(3) CO emissions from the diesel-fired emergency generator (EU-009) shall not exceed 2.61 g/hp-hr, based on a three-hour average.

(10) CO BACT – Diesel-Fired Fire Pump (EU-016)

Step 1: Identify Potential Control Technologies
Today's stationary diesel-fired emergency compression ignition internal combustion engines are sold as package units with an engineering design tailored to meet the emission limitations of 40 CFR 60, Subpart IIII and 40 CFR 63, Subpart ZZZZ. The manufacturer provides an engine that is in compliance with the applicable NSPS and NESHAP and the owner/operator is expected to maintain and operate the unit to guarantee compliance with applicable emission limitations. Based on the review of information for this BACT, IDEM has determined that add-on control technologies are not practical.

Step 2: Eliminate Technically Infeasible Options
The test for technical feasibility of any control option is whether it is both available and applicable to reducing the target pollutant. IDEM, OAQ has not identified any technically feasible add-on control options for the diesel-fired fire pump (EU-016).

Step 3: Rank the Remaining Control Technologies by Control Effectiveness
IDEM, OAQ has not identified any technically feasible add-on control options for the diesel-fired fire pump (EU-016).

Step 4: Evaluate the Most Effective Controls and Document the Results
The following table lists the proposed CO BACT determination for Ohio Valley Resources, LLC along with the existing CO BACT determinations for similar emission units. All data in the table is based on the information obtained from the permit application submitted by Ohio Valley Resources, LLC, the U.S. EPA RACT/BACT/LAER Clearinghouse (RBLC), Indiana issued permits, and electronic versions of permits available at the websites of other permitting agencies.

RACT/BACT/LEAR CLEARINGHOUSE DATA
Diesel-Fired Fire Pump (EU-016) – CO

RBLC ID	Facility	Issued Date	Process Description	Capacity	Limitation	Control Method
T 147-32322-00062	**Ohio Valley Resources, LLC**	**Proposed**	**Fire Pump EU-016**	**481 HP**	**2.6 g/hp-hr, 3 hr avg.**	**Good Combustion Practices, Usage Limit**
IA-0105	Iowa Fertilizer Company	10/26/12	Fire Pump	235 KW	3.5 g/KW-hr	Good Combustion Practices 2.6 g/hp-hr
MI-0389	Consumers Energy	12/29/09	Fire Pump	525 HP	2.6 g/hp-hr	None
LA-0254	Ninemile Point Electric Generating	08/16/11	Emergency Fire Pump	350 HP	2.6 g/Hp-hr	Good Combustion Practices
FL-0322	Southeast Renewable Fuels, LLC	12/23/10	Emergency Diesel Fire Pump	600 HP	2.6 g/Hp-hr	Comply with 40 CFR 60, Subpart IIII
SD-0005	Basin Electric Power Coop	10/14/11	Fire Pump	577 HP	None	40 CFR 60, Subpart IIII

RBLC Review
The potential to emit CO for this fire pump is 0.69 TPY based on 500 hours of operation. The applicant proposed a 200 hour limit on annual operation. This limit reduces emissions to 0.28 tons per year. The RBLC table above indicates add-on control technology is not used for CO reduction. CO emissions are reduced by good combustion practice and maintenance.

Applicant Proposal
The applicant proposed the following as BACT:

(a) CO emissions from the diesel-fired emergency fire pump (EU-016) shall be minimized by compliance with 40 CFR 60, Subpart IIII;

(b) CO emissions shall not exceed 2.6 g/hp-hr; and

(c) The diesel-fired emergency fire pump shall not operate more than 200 hours per year.

The applicant has accepted top BACT.

Step 5: Select BACT

IDEM, OAQ has established CO BACT for the diesel-fired fire pump (EU-016) as:

(1) Operation of the Diesel-Fired Emergency Firewater Pump (EU-016) shall not exceed 200 hours per twelve consecutive month period with compliance determined at the end of each month.

(2) CO emissions from the Diesel-Fired Emergency Firewater Pump (EU-016) shall be controlled by the use of good combustion practices.

(3) CO emissions from the diesel-fired fire pump (EU-016) shall not exceed 2.60 g/hp-hr, based on a three-hour average.

VOC BACT Determinations

(1) VOC BACT - Primary Reformer (EU-003)

Step 1: Identify Potential Control Technologies

IDEM, OAQ has identified the following VOC control technologies for the Primary Reformer (EU-003):

(1) Thermal Oxidation;

(2) Catalytic Oxidation;

(3) Flares; and

(4) Good Combustion Practices.

Each of these control technologies is discussed in Step 2 below.

Step 2: Eliminate Technically Infeasible Options

Thermal Oxidizers

The thermal oxidizer has a stabilized flame maintained by a combination of auxiliary fuel, waste gas compounds, and supplemental air added when necessary. This technology is typically applied for destruction of organic vapors and is considered a technology for controlling VOC emissions. Upon passing through the flame, the gas containing VOC is heated from its inlet temperature to its ignition temperature (It is the temperature at which the combustion reaction rate (and consequently the energy production rate) exceeds the rate of heat losses, thereby raising the temperature of the gases to some higher value). Thus, any VOC/air mixture will ignite if its temperature is raised to a sufficiently high level. The VOC-containing mixture ignites at some temperature between the preheat temperature and the reaction temperature. The ignition occurs at some point during the heating of a waste stream. The mixture continues to react as it flows through the combustion chamber.

Most thermal units are designed to provide no more than 1 second of residence time to the waste gas with typical temperatures of 1,200 to 2,000 °F. Once the unit is designed and built, the residence time is not easily changed, so that the required reaction temperature becomes a function of the particular gaseous species and the level of control. Regenerative Thermal Oxidizers consists of direct contact heat exchangers constructed of a ceramic material that can tolerate the high temperatures needed to achieve ignition of the waste stream.

The inlet gas first passes through a hot ceramic bed thereby heating the stream (and cooling the bed) to its ignition temperature. The hot gases then react (releasing energy) in the combustion chamber and while passing through another ceramic bed, thereby heating it to the combustion chamber outlet temperature. The process flows are then switched, feeding the inlet stream to the hot bed. This cyclic process affords high energy recovery (up to 95%). It is impractical for thermal oxidizers to reduce emissions of VOC from a properly operated natural gas combustion units. This is due to the large energy input required to obtain the required destruction temperature because the exhaust stream lacks adequate fuel.

The use of a thermal oxidizer is not a technically feasible control option for the Primary Reformer (EU-003) at this source.

Catalytic Oxidizers
Catalytic oxidation is also a widely used control technology to control pollutants where the waste gas is passed through a flame area and then through a catalyst bed for complete combustion of the waste in the gas. This technology is typically applied for destruction of organic vapors and is considered a technology for controlling VOC emissions. A catalyst is an element or compound that speeds up a reaction at lower temperatures (compared to thermal oxidation) without the catalyst undergoing change itself. Catalytic oxidizers operate at 650°F to 1000°F and require approximately 1.5 to 2.0 ft^3 of catalyst per 1000 standard ft^3 gas flow.

Emissions from some emission units may contain significant amount of particulates. These particulates can poison the catalyst resulting in the failure of catalytic oxidation.

For some fuels, such as coal and residual oil, contaminants would likely be present in such concentrations so as to foul catalysts quickly thereby making such systems infeasible due to the need to constantly replace catalyst materials. In addition, the use of oxidation catalysts on units with high sulfur fuels can also result in the creation of sulfuric acid mist through the conversion of SO_2 to SO_3 and subsequent combination with moisture in the exhaust gas. The use of an oxidation catalyst to control VOC emissions is feasible for gas fired units because the fuel is a low sulfur fuel with relatively low concentrations of other contaminants, such as metals. Due to the lower operating temperature requirements, it is possible to use catalytic oxidizers on reformer exhaust gases. While it is physically feasible to use catalytic oxidation, it is not normally used to control VOC emissions from natural gas combustion due to excessive costs.

The use of a catalytic oxidizer is not a technically feasible control option for the Primary Reformer (EU-003) at this source.

Flare
The low heating value of the Primary Reformer (EU-003) exhaust is too low for flaring. As there are insufficient organics in this vent stream to support combustion, use of a flare would require a significant addition of supplementary fuel. Therefore, a secondary impact of the use of a flare for this stream would be the creation of additional emissions from burning supplemental fuel, including VOC.

The use of a flare is not a technically infeasible option for the Primary Reformer (EU-003) at this source.

Combustion Control
This type of control is appropriate for any type of fuel combustion source. Combustion process controls involve combustion chamber designs and operating practices that improve the oxidation process and minimize incomplete combustion. Factors affecting VOC emissions include firing temperatures, residence time in the combustion zone and combustion chamber mixing characteristics. Combustion control is a technically feasible control option for the Primary Reformer (EU-003).

Step 3: Rank the Remaining Control Technologies by Control Effectiveness

IDEM, OAQ has identified a single control technology for VOC control from the Primary Reformer (EU-003). Therefore, no ranking is necessary.

Step 4: Evaluate the Most Effective Controls and Document the Results

The following table lists the proposed VOC BACT determination for Ohio Valley Resources, LLC along with the existing VOC BACT determinations for similar emission units. All data in the table is based on the information obtained from the permit application submitted by Ohio Valley Resources, LLC, the U.S. EPA RACT/BACT/LAER Clearinghouse (RBLC), Indiana issued permits, and electronic versions of permits available at the websites of other permitting agencies.

RACT/BACT/LEAR CLEARINGHOUSE DATA
Primary Reformer (EU-003) – VOC

RBLC ID	Facility	Issued Date	Process Description	Capacity	Limitation	Control Method
IA-0105	Iowa Fertilizer Company	10/26/12	Syngas Primary Reformer	1.13 MMCF/hr 1,152.6 MMBtu/hr	0.0014 lb/MMBtu 6.95 TPY 1.6 lb/hr	Good Combustion Practices
LA-0211	Garyville Refinery	12/27/06	Hydrogen Reformer Furnace Flue Gas Vent	1,412.50 MMBtu/hr	0.0015 lb/MMBtu 2.11 lb/hr	Proper Design, Operation and Good Combustion Practices
T147-32322-00062	**Ohio Valley Resources, LLC**	**Proposed**	**Methane Primary Reformer**	**1,006.4 MMBtu/hr**	**5.5 lb/MMCF, 3 hr avg.**	Proper Design, Operation, Good Combustion, Usage Limit
OK-0134	Pryor Plant Chemical	02/23/09	Primary Reformer EUID #101	700 ton ammonia per day	1.2 lb/hr	None, 225 MMBtu/hr
OK-0135	Pryor Plant Chemical	02/23/09	Primary Reformer	700 ton ammonia per day	1.21 lb/hr	None, 225 MMBtu/hr
NM-0050	Artesia Refinery	12/14/07	Steam Methane Reformer	337 MMBtu/hr	0.0050 lb/MMBtu 1.685 lb/hr	Combust Gaseous Fuel Only

RBLC Review

The potential to emit VOC from the Primary Reformer (EU-003) is 23.77 tons per year. A review of RBLC entries for similar units indicates add-on controls are not practical for emission units of this type. The entries center on proper design and good combustion practices to ensure complete combustion. While the Garyville Refinery is lower, the Garryville Refinery uses a hydrogen rich fuel which is a different technology from the steam methane reformer used in the Ohio Valley Resources and Iowa Fertilizer Company facilities.

Applicant Proposal

The applicant proposed the following for BACT:

(a) Primary Reformer (EU-003) shall combust natural gas and/or process off gas streams;

(b) VOC emissions from the Primary Reformer (EU-003) shall be controlled by good combustion practices;

(c) VOC emissions shall not exceed 0.0054 lb/MMBtu; and

The applicant's proposal is consistent with a majority of the entries in the RBLC for VOCs. These emission limits are based on the uncontrolled emission factors found in AP-42. A permit for the Iowa Fertilizer Company (IFC) was recently issued by the Iowa Department of Natural Resources (IDNR) with a proposed emission rate of 0.0014 lb/MMBtu. The IFC permit limit is lower than the limit proposed by the applicant. IDNR established this limit based on two stack tests at a single boiler. IDEM believes the emission rate proposed by the applicant is appropriate for BACT based on the following factors:

1. Add-on emission controls have been demonstrated to be infeasible or not cost-effective.
2. The majority of the entries in the RBLC for uncontrolled natural gas-fired combustion units are derived from the AP-42 emission factors, which are based on stack tests on a large sample size of natural gas-burning facilities.
3. The emission limits in the IFC permit set by IDNR are based on two stack tests at the same facility – a 429 MMBtu/hr auxiliary boiler located at the Walter Scott Generating Plant in Council Bluffs, Iowa. These test results do not establish BACT for the Primary Reformer at Ohio Valley Resources.
    a. Two stack test results at the same facility are not representative of the emission rate achievable at a large range of natural gas facility types and sizes. The AP-42 emission factor for natural gas combustion is a better reflection of what is achievable for an uncontrolled natural gas unit.
    b. IFC's facilities have not yet begun operations, and consequently the achievability of the IFC BACT limits have not been demonstrated in practice.

Step 5: Select BACT

IDEM, OAQ has established VOC BACT for the Primary Reformer (EU-003) as:

(1) VOC emissions from the operation of Primary Reformer (EU-003) shall be controlled through the use of good combustion practices.

(2) The Primary Reformer (EU-003) shall combust natural gas and/or process off gas streams.

(3) VOC emissions from the Primary Reformer (EU-003) shall not exceed 5.51 lb/MMCF, based on a three-hour average.

(2) VOC BACT – CO_2 Purification Process (EU-004)

Step 1: Identify Potential Control Technologies

IDEM, OAQ has identified the following VOC control technologies for the CO_2 Purification Process Vent (EU-004):

(1) Thermal Oxidation;

(2) Flares; and

(3) Proper Selection of Process Catalyst.

Each of these control technologies is discussed below in Step 2.

Step 2: Eliminate Technically Infeasible Options

(a) **Thermal Oxidizers**

Regenerative thermal oxidation is effective at controlling VOC emissions and is typically used to control waste streams containing organics. Thermal oxidizers are designed to maintain a stable flame through combustion of a combination of waste gases, auxiliary fuel, and supplemental air. For the CO_2 vent the flow of gas to be controlled is very high (231,710 lb/hr) and 95% of this stream is CO_2 with another 2% as water vapor. Neither of these constituents are combustible. Therefore, combustion of this stream to control the dilute amount of VOCs is technically infeasible.

The use of a thermal oxidizer is not a technically feasible control option for the CO_2 Purification Process Vent (EU-004) at this source.

(b) **Flare**

The low heating value of the CO_2 Purification Process Vent (EU-004) exhaust is too low for flaring. As there are insufficient organics in this vent stream to support combustion, use of a flare would require a significant addition of supplementary fuel. Therefore, a secondary impact of the use of a flare for this stream would be the creation of additional emissions from burning supplemental fuel, including VOC.

The use of a flare is not a technically infeasible option for the CO_2 Purification Process Vent (EU-004) at this source.

(c) **Proper Selection of Process Catalyst**

The applicant can select a process catalyst that minimizes VOC emissions while maximizing the optimum catalytic conversion of CO to CO_2 in the high and low shift converters.

The proper selection of a low VOC catalyst is a feasible control option for the CO_2 Purification Process Vent (EU-004).

Step 3: Rank the Remaining Control Technologies by Control Effectiveness

Only one control technology has been identified; therefore, a ranking is not required.

Step 4: Evaluate the Most Effective Controls and Document the Results

The following table lists the proposed VOC BACT determination for Ohio Valley Resources, LLC along with the existing VOC BACT determinations for similar emission units. All data in the table is based on the information obtained from the permit application submitted by Ohio Valley Resources, LLC, the U.S. EPA RACT/BACT/LAER Clearinghouse (RBLC), Indiana issued permits, and electronic versions of permits available at the websites of other permitting agencies.

RACT/BACT/LEAR CLEARINGHOUSE DATA CO_2 Purification Process (EU-004) – VOC						
RBLC ID	**Facility**	**Issued Date**	**Process Description**	**Capacity**	**Limitation**	**Control Method**
T147-32322-00062	**Ohio Valley Resources, LLC**	**Proposed**	**CO2 Purification Process**	**3,570 ton CO_2 per day**	**0.0558 lb/ton ammonia, 3 hr avg.**	**None, Usage Limit**
IA-0105	Iowa Fertilizer Company	10/26/12	CO_2 Regenerator	3,012 MT/day 3,313 ton/day	0.106 lb/ton ammonia	Good Operational Practices

RBLC Review
The CO_2 Purification Process Vent (EU-004) has the potential to emit VOC of 28.51 tons per year. This is equivalent to 0.0558 lb VOC per ton of ammonia. The RBLC has only one entry that can be compared to the CO_2 Purification Process at the Ohio Valley Resources, LLC facility. The Iowa Fertilizer Company has a slightly higher capacity but has nearly twice the VOC emission rate on a ton of ammonia produced basis.

Applicant Proposal
The applicant proposed the following for BACT:

(a) VOC emissions from the CO_2 Purification Process Vent (EU-004) shall not exceed 0.0558 lb/ton of ammonia produced; and

(b) Ammonia production shall not exceed 1,022,000 tons per twelve consecutive month period with compliance determined at the end of each month.

The applicant has accepted top BACT.

Step 5: Select BACT
IDEM, OAQ has established VOC BACT for the CO_2 Purification Process Vent as:

(1) Ammonia production shall not exceed 1,022,000 tons per twelve consecutive month period with compliance determined at the end of each month.

(2) The use of a low VOC catalyst providing a maximum VOC emission rate of 0.0558 lb VOC per ton of ammonia produced or less, based on a three-hour average.

(3) VOC BACT – Front End Process Flare (EU-007)

Step 1: Identify Potential Control Technologies
The following VOC control technologies are available to the Front End Process Flare (EU-007) at this source:

(1) Flare Design and Monitoring;

(2) Process Flaring Minimization Practices; and

(3) Flare Gas Recovery.

Each of these VOC control technologies are evaluated below in Step 2.

Step 2: Eliminate Technically Infeasible Options

(a) **Flare design and monitoring**

Flare design and good combustion practices – Flare design and monitoring are key elements in emissions performance of flares. The flare must be properly operated and maintained in order to achieve the anticipated emission rates guaranteed by the flare manufacturer.

The use of proper flare design and good combustion practices is a technically feasible control option for the Front End Process Flare (EU-007) at this source.

(b) **Process flaring minimization practices**

Process flaring minimization practices – To the extent actions can be taken to minimize the volume of gas going to the flare, emissions of VOC will be less. Flaring minimization practices are feasible and are evaluated in the analysis of BACT.

The use of process flaring minimization practices is a technically feasible control option for the Front End Process Flare (EU-007) at this source.

(c) **Flare gas recovery**

Flare gas recovery – Flare gas recovery has been implemented at some facilities that produce and use internally generated fuel gas streams such as petroleum refineries. However, flare gas recovery for the Ohio Valley Resources, LLC facility is not feasible for the following reasons.

(1) First, unlike a refinery's nearly continuous supply of flared gases, flaring at the proposed Ohio Valley Resources, LLC facility will be an infrequent occurrence.

(2) Another difference is that the Ohio Valley Resources, LLC flaring events, the flared material may not be suitable for use as a fuel gas.

The use of a flare gas recovery system is not a technically feasible control option for the Front End Process Flare (EU-007) at this source.

Step 3: Rank the Remaining Control Technologies by Control Effectiveness

All technically feasible control options have been selected as BACT by the applicant. A ranking is not required.

Step 4: Evaluate the Most Effective Controls and Document the Results

The following table lists the proposed VOC BACT determination for Ohio Valley Resources, LLC along with the existing VOC BACT determinations for similar emission units. All data in the table is based on the information obtained from the permit application submitted by Ohio Valley Resources, LLC, the U.S. EPA RACT/BACT/LAER Clearinghouse (RBLC), Indiana issued permits, and electronic versions of permits available at the websites of other permitting agencies.

RACT/BACT/LEAR CLEARINGHOUSE DATA Front End Process Flare (EU-007) – VOC						
RBLC ID	**Facility**	**Issued Date**	**Process Description**	**Capacity**	**Limitation**	**Control Method**
T147-32322-00062	**Ohio Valley Resources, LLC**	**Proposed**	**Front End Process Flare**	**0.253 MMBtu/hr**	**0.0054 lb/MMBtu, pilot and 47.26 lb/hr, venting**	**Good Combustion Practices, Usage Limit**
IA-0089	Homeland Energy Solutions, LLC	08/08/07	Startup and Shutdown Flares	25 MMBtu	0.006 lb/MMBtu	None
IA-0105	Iowa Fertilizer Company	10/26/12	Ammonia Flare	0.4 MMBtu/hr	No Numerical Limit	Good Combustion Practices
LA-0213	Valero Refining, St. Charles Refinery	11/17/09	Flare 1 – 5	Not Specified	No emissions	No limit on pilot flare

RBLC Review
The potential to emit VOC from the front end process flare is 0.89 tons per year. A review of the RBLC entries in the table above indicates add-on controls are not required for flares of this size combusting natural gas. Most RBLC entries contain a pound per hour emission rate based on the combustion of natural gas such as the Homeland Energy Solutions flare. The emission rate of the Homeland Energy Solutions flare is the same as the Front End Process Flare (EU-007).

Applicant Proposal
The applicant proposed the following as BACT:

(a) Proper design and good combustion practices;

(b) The use of natural gas; and

(c) The use of flare minimization practices (FMP).

Step 5: Select BACT
IDEM, OAQ has established VOC BACT for the Front End Process Flare (EU-007) as:

(1) In order to control VOC emissions, the pilot and purge gas fuels used in the flare shall be natural gas.

(2) Venting in the Front End Process Flare (EU-007) shall not exceed 336 hours per twelve consecutive month period with compliance determined at the end of each month.

(3) Comply with the following flare minimization practices to reduce emissions during startups, shutdowns, and other flaring events:

(A) Flare Use Minimization: Process syngas streams to flare EU-007 shall not contain ammonia. During the startup of the sequential reformer, only one process stream at a time shall be sent to the flare to the extent practicable. Maximize the use of process syngas during the startup of the Ammonia Unit;

(B) The Permittee shall train all operators responsible for the day-to-day operation of the flares on the flare minimization practices and the specific procedures to follow during process startup, shutdown, and other flaring events; and

(C) The Permittee shall investigate the “root cause” of malfunction events that cause flaring events other than at startup or shutdown. This root cause analysis shall identify the apparent cause of unanticipated flaring event and shall recommend additional preventive measures that will minimize the chance of a repeat event. The Permittee shall implement the recommended preventive measures.

(4) VOC emissions shall be controlled by use of the following practices:

(A) Flares shall be designed for and operated with no visible emissions, except for periods not to exceed 5 minutes during any two consecutive hours;

(B) Flares shall be operated with a flame present at all times; and

(C) Flares shall be continuously monitored to assure the presence of a pilot flame with a thermocouple, infrared monitor, or other approved device.

(5) VOC emissions from the Front End Process Flare (EU-007) shall not exceed 0.0054 lb/MMBtu, based on a three-hour average, during normal operations, non-venting periods.

(6) VOC emissions from the Front End Process Flare (EU-007) shall not exceed 47.26 lb/hr, based on a three-hour average, during venting events.

(4) VOC BACT – Ammonia Catalyst Startup Heater (EU-010)

Step 1: Identify Potential Control Technologies

IDEM, OAQ has identified the following VOC control technologies for the Ammonia Catalyst Startup Heater (EU-010):

(1) Thermal Oxidation;

(2) Catalytic Oxidation;

(3) Flares; and

(4) Good Combustion Practices.

Step 2: Eliminate Technically Infeasible Options

(a) **Thermal Oxidizers**
The thermal oxidizer has a stabilized flame maintained by a combination of auxiliary fuel, waste gas compounds, and supplemental air added when necessary. This technology is typically applied for destruction of organic vapors. Upon passing through the flame, the gas containing VOC is heated from its inlet temperature to its ignition temperature. It is the temperature at which the combustion reaction rate and consequently the energy production rate exceeds the rate of heat losses, thereby

raising the temperature of the gases to some higher value. Thus, any VOC/air mixture will ignite if its temperature is raised to a sufficiently high level. The VOC-containing mixture ignites at some temperature between the preheat temperature and the reaction temperature. The ignition occurs at some point during the heating of a waste stream. The mixture continues to react as it flows through the combustion chamber.

Most thermal units are designed to provide no more than 1 second of residence time to the waste gas with typical temperatures of 1,200 to 2,000°F. Once the unit is designed and built, the residence time is not easily changed, so that the required reaction temperature becomes a function of the particular gaseous species and the level of control. It is impractical for thermal oxidizers to reduce emissions of VOC from a properly operated natural gas combustion units. This is due to the large energy input required to obtain the required destruction temperature because the exhaust stream lacks adequate fuel. The use of a thermal oxidizer is not a technically feasible control option for the Ammonia Catalyst Startup Heater (EU-010) at this source.

(b) **Catalytic Oxidizers**
Catalytic oxidation is also a widely used control technology to control pollutants where the waste gas is passed through a flame area and then through a catalyst bed for complete combustion of the waste in the gas. This technology is typically applied for destruction of organic vapors. A catalyst is an element or compound that speeds up a reaction at lower temperatures (compared to thermal oxidation) without the catalyst undergoing change itself. Catalytic oxidizers operate at 650°F to 1000°F and require approximately 1.5 to 2.0 ft^3 of catalyst per 1000 standard ft^3 gas flow.

Emissions from some emission units may contain significant amount of particulates. These particulates can poison the catalyst resulting in the failure of catalytic oxidation. For some fuels, such as coal and residual oil, contaminants would likely be present in such concentrations so as to foul catalysts quickly thereby making such systems infeasible due to the need to constantly replace catalyst materials. In addition, the use of oxidation catalysts on units with high sulfur fuels can also result in the creation of sulfuric acid mist through the conversion of SO2 to SO3 and subsequent combination with moisture in the exhaust gas. The use of catalytic oxidation for the exhaust of a properly designed natural gas combustion source is not practical. This is due to the fact that this exhaust does not have enough organics to support combustion and a large amount of additional combustion fuel is required. The use of a catalytic oxidizer is not a technically feasible control option for the Ammonia Catalyst Startup Heater (EU-010) at this source.

(c) **Flare**
The low heating value of the Ammonia Catalyst Startup Heater (EU-010) exhaust is too low for flaring. As there are insufficient organics in this vent stream to support combustion, use of a flare would require a significant addition of supplementary fuel. Therefore, a secondary impact of the use of a flare for this stream would be the creation of additional emissions from burning supplemental fuel, including VOC. The VOC emissions created by this unit are due to natural gas combustion, additional natural gas would increase VOC emissions. The use of a flare is not a technically infeasible option for the Ammonia Catalyst Startup Heater (EU-010) at this source.

(d) **Combustion Control**
This type of control is appropriate for any type of fuel combustion source. Combustion process controls involve combustion chamber designs and operating practices that improve the oxidation process and minimize incomplete combustion. Factors affecting VOC emissions include firing temperatures, residence time in the combustion zone and combustion chamber mixing characteristics. Combustion control is a technically feasible control option for the Ammonia Catalyst Startup Heater (EU-010).

Step 3: Rank the Remaining Control Technologies by Control Effectiveness

The only conventional VOC control technology that is technologically feasible for the Ammonia Catalyst Startup Heater (EU-010) is good combustion practices. A ranking is not necessary.

Step 4: Evaluate the Most Effective Controls and Document the Results

The following table lists the proposed VOC BACT determination for Ohio Valley Resources, LLC along with the existing VOC BACT determinations for similar emission units. All data in the table is based on the information obtained from the permit application submitted by Ohio Valley Resources, LLC, the U.S. EPA RACT/BACT/LAER Clearinghouse (RBLC), Indiana issued permits, and electronic versions of permits available at the websites of other permitting agencies.

RACT/BACT/LEAR CLEARINGHOUSE DATA
Ammonia Catalyst Startup Heater (EU-010) – VOC

RBLC ID	Facility	Issued Date	Process Description	Capacity	Limitation	Control Method
IA-0105	Iowa Fertilizer Company	10/26/2012	Startup Heater	110.12 MMBtu/hr	0.0014 lb/MMBtu	Good Combustion Practices
T 147-32322-00062	**Ohio Valley Resources, LLC**	**Proposed**	**Catalyst Startup Heater**	**106.3 MMBtu/hr**	**5.5 lb/MMCF, 3 hr avg.**	**Good Combustion Practices, Usage Limit**
OH-0329	BP Products Husky Refining	08/07/09	Reformer Heater	519 MMBtu/hr	2.8 lb/hr	None, 0.0054 lb/MMBtu
LA-0197	Conoco Phillips, Alliance	07/21/09	Gasoline Feed Heater	138.12 MMBtu/hr	0.74 lb/hr	None, 0.0054 lb/MMBtu
WY-0067	Williams Field Services	04/01/09	Hot Oil Heater	84 MMBt/hr	0.02 lb/MMBtu	None
OK-0134	Pryor Plant Chemical Company	02/23/09	Nitric Acid Preheaters	20 MMBtu/hr	0.11 lb/hr	None, 0.0054 lb/MMBtu
SC-0115	GP Clarendon LP	02/10/09	Backup Oil Heater	75 MMBtu/hr	0.39 lb/hr	None, 0.0054 lb/MMBtu

RBLC Review

The potential to emit VOC of the Ammonia Catalyst Startup Heater (EU-010) is 2.51 TPY. A review of the RBLC entries for VOC control in auxiliary boilers shows the only control method practical is good combustion practice.

Applicant Proposal

The applicant proposed the following for BACT:

(a) The use of natural gas;

(b) Good design and combustion practices;

(c) VOC emissions shall not exceed 0.0054 lb/MMBtu; and

(d) Natural gas usage shall not exceed 20.84 MMCF per twelve consecutive month period with compliance determined at the end of each month.

The applicant’s proposal is consistent with a majority of the entries in the RBLC for VOC emissions. These emission limits are based on the uncontrolled emission factors found in AP-42. A permit for the Iowa Fertilizer Company (IFC) was recently issued by the Iowa Department of Natural Resources (IDNR) with a proposed emission rate of 0.0014 lb/MMBtu. The IFC permit limit is lower than the limit proposed by the applicant. IDNR established this limit based on two stack tests at a single boiler. IDEM believes the emission rate proposed by the applicant is appropriate for BACT based on the following factors:

1. Add-on emission controls have been demonstrated to be infeasible or not cost-effective.

2. The majority of the entries in the RBLC for uncontrolled natural gas-fired combustion units are derived from the AP-42 emission factors, which are based on stack tests on a large sample size of natural gas-burning facilities.

3. The emission limits in the IFC permit set by IDNR are based on two stack tests at the same facility – a 429 MMBtu/hr auxiliary boiler located at the Walter Scott Generating Plant in Council Bluffs, Iowa. These test results do not establish BACT for the Ammonia Catalyst Startup Heater at Ohio Valley Resources.

    a. Two stack test results at the same facility are not representative of the emission rate achievable at a large range of natural gas facility types and sizes. The AP-42 emission factor for natural gas combustion is a better reflection of what is achievable for an uncontrolled natural gas unit.

    b. IFC’s facilities have not yet begun operations, and consequently the achievability of the IFC BACT limits have not been demonstrated in practice.

Step 5: Select BACT

IDEM, OAQ has established VOC BACT for the Ammonia Catalyst Startup Heater (EU-010) as:

(1) In order to control VOC emissions, the Ammonia Catalyst Startup Heater (EU-010) shall combust natural gas.

(2) In order to control VOC emissions, the Ammonia Catalyst Startup Heater (EU-010) shall be controlled by good heater design and good combustion practices.

(3) Fuel usage in the Ammonia Catalyst Startup Heater (EU-010) shall not exceed 20.84 MMCF per twelve consecutive month period with compliance determined at the end of each month.

(4) VOC emissions from the Ammonia Catalyst Startup Heater (EU-010) shall not exceed 5.50 lb/MMCF, based on a three-hour average.

(5) VOC BACT – Back End Ammonia Process Vent Flare (EU-006)

Step 1: Identify Potential Control Technologies

The following VOC control technologies are available to the Back End Ammonia Process Vent Flare (EU-006) at this source:

(1) Flare Design and Monitoring;

(2) Process Flaring Minimization practices; and

(3) Flare Gas Recovery.

Each of these VOC control technologies are evaluated below in Step 2.

Step 2: Eliminate Technically Infeasible Options

(a) **Flare design and monitoring**
Flare design and good combustion practices – Flare design and monitoring are key elements in emissions performance of flares. The flare must be properly operated and maintained in order to achieve the anticipated emission rates guaranteed by the flare manufacturer.

The use of proper flare design and good combustion practices is a technically feasible control option for the Back End Ammonia Process Vent Flare (EU-006) at this source.

(b) **Process flaring minimization practices**
Process flaring minimization practices – To the extent actions can be taken to minimize the volume of gas going to the flare, emissions of VOC will be less. Flaring minimization practices are feasible and are evaluated in the analysis of BACT.

The use of process flaring minimization practices is a technically feasible control option for the Back End Ammonia Process Vent Flare (EU-006) at this source.

(c) **Flare gas recovery**
Flare gas recovery – Flare gas recovery has been implemented at some facilities that produce and use internally generated fuel gas streams such as petroleum refineries. However, flare gas recovery for the Ohio Valley Resources, LLC facility is not feasible for the following reasons.

(1) First, unlike a refinery's nearly continuous supply of flared gases, flaring at the proposed Ohio Valley Resources, LLC facility will be an infrequent occurrence.

(2) Another difference is that the Ohio Valley Resources, LLC flaring events, the flared material may not be suitable for use as a fuel gas.

The use of a flare gas recovery system is not a technically feasible control option for the Back End Ammonia Process Vent Flare (EU-006) at this source.

Step 3: Rank the Remaining Control Technologies by Control Effectiveness
All technically feasible control options have been selected as BACT by the applicant. No ranking is required.

Step 4: Evaluate the Most Effective Controls and Document the Results
The following table lists the proposed VOC BACT determination for Ohio Valley Resources, LLC along with the existing VOC BACT determinations for similar emission units. All data in the table is based on the information obtained from the permit application submitted by Ohio Valley Resources, LLC, the U.S. EPA RACT/BACT/LAER Clearinghouse (RBLC), Indiana issued permits, and electronic versions of permits available at the websites of other permitting agencies.

RACT/BACT/LEAR CLEARINGHOUSE DATA Back End Process Flare (EU-006) – VOC						
RBLC ID	**Facility**	**Issued Date**	**Process Description**	**Capacity**	**Limitation**	**Control Method**
T147-32322-00062	**Ohio Valley Resources, LLC**	**Proposed**	**Back End Process Flare EU-006**	**0.253 MMBtu/hr**	**0.0054 lb/MMBtu, pilot and 11.73 lb/hr, venting**	**Good Combustion Practices, Usage Limit**
IA-0089	Homeland Energy Solutions, LLC	08/08/07	Startup and Shutdown Flares	25 MMBtu	0.006 lb/MMBtu	None
IA-0105	Iowa Fertilizer Company	10/26/12	Ammonia Flare	0.4 MMBtu/hr	No Numerical Limit	Good Combustion Practices
LA-0213	Valero Refining, St. Charles Refinery	11/17/09	Flare 1 – 5	Not Specified	No emissions from process, no limit on pilot	None

RBLC Review
The potential to emit VOC from the front end process flare is 0.01 tons per year. A review of the RBLC entries in the table above indicates add-on controls are not required for flares of this size combusting natural gas. The emission rate listed for the Homeland Energy Solutions flare is the emission factor for natural gas. It is the same emission rate used by OVR in emission calculations.

Applicant Proposal
The applicant proposed the following for BACT:

(a) Proper design and good combustion practices;

(b) The use of natural gas; and

(c) The use of flare minimization practices.

Step 5: Select BACT
IDEM, OAQ has established VOC BACT for the Back End Process Flare (EU-006) as:

(1) In order to control VOC emissions, the pilot and purge gas fuels used in the flare shall be natural gas.

(2) Venting in the Back End Ammonia Process Flare (EU-006) shall not exceed 336 hours per twelve consecutive month period with compliance determined at the end of each month.

(3) Comply with the following flare minimization practices to reduce emissions during startups, shutdowns, and other flaring events:

(A) Flare Use Minimization: Flare EU-006 shall be limited to flaring ammonia during high-pressure events to the extent practicable. The ammonia compressor main shall be depressurized prior to compressor maintenance. The Permittee shall limit venting ammonia rich streams to Flare EU-006 to the extent practicable during non-emergency startup and shutdown operations;

(B) The Permittee shall train all operators responsible for the day-to-day operation of the flares on the flare minimization practices and the specific procedures to follow during process startup, shutdown, and other flaring events; and

(C) The Permittee shall investigate the “root cause” of malfunction events that cause flaring events other than at startup or shutdown. This root cause analysis shall identify the apparent cause of unanticipated flaring event and shall recommend additional preventive measures that will minimize the chance of a repeat event. The Permittee shall implement the recommended preventive measures.

(4) VOC emissions from the Back End Ammonia Process Vent Flare (EU-006) shall be controlled by the use of the following practices:

(A) Flares shall be designed for and operated with no visible emissions, except for periods not to exceed 5 minutes during any two consecutive hours;

(B) Flares shall be operated with a flame present at all times; and

(C) Flares shall be continuously monitored to assure the presence of a pilot flame with a thermocouple, infrared monitor, or other approved device.

(5) VOC emissions from the Back End Process Flare (EU-006) shall not exceed 0.0054 lb/MMBtu, based on a three-hour average, during normal operations, non-venting period.

(6) VOC emission from the Back End Process Flare (EU-006) shall not exceed 11.73 lb/hr, based on a three-hour average, during venting events.

(6) VOC BACT – Ammonia Storage System Flare (EU-005)

Step 1: Identify Potential Control Technologies

The following VOC control technologies are available to the Ammonia Storage System Flare (EU-005) at this source:

(1) Flare Design and Monitoring;

(2) Process Flaring Minimization practices; and

(3) Flare Gas Recovery.

Each of these VOC control technologies are evaluated below in Step 2.

Step 2: Eliminate Technically Infeasible Options

(a) **Flare design and monitoring**
Flare design and good combustion practices – Flare design and monitoring are key elements in emissions performance of flares. The flare must be properly operated and maintained in order to achieve the anticipated emission rates guaranteed by the flare manufacturer. The use of proper flare design and good combustion practices is a technically feasible control option for the Ammonia Storage System Flare (EU-005) at this source.

(b) **Process flaring minimization practices**
Process flaring minimization practices – To the extent actions can be taken to minimize the volume of gas going to the flare, emissions of VOC will be less. Flaring minimization practices are feasible and are evaluated in the analysis of BACT. The use of process flaring minimization practices is a technically feasible control option for the Ammonia Storage System Flare (EU-005) at this source.

(c) **Flare gas recovery**
Flare gas recovery – Flare gas recovery has been implemented at some facilities that produce and use internally generated fuel gas streams such as petroleum refineries. However, flare gas recovery for the Ohio Valley Resources, LLC facility is not feasible for the following reasons.

(1) First, unlike a refinery's nearly continuous supply of flared gases, flaring at the proposed Ohio Valley Resources, LLC facility will be an infrequent occurrence.

(2) Another difference is that the Ohio Valley Resources, LLC flaring events, the flared material may not be suitable for use as a fuel gas.

The use of a flare gas recovery system is not a technically feasible control option for the Ammonia Storage System Flare (EU-005) at this source.

Step 3: Rank the Remaining Control Technologies by Control Effectiveness
All technically feasible control options have been selected as BACT by the applicant. A ranking is not required.

Step 4: Evaluate the Most Effective Controls and Document the Results
The following table lists the proposed VOC BACT determination for Ohio Valley Resources, LLC along with the existing VOC BACT determinations for similar emission units. All data in the table is based on the information obtained from the permit application submitted by Ohio Valley Resources, LLC, the U.S. EPA RACT/BACT/LAER Clearinghouse (RBLC), Indiana issued permits, and electronic versions of permits available at the websites of other permitting agencies.

RACT/BACT/LEAR CLEARINGHOUSE DATA
Ammonia Storage System Flare (EU-005) – VOC

RBLC ID	Facility	Issued Date	Process Description	Capacity	Limitation	Control Method
T147-32322-00062	**Ohio Valley Resources, LLC**	**Proposed**	**Ammonia Storage Flare EU-005**	**0.126 MMBtu/hr**	**0.0054 lb/MMBtu**	**Good Combustion Practices, Usage Limit**
IA-0089	Homeland Energy Solutions	08/08/07	Startup and Shutdown Flares	25 MMBtu	0.006 lb/MMBtu	None
IA-0105	Iowa Fertilizer Company	10/26/12	Ammonia Flare	0.4 MMBtu/hr	No Numerical Limit	Good Combustion Practices
LA-0213	Valero, St. Charles Refinery	11/17/09	Flare 1 – 5	Not Specified	No emissions	No limit on pilot flare

RBLC Review

The potential to emit VOC from the Ammonia Storage System Flare (EU-005) is 0.003 tons per year. A review of the RBLC entries in the table above indicates add-on controls are not required for flares of this size combusting natural gas. Add-on controls are not practical due to the low VOC emission rate of this flare.

Applicant Proposal

The applicant proposed the following as BACT:

(a) Proper design and good combustion practices;

(b) The use of natural gas; and

(c) The use of flare minimization practices (FMP).

Step 5: Select BACT

IDEM, OAQ has established VOC BACT for the Ammonia Storage System Flare (EU-005) as:

(1) In order to control VOC emissions, the pilot and purge gas fuels used in the flare shall be natural gas.

(2) Venting for Startup, Shutdown and Malfunction shall not exceed 168 hours per twelve consecutive month period with compliance determined at the end of each month.

(3) Comply with the following flare minimization practices to reduce emissions during startups, shutdowns, and other flaring events:

  (A) Flare Use Minimization: The Permittee shall limit periods when the backup storage compressor and the ammonia refrigeration compressor are offline at the same time to the extent practicable;

  (B) The Permittee shall train all operators responsible for the day-to-day operation of the flares on the flare minimization practices and the specific procedures to follow during process startup, shutdown, and other flaring events; and

  (C) The Permittee shall investigate the “root cause” of malfunction events that cause flaring events other than at startup or shutdown. This root cause analysis shall identify the apparent cause of unanticipated flaring event and shall recommend additional preventive measures that will minimize the chance of a repeat event. The Permittee shall implement the recommended preventive measures.

(4) VOC emissions shall be controlled by use of the following practices:

  (A) Flares shall be designed for and operated with no visible emissions, except for periods not to exceed 5 minutes during any two consecutive hours;

  (B) Flares shall be operated with a flame present at all times; and

  (C) Flares shall be continuously monitored to assure the presence of a pilot flame with a thermocouple, infrared monitor, or other approved device.

(5) VOC emissions from the Ammonia Storage System Flare (EU-005) shall not exceed 0.0054 lb/MMBtu, based on a three-hour average.

(7) VOC BACT – Two Identical UAN Storage Tanks (EU-012A and EU-012B)

Step 1: Identify Potential Control Technologies

The following control technologies have been identified to control VOC emissions from the UAN Storage Tanks (EU-012A and EU-012B):

(a) **Add-on Controls:** IDEM, OAQ has identified the following add-on controls capable of VOC control

(1) Thermal Oxidation
(2) Catalytic Oxidation
(3) Vapor Recovery System
(4) Flare
(5) Nitrogen Blanket
(6) Condenser

The UAN storage tanks, identified as EU-012A and EU-012B contain a dilute solution with a low vapor pressure. The applicant estimates emissions from each tank at 0.7 tons per year. Due to the low vapor pressure of the dilute solution, there are no economical add-on control methods available to the UAN storage tanks.

(b) **Submerged Fill**

Loading losses occur in cargo carrier loading as the organic vapors are displaced as the liquid product is loaded. The organic vapors can contain residual vapors from the last product loaded, vapors transferred to the tank in a vapor balance system and vapors generated in the tank as new product is loaded. The amount of vapors generated can be controlled by the type of loading method used. In splash loading, the fill pipe is only lowered part way into the tank. This results in large amounts of turbulence in the liquid and results in close contact of the VOC with the vapor which increase emissions. The submerged fill method is an alternate filling method used to reduce the amount of vapor/liquid contact. In the submerged fill method, the fill pipe extends below the liquid surface. As the liquid is transferred to the tank, the submerged fill pipe significantly reduces turbulence, air/liquid contact and results in lower overall VOC emissions. Submerged fill is considered a technologically feasible control option.

(b) **Tank Color**

Color selection can contribute to elevated emissions of VOC. Black or darker colored tanks absorb more frequencies of light. This energy is transferred to the contents of the tank as heat through conduction in the tank wall. As the liquid heats, the vapor pressure rises and potential VOC emissions increase. The reverse is true for light colored or reflective tanks. Tank color selection is a technically feasible control option for the UAN Storage Tanks.

Step 2: Eliminate Technically Infeasible Options

IDEM, OAQ has identified submerged fill and tank color selection as technologically feasible VOC control methods for the UAN Storage Tanks.

Step 3: Rank the Remaining Control Technologies by Control Effectiveness

The applicant has accepted both control options; therefore, a ranking is not necessary.

Step 4: Evaluate the Most Effective Controls and Document the Results

The following table lists the proposed VOC BACT determination for Ohio Valley Resources, LLC along with the existing VOC BACT determinations for similar emission units. All data in the table is based on the information obtained from the permit application submitted by Ohio Valley Resources, LLC, the U.S. EPA RACT/BACT/LAER Clearinghouse (RBLC), Indiana issued permits, and electronic versions of permits available at the websites of other permitting agencies.

RACT/BACT/LEAR CLEARINGHOUSE DATA UAN Storage Tanks (EU-012A and EU-012B) – VOC						
RBLC ID	**Facility**	**Issued Date**	**Process Description**	**Capacity**	**Limitation**	**Control Method**
T147-32322-00062	**Ohio Valley Resources, LLC**	**Proposed**	**UAN EU-012A/B**	**30 tons UAN, each**	**None**	**Submerged Fill and White Shell**
There are no RBLC entries for UAN or similar organic liquids.						

RBLC Review
The RBLC did not contain any entries for UAN or similar organic liquids.

Applicant Proposal
The applicant proposed the use of a white tank with submerged fill for VOC control of the UAN Storage Tanks. This represents top BACT.

Step 5: Select BACT
IDEM, OAQ has established VOC BACT for the UAN Storage Tanks (EU-012A and EU-012B) as:

(1) The use of white tank shells.

(2) The use of submerged/bottom fills.

(8) VOC BACT – Three Identical UAN Day Tanks (EU-020A, EU-20B and EU-20C)

Step 1: Identify Potential Control Technologies
The following control technologies have been identified to control VOC emissions from the UAN Day Tanks (EU-020A, EU-020B and EU-020C):

(a) **Add-on Controls:** IDEM, OAQ has identified the following add-on controls capable of VOC control

(1) Thermal Oxidation
(2) Catalytic Oxidation
(3) Vapor Recovery System
(4) Flare
(5) Nitrogen Blanket
(6) Condenser

The UAN Day Tanks, identified as EU-020A, EU-020B and EU-020C contain a dilute solution with a very low vapor pressure. The applicant estimates emissions from each tank at 0.26 tons per year. Due to the low vapor pressure of the dilute solution, there are no economical add-on control methods available to the UAN storage tanks.

(b) **Submerged Fill**
Loading losses occur in cargo carrier loading as the organic vapors are displaced as the liquid product is loaded. The organic vapors can contain residual vapors from the last product loaded, vapors transferred to the tank in a vapor balance system and vapors generated in the tank as new product is loaded. The amount of vapors generated can be controlled by the type of loading method used. In splash loading, the fill pipe is only lowered part way into the tank. This results in large amounts of turbulence in the liquid and results in close contact of the VOC with the vapor which increase emissions. The submerged fill method is an alternate filling method used to reduce the amount of vapor/liquid contact. In the submerged fill method, the fill pipe extends below the liquid surface. As the liquid is transferred to the tank, the submerged fill pipe significantly reduces turbulence, air/liquid contact and results in lower overall VOC emissions.

Submerged fill is considered a technologically feasible control option.

(c) **Tank Color**
Color selection can contribute to elevated emissions of VOC. Black or darker colored tanks absorb more frequencies of light. This energy is transferred to the contents of the tank as heat through conduction in the tank wall. As the liquid heats, the vapor pressure rises and potential VOC emissions increase. The reverse is true for light colored or reflective tanks. Tank color selection is a technically feasible control option.

Step 2: Eliminate Technically Infeasible Options
IDEM, OAQ has identified submerged fill and tank color selection as technologically feasible VOC control methods for the UAN Day Tanks.

Step 3: Rank the Remaining Control Technologies by Control Effectiveness
The applicant has accepted both control options; therefore, a ranking is not necessary.

Step 4: Evaluate the Most Effective Controls and Document the Results
The following table lists the proposed VOC BACT determination for Ohio Valley Resources, LLC along with the existing VOC BACT determinations for similar emission units. All data in the table is based on the information obtained from the permit application submitted by Ohio Valley Resources, LLC, the U.S. EPA RACT/BACT/LAER Clearinghouse (RBLC), Indiana issued permits, and electronic versions of permits available at the websites of other permitting agencies.

RACT/BACT/LEAR CLEARINGHOUSE DATA
UAN Day Tanks (EU-020A, EU-020B and EU-020C) – VOC

RBLC ID	Facility	Issued Date	Process Description	Capacity	Limitation	Control Method
T147-32322-00062	**Ohio Valley Resources, LLC**	**Proposed**	**UAN EU-020A, B and C**	**750 tons UAN, each**	**None**	**Submerged Fill and White Shell**
There are no RBLC entries for UAN or similar organic liquids.						

RBLC Review
The RBLC did not contain any entries for UAN or similar organic liquids.

Applicant Proposal
The applicant proposed the use of a white tank with submerged fill for VOC control of the UAN Day Tanks. This represents top BACT.

Step 5: Select BACT
IDEM, OAQ has established VOC BACT for the UAN Day Tanks (EU-020A, EU-020B and EU-020C) as:

(1) The use of white tank shells.

(2) The use of submerged/bottom fills.

(9) VOC BACT – Two Fugitive UAN Loadout Facilities (EU-024A and EU-024B)

Step 1: Identify Potential Control Technologies
The UAN Loadout Facilities, identified as EU-024A and EU-024B contain a dilute solution with a very low vapor pressure. The applicant estimates emissions from each tank at 1.95 tons per year. Due to the low vapor pressure of the dilute solution, the only economical control method for these tanks is the use of submerged fill during loadout.

Step 2: Eliminate Technically Infeasible Options

(a) **Submerged Fill**
Loading losses occur in cargo carrier loading as the organic vapors are displaced as the liquid product is loaded. The organic vapors can contain residual vapors from the last product loaded, vapors transferred to the tank in a vapor balance system and vapors generated in the tank as new product is loaded. The amount of vapors generated can be controlled by the type of loading method used. In splash loading, the fill pipe is only lowered part way into the tank. This results in large amounts of turbulence in the liquid and results in close contact of the VOC with the vapor which increase emissions. The submerged fill method is an alternate filling method used to reduce the amount of vapor/liquid contact. In the submerged fill method, the fill pipe extends below the liquid surface. As the liquid is transferred to the tank, the submerged fill pipe significantly reduces turbulence, air/liquid contact and results in lower overall VOC emissions. The use of submerged fill is a feasible control method for the UAN Loadout Facilities (EU-024A and EU-024B).

(b) **Vapor Balance Service**
In vapor balance service, the organic rich vapor inside the empty cargo carrier is vented back to the terminal storage tank as the product liquid displaces the vapor space in the cargo carrier. The organic rich vapor is not released but transferred back into the storage facility which is controlled by a VOC/HAP control device. A vapor balance system is not a feasible control option for the UAN Loadout Facilities (EU-024A and EU-024B) because the emissions are low and a dedicated control device is not practical.

(c) **Dedicated Cargo Carrier Service**
Some cargo carriers are designated to carry a single product and are practicing dedicated service. The recent loading history of the cargo carrier is just as important as the product currently being loaded. The vapors displaced by loading the cargo carrier contain VOCs from the last product. If the last product loaded was VOC-free or if the tanker was just cleaned, the vapor will essentially be clean air. If the last product was gasoline or an organic chemical with high vapor pressure, the vapor will be extremely high in VOC. The use of a dedicated cargo carrier service is a feasible control method for the UAN Loadout Facilities (EU-024A and EU-024B).

(d) **Thermal Oxidizer**

The thermal oxidizer has a stabilized flame maintained by a combination of auxiliary fuel, waste gas compounds, and supplemental air added when necessary. This technology is typically applied for destruction of organic vapors. Upon passing through the flame, the gas containing VOC is heated from its inlet temperature to its ignition temperature. It is the temperature at which the combustion reaction rate and consequently the energy production rate exceeds the rate of heat losses, thereby raising the temperature of the gases to some higher value. Thus, any VOC/air mixture will ignite if its temperature is raised to a sufficiently high level. The VOC-containing mixture ignites at some temperature between the preheat temperature and the reaction temperature. The ignition occurs at some point during the heating of a waste stream. The mixture continues to react as it flows through the combustion chamber.

Most thermal units are designed to provide no more than 1 second of residence time to the waste gas with typical temperatures of 1,200 to 2,000°F. Once the unit is designed and built, the residence time is not easily changed, so that the required reaction temperature becomes a function of the particular gaseous species and the level of control. It is impractical for thermal oxidizers to reduce emissions of VOC from emission streams containing low amounts of VOC. This is due to the large energy input required to obtain the required destruction temperature because the exhaust stream lacks adequate fuel. The addition fuel required to raise the temperatures required would also created additional VOC. In this case, the VOC created by the combustion of added fuel would surpass emissions from the UAN Loadout Facilities (EU-024A and EU-024B). The use of a thermal oxidizer is not a feasible control option for the UAN Loadout Facilities (EU-024A and EU-024B).

(e) **Flare**

The low heating value of the UAN Loadout Facilities (EU-024A and EU-024B) exhaust is too low for flaring. As there are insufficient organics in this vent stream to support combustion, use of a flare would require a significant addition of supplementary fuel. Therefore, a secondary impact of the use of a flare for this stream would be the creation of additional emissions from burning supplemental fuel, including VOC. The use of a flare is not a feasible control option for the UAN Loadout Facilities (EU-024A and EU-024B).

Step 3: Rank the Remaining Control Technologies by Control Effectiveness

The applicant has accepted all feasible control options. No ranking is necessary.

Step 4: Evaluate the Most Effective Controls and Document the Results

The following table lists the proposed VOC BACT determination for Ohio Valley Resources, LLC along with the existing VOC BACT determinations for similar emission units. All data in the table is based on the information obtained from the permit application submitted by Ohio Valley Resources, LLC, the U.S. EPA RACT/BACT/LAER Clearinghouse (RBLC), Indiana issued permits, and electronic versions of permits available at the websites of other permitting agencies.

RACT/BACT/LEAR CLEARINGHOUSE DATA UAN Loadout Facilities (EU-024A and EU-024B) – VOC						
RBLC ID	**Facility**	**Issued Date**	**Process Description**	**Capacity**	**Limitation**	**Control Method**
T147-32322-00062	**Ohio Valley Resources, LLC**	**Proposed**	**UAN Loadout Facilities EU-024A/B**	**237,184 Kgallons/yr**	**None**	**Submerged Fill and dedicated or clean service**
There are no RBLC entries for UAN or similar organic liquids.						

RBLC Review
The RBLC does not contain VOC control measures for liquids with similar physical properties as the dilute UAN solution.

Applicant Proposal
The applicant proposed the use of submerged fill and dedicated or clean cargo carrier operation.

Step 5: Select BACT
IDEM, OAQ has established VOC BACT for the UAN day tanks, identified as EU-024A and EU-024B is:

VOC emissions from the UAN Loadout Facilities (EU-024A and EU-024B) shall each be controlled by the use of submerged/bottom fill and dedicated or clean cargo carrier operation.

(10) VOC BACT – UAN Plant Vent Flare (EU-017)

Step 1: Identify Potential Control Technologies
The following VOC control technologies are available to the UAN Plant Vent Flare (EU-017) at this source:

(1) Flare Design and Monitoring;

(2) Process Flaring Minimization Practices; and

(3) Flare Gas Recovery.

Each of these VOC control technologies are evaluated below in Step 2.

Step 2: Eliminate Technically Infeasible Options

(a) **Flare design and monitoring**
Flare design and good combustion practices – Flare design and monitoring are key elements in emissions performance of flares. The flare must be properly operated and maintained in order to achieve the anticipated emission rates guaranteed by the flare manufacturer. The use of proper flare design and good combustion practices is a technically feasible control option for the UAN Plant Vent Flare (EU-017) at this source.

(b) **Process flaring minimization practices**
Process flaring minimization practices – To the extent actions can be taken to minimize the volume of gas going to the flare, emissions of VOC will be less. Flaring minimization practices are feasible and are evaluated in the analysis of BACT. The use of process flaring minimization practices is a technically feasible control option for the UAN Plant Vent Flare (EU-017) at this source.

(c) **Flare gas recovery**
Flare gas recovery – Flare gas recovery has been implemented at some facilities that produce and use internally generated fuel gas streams such as petroleum refineries. However, flare gas recovery for the Ohio Valley Resources, LLC facility is not feasible for the following reasons.

(1) First, unlike a refinery's nearly continuous supply of flared gases, flaring at the proposed Ohio Valley Resources, LLC facility will be an infrequent occurrence.

(2) Another difference is that the Ohio Valley Resources, LLC flaring events, the flared material may not be suitable for use as a fuel gas.

The use of a flare gas recovery system is not a technically feasible control option for the UAN Plant Vent Flare (EU-017) at this source.

Step 3: Rank the Remaining Control Technologies by Control Effectiveness
The applicant has accepted all feasible control options. Therefore, a ranking is not required.

Step 4: Evaluate the Most Effective Controls and Document the Results
The following table lists the proposed VOC BACT determination for Ohio Valley Resources, LLC along with the existing VOC BACT determinations for similar emission units. All data in the table is based on the information obtained from the permit application submitted by Ohio Valley Resources, LLC, the U.S. EPA RACT/BACT/LAER Clearinghouse (RBLC), Indiana issued permits, and electronic versions of permits available at the websites of other permitting agencies.

RACT/BACT/LEAR CLEARINGHOUSE DATA
UAN Plant Vent Flare (EU-017) – VOC

RBLC ID	Facility	Issued Date	Process Description	Capacity	Limitation	Control Method
T147-32322-00062	**Ohio Valley Resources, LLC**	**Proposed**	**UAN Plant Vent Flare EU-017**	**0.189 MMBtu/hr**	**0.0054 lb/MMBtu**	**Good Combustion Practices, Usage Limit**
IA-0089	Homeland Energy Solutions, LLC	08/08/07	Startup and Shutdown Flares	25 MMBtu	0.006 lb/MMBtu	None
IA-0105	Iowa Fertilizer Company	10/26/12	Ammonia Flare	0.4 MMBtu/hr	No Numerical Limit	Good Combustion Practices
LA-0213	Valero Refining, St. Charles Refinery	11/17/09	Flare 1 – 5	Not Specified	No emissions	No limit on pilot flare

RBLC Review
The potential to emit VOC from the UAN Plant Vent Flare (EU-017) is 0.0045 tons per year. A review of the RBLC entries in the table above indicates add-on controls are not required for flare of this size combusting natural gas.

Applicant Proposal
The applicant proposed the following for BACT:

(a) The UAN Plant Vent Flare (EU-017) shall combust natural gas;

(b) VOC emissions shall be controlled by the use of flare minimization practices (FMP) and the use of good combustion practices;

(c) VOC emissions from the UAN Plant Vent Flare (EU-017) shall not exceed 5.5 lb/MMCF; and

(d) Venting for Startup, Shutdown and Malfunction shall not exceed 336 hours per twelve consecutive month period with compliance determined at the end of each month.

The applicant has accepted top BACT. IDEM, OAQ is adding an emission limitation to make startup, shutdown and malfunction emissions enforceable.

Step 5: Select BACT
IDEM, OAQ has established VOC BACT for the UAN Plant Vent Flare (EU-017) as:

(1) In order to control VOC emissions, the pilot and purge gas fuels used in the flare shall be natural gas.

(2) Venting for Startup, Shutdown and Malfunction shall not exceed 336 hours per twelve consecutive month period with compliance determined at the end of each month.

(3) Comply with the following flare minimization practices to reduce emissions during startups, shutdowns, and other flaring events:

    (A) Flare Use Minimization: The UAN process shall be properly operated to avoid emergency upsets. Startup time of the Nitric Acid Units shall be minimized. During emergency upsets of the Nitric Acid Units, the Permittee shall return some of the high and low-pressure off-gas back to the urea process as soon as urea production is reduced to a level that safely allows this;

    (B) The Permittee shall train all operators responsible for the day-to-day operation of the flares on the flare minimization practices and the specific procedures to follow during process startup, shutdown, and other flaring events; and

    (C) The Permittee shall investigate the “root cause” of malfunction events that cause flaring events other than at startup or shutdown. This root cause analysis shall identify the apparent cause of unanticipated flaring event and shall recommend additional preventive measures that will minimize the chance of a repeat event. The Permittee shall implement the recommended preventive measures.

(4) VOC emissions shall be controlled by use of the following practices:

    (A) Flares shall be designed for and operated with no visible emissions, except for periods not to exceed 5 minutes during any two consecutive hours;

    (B) Flares shall be operated with a flame present at all times; and

    (C) Flares shall be continuously monitored to assure the presence of a pilot flame with a thermocouple, infrared monitor, or other approved device.

(5) VOC emissions from the UAN Plant Vent Flare (EU-017) shall not exceed 0.0054 lb/MMBtu, based on a three-hour average.

(11) VOC BACT – Diesel Exhaust Fluid (DEF) Tank (EU-021)

Step 1: Identify Potential Control Technologies

IDEM, OAQ has identified the following VOC control technologies for the DEF Tank (EU-021):

(a) **Add-on Controls:** IDEM, OAQ has identified the following add-on controls capable of VOC control

(1) Thermal Oxidation
(2) Catalytic Oxidation
(3) Vapor Recovery System
(4) Flare
(5) Nitrogen Blanket
(6) Condenser

The DEF tank, identified as EU-021 contains a dilute solution with a very low vapor pressure. The applicant estimates emissions from this tank at less than 0.01 ton per year. Due to the low vapor pressure of the dilute solution, there are no economical add-on control technologies for this tank.

(b) **Submerged Fill**

Loading losses occur in cargo carrier loading as the organic vapors are displaced as the liquid product is loaded. The organic vapors can contain residual vapors from the last product loaded, vapors transferred to the tank in a vapor balance system and vapors generated in the tank as new product is loaded. The amount of vapors generated can be controlled by the type of loading method used. In splash loading, the fill pipe is only lowered part way into the tank. This results in large amounts of turbulence in the liquid and results in close contact of the VOC with the vapor which increase emissions. The submerged fill method is an alternate filling method used to reduce the amount of vapor/liquid contact. In the submerged fill method, the fill pipe extends below the liquid surface. As the liquid is transferred to the tank, the submerged fill pipe significantly reduces turbulence, air/liquid contact and results in lower overall VOC emissions.

Submerged fill is considered a technologically feasible control option.

(c) **Tank Color**

Color selection can contribute to elevated emissions of VOC. Black or darker colored tanks absorb more frequencies of light. This energy is transferred to the contents of the tank as heat through conduction in the tank wall. As the liquid heats, the vapor pressure rises and potential VOC emissions increase. The reverse is true for light colored or reflective tanks. Tank color selection is a technically feasible control option.

Step 2: Eliminate Technically Infeasible Options

IDEM, OAQ has identified submerged fill and tank color as feasible VOC control technologies for the DEF Tank (EU-021).

Step 3: Rank the Remaining Control Technologies by Control Effectiveness

The applicant has accepted all technically feasible control technologies as BACT. Therefore, a ranking is not necessary

Step 4: Evaluate the Most Effective Controls and Document the Results

The following table lists the proposed VOC BACT determination for Ohio Valley Resources, LLC along with the existing VOC BACT determinations for similar emission units. All data in the table is based on the information obtained from the permit application submitted by Ohio Valley Resources, LLC, the U.S. EPA RACT/BACT/LAER Clearinghouse (RBLC), Indiana issued permits, and electronic versions of permits available at the websites of other permitting agencies.

RACT/BACT/LEAR CLEARINGHOUSE DATA
Diesel Exhaust Fluid (DEF) Tank (EU-021) – VOC

RBLC ID	Facility	Issued Date	Process Description	Capacity	Limitation	Control Method
T147-32322-00062	**Ohio Valley Resources, LLC**	**Proposed**	**Diesel Exhaust Fluid Tank EU-021**	**100 tons**	**None**	**Submerged Fill and dedicated or clean service**
There are no RBLC entries for diesel exhaust fluid or similar organic liquids.						

RBLC Review
The RBLC does not contain VOC control measures for liquids with similar physical properties as the diesel exhaust fluid solution. DEF is a dilute ammonia solution.

Applicant Proposal
The applicant proposed the use of submerged fill and a white storage shell.

Step 5: Select BACT

IDEM, OAQ has established VOC BACT for the DEF Storage Tank (EU-021) as:

(1) The use of a white tank shell.

(2) The use of submerged/bottom fill.

(12) VOC BACT – DEF Truck Loadout (EU-025)

Step 1: Identify Potential Control Technologies

The DEF Truck Loadout Facility, identified as EU-025 contains a dilute solution with a very low vapor pressure. The applicant estimates emissions from this tank at less than 0.05 ton per year. Due to the low vapor pressure of the dilute solution, IDEM, OAQ has not identified any feasible add-on control technologies for this operation. The only feasible control option for this operation is the use of submerged fill.

Step 2: Eliminate Technically Infeasible Options

(a) **Submerged Fill**
Loading losses occur in cargo carrier loading as the organic vapors are displaced as the liquid product is loaded. The organic vapors can contain residual vapors from the last product loaded, vapors transferred to the tank in a vapor balance system and vapors generated in the tank as new product is loaded. The amount of vapors generated can be controlled by the type of loading method used. In splash loading, the fill pipe is only lowered part way into the tank. This results in large amounts of turbulence in the liquid and results in close contact of the VOC with the vapor which increase emissions. The submerged fill method is an alternate filling method used to reduce the amount of vapor/liquid contact. In the submerged fill

method, the fill pipe extends below the liquid surface. As the liquid is transferred to the tank, the submerged fill pipe significantly reduces turbulence, air/liquid contact and results in lower overall VOC emissions.

Submerged fill is considered a technologically feasible control option.

Step 3: Rank the Remaining Control Technologies by Control Effectiveness

IDEM, OAQ has identified only one feasible VOC control technologies for this operation. Therefore, a ranking is not necessary.

Step 4: Evaluate the Most Effective Controls and Document the Results

The following table lists the proposed VOC BACT determination for Ohio Valley Resources, LLC along with the existing VOC BACT determinations for similar emission units. All data in the table is based on the information obtained from the permit application submitted by Ohio Valley Resources, LLC, the U.S. EPA RACT/BACT/LAER Clearinghouse (RBLC), Indiana issued permits, and electronic versions of permits available at the websites of other permitting agencies.

RACT/BACT/LEAR CLEARINGHOUSE DATA
Diesel Exhaust Fluid (DEF) Truck Loadout (EU-025) – VOC

RBLC ID	Facility	Issued Date	Process Description	Capacity	Limitation	Control Method
T147-32322-00062	**Ohio Valley Resources, LLC**	**Proposed**	**DEF Truck Loadout EU-025**	**7.9 kgallons/hr**	**None**	**Submerged Fill**
There are no RBLC entries for diesel exhaust fluid or similar organic liquids.						

RBLC Review

The RBLC does not contain entries for VOC control of diesel exhaust fluid from loading racks. The potential to emit VOC of this facility is less than 0.1 tons per year. Add-on controls are obviously not cost effective.

Applicant Proposal

The applicant proposes the use of submerged fill to control VOC emissions from the DEF loadout facility. This is top BACT.

Step 5: Select BACT

IDEM, OAQ has approved the following as VOC BACT for the DEF Loadout (EU-025): The Permittee shall use a submerged/bottom fill system.

(13) VOC BACT – Four (4) Identical 218 MMBtu/hr Natural-Gas Fired Boilers (EU-011A, EU-011B, EU-011C and EU-011D)

Step 1: Identify Potential Control Technologies

IDEM, OAQ has identified the following VOC control technologies for the natural gas-fired boilers (EU-011A, EU-011B, EU-011C and EU-011D):

(1) Thermal Oxidation;

(2) Catalytic Oxidation;

(3) Flares; and

(4) Good Combustion Practices.

Each of these control technologies is discussed below in Step 2.

Step 2: Eliminate Technically Infeasible Options

(a) **Thermal Oxidizers**

The thermal oxidizer has a stabilized flame maintained by a combination of auxiliary fuel, waste gas compounds, and supplemental air added when necessary. This technology is typically applied for destruction of organic vapors. Upon passing through the flame, the gas containing VOC is heated from its inlet temperature to its ignition temperature. The ignition temperature is the temperature at which the combustion reaction rate and consequently the energy production rate exceed the rate of heat losses, thereby raising the temperature of the gases to some higher value. Thus, any VOC/air mixture will ignite if its temperature is raised to a sufficiently high level. The VOC-containing mixture ignites at some temperature between the preheat temperature and the reaction temperature. The ignition occurs at some point during the heating of a waste stream. The mixture continues to react as it flows through the combustion chamber.

Most thermal units are designed to provide no more than 1 second of residence time to the waste gas with typical temperatures of 1,200 to 2,000°F. Once the unit is designed and built, the residence time is not easily changed, so that the required reaction temperature becomes a function of the particular gaseous species and the level of control. It is impractical for thermal oxidizers to reduce emissions of VOC from a properly operated natural gas combustion units. This is due to the large energy input required to obtain the required destruction temperature because the exhaust stream lacks adequate fuel.

The use of a thermal oxidizer is not a technically feasible control option for the natural gas-fired boilers (EU-011A, EU-011B, EU-011C and EU-011D) at this source.

(b) **Catalytic Oxidizers**

Catalytic oxidation is also a widely used control technology to control pollutants where the waste gas is passed through a flame area and then through a catalyst bed for complete combustion of the waste in the gas. This technology is typically applied for destruction of organic vapors. A catalyst is an element or compound that speeds up a reaction at lower temperatures (compared to thermal oxidation) without the catalyst undergoing change itself. Catalytic oxidizers operate at 650°F to 1000°F and require approximately 1.5 to 2.0 ft^3 of catalyst per 1000 standard ft^3 gas flow.

Emissions from some emission units may contain significant amount of particulates. These particulates can poison the catalyst resulting in the failure of catalytic oxidation. For some fuels, such as coal and residual oil, contaminants would likely be present in such concentrations so as to foul catalysts quickly thereby making such systems infeasible due to the need to constantly replace catalyst materials. In addition, the use of oxidation catalysts on units with high sulfur fuels can also result in the creation of sulfuric acid mist through the conversion of SO_2 to SO_3 and subsequent combination with moisture in the exhaust gas. The use of catalytic oxidation for the exhaust of a properly designed natural gas combustion source is not practical. This is due to the fact that this exhaust does not have enough organics to support combustion and a large amount of additional combustion fuel is required. The use of a catalytic oxidizer is a technically feasible control option for the natural gas-fired boilers (EU-011A, EU-011B, EU-011C and EU-011D) at this source.

(c) **Flare**
The low heating value of the natural gas-fired boilers (EU-011A, EU-011B, EU-011C and EU-011D) exhaust is too low for flaring. As there are insufficient organics in this vent stream to support combustion, use of a flare would require a significant addition of supplementary fuel. Therefore, a secondary impact of the use of a flare for this stream would be the creation of additional emissions from burning supplemental fuel, including VOC. Since VOC emissions are from natural gas combustion alone, the combustion of natural gas in a flare would actually increase VOC emissions.

The use of a flare is not a technically infeasible option for the natural gas-fired boilers (EU-011A, EU-011B, EU-011C and EU-011D) at this source.

(d) **Combustion Control**
This type of control is appropriate for any type of fuel combustion source. Combustion process controls involve combustion chamber designs and operating practices that improve the oxidation process and minimize incomplete combustion. Factors affecting VOC emissions include firing temperatures, residence time in the combustion zone and combustion chamber mixing characteristics. Combustion control is a technically feasible control option for the natural gas-fired boilers (EU-011A, EU-011B, EU-011C and EU-011D).

Step 3: Rank the Remaining Control Technologies by Control Effectiveness
The only conventional VOC control technology that is technologically feasible for the natural gas-fired boilers (EU-011A, EU-011B, EU-011C and EU-011D) is good combustion practices. A ranking is not necessary.

Step 4: Evaluate the Most Effective Controls and Document the Results
The following table lists the proposed VOC BACT determination for Ohio Valley Resources, LLC along with the existing VOC BACT determinations for similar emission units. All data in the table is based on the information obtained from the permit application submitted by Ohio Valley Resources, LLC, the U.S. EPA RACT/BACT/LAER Clearinghouse (RBLC), Indiana issued permits, and electronic versions of permits available at the websites of other permitting agencies.

RACT/BACT/LEAR CLEARINGHOUSE DATA
Boilers (EU-011A, EU-011B, EU-011C and EU-011D) – VOC

RBLC ID	Facility	Issued Date	Process Description	Capacity	Limitation	Control Method
IA-0105	Iowa Fertilizer Company	10/26/2012	Auxiliary Boiler	472.4 MMBtu/hr	0.0014 lb/MMBtu	Good Combustion Practices
T 147-32322-00062	**Ohio Valley Resources, LLC**	**Proposed**	**Boilers EU-011A to EU-011B**	**218 MMBtu/hr Each**	**5.5 lb/MMCF, 3 hr avg.**	**Combustion Practices, Usage Limit**
WV-0023	Longview Power, LLC	02/03/09	Auxiliary Natural Gas Boiler	225 MMBtu/hr	0.0054 lb/MMBtu 1.215 lb/hr	Use Natural Gas, Good Combustion Practices
OH-0310	American Municipal Power Generating	10/08/09	Auxiliary Natural Gas Boiler	150 MMBtu/hr	5.5 lb/MMCF 0.83 lb/hr 0.006 lb/MMBtu	None
NJ-0043	Liberty Generating Station	03/28/02	Auxiliary Natural Gas Boiler	200 MMBtu/hr	50 ppmvd,7% O_2 1.6 lb/hr, 0.008 lb/MMBtu	None
TX-0386	Amella Energy Center	08/26/04	Auxiliary Natural Gas Boiler	155 MMBtu/hr	3.1 lb/hr 0.02 lb/MMBtu	None

RBLC Review
The potential to emit VOC for each boiler is 5.15 tons per year. The majority of RBLC entries for VOC control of natural gas-fired boilers typically show good combustion practices and an emission rate corresponding to 5.5 lb/MMCF.

Applicant Proposal
The applicant proposed the following as BACT:

(a) The use of natural gas;

(b) Good design and good combustion practices;

(c) VOC emission rate shall not exceed 5.5 lb/MMCF; and

(d) Combined fuel usage in the natural gas-fired boilers (EU-011A, EU-011B, EU-011C and EU-011D) shall not exceed 2,802 MMCF per twelve consecutive month period with compliance determined at the end of each month.

The applicant's proposal is consistent with a majority of the entries in the RBLC for VOC emissions. These emission limits are based on the uncontrolled emission factors found in AP-42. A permit for the Iowa Fertilizer Company (IFC) was recently issued by the Iowa Department of Natural Resources (IDNR) with a proposed emission rate of 0.0014 lb/MMBtu. The IFC permit limit is lower than the limit proposed by the applicant. IDNR established this limit based on two stack tests at a single boiler. IDEM believes the emission rate proposed by the applicant is appropriate for BACT based on the following factors:

1. Add-on emission controls have been demonstrated to be infeasible or not cost-effective.

2. The majority of the entries in the RBLC for uncontrolled natural gas-fired combustion units are derived from the AP-42 emission factors, which are based on stack tests on a large sample size of natural gas-burning facilities.

3. The emission limits in the IFC permit set by IDNR are based on two stack tests at the same facility – a 429 MMBtu/hr auxiliary boiler located at the Walter Scott Generating Plant in Council Bluffs, Iowa. These test results do not establish BACT for the boilers at Ohio Valley Resources.

    a. Two stack test results at the same facility are not representative of the emission rate achievable at a large range of natural gas facility types and sizes. The AP-42 emission factor for natural gas combustion is a better reflection of what is achievable for an uncontrolled natural gas unit.

    b. IFC's facilities have not yet begun operations, and consequently the achievability of the IFC BACT limits have not been demonstrated in practice.

Step 5: Select BACT
IDEM, OAQ has established VOC BACT for the Natural Gas-Fired Boilers (EU-011A, EU-011B, EU-011C and EU-011D) as:

(a) VOC emissions from the boilers (EU-011A, EU-011B, EU-011C and EU-011D) shall be controlled through the use of proper boiler design and good combustion practices.

(b) Combined fuel usage in the boilers (EU-011A, EU-011B, EU-011C and EU-011D) shall not exceed 2,802 MMCF per twelve consecutive month period with compliance determined at the end of each month.

(c) The boilers (EU-011A, EU-011B, EU-011C, and EU-011D) shall combust natural gas.

(d) VOC emissions from each of the boilers (EU-011A, EU-011B, EU-011C, and EU-011D) shall not exceed 5.5 lb/MMCF, based on a three-hour average.

(14) VOC BACT – Diesel-Fired Emergency Generator (EU-009)

Step 1: Identify Potential Control Technologies

Today's stationary diesel-fired emergency compression ignition internal combustion engines are sold as package units with an engineering design tailored to meet the emission limitations of 40 CFR 60, Subpart IIII and 40 CFR 63, Subpart ZZZZ. The manufacturer provides an engine that is in compliance with the applicable NSPS and NESHAP and the owner/operator is expected to maintain and operate the unit to guarantee compliance with applicable emission limitations. Based on the review of information for this BACT, IDEM has determined the only control method available for VOC for emergency stationary compression ignition internal combustion engines is good combustion practices.

Step 2: Eliminate Technically Infeasible Options

The only feasible control option for the diesel-fired emergency generator (EU-009) is good combustion practices.

Step 3: Rank the Remaining Control Technologies by Control Effectiveness

The applicant has accepted the only feasible control option. Therefore, a ranking is not required.

Step 4: Evaluate the Most Effective Controls and Document the Results

The following table lists the proposed VOC BACT determination for Ohio Valley Resources, LLC along with the existing VOC BACT determinations for similar emission units. All data in the table is based on the information obtained from the permit application submitted by Ohio Valley Resources, LLC, the U.S. EPA RACT/BACT/LAER Clearinghouse (RBLC), Indiana issued permits, and electronic versions of permits available at the websites of other permitting agencies.

RACT/BACT/LEAR CLEARINGHOUSE DATA
Diesel-Fired Emergency Generator (EU-009) – VOC

RBLC ID	Facility	Issued Date	Process Description	Capacity	Limitation	Control Method
NV-0050	MGM Mirage	11/30/09	Diesel Generator	2,206 HP	0.0003 lb/HP-hr	None, 0.14 g/hp-hr
T 147-32322-00062	**Ohio Valley Resource, LLC**	**Proposed**	**Emergency Generator**	**4,690 HP**	**0.31 g/hp-hr, 3 hr avg.**	**Usage Limit**
IA-0105	Iowa Fertilizer Company	10/26/12	Emergency Generator	2,000 KW	0.4 g/hp-hr	None
LA-0254	Entergy Louisiana, LLC	08/06/11	Diesel Generator	1,250 HP	1 g/hp-hr	None
SC-0113	Pyramax Ceramics, Inc.	02/08/12	Emergency Generators 1 to 8	757 HP	4 g/KW-hr	None, 2.98 g/hp-hr
ID-0018	Idaho Power Company, Langley Gulch	06/25/10	Diesel Generator	750 KW	6.4 g/KW-hr	None, 4.78 g/hp-hr

RBLC Review
The lowest emission rate listed in the RBLC is for the MGM Mirage generator. This unit emits 0.14 g VOC/hp-hr. The applicant proposes 0.31 g VOC/hp-hr which is significantly higher. None of the entries include a control method. Add-on control technology is not used to control VOC from these generators.

Applicant Proposal
The applicant proposed the following as BACT:

(a) Compliance with 40 CFR 60, Subpart IIII;

(b) Good combustion practices;

(c) VOC emissions shall not exceed 0.31 g/hp-hr; and

(d) The generator shall not operate more than 200 hours per year.

The applicant proposes to control emissions by limiting the hours of usage to obtain an equivalent annual emission rate. Baseline emissions for this unit are 0.32 tons VOC per year using 0.31 g/hp-hr and 200 hours of operation. The applicant could install a unit with a 0.14 g/hp-hr emission rate with a standard PTE operating period of 500 hours, which results in annual emissions of 0.36 tons VOC per year. The combination of 0.31 g/hp-hr and 200 hours of operation results in lower emissions and is BACT for this unit.

Step 5: Select BACT

IDEM, OAQ has established VOC BACT for the diesel-fired emergency generator (EU-009) as:

(1) The hours of operation of the diesel-fired emergency generator (EU-009) shall not exceed 200 hours per twelve consecutive month period with compliance determined at the end of each month.

(2) VOC emissions shall be controlled by the use of good combustion practices.

(3) VOC emissions from the diesel-fired emergency generator (EU-009) shall not exceed 0.31 g/hp-hr, based on a three-hour average.

(15) VOC BACT – Fugitive Emissions

Step 1: Identify Potential Control Technologies

IDEM, OAQ has identified the following VOC control technologies for fugitive VOC emissions from this source:

(1) Leak Detection and Control Program (LDAR); and

(2) No Control Option.

Step 2: Eliminate Technically Infeasible Options

(a) **Leak Detection and Control Program (LDAR)**
A leak detection and control program (LDAR) is a systematic method of finding and eliminating fugitive emissions from leaking pumps, valves, compressors, pipe fitting, sampling connections, etc. LDAR is a work practice that assists sources identify leaking equipment so that emissions can be reduced though systematic repair or replacement. The key to the effectiveness of fugitive emission control is the regularly scheduled inspections and a defined repair/replacement schedule. The use of an LDAR program is a technically feasible control option for the fugitive VOC emissions at this source.

(b) **No Control**
It is possible that fugitive emissions from a source are so small that the time and cost required to establish and implement an LDAR program are not cost effective. Fugitive VOC emissions were estimated by the source at 0.01 tons per year. The use of no control is a technically feasible control option for the fugitive VOC emissions at this source.

Step 3: Rank the Remaining Control Technologies by Control Effectiveness

IDEM, OAQ has ranked the control technologies in order of effectiveness as follows:

(1) LDAR (98% control)

(2) No Control (0% control)

The applicant proposed an LDAR program which is top BACT. Therefore, a ranking is not required.

Step 4: Evaluate the Most Effective Controls and Document the Results

The following table lists the proposed VOC BACT determination for Ohio Valley Resources, LLC along with the existing VOC BACT determinations for similar emission units. All data in the table is based on the information obtained from the permit application submitted by Ohio Valley Resources, LLC, the U.S. EPA RACT/BACT/LAER Clearinghouse (RBLC), Indiana issued permits, and electronic versions of permits available at the websites of other permitting agencies.

RACT/BACT/LEAR CLEARINGHOUSE DATA
Fugitive Emissions (EU-011C and EU-011D) – VOC

RBLC ID	Facility	Issued Date	Process Description	Capacity	Limitation	Control Method
T 147-32322-00062	**Ohio Valley Resources, LLC**	**Proposed**	**Process Fugitive VOC**	**NA**	**None**	**LDAR Program**
LA-0245	Valero, Hydrogen Plant	12/15/10	Fugitives FUG0030	NA	23.74 TPY	LDAR that meets LA Refinery MACT
TX-0575	Sabina Petrochemicals	08/20/10	ALKFUG, BDEFUG, UTILFUG	NA	9.01 TPY	LEAR Leak Detection and Repair Program 98% Control
FL-0318	Highlands Ethanol Facility	12/10/09	Fugitive VOC Equipment Leaks	NA	19.6 TPY	LDAR Program
LA-0197	Alliance Refinery	07/21/09	Unit Fugitives	NA	13.22 lb/hr 57.89 TPY	LDAR that meets LA Refinery MACT
FL-0322	Southeast Renewable Fuels, LLC	12/23/10	Fugitive VOC Emissions	NA	6.5 TPY	LDAR Program

RBLC Review

The potential to emit fugitive VOC from this source is 0.01 TPY. A review of the RBLC entries in the table above indicates fugitive VOC emissions are typically controlled by an LDAR program. The applicant proposed an LDAR program.

Applicant Proposal

The applicant proposes the following for BACT:

(a) Fugitive VOC emissions shall be controlled by a Leak Detection and Repair (LDAR) program.

A numerical limit is not required because potential emissions are so small.

Step 5: Select BACT

IDEM, OAQ has approved the proposed VOC BACT for fugitive VOC emissions from equipment leaks as the use of a leak detection and repair (LDAR) program. The leak detection and repair program specified in 40 CFR 60, Subpart VVa, as identified in Condition D.4.7 shall serve as BACT for VOC fugitive emissions.

(16) VOC BACT – Diesel-Fired Emergency Fire Water Pump (EU-016)

Step 1: Identify Potential Control Technologies

Today’s stationary diesel-fired emergency compression ignition internal combustion engines are sold as package units with an engineering design tailored to meet the emission limitations of 40 CFR 60, Subpart IIII and 40 CFR 63, Subpart ZZZZ. The manufacturer provides an engine that is in compliance with the applicable NSPS and NESHAP and the owner/operator is expected to maintain and operate the unit to guarantee compliance with applicable emission limitations.

Step 2: Eliminate Technically Infeasible Options

The only feasible control option for the diesel-fired fire pump (EU-016) is good combustion practices.

Step 3: Rank the Remaining Control Technologies by Control Effectiveness

The applicant has accepted the only feasible control method. Therefore, a ranking and further analysis is not required.

Step 4: Evaluate the Most Effective Controls and Document the Results

The following table lists the proposed VOC BACT determination for Ohio Valley Resources, LLC along with the existing VOC BACT determinations for similar emission units. All data in the table is based on the information obtained from the permit application submitted by Ohio Valley Resources, LLC, the U.S. EPA RACT/BACT/LAER Clearinghouse (RBLC), Indiana issued permits, and electronic versions of permits available at the websites of other permitting agencies.

RACT/BACT/LEAR CLEARINGHOUSE DATA
Diesel-Fired Emergency Fire Pump (EU-016) – VOC

RBLC ID	Facility	Issued Date	Process Description	Capacity	Limitation	Control Method
T 147-32322-00062	**Ohio Valley Resources**	**Proposed**	**Fire Pump EU-016**	**481 HP**	**0.141 g/hp-hr, 3 hr avg.**	**Combustion Practices, Usage Limit**
IA-0105	Iowa Fertilizer Company	10/26/12	Fire Pump	235 KW	0.25 g/KW-hr 0.03 TPY	None, 0.187 g/hp-hr
SC-0113	Pyramax Ceramics, Inc.	02/08/12	Fire Pump	500 HP	4 g/KW-hr	None, 3 g/hp-hr
LA-0254	Entergy Louisiana, LLC	08/06/11	Emergency Fire Pump	350 HP	1 g/hp-hr	None
ID-0018	Idaho Power, Langley Gulch	06/25/10	Fire Pump Engine	235 KW	4 g/KW-hr	None, 3 g/hp-hr
OK-0129	Associated Electric Cooperative	01/23/09	Fire Pump	267 HP	0.66 lb/hr	None, 1.12 g/hp-hr

RBLC Review
The potential to emit VOC of the diesel-fired emergency fire pump is 0.04 TPY, when operating at 500 hours per year. This unit will be limited by permit to operate no more than 200 hours per year, with a PTE of 0.01 TPY. A review of the RBLC table above indicates add-on controls are not used to control VOC emissions from these engines. The applicant proposes an emission rate of 0.141 g/hp-hr. This represents the lowest emission rate of any VOC BACT limit in the RBLC and represents top BACT.

Applicant Proposal
The applicant proposed the following as BACT:

(a) Good combustion practices;

(b) Compliance with 40 CFR 60, Subpart IIII;

(c) VOC emissions shall not exceed 0.141 g/hp-hr, based on a three hour average; and

(d) The fire pump shall not operate more than 200 hours per year.

Step 5: Select BACT
IDEM, OAQ has established VOC BACT for the diesel-fired fire pump (EU-016) as:

(1) Operation of the Diesel-Fired Emergency Firewater Pump (EU-016) shall not exceed 200 hours per twelve consecutive month period with compliance determined at the end of each month.

(2) VOC emissions from the Diesel-Fired Emergency Firewater Pump (EU-016) shall be controlled by the use of good combustion practices.

(3) VOC emissions from the diesel-fired fire pump (EU-016) shall not exceed 0.141 g/hp-hr, based on a three-hour average.

(17) VOC BACT – Gasoline Transfer Dispensing Operations (EU-015)

Step 1: Identify Potential Control Technologies
The gasoline transfer and dispensing operation is an insignificant activity with negligible emissions. This operation involves dispensing of gasoline into portable equipment like lawn mowers and portable generators. There are no feasible control options for the gasoline transfer dispensing operation (EU-015) due to its size. Therefore, BACT is no control.

Step 2: Eliminate Technically Infeasible Options
This step is not necessary.

Step 3: Rank the Remaining Control Technologies by Control Effectiveness
There are no practical control measures due to the size of the operation.

Step 4: Evaluate the Most Effective Controls and Document the Results
This step is not necessary.

Step 5: Select BACT
This step is not necessary.

(18) VOC BACT – Petroleum Fuel Other Than Gasoline Dispensing Operations (EU-014)

Step 1: Identify Potential Control Technologies
The petroleum fuel transfer and dispensing operation is an insignificant activity with negligible emissions. This operation involves dispensing of diesel into portable equipment like portable generators. There are no feasible control options for EU-014 due to its size. Therefore, BACT is no control.

Step 2: Eliminate Technically Infeasible Options
This step is not necessary.

Step 3: Rank the Remaining Control Technologies by Control Effectiveness
This step is not necessary because there are no feasible control methods due to the size of the operation.

Step 4: Evaluate the Most Effective Controls and Document the Results
This step is not necessary.

Step 5: Select BACT
This step is not necessary.

Greenhouse Gas (GHG) BACT Determinations

(1) GHG BACT - CO_2 Purification Process (EU-004)

Step 1: Identify Potential Control Technologies
The following greenhouse gas (GHG) control technologies or operational practices should be evaluated for the CO_2 Purification Process (EU-004):

(1) Carbon Capture and Sequestration (CCS);

(2) Sale of the Captured CO_2; and

(3) Use CO_2 to Manufacturer Urea (Good Operational Practices).

Step 2: Eliminate Technically Infeasible Options

(a) **Carbon Capture and Sequestration (CCS)**

CCS would be used to capture CO_2 from the exhaust, purify, compress, and transport via pipeline to either a storage location or another pipeline for use in Enhanced Oil Recovery (EOR). CCS involves four main steps as follows:

(1) The capture of CO_2 from sources including combusted exhaust streams and the CO_2 vent;

(2) The cleanup of emission streams to remove impurities to meet pipeline specifications and to compress the CO_2 to pipeline conditions;

(3) The transport of compressed CO_2 to a sequestration site; and

(4) Sequestration of CO_2.

The primary source of CO_2 at the plant is the CO_2 purification vent. The CO_2 vent is a high purity CO_2 stream. Assuming a 90% capture efficiency of CO_2, CCS would decrease CO_2 emissions by 1,153,834 TPY CO_2 when urea is not being produced. Due to the high purity of the CO_2 stream, little to no additional treatment or cleanup would be necessary to bring the CO_2 purification vent to pipeline conditions. At this time, existing infrastructure to support the transportation of purified CO_2 does not exist. Therefore, transportation of the CO_2 stream would require the construction of a pipeline to the nearest sequestration site.

Sequestration can either be geologic (i.e. injecting CO_2 into geologic formations for long-term storage) or for use in EOR operations (i.e. injection of CO_2 into oil and gas wells to enhance production). At this time, existing infrastructure for either application does not exist. Therefore, OVR would have to develop caverns for long term storage or identify a purchaser for EOR.

When considering if a control technology is technically feasible, it must be available and applicable. A control technology is applicable if it can reasonably be installed and operated on the source type under consideration. If a given technology has not been used on the emission unit, thought should be given on transferring technology from similar gas streams with the same physical and chemical properties.

For a technology to be considered available, consideration should be given to:

(1) Land acquisition;

(2) The need for federal funding:

(3) Timing of available transportation infrastructure; and

(4) Developing a site for long term storage.

Land Acquisition – Long Term Storage Reservoirs

There are three main types of storage reservoirs for the storage of CO_2: oil and gas fields, coal seams that can no longer be mined and saline formations. The use of CO_2 in enhanced oil recovery has been demonstrated and is currently in use. However, there are no demonstrated sites near the Ohio Valley Resources, LLC site.

The use of coal seams and saline injection for sequestration are still under development and there are several sites in the area participating in sequestration research projects. These projects were funded by the U.S. Department of Energy and are not available to the OVR project.

Federal Funding

Projects underway today for coal seam or saline injection required federal funding because the technology is experimental and costly. OVR does not believe federal funding would be available for this project.

Timing of Available Transportation Infrastructure

Currently, the infrastructure needed to support carbon capture and sequestration does not exist in Spencer County, Indiana. IDEM, OAQ recently approved a Part 70 Operating Permit for Indiana Gasification (IG) to construct a substitute natural gas and liquefied CO_2 production plant that will be located near the OVR facility. The IG project includes the construction of a pipeline to transport their liquefied CO_2 product to the Gulf Coast for use in enhanced oil recovery efforts. At this time, construction has not begun and there may be a delay in the start of construction. In fact, until the pipeline is constructed there are no guarantees the pipeline will ever be constructed.

The business plan of OVR is completely independent of the IG facility. The OVR facility will be constructed regardless of the ability of IG to complete construction. The feasibility analysis for GHG BACT requirements will focus on the technical and economic feasibility of the OVR project alone.

The use of Carbon Capture and Sequestration is considered infeasible for the CO_2 Process Vent (EU-004) because the technology is not applicable as described above.

(b) **Sale of Captured CO_2**

The most practical use of captured CO_2 is in the oil and gas industry. CO_2 has been used in enhanced oil recovery for several years. The nearest purchaser of CO_2 for use in enhanced oil recovery is Denbury's Green Pipeline. The nearest tie in point for this pipeline is in Jackson Dome, Mississippi, which is nearly 400 miles away. The applicant provided the following economic analysis to document the cost of a pipeline for use by OVR. The analysis follows:

Control Alternative	Captured GHG Emissions (TPY)	Emission Reduction (TPY)	Capital Cost ($)	Operating Cost ($/yr)	Total Annualized Costs ($/yr)	Cost Effectiveness ($/ton)	Other Impacts
Sale to Buyer	1,153,834	1,153,834	$518,699,518	$3,452,800	$87,871,147	$76.16	Taking right of way from home owners

The annual cost of the control method is an economic hardship for the OVR facility. The sale of CO_2 as a product is not considered feasible; because, the pipeline for the OVR facility as a single user was determined above to be infeasible because it is unavailable.

Use CO_2 to Manufacture Urea (Good Operational Practices)
The OVR facility is designed to use a portion of the CO_2 created in the CO_2 purification process to manufacturer urea. Good Operational Practices to use as much CO_2 in the manufacture of urea is a feasible control strategy for the CO_2 Purification Process Vent (EU-004).

Step 3: Rank the Remaining Control Technologies by Control Effectiveness
The remaining control technology, use of CO_2 to produce urea, has positive economic and environmental impacts. Its use as a raw material to produce urea reduces or eliminates the need to purchase CO_2 for urea production. The use of CO2 to produce urea decreases the total amount vented to the atmosphere from the CO_2 purification vent.

Step 4: Evaluate the Most Effective Controls and Document the Results
The following table lists the proposed GHG BACT determinations for similar emission units. All data in the table is based on the information obtained from the permit application submitted by Ohio Valley Resources, LLC, the U.S. EPA RACT/BACT/LAER Clearinghouse (RBLC), Indiana issued permits, and electronic versions of permits available at the websites of other permitting agencies.

RACT/BACT/LEAR CLEARINGHOUSE DATA
CO_2 Purification Process (EU-004) – Greenhouse Gases

RBLC ID	Facility	Issued Date	Process Description	Capacity	Limitation	Control Method
T147-32322-00062	**Ohio Valley Resources, LLC**	**Proposed**	**CO_2 Purification**	**3,570 tons/day CO_2**	**CO2 – 1.275 tons CO_2 per ton ammonia; 2,800 tons ammonia per day, 3 hr avg.**	**Good Operational Practices, Usage Limit**
IA -0105	Iowa Fertilizer Company	10/26/12	CO_2 Regenerator	3,012 MT/day 3,313 ton/day	CO_2 – 1.26 ton/ton ammonia CO_2e – 1,211,847 TPY	Good Operational Practices

RBLC Review
The potential to emit CO_2e from the CO_2 Purification Process (EU-004) is estimated at 1,304,070 TPY. This equates to 1.275 tons CO_2e per ton of ammonia produced. The RBLC has limited entries for processes similar to the CO_2 Purification Process. In fact, there is one and it has not been constructed. Add-on GHG control technologies were not used. The Iowa Fertilizer Company uses good operational practices to minimize GHG emissions. This is the same proposal as OVR.

Applicant Proposal
The applicant proposes the following as BACT:

(a) The applicant proposes to use CO_2 from the CO_2 purification process for the manufacture of urea while the urea unit is operating.

The applicant selected BACT as the use of CO_2 emissions to produce urea only while the urea unit is operating. It is important to note that OVR can only use CO_2 from this vent when the urea unit is operating. If the urea unit is shut down and OVR chooses to make only ammonia fertilizer then venting all of the CO_2 would be considered BACT in this operating scenario. OVR will need the flexibility to produce only ammonia fertilizer depending on market conditions. The CO_2e emissions will be limited to 1,282,038 tpy.

The emission rates of CO_2 per ton of ammonia are similar for both the OVR and the Iowa facilities. The emission rate of the Iowa facility is fractionally smaller and due primarily to rounding. It should be noted the processes are not identical but the emission rates are similar. The applicant has accepted top BACT.

Step 5: Select BACT

IDEM, OAQ has established GHG BACT for the CO_2 Purification Process (EU-004) as:

(1) Ammonia production shall not exceed 1,022,000 tons per twelve consecutive month period with compliance determined at the end of each month.

(2) Good Operational Practices to achieve a CO_2 emission rate of 1.275 tons CO_2 per ton of ammonia, based on a three-hour average.

IDEM, OAQ selected an emission limit based on CO_2 instead of CO_2e; because, the gases in the CO_2 purification vent are comprised of greater than 99% CO_2.

(2) GHG BACT - Primary Reformer (EU-003)

Step 1: Identify Potential Control Technologies

The following greenhouse gas (GHG) control technologies or operational practices should be evaluated for the Primary Reformer (EU-003):

(1) Carbon Capture and Sequestration (CCS);

(2) Combustion of methane containing off-gas streams as fuel;

(3) Energy Efficient Design and Combustion Practices; and

(4) Use a low carbon fuel.

Step 2: Eliminate Technically Infeasible Options

(a) **Carbon Capture and Sequestration (CCS)**

CCS would be used to capture CO_2 from the exhaust, purify, compress, and transport via pipeline to either a storage location or another pipeline for use in Enhanced Oil Recovery (EOR). CCS involves four main steps as follows:

(1) The capture of $CO_{2;}$

(2) The cleanup of emission streams to remove impurities to meet pipeline specifications and to compress the CO_2 to pipeline conditions;

(3) The transport of compressed CO_2 to a sequestration site; and

(4) Sequestration of CO_2.

Greenhouse Gas emissions from the Primary Reformer (EU-003) are significantly more dilute than the CO_2 Purification Process Vent (EU-004). As a dilute exhaust stream, OVR is not required to evaluate CSS for the Primary Reformer (EU-003) because the technology is not considered available under EPA guidance. The technology is also not applicable for the same reasons as the CO_2 Purification Process Vent (EU-004). CSS would require land acquisition for the pipeline and sequestration site, federal funding and infrastructure that are not available. The use of Carbon Capture and Sequestration is considered infeasible for the Primary Reformer (EU-003) because the technology is not applicable and available as described above.

(b) **Combustion of Methane as Fuel**
The combustion of process waste gases containing methane will destroy any methane in the streams, as well as other organic material, and generate CO_2. Since methane has a higher GWP than CO_2, the result is a reduction in greenhouse gas emissions as CO_2e. The use of combustion of methane as fuel is considered feasible for the Primary Reformer (EU-003).

(c) **Energy Efficient Design and Combustion Practices**
The use of good design and combustion practices will ensure the Primary Reformer (EU-003) is operating as efficiently as possible. Efficient operation ensures emissions of greenhouses gases are minimized. Some of the design and combustion practices available to OVR for use in the Primary Reformer (EU-003) are:

(1) Heat from the primary convection section of the reformer can be used to preheat the feed gas to the reformer.

(2) The reformer could use inlet air controls to limit excess air. Limiting excess air increases combustion efficiency by reducing the amount of air that must be heated during combustion.

(3) The reformer can be designed to achieve 90% thermal efficiency.

(4) The primary reformer can be maintained in accordance with 40 CFR 63, Subpart DDDDD.

Energy efficient design and combustion practices are considered feasible for the Primary Reformer (EU-003).

(d) **Use of a Low Carbon Fuel**
The primary fuel can be selected to minimize the carbon content which reduces the carbon available for conversion to CO_2. Combustion of natural gas as a primary fuel is a technically feasible control option for the Primary Reformer (EU-003).

Step 3: Rank the Remaining Control Technologies by Control Effectiveness
The applicant has selected all feasible control options. Therefore, a ranking or further analysis is not necessary.

Step 4: Evaluate the Most Effective Controls and Document the Results
The following table lists the proposed GHG BACT determinations for similar emission units. All data in the table is based on the information obtained from the permit application submitted by Ohio Valley Resources, LLC, the U.S. EPA RACT/BACT/LAER Clearinghouse (RBLC), Indiana issued permits, and electronic versions of permits available at the websites of other permitting agencies.

RACT/BACT/LEAR CLEARINGHOUSE DATA
Primary Reformer (EU-003) – Greenhouse Gases

RBLC ID	Facility	Issued Date	Process Description	Capacity	Limitation	Control Method
T147-32322-00062	**Ohio Valley Resources, LLC**	**Proposed**	**Primary Reformer**	**1,006.4 MMBtu/hr**	**CO_2 – 59.61 ton/MMCF, 3 hr avg. CO_2 emissions limited to 515,246 tons/12 month period; 90% thermal efficiency**	**Energy Efficient Design and Emissions Limit**
IA-0105	Iowa Fertilizer Company	10/26/12	Primary Reformer	1.13 MMCF/hr	CH_4 - 0.0023 lb/MMBtu N_2O - 0.0006 lb/MMBtu CO_2e - 596,905 TPY	Good Combustion Practices
LA-0248	Nucor-Direct Reduction Plant	01/27/11	DRI-108 DRI Unit #1 Reformer	12,168 billion Btu/yr, 1,389 MMBtu/hr	CO_2 – 11.79 MMBtu/ton of DRI, 5,000,000 ton DRI/yr	Good Combustion Practices
LA-0248	Nucor-Direct Reduction Plant	01/27/11	DRI-208 DRI Unit #1 Reformer	12,168 billion Btu/yr, 1,389 MMBtu/hr	CO_2 – 11.79 MMBtu/ton of DRI, 5,000,000 ton DRI/yr	Good Combustion Practices
LA-0263	Phillips 66, Alliance Refinery	07/25/12	Steam Methane Reformer	216 MMBtu/hr	CO_2e – 183,784 TPY	Good Combustion Practices

RBLC Review
All of the entries in the RBLC rely upon good combustion practices as the only practical control method for greenhouse gases. OVR's proposal is typical of the control technology available today.

Applicant Proposal
The applicant proposes the following as BACT:

(a) OVR proposes the combustion of methane containing process off-gas streams in the reformer, good design and combustion practices, and the use of a low carbon fuel. OVR proposes an emission limitation of 515,751 TPY of CO_2e.

The emission rates in the table above are all consistent with emission factors published in the greenhouse gas reporting rule. It appears all facilities used standard emission factors as the BACT limit for greenhouse gas emissions from the primary reformer.

Step 5: Select BACT
IDEM, OAQ has established GHG BACT for the Primary Reformer as:

(1) GHG emissions from the operation of Primary Reformer (EU-003) shall be controlled through the use of good combustion practices.

(2) The Primary Reformer (EU-003) shall combust natural gas and/or process off gas streams.

(3) CO_2 emissions from the Primary Reformer (EU-003) shall not exceed 59.61 tons/MMCF, based on a three-hour average.

(4) The Primary Reformer (EU-003) shall be equipped with the following energy efficiency features: air inlet controls and flue gas heat recovery to pre-heat inlet fuel, inlet air and inlet steam flows.

(5) The Primary Reformer (EU-003) shall be designed to achieve a thermal efficiency of 90% (HHV).

(6) CO_2 emissions from the Primary Reformer (EU-003) shall not exceed 515,246 tons per twelve consecutive month period with compliance determined at the end of each month.

This analysis focuses on the emissions of CO_2 only. While other GHGs, such as methane and N_2O, are present in trace quantities, there are no known add on control technologies for these pollutants coming from combustion sources. To the extent measures are identified that reduce fuel use and thereby CO_2, the other GHGs will be reduced accordingly. Therefore, CO_2 serves as a useful surrogate for other GHGs in this regard.

(3) GHG BACT – Front End Process Flare (EU-007)

Step 1: Identify Potential Control Technologies

IDEM, OAQ has identified the following greenhouse gas (GHG) control technologies or operational procedures for use in the Front End Process Flare (EU-007):

(1) Carbon Capture and Sequestration (CCS);
(2) Good Design and Combustion Practices;
(3) Flare Minimization practices (FMP); and
(4) Low Carbon Fuel for Pilot and Sweep Gas.

Step 2: Eliminate Technically Infeasible Options

(a) **Carbon Capture and Sequestration (CCS)**

Greenhouse gas emissions from the Front End Process Flare (EU-007) are created in the flare from the combustion of fuel in the pilot and are relatively small. The potential to emit greenhouse gases from the combustion of natural gas is 19,324 TPY. This is approximately 2% of total GHG emissions. As discussed above for the CO_2 Purification Process, U.S. EPA guidance indicates that CCS is not applicable to dilute industrial CO_2 streams. CCS is also not available to OVR for the Front End Process Flare (EU-007) because it would require land acquisition for the pipeline, a sequestration site, federal funding and infrastructure that is not available. Carbon Capture and Sequestration are considered infeasible.

(b) **Good Design and Operation**

The flares will be designed to comply with the requirements of 40 CFR 60.18. The design will ensure the control of process off-gas streams sent to them. Greenhouse Gas emissions from the flares are primarily a function of combusting the waste gases flared and the initial composition of these streams. Good design and operation will ensure the flare is operating to achieve optimum combustion which reduces greenhouse gas emissions. Good design and operation are considered feasible control technologies for the Front End Process Flare (EU-007).

(c) **Flare Minimization Practices (FMP)**

The flare minimization practices are a method of operation that reduces greenhouse gas emissions by minimizing emergency and maintenance, startup and shutdown (MSS) releases to the flare. Shorter operating times will result in less greenhouse gas emissions. The FMP will document procedures to be implemented to minimize or prevent emissions from the flare while allowing for the safe operation of the plant. A plan would address operational requirements for a cold start of the facility, startup and shutdown of individual units, and unplanned outages that may result in releases to the flares. Flare minimization practices are considered a feasible control option for the Front End Process Flare (EU-007).

(d) **Low Carbon Fuel**
The primary fuel can be selected to minimize the carbon content which reduces the carbon available for conversion to CO_2. Combustion of natural gas as a primary fuel is a technically feasible control option.

Step 3: Rank the Remaining Control Technologies by Control Effectiveness
All feasible control options have been selected. Therefore, a ranking is not necessary.

Step 4: Evaluate the Most Effective Controls and Document the Results
The following table lists the proposed GHG BACT determinations for similar emission units. All data in the table is based on the information obtained from the permit application submitted by Ohio Valley Resources, LLC, the U.S. EPA RACT/BACT/LAER Clearinghouse (RBLC), Indiana issued permits, and electronic versions of permits available at the websites of other permitting agencies.

RACT/BACT/LEAR CLEARINGHOUSE DATA
Front End Process Flare (EU-007) – Greenhouse Gases

RBLC ID	Facility	Issued Date	Process Description	Capacity	Limitation	Control Method
T147-32322-00062	**Ohio Valley Resources**	**Proposed**	**Process Flare EU-007**	**0.253 MMBtu/hr**	**CO_2 – 116.89 lb/MMBtu, pilot and 511.80 ton/hr, venting**	**Good Combustion Practices**
T153-29394-00005	Hoosier Energy REC, Merom	11/10/11	Coal Bed Methane Flare	25 MMBtu/hr	CO_2-3,235 lb/hr CH_4-0.06 lb/hr N_2O-0.05 lb/hr	Good Combustion Practices
LA-0257	Sabine Pass LNG Terminal	12/06/11	Marine Flare	1,590 MMBtu/hr	CO_2e – 2,909 TPY	Proper Operation, Monitor Flame
LA-0257	Sabine Pass LNG Terminal	12/06/11	Wet/Dry Gas Flares (4)	0.26 MMBtu/hr	CO_2e – 133 TPY	Proper Operation, Monitor Flame
IA-0105	Iowa Fertilizer Company	10/26/12	Ammonia Flare	0.4 MMBtu/hr	None	Good Work Practices

RBLC Review
A review of the RBLC indicates add-on controls are not typically used with flares. Greenhouse gas emissions are controlled by good combustion and design practices and the monitoring of the presence of a pilot flare.

Applicant Proposal
The applicant proposes the following as BACT:

(a) The applicant proposes good design and operation practices, the use of flare minimization practices and the use of a low carbon fuel such as natural gas for the pilot and sweep gas.

Step 5: Select BACT

IDEM, OAQ has established GHG BACT for the Front End Process Flare (EU-007) as:

(1) In order to control GHG emissions, the pilot and purge gas fuels used in the flare shall be natural gas.

(2) Venting in the Front End Process Flare (EU-007) shall not exceed 336 hours per twelve consecutive month period with compliance determined at the end of each month.

(3) Comply with the following flare minimization practices to reduce emissions during startups, shutdowns, and other flaring events:

  (A) Flare Use Minimization: Process syngas streams to flare EU-007 shall not contain ammonia. During the startup of the sequential reformer, only one process stream at a time shall be sent to the flare to the extent practicable. Maximize the use of process syngas during the startup of the Ammonia Unit;

  (B) The Permittee shall train all operators responsible for the day-to-day operation of the flares on the flare minimization practices and the specific procedures to follow during process startup, shutdown, and other flaring events; and

  (C) The Permittee shall investigate the “root cause” of malfunction events that cause flaring events other than at startup or shutdown. This root cause analysis shall identify the apparent cause of unanticipated flaring event and shall recommend additional preventive measures that will minimize the chance of a repeat event. The Permittee shall implement the recommended preventive measures.

(4) GHG emissions shall be controlled by use of the following practices:

  (A) Flares shall be designed for and operated with no visible emissions, except for periods not to exceed 5 minutes during any two consecutive hours;

  (B) Flares shall be operated with a flame present at all times; and

  (C) Flares shall be continuously monitored to assure the presence of a pilot flame with a thermocouple, infrared monitor, or other approved device.

(5) CO_2 emissions from the Front End Process Flare (EU-007) shall not exceed 116.89 lb CO_2/MMBtu, based on a three-hour average, during normal operation, non-venting periods.

(6) CO_2 emissions from the Front End Process Flare (EU-007) shall not exceed 511.80 ton CO_2/hr, based on a three-hour average, during venting events.

This analysis focuses on the emissions of CO_2 only. While other GHGs, such as methane and N_2O, are present in trace quantities, there are no known add on control technologies for these pollutants coming from combustion sources. To the extent measures are identified that reduce fuel use and thereby CO_2, the other GHGs will be reduced accordingly. Therefore, CO_2 serves as a useful surrogate for other GHGs in this regard.

(4) GHG BACT – Ammonia Catalyst Startup Heater (EU-010)

Step 1: Identify Potential Control Technologies

IDEM, OAQ has identified the following greenhouse gas control technologies for the Ammonia Catalyst Startup Heater (EU-010):

(1) Carbon Capture and Sequestration (CCS);

(2) Good Design and Combustion Practices; and

(3) Low Carbon Fuel.

Step 2: Eliminate Technically Infeasible Options

IDEM, OAQ has evaluated the following technologies for use in the Ammonia Catalyst Startup Heater (EU-010):

(a) **Carbon Capture and Sequestration (CCS)**
The Ammonia Catalyst Startup Heater (EU-010) is used during plant startup to preheat the catalyst until a temperature is reached where the reaction is self sustaining. The unit will operate for a maximum of 200 hours per year for plant startups and maintenance. Greenhouse gas emissions are created by the combustion of fuel in the heater. As such, the exhaust stream is dilute and according to U.S. EPA guidance, CCS is not applicable to the Ammonia Catalyst Startup Heater (EU-010). Also, CCS is not available to the Ammonia Catalyst Startup Heater (EU-010) because it would require land acquisition for the pipeline, a sequestration site, federal funding and infrastructure that is not available. Carbon Capture and Sequestration is not a technically feasible control technology for the Ammonia Catalyst Startup Heater (EU-010).

(b) **Good Design and Combustion Practices**
The proper design, operation and maintenance of the Ammonia Catalyst Startup Heater (EU-010) will ensure optimal operation and the minimization of greenhouse gas emissions. Operation of the heater can be controlled by the use of inlet air control sensors that limit excess air and result in optimal combustion. The Ammonia Catalyst Startup Heater (EU-010) will be maintained in accordance with 40 CFR 63, Subpart DDDDD. Good design and combustion practices are a technically feasible control technology for the Ammonia Catalyst Startup Heater (EU-010).

(c) **Low Carbon Fuel**
The primary fuel can be selected to minimize the carbon content which reduces the carbon available for conversion to CO_2. Combustion of a low carbon fuel such as natural gas as a pilot and purge gas fuel is a technically feasible control option for the Ammonia Catalyst Startup Heater (EU-010).

Step 3: Rank the Remaining Control Technologies by Control Effectiveness

The applicant has selected all technically feasible control options for the Ammonia Catalyst Startup Heater (EU-010); therefore, there is no need to rank control options.

Step 4: Evaluate the Most Effective Controls and Document the Results

The following table lists the proposed GHG BACT determinations for similar emission units. All data in the table is based on the information obtained from the permit application submitted by Ohio Valley Resources, LLC, the U.S. EPA RACT/BACT/LAER Clearinghouse (RBLC), Indiana issued permits, and electronic versions of permits available at the websites of other permitting agencies.

RACT/BACT/LEAR CLEARINGHOUSE DATA
Ammonia Catalyst Startup Heater (EU-010) – Greenhouse Gases

RBLC ID Permit #	Facility	Issued Date	Process Description	Capacity	Limitation	Control Method
T147-32322-00062	**Ohio Valley Resources**	**Proposed**	**Startup Heater (EU-010)**	**106.3 MMBtu/hr**	**CO_2 - 59.61 tons/MMCF, 3 hr avg.**	**Good Combustion Practices, Usage Limit**
IA-0105	Iowa Fertilizer Company	10/26/12	Startup Heater	110.12 MMBtu/hr	CO_2 – 117 lb/MMBtu CO_2 e – 638 TPY N_2O – 0.0006 lb/MMBtu	None
SC-0142	Showa Denko Carbon	06/08/12	Hot Oil Heater	5 MMBtu/hr	CO2e – 3,093 TPY	None, 141.23 lb/MMBtu CO_2e

RBLC Review
There are limited entries for greenhouse gas emissions from natural gas process heaters in the RBLC. None of the emission units listed in the table control greenhouse gas emissions.

Applicant Proposal
The applicant proposes the following as BACT:

(a) The applicant proposed the use of a low carbon fuel and good design and combustion practices.

The applicant proposed top BACT.

Step 5: Select BACT
IDEM, OAQ has established GHG BACT for the Ammonia Catalyst Startup Heater (EU-010) as:

(1) In order to control GHG emissions, the Ammonia Catalyst Startup Heater (EU-010) shall combust natural gas.

(2) In order to control GHG emissions, the Ammonia Catalyst Startup Heater (EU-010) shall be controlled by good heater design and good combustion practices.

(3) Fuel usage in the Ammonia Catalyst Startup Heater (EU-010) shall not exceed 20.84 MMCF per twelve consecutive month period with compliance determined at the end of each month.

(4) CO_2 emissions from the Ammonia Catalyst Startup Heater (EU-010) shall not exceed 59.61 ton/MMCF, based on a three-hour average.

This analysis focuses on the emissions of CO_2 only. While other GHGs, such as methane and N_2O, are present in trace quantities, there are no known add on control technologies for these pollutants coming from combustion sources. To the extent measures are identified that reduce fuel use and thereby CO_2, the other GHGs will be reduced accordingly. Therefore, CO_2 serves as a useful surrogate for other GHGs in this regard.

(5) GHG BACT – Back End Ammonia Process Vent Flare (EU-006)

Step 1: Identify Potential Control Technologies

IDEM, OAQ has identified the following greenhouse gas (GHG) control technologies or operational procedures for use in the Back End Ammonia Process Vent Flare (EU-006):

(1) Carbon Capture and Sequestration (CCS);

(2) Good Design and Combustion Practices;

(3) Flare Minimization Practices (FMP); and

(4) Low Carbon Fuel for Pilot and Sweep Gas.

Carbon Capture and Sequestration (CCS)

Greenhouse gas emissions from the Back End Ammonia Process Vent Flare (EU-006) are created in the flare from the combustion of fuel in the pilot and are relatively small. The potential to emit greenhouse gases from the combustion of natural gas is 19,610 TPY. This is approximately 2% of total GHG emissions. As discussed above for the CO_2 Purification Process, U.S. EPA guidance indicates that CCS is not applicable to dilute industrial CO_2 streams. CCS is also not available to OVR for the Back End Ammonia Process Vent Flare (EU-006) because it would require land acquisition for the pipeline and sequestration site, federal funding and infrastructure that are not available. Carbon Capture and Sequestration are considered infeasible control technologies for the Back End Ammonia Process Vent Flare (EU-006).

Good Design and Operation

The flares will be designed to comply with the requirements of 40 CFR 60.18. The design will ensure the control of process off-gas streams sent to them. Greenhouse Gas emissions from the flares are primarily a function of combusting the waste gases flared and the initial composition of these streams. Good design and operation will ensure the flare is operating to achieve optimum combustion which reduces greenhouse gas emissions. Good design and operation are considered feasible control technologies for the Back End Ammonia Process Vent Flare (EU-006).

Flare Minimization Practices (FMP)

Flare minimization practices are a method of operation that reduces greenhouse gas emissions by minimizing emergency and maintenance, startup and shutdown (MSS) releases to the flare. Shorter operating times will result in less greenhouse gas emissions.

The FMP will document procedures to be implemented to minimize or prevent emissions from the flare while allowing for the safe operation of the plant. A plan would address operational requirements for a cold start of the facility, startup and shutdown of individual units, and unplanned outages that may result in releases to the flares. Flare minimization practices are considered a feasible control option for the Back End Ammonia Process Vent Flare.

Low Carbon Fuel

The primary fuel can be selected to minimize the carbon content which reduces the carbon available for conversion to CO_2. Combustion of low carbon fuels such as natural gas for the pilot and purge gas is a technically feasible control option for the Back End Ammonia Process Vent Flare (EU-006).

Step 3: Rank the Remaining Control Technologies by Control Effectiveness

All feasible control options have been selected. Therefore, no ranking is necessary.

Step 4: Evaluate the Most Effective Controls and Document the Results

The following table lists the proposed GHG BACT determinations for similar emission units. All data in the table is based on the information obtained from the permit application submitted by Ohio Valley Resources, LLC, the U.S. EPA RACT/BACT/LAER Clearinghouse (RBLC), Indiana issued permits, and electronic versions of permits available at the websites of other permitting agencies.

RACT/BACT/LEAR CLEARINGHOUSE DATA
Back End Ammonia Process Flare (EU-006) – Greenhouse Gases

RBLC ID	Facility	Issued Date	Process Description	Capacity	Limitation	Control Method
T147-32322-00062	**Ohio Valley Resources**	**Proposed**	**Process Flare EU-006**	**0.253 MMBtu/hr**	**CO_2-116.89 lb/MMBtu, pilot and 127.12 ton/hr, venting**	**Good Combustion Practices, limited use**
T153-29394-00005	Hoosier Energy REC, Merom	11/10/11	Coal Bed Methane Flare	25 MMBtu/hr	CO_2-3,235 lb/hr CH_4-0.06 lb/hr N_2O-0.05 lb/hr	Good Combustion Practices
LA-0257	Sabine Pass LNG Terminal	12/06/11	Marine Flare	1,590 MMBtu/hr	CO_2e – 2,909 TPY	Proper Operation, Monitor Flame
LA-0257	Sabine Pass LNG Terminal	12/06/11	Wet/Dry Gas Flares (4)	0.26 MMBtu/hr	CO_2e – 133 TPY	Proper Operation, Monitor Flame
IA-0105	Iowa Fertilizer Company	10/26/12	Ammonia Flare	0.4 MMBtu/hr	None	Good Work Practices

RBLC Review

A review of the RBLC indicates add-on controls are not typically used with flares. Greenhouse gas emissions are controlled by good combustion and design practices and the monitoring of the presence of a pilot flare.

Applicant Proposal

The applicant proposed the following as BACT:

(a) Good design and good combustion practices;

(b) The use of flare minimization practices; and

(c) The use of natural gas for the pilot and sweep gas.

Step 5: Select BACT

IDEM, OAQ has established GHG BACT for the Back End Ammonia Process Vent Flare (EU-006) as:

(1) In order to control GHG emissions, the pilot and purge gas fuels used in the flare shall be natural gas.

(2) Venting in the Back End Ammonia Process Flare (EU-006) shall not exceed 336 hours per twelve consecutive month period with compliance determined at the end of each month.

(3) Comply with the following flare minimization practices to reduce emissions during startups, shutdowns, and other flaring events:

(A) Flare Use Minimization: Flare EU-006 shall be limited to flaring ammonia during high-pressure events to the extent practicable. The ammonia compressor main shall be depressurized prior to compressor maintenance. The Permittee shall limit venting ammonia rich streams to Flare EU-006 to the extent practicable during non-emergency startup and shutdown operations;

(B) The Permittee shall train all operators responsible for the day-to-day operation of the flares on the flare minimization practices and the specific procedures to follow during process startup, shutdown, and other flaring events; and

(C) The Permittee shall investigate the “root cause” of malfunction events that cause flaring events other than at startup or shutdown. This root cause analysis shall identify the apparent cause of unanticipated flaring event and shall recommend additional preventive measures that will minimize the chance of a repeat event. The Permittee shall implement the recommended preventive measures.

(4) GHG emissions from the Back End Ammonia Process Vent Flare (EU-006) shall be controlled by the use of the following practices:

(A) Flares shall be designed for and operated with no visible emissions, except for periods not to exceed 5 minutes during any two consecutive hours;

(B) Flares shall be operated with a flame present at all times; and

(C) Flares shall be continuously monitored to assure the presence of a pilot flame with a thermocouple, infrared monitor, or other approved device.

(5) CO_2 emissions from the Back End Ammonia Process Vent Flare (EU-006) shall not exceed 116.89 lb/MMBtu, based on a three-hour average, during normal operations, non-venting periods.

(6) CO_2 emissions from the Back End Ammonia Process Vent Flare (EU-006) shall not exceed 127.12 ton CO_2/hr, based on a three-hour average, during venting events.

This analysis focuses on the emissions of CO_2 only. While other GHGs, such as methane and N_2O, are present in trace quantities, there are no known add on control technologies for these pollutants coming from combustion sources. To the extent measures are identified that reduce fuel use and thereby CO_2, the other GHGs will be reduced accordingly. Therefore, CO_2 serves as a useful surrogate for other GHGs in this regard.

(6) GHG BACT – Ammonia Storage Flare (EU-005)

Step 1: Identify Potential Control Technologies

IDEM, OAQ has identified the following greenhouse gas (GHG) control technologies or operational procedures for use in the Ammonia Storage Flare (EU-005):

(1) Carbon Capture and Sequestration (CCS);

(2) Good Design and Combustion Practices;

(3) Flare Minimization Practices (FMP); and

(4) Low Carbon Fuel for Pilot and Sweep Gas.

Step 2: Eliminate Technically Infeasible Options

(a) **Carbon Capture and Sequestration (CCS)**
Greenhouse gas emissions from the Ammonia Storage Flare (EU-005) are created in the flare from the combustion of fuel in the pilot and are relatively small. The potential to emit greenhouse gases from the combustion of natural gas are 228 TPY. This is less than 0.1% of total GHG emissions. As discussed above for the CO_2 Purification Process, U.S. EPA guidance indicates that CCS is not applicable to dilute industrial CO_2 streams. CCS is also not available to OVR for the Ammonia Storage Flare (EU-005) because it would require land acquisition for the pipeline, a sequestration site, federal funding and infrastructure that is not available. Carbon Capture and Sequestration are considered infeasible control technologies.

(b) **Good Design and Operation**
The flares will be designed to comply with the requirements of 40 CFR 60.18. The design will ensure the control of process off-gas streams sent to them. Greenhouse Gas emissions from the flares are primarily a function of combusting the waste gases flared and the initial composition of these streams. Good design and operation will ensure the flare is operating to achieve optimum combustion which reduces greenhouse gas emissions. Good design and operation are considered feasible control technologies for the Ammonia Storage Flare (EU-005).

(c) **Flare Minimization Practices (FMP)**
Flare minimization practices are a method of operation that reduces greenhouse gas emissions by minimizing emergency and maintenance, startup and shutdown (MSS) releases to the flare. Shorter operating times will result in less greenhouse gas emissions. The FMP will document procedures to be implemented to minimize or prevent emissions from the flare while allowing for the safe operation of the plant. A plan would address operational requirements for a cold start of the facility, startup and shutdown of individual units, and unplanned outages that may result in releases to the flares. Flare minimization practices are considered a feasible control option for the Ammonia Storage Flare (EU-005).

(d) **Low Carbon Fuel**
The primary fuel can be selected to minimize the carbon content which reduces the carbon available for conversion to CO_2. Combustion of low carbon fuels such as natural gas for the pilot and purge gas is a technically feasible control option for the Ammonia Storage Flare (EU-005).

Step 3: Rank the Remaining Control Technologies by Control Effectiveness

All feasible control options have been selected. Therefore, no ranking or additional analysis is necessary.

Step 4: Evaluate the Most Effective Controls and Document the Results

The following table lists the proposed GHG BACT determinations for similar emission units. All data in the table is based on the information obtained from the permit application submitted by Ohio Valley Resources, LLC, the U.S. EPA RACT/BACT/LAER Clearinghouse (RBLC), Indiana issued permits, and electronic versions of permits available from other permitting agencies.

RACT/BACT/LEAR CLEARINGHOUSE DATA Ammonia Storage Flare (EU-005) – Greenhouse Gases						
RBLC ID	**Facility**	**Issued Date**	**Process Description**	**Capacity**	**Limitation**	**Control Method**
T147-32322-00062	**Ohio Valley Resources, LLC**	**Proposed**	**Ammonia Storage Flare EU-005**	**0.126 MMBtu/hr**	CO_2- 52.02 lb/hr	**Good Combustion Practices, Usage Limit**
T153-29394-00005	Hoosier Energy REC, Merom	11/10/11	Coal Bed Methane Flare	25 MMBtu/hr	CO_2-3,235 lb/hr CH_4-0.06 lb/hr N_2O-0.05 lb/hr	Good Combustion Practices
LA-0257	Sabine Pass LNG Terminal	12/06/11	Marine Flare	1,590 MMBtu/hr	CO_2e – 2,909 TPY	Proper Operation, Monitor Flame
LA-0257	Sabine Pass LNG Terminal	12/06/11	Wet/Dry Gas Flares (4)	0.26 MMBtu/hr	CO_2e – 133 TPY	Proper Operation, Monitor Flame
IA-0105	Iowa Fertilizer Company	10/26/12	Ammonia Flare	0.4 MMBtu/hr	None	Good Work Practices

RBLC Review
A review of the RBLC indicates add-on controls are not typically used with flares. Greenhouse gas emissions are controlled by good combustion and design practices and the monitoring of the presence of a pilot flare.

Applicant Proposal
The applicant proposed the following as BACT:

(a) Good design and good combustion practices;

(b) The use of flare minimization practices; and

(c) The use of natural gas for the pilot and sweep gas.

<u>Step 5: Select BACT</u>
IDEM, OAQ has established GHG BACT for the Ammonia Storage Flare (EU-005) as:

(1) In order to control GHG emissions, the pilot and purge gas fuels used in the flare shall be natural gas.

(2) Venting for Startup, Shutdown and Malfunction shall not exceed 168 hours per twelve consecutive month period with compliance determined at the end of each month.

(3) Comply with the following flare minimization practices to reduce emissions during startups, shutdowns, and other flaring events:

    (A) Flare Use Minimization: The Permittee shall limit periods when the backup storage compressor and the ammonia refrigeration compressor are offline at the same time to the extent practicable;

    (B) The Permittee shall train all operators responsible for the day-to-day operation of the flares on the flare minimization practices and the specific procedures to follow during process startup, shutdown, and other flaring events; and

(C) The Permittee shall investigate the “root cause” of malfunction events that cause flaring events other than at startup or shutdown. This root cause analysis shall identify the apparent cause of unanticipated flaring event and shall recommend additional preventive measures that will minimize the chance of a repeat event. The Permittee shall implement the recommended preventive measures.

(4) GHG emissions shall be controlled by use of the following practices:

(A) Flares shall be designed for and operated with no visible emissions, except for periods not to exceed 5 minutes during any two consecutive hours;

(B) Flares shall be operated with a flame present at all times; and

(C) Flares shall be continuously monitored to assure the presence of a pilot flame with a thermocouple, infrared monitor, or other approved device.

(5) CO_2 emissions from the Ammonia Storage Flare (EU-005) shall not exceed 52.02 lb/hr, based on a three-hour average.

This analysis focuses on the emissions of CO_2 only. While other GHGs, such as methane and N_2O, are present in trace quantities, there are no known add on control technologies for these pollutants coming from combustion sources. To the extent measures are identified that reduce fuel use and thereby CO_2, the other GHGs will be reduced accordingly. Therefore, CO_2 serves as a useful surrogate for other GHGs in this regard.

(7) GHG BACT – Two Identical Nitric Acid Units (EU-001A and EU-001B)

Step 1: Identify Potential Control Technologies

The following GHG control technologies apply to the Nitric Acid Units (EU-001A and EU-001B):

(1) Primary Controls – Suppression of N_2O formation

(2) Secondary Controls – Reduction of N_2O after formation

(3) Tertiary Controls – Reduction of N_2O using catalytic control

(4) Plant Energy Efficiency Considerations

Step 2: Eliminate Technically Infeasible Options

(a) **Primary Controls – Suppression of N_2O formation**

Primary controls refer to the modifications made to the catalyst and reaction conditions in the oxidation step to reduce the amount of N_2O formed. Types of primary controls include extension of the ammonia oxidation reactor. The extended reactor includes an extra chamber free of catalyst between the catalyst and the heat exchangers, allowing additional residence time. Additional primary controls include modification to the oxidation catalyst. The use of primary controls would be considered an inherently lower emitting design. The use of primary controls for greenhouse gas control for the Nitric Acid Units (EU-001A and EU-001B) is technically feasible.

(b) **Secondary Controls – Reduction of N_2O after formation**
Secondary control refer to reductions in N_2O through the use of an additional catalyst, immediately after the oxidation step in the ammonia burner, in which N_2O is decomposed into nitrogen and oxygen. The use of secondary controls would be an add-on control technology. The use of secondary controls for greenhouse gas control for the Nitric Acid Units (EU-001A and EU-001B) is technically feasible.

(c) **Tertiary Controls – Reduction of N_2O using catalytic control**
Tertiary controls refer to reduction in N_2O through catalytic reduction or decomposition after formation in the oxidation step. The catalyst can be placed either before or after the expander. The two types of catalyst used are non-selective catalytic reduction (NSCR) and catalytic decomposition. The NSCR system reacts with the N_2O and some sort of fuel over a catalyst to produce nitrogen and water. The catalytic decomposition process does not require any added fuels or reagents to decompose N_2O to nitrogen and oxygen. The use of tertiary controls would be add-on technology.

(d) **Plant Energy Efficiency Considerations**
Plant energy efficiency considerations include process integration and heat recovery for steam production. The exothermic nature of the reactions means the nitric acid units are net exporters of energy. Therefore, careful consideration should be given to recovering as much of this thermal energy as possible to reduce the overall energy input to the plant. When energy inputs are reduced, greenhouse gas emissions are reduced. The use of plant energy efficiency considerations is a technically feasible control option for the Nitric Acid Units (EU-001A and EU-001B).

(e) **Uhde EnviNOx System**
The EnviNOx system is a patented system capable of reducing both NOx and N_2O emissions from waste industrial gases. The system was developed by Uhde GmbH in Germany and uses a new type of catalyst to convert N_2O and NOx to N_2, O_2 and H_2O in a two stage reactor. This technology has been commercially available since September 2003 for nitric acid plants designed by Uhde. The OVR facility was not designed by Uhde and the patented technology is unavailable. The Uhde EnviNOx system is not a technically feasible option.

Step 3: Rank the Remaining Control Technologies by Control Effectiveness

IDEM, OAQ has reviewed the information submitted in support of this BACT determination and has ranked the remaining control options as shown below:

(1) Tertiary Control (95% reduction, vendor guarantee)

(2) Secondary Control (70% to 90% reduction)

(3) Primary Control (30% to 85% reduction)

(4) Plant Efficiency Considerations

Tertiary control has the highest control efficiency and has been selected as BACT.

Step 4: Evaluate the Most Effective Controls and Document the Results

The following table lists the proposed GHG BACT determinations for similar emission units. All data in the table is based on the information obtained from the permit application submitted by Ohio Valley Resources, LLC, the U.S. EPA RACT/BACT/LAER Clearinghouse (RBLC), Indiana issued permits, and electronic versions of permits available at the websites of other permitting agencies.

RACT/BACT/LEAR CLEARINGHOUSE DATA
Nitric Acid Plants (EU-001A and EU-001B) – Greenhouse Gases

RBLC ID	Facility	Issued Date	Process Description	Capacity	Limitation	Control Method
T147-32322-00062	**Ohio Valley Resources, LLC**	**Proposed**	**Nitric Acid Plants**	**630 tons per day, each**	**1.05 lb N_2O per ton nitric acid, 3 hr avg.**	**Catalytic Decomposition, Usage Limit**
IA-0105	Iowa Fertilizer Company	10/26/12	Nitric Acid Plant	1,905 MT/day	N_2O – 30 ppmv CO_2e – 29,543 TPY CH_4 – 40 ppmv	**N_2O** Uhde EnviNOx System with 98% control **Methane** Good Operational Practices **CO_2e** Uhde EnviNOx System

RBLC Review
The Iowa Fertilizer Company is the only one entry in the RBLC for N_2O reduction in a nitric acid plant. However, the control technology used in the Iowa Fertilizer Company is unavailable to Ohio Valley Resources. Therefore, the applicant's proposal will be BACT for this unit.

Applicant Proposal
The applicant proposed the use of tertiary controls using catalytic decomposition to achieve an outlet N_2O concentration of 1,800 ppmv and 95% control efficiency as BACT. This is top BACT.

Step 5: Select BACT
IDEM, OAQ has established GHG BACT for the Nitric Acid Units (EU-001A and EU-001B) as:

(1) The combined nitric acid production from Nitric Acid Plants (EU-001A and EU-001B) shall not exceed 459,900 tons of 100% nitric acid per twelve consecutive month period with compliance determined at the end of each month.

(2) N_2O emissions from each of the Nitric Acid Units (EU-001A and EU-001B) shall be controlled at all times by a catalytic decomposition process.

(3) N_2O emissions from each of the Nitric Acid Units (EU-001A and EU-001B) shall not exceed 1.05 lb N_2O per ton of nitric acid, based on a three-hour average.

IDEM, OAQ selected an emission limit based on N_2O instead of CO_2e because the only GHG reduced by the emission control system is N_2O. The limit, therefore, requires a high level of performance in reducing the only GHG that can be controlled by the emission control system. N_2O emissions comprise 95% of the pre-control CO_2e emitted by the nitric acid stacks. The system does not reduce emissions of any other GHGs. CO_2 is present in nitric acid plant stack: it originates in the compressed air that is used as part of the nitric acid manufacturing process.

(8) GHG BACT – Two Identical Ammonium Nitrate Plants (EU-002A and EU-002B)

Step 1: Identify Potential Control Technologies

IDEM, OAQ has identified the following potential control technologies for greenhouse gas emissions from the Ammonium Nitrate Plants (EU-002A) and (EU-002B):

(1) Carbon Capture and Sequestration (CCS); and

(2) Process Optimization.

Step 2: Eliminate Technically Infeasible Options

IDEM, OAQ has evaluated the following technologies for use in the Ammonium Nitrate Plants (EU-002A) and (EU-002B):

(a) **Carbon Capture and Sequestration (CCS)**

The Ammonium Nitrate Plants (EU-002A) and (EU-002B) have a dilute stream of CO_2 from the reformer process that did not react to create urea. As such, the exhaust stream is dilute and according to U.S. EPA guidance, CCS is not applicable to the Ammonium Nitrate Plants (EU-002A) and (EU-002B). Also, CCS is not available to the Ammonium Nitrate Plants (EU-002A) and (EU-002B) because it would require land acquisition for the pipeline, a sequestration site, federal funding and infrastructure that is not available.

Carbon Capture and Sequestration is not a technically feasible control technology for the Ammonium Nitrate Plants (EU-002A) and (EU-002B).

(b) **Process Optimization**

Greenhouse gas emissions in the form of CO_2 from the Ammonium Nitrate Plants (EU-002A) and (EU-002B) are a result of an incomplete reaction in the primary reformer. As the reaction comes closer to completion, CO_2 and CO_2e emissions will be reduced. Process optimization of the Primary Reformer (EU-003) will result in a reduction of greenhouse gas emission from the Ammonium Nitrate Plants (EU-002A) and (EU-002B). Process optimization of the Primary Reformer (EU-003) is a feasible control option for the Ammonium Nitrate Plants (EU-002A) and (EU-002B).

Step 3: Rank the Remaining Control Technologies by Control Effectiveness

IDEM, OAQ was able to identify only one feasible control option for the Ammonium Nitrate Plants (EU-002A) and (EU-002B). Therefore, a ranking is not necessary.

Step 4: Evaluate the Most Effective Controls and Document the Results

The following table lists the proposed GHG BACT determinations for similar emission units. All data in the table is based on the information obtained from the permit application submitted by Ohio Valley Resources, LLC, the U.S. EPA RACT/BACT/LAER Clearinghouse (RBLC), Indiana issued permits, and electronic versions of permits available at the websites of other permitting agencies.

RACT/BACT/LEAR CLEARINGHOUSE DATA Ammonium Nitrate Plants (EU-002A and EU-002B) – Greenhouse Gases						
RBLC ID	**Facility**	**Issued Date**	**Process Description**	**Capacity**	**Limitation**	**Control Method**
T 147-32322-00062	**Ohio Valley Resources, LLC**	**Proposed**	**Ammonium Nitrate Plants**	**798 ton AN/day**	**132.31 lb CO_2 / ton AN, 3 hr avg.**	**Usage Limit**
No RBLC Entries are Available						

RBLC Review
There are no entries in the RBLC for greenhouse gas emissions from ammonium nitrate plants. The applicant did include emission calculations showing there are greenhouse gas emissions from these plants. The potential to emit CO_2e for each plant is 43,464 tons per year. IDEM, OAQ was able to determine process optimization of the Ammonium Nitrate Plants (EU-002A and EU-002B) as the single feasible control option. Therefore, it is BACT for Greenhouse Gases (GHG).

Applicant Proposal
The applicant proposed the following as BACT: Greenhouse gas emissions from the Ammonium Nitrate Plants (EU-002A and EU-002B) shall not exceed 132.31 lb CO2 per ton AN.

Step 5: Select BACT
IDEM, OAQ has established GHG BACT for the Ammonium Nitrate Plants (EU-002A and EU-002B) as:

(1) The maximum combined production of urea ammonium nitrate (UAN) for the Ammonium Nitrate Plants (EU-002A and EU-002B) shall not exceed 1,314,000 tons per year.

(2) CO_2 emissions from the Ammonium Nitrate Plants (EU-002A and EU-002B) shall be controlled by good operational practices in the reformer process including the Primary Reformer (EU-003) and CO_2 Purification Process (EU-004).

(3) CO_2 emissions from each of the Ammonium Nitrate Plants (EU-002A and EU-002B) shall not exceed 132.31 lb CO_2 per ton UAN, based on a three-hour average.

IDEM, OAQ selected an emission limit based on CO_2 instead of CO_2e because CO_2 is the only GHG present in the exhaust. The CO_2 in this exhaust is CO_2 sent from the CO_2 production vent that is not consumed in the urea production process.

(9) GHG BACT – UAN Plant Vent Flare (EU-017)

Step 1: Identify Potential Control Technologies
IDEM, OAQ has identified the following greenhouse gas (GHG) control technologies or operational procedures for use in the UAN Plant Vent Flare (EU-017):

(1) Carbon Capture and Sequestration (CCS);

(2) Good Design and Combustion Practices;

(3) Flare Minimization Practices (FMP); and

(4) Low Carbon Fuel for Pilot and Sweep Gas.

Step 2: Eliminate Technically Infeasible Options

(a) **Carbon Capture and Sequestration (CCS)**
Greenhouse gas emissions from the UAN Plant Vent Flare (EU-017) are created in the flare from the combustion of fuel in the pilot and are relatively small. The potential to emit greenhouse gases from the combustion of natural gas is 3,293 TPY. This is less than 0.1% of total GHG emissions. As discussed above for the CO_2 Purification Process, U.S. EPA guidance indicates that CCS is not applicable to dilute industrial CO_2 streams. CCS is also not available to OVR for the UAN Plant Vent Flare (EU-017) because it would require land acquisition for the pipeline and sequestration site, federal funding and infrastructure that is not available.

Carbon Capture and Sequestration are considered infeasible control technologies for the UAN Plant Vent Flare (EU-017).

(b) **Good Design and Operation**
The flares will be designed to comply with the requirements of 40 CFR 60.18. The design will ensure the control of process off-gas streams sent to them. Greenhouse Gas emissions from the flares are primarily a function of combusting the waste gases flared and the initial composition of these streams. Good design and operation will ensure the flare is operating to achieve optimum combustion which reduces greenhouse gas emissions.

Good design and operation are considered feasible control technologies for the UAN Plant Vent Flare (EU-017).

(c) **Flare Minimization Practices (FMP)**
Flare minimization practices are a method of operation that reduces greenhouse gas emissions by minimizing emergency and maintenance, startup and shutdown (MSS) releases to the flare. Shorter operating times will result in less greenhouse gas emissions.

The FMP will document procedures to be implemented to minimize or prevent emissions from the flare while allowing for the safe operation of the plant. A plan would address operational requirements for a cold start of the facility, startup and shutdown of individual units, and unplanned outages that may result in releases to the flares. Flare minimization practices are considered a feasible control option for the UAN Plant Vent Flare (EU-017).

(d) **Low Carbon Fuel**
The primary fuel can be selected to minimize the carbon content which reduces the carbon available for conversion to CO_2. Combustion of low carbon fuels such as natural gas for the pilot and purge gas is a technically feasible control option for the UAN Plant Vent Flare (EU-017).

Step 3: Rank the Remaining Control Technologies by Control Effectiveness

All feasible control options have been selected. Therefore, no ranking or additional analysis is necessary.

Step 4: Evaluate the Most Effective Controls and Document the Results

The following table lists the proposed GHG BACT determinations for similar emission units. All data in the table is based on the information obtained from the permit application submitted by Ohio Valley Resources, LLC, the U.S. EPA RACT/BACT/LAER Clearinghouse (RBLC), Indiana issued permits, and electronic versions of permits available at the websites of other permitting agencies.

RACT/BACT/LEAR CLEARINGHOUSE DATA UAN Plant Vent Flare (EU-017) – Greenhouse Gases						
RBLC ID	**Facility**	**Issued Date**	**Process Description**	**Capacity**	**Limitation**	**Control Method**
T147-32322-00062	**Ohio Valley Resources, LLC**	**Proposed**	**UAN Plant Flare EU-017**	**0.189 MMBtu/hr**	**CO_2-116.89 lb/MMBtu, pilot, 5.59 tons/hr, flaring**	**Good Combustion Practices, Usage Limit**
T153-29394-00005	Hoosier Energy REC, Merom Station	11/10/11	Coal Bed Methane Flare	25 MMBtu/hr	CO_2-3,235 lb/hr CH_4-0.06 lb/hr N_2O-0.05 lb/hr	Good Combustion Practices
LA-0257	Sabine Pass LNG Terminal	12/06/11	Marine Flare	1,590 MMBtu/hr	CO_2e – 2,909 TPY	Proper Operation, Monitor Flame
LA-0257	Sabine Pass LNG Terminal	12/06/11	Wet/Dry Gas Flares (4)	0.26 MMBtu/hr	CO_2e – 133 TPY	Proper Operation, Monitor Flame
IA-0105	Iowa Fertilizer Company	10/26/12	Ammonia Flare	0.4 MMBtu/hr	None	Good Work Practices

RBLC Review

A review of the RBLC indicates add-on controls are not typically used with flares. Greenhouse gas emissions are controlled by good combustion and design practices and the monitoring of the presence of a pilot flare.

Applicant Proposal

The applicant proposed the following as BACT:

(a) Good design and combustion practices;

(b) The use of flare minimization practices; and

(c) The use of natural gas for the pilot and sweep gas.

The applicant has accepted top BACT. IDEM, OAQ is adding an emission limitation to make startup, shutdown and malfunction emissions enforceable.

Step 5: Select BACT

IDEM, OAQ has established GHG BACT for the UAN Plant Vent Flare (EU-017) as:

(1) In order to control GHG emissions, the pilot and purge gas fuels used in the flare shall be natural gas.

(2) Venting for Startup, Shutdown and Malfunction shall not exceed 336 hours per twelve consecutive month period with compliance determined at the end of each month.

(3) Comply with the following flare minimization practices to reduce emissions during startups, shutdowns, and other flaring events:

(A) Flare Use Minimization: The UAN process shall be properly operated to avoid emergency upsets. Startup time of the Nitric Acid Units shall be minimized. During emergency upsets of the Nitric Acid Units, the Permittee shall return some of the high and low-pressure off-gas back to the urea process as soon as urea production is reduced to a level that safely allows this;

(B) The Permittee shall train all operators responsible for the day-to-day operation of the flares on the flare minimization practices and the specific procedures to follow during process startup, shutdown, and other flaring events; and

(C) The Permittee shall investigate the “root cause” of malfunction events that cause flaring events other than at startup or shutdown. This root cause analysis shall identify the apparent cause of unanticipated flaring event and shall recommend additional preventive measures that will minimize the chance of a repeat event. The Permittee shall implement the recommended preventive measures.

(4) GHG emissions shall be controlled by use of the following practices:

(A) Flares shall be designed for and operated with no visible emissions, except for periods not to exceed 5 minutes during any two consecutive hours;

(B) Flares shall be operated with a flame present at all times; and

(C) Flares shall be continuously monitored to assure the presence of a pilot flame with a thermocouple, infrared monitor, or other approved device.

(5) CO_2 emissions from the UAN Plant Vent Flare (EU-017) shall not exceed 116.89 lb/MMBtu, based on a three-hour average, during normal operations, non-venting events.

(6) CO_2 emissions from the UAN Plant Vent Flare (EU-017) shall not exceed 5.59 tons/hr, based on a three-hour average, during venting events.

This analysis focuses on the emissions of CO_2 only. While other GHGs, such as methane and N_2O, are present in trace quantities, there are no known add on control technologies for these pollutants coming from combustion sources. To the extent measures are identified that reduce fuel use and thereby CO_2, the other GHGs will be reduced accordingly. Therefore, CO_2 serves as a useful surrogate for other GHGs in this regard.

(10) GHG BACT – Four (4) Identical 218 MMBtu/hr Natural Gas-Fired Boilers (EU-011A, EU-011B, EU-011C and EU-011D)

Step 1: Identify Potential Control Technologies

IDEM, OAQ has identified the following potential control technologies for the Natural Gas-Fired Boilers (EU-011A, EU-011B, EU-011C and EU-011D):

(1) Carbon Capture and Sequestration (CCS);

(2) Energy Efficient Design and Good Combustion Practices; and

(3) Low Carbon Fuel.

Step 2: Eliminate Technically Infeasible Options

(a) **Carbon Capture and Sequestration (CCS)**

CCS would be used to capture CO_2 from the exhaust, purify, compress, and transport via pipeline to either a storage location or another pipeline for use in Enhanced Oil Recovery (EOR). CCS involves four main steps as follows:

(1) The capture of CO_2 from sources including combusted exhausts streams and the CO_2 vent;

(2) The cleanup of emission streams to remove impurities to meet pipeline specifications and compress the CO_2 to pipeline conditions;

(3) The transport of compressed CO_2 to a sequestration site; and

(4) Sequestration of CO_2.

When considering if a control technology is technically feasible, it must be available and applicable. A control technology is applicable if it can reasonably be installed and operated on the source type under consideration. If a given technology has not been used on the emission unit, thought should be given on transferring technology from similar gas streams with the same physical and chemical properties.

For a technology to be considered available, consideration should be given to:

(1) Land acquisition;

(2) The need for federal funding;

(3) Timing of available transportation infrastructure; and

(4) Developing a site for long term storage.

The discussion included for the CO_2 Purification Process Vent (EU-004) indicated that CCS as a control technology is not available to OVR. Therefore, Carbon Capture and Sequestration is not a technically feasible control technology for the Natural Gas-Fired Boilers (EU-011A, EU-011B, EU-011C and EU-011D).

(b) **Energy Efficient Design and Combustion Practices**
The proper design, operation and maintenance of the Natural Gas-Fired Boilers (EU-011A, EU-011B, EU-011C and EU-011D) will ensure optimal operation and the minimization of greenhouse gas emissions. Energy efficient design considerations include air inlet controls, heat recovery, condensate recovery, and blowdown heat recovery. The boilers can be designed to achieve 80% thermal efficiency. The Natural Gas-Fired Boilers (EU-011A, EU-011B, EU-011C and EU-011D) will be maintained in accordance with 40 CFR 63, Subpart DDDDD.

Good design and combustion practices are a technically feasible control technology for the Natural Gas-Fired Boilers (EU-011A, EU-011B, EU-011C and EU-011D).

(c) **Low Carbon Fuel**
The primary fuel can be selected to minimize the carbon content which reduces the carbon available for conversion to CO_2. Combustion of low carbon fuels such as natural gas is a technically feasible control option for the Natural Gas-Fired Boilers (EU-011A, EU-011B, EU-011C and EU-011D).

Step 3: Rank the Remaining Control Technologies by Control Effectiveness

The applicant has selected both of the feasible control technologies or operational practices. Therefore, no ranking or additional analysis is necessary.

Step 4: Evaluate the Most Effective Controls and Document the Results

The following table lists the proposed GHG BACT determinations for similar emission units. All data in the table is based on the information obtained from the permit application submitted by Ohio Valley Resources, LLC, the U.S. EPA RACT/BACT/LAER Clearinghouse (RBLC), Indiana issued permits, and electronic versions of permits available at the websites of other permitting agencies.

RACT/BACT/LEAR CLEARINGHOUSE DATA
Boilers (EU-011A, EU-011B, EU-011C and EU-011D) – Greenhouse Gases

RBLC ID Permit #	Facility	Issued Date	Process Description	Capacity	Limitation	Control Method
T 147-32322-00062	**Ohio Valley Resources, LLC**	**Proposed**	**Boilers EU-011A to EU-011D**	**218 MMBtu/hr each**	**CO_2 – 59.61 ton/MMCF, 3 hr avg.**	**Good Combustion Practices, Usage Limit**
IA-0105	Iowa Fertilizer Company	10/26/12	Startup Heater	110.12 MMBtu/hr	CO_2 – 117 lb/MMBtu CH_4 – 0.0023 lb/MMBtu N_2O – 0.0006 lb/MMBtu CO_2e – 638 TPY	Good Combustion Practices
IA-0105	Iowa Fertilizer Company	10/26/12	Auxiliary Boiler	472.4 MMBtu/hr	CO_2 – 117 lb/MMBtu CH_4 – 0.0023 lb/MMBtu N_2O – 0.0006 lb/MMBtu CO_2e – 638 TPY	Good Combustion Practices
T147-30464-00060	Indiana Gasification, LLC	06/27/12	Auxiliary Boiler	172 MMBtu/hr	88,167 tons CO_2 per year	81% Thermal Efficiency, Use Natural Gas, Efficient Design

RBLC Review

None of the RBLC entries for greenhouse gas emissions from boilers required the use of an add-on control device. GHG emissions are controlled by good combustion practices and the emission limitations shown are from 40 CFR 98, Subpart C. OVR proposes the same control strategy.

Applicant Proposal

The applicant proposed the following as BACT:

(a) The use of natural gas along with good design and combustion practices.

Step 5: Select BACT

IDEM, OAQ has established GHG BACT for the Natural Gas-Fired Boilers (EU-011A, EU-011B, EU-011C and EU-011D) as:

(a) GHG emissions from the boilers (EU-011A, EU-011B, EU-011C and EU-011D) shall be controlled through the use of proper boiler design and good combustion practices.

(b) Combined fuel usage in the boilers (EU-011A, EU-011B, EU-011C and EU-011D) shall not exceed 2,802 MMCF per twelve consecutive month period with compliance determined at the end of each month.

(c) The boilers (EU-011A, EU-011B, EU-011C, and EU-011D) shall combust natural gas.

(d) CO_2 emissions from each of the boilers (EU-011A, EU-011B, EU-011C, and EU-011D) shall not exceed 59.61 tons/MMCF, based on a three-hour average.

(e) Each of the boilers (EU-011A, EU-011B, EU-011C and EU-011D) shall be equipped with the following energy efficient design features: air inlet controls, heat recovery, condensate recovery, and blowdown heat recovery.

(f) Each of the boilers (EU-011A, EU-011B, EU-011C and EU-011D) shall be designed to achieve a thermal efficiency of 80% (HHV).

This analysis focuses on the emissions of CO_2 only. While other GHGs, such as methane and N_2O, are present in trace quantities, there are no known add on control technologies for these pollutants coming from combustion sources. To the extent measures are identified that reduce fuel use and thereby CO_2, the other GHGs will be reduced accordingly. Therefore, CO_2 serves as a useful surrogate for other GHGs in this regard.

(11) GHG BACT – Diesel-Fired Emergency Generator (EU-009)

Step 1: Identify Potential Control Technologies

Today's stationary diesel-fired emergency compression ignition internal combustion engines are sold as package units with an engineering design tailored to meet the emission limitations of 40 CFR 60, Subpart IIII and 40 CFR 63, Subpart ZZZZ. The manufacturer provides an engine that is in compliance with the applicable NSPS and NESHAP and the owner/operator is expected to maintain and operate the unit to guarantee compliance with applicable emission limitations. Based on the review of information for this BACT, IDEM has determined the only control method available for GHG for emergency stationary compression ignition internal combustion engines is good combustion practices.

Step 2: Eliminate Technically Infeasible Options

The only feasible control option for the Diesel-Fired Emergency Generator (EU-009) is good combustion practices.

Step 3: Rank the Remaining Control Technologies by Control Effectiveness

There is only one control option; therefore, a ranking is not needed.

Step 4: Evaluate the Most Effective Controls and Document the Results

The following table lists the proposed GHG BACT determinations for similar emission units. All data in the table is based on the information obtained from the permit application submitted by Ohio Valley Resources, LLC, the U.S. EPA RACT/BACT/LAER Clearinghouse (RBLC), Indiana issued permits, and electronic versions of permits available at the websites of other permitting agencies.

RACT/BACT/LEAR CLEARINGHOUSE DATA

Diesel-Fired Emergency Generator (EU-009) – Greenhouse Gases

RBLC ID Permit #	Facility	Issued Date	Process Description	Capacity	Limitation	Control Method
T 147-32322-00062	**Ohio Valley Resources, LLC**	**Proposed**	**Emergency Generator**	**4,690 HP**	**CO_2 – 526.39 g/hp-hr, 3 hr avg.**	**Combustion Practices, Use Limit**
IA-0105	Iowa Fertilizer Company	10/26/12	Emergency Generator	2,000 KW	CO_2e – 788.5 TPY CO_2 – 1.55 g/KW-hr CH4 – 0.0001 g/KW-hr	Good Combustion Practices
AK-0076	Exxon, Point Thomson Production Facility	08/20/12	Emergency Generator	1,750 KW	CO_2 – No Numerical Limit	Good Combustion, 40 CFR 60, Subpart IIII
MI-0402	Wolverine Power, Sumpter Power Plant	11/17/11	Emergency Generator	732 HP	CO_2e – 716 lb/hr	Good Combustion Practices
LA-0254	Ninemile Point Electric Generating Plant	08/16/11	Emergency Generator	1,250 HP	CO_2 – 163 lb/MMBtu	Proper Operation and Good Combustion
T147-30464-00060	Indiana Gasification, LLC	06/27/12	Emergency Generator (5 Units)	2 @ 1,341 HP 3 @ 575 HP	Total CO_2 emissions limited to 84 tons CO_2 per year	Good Design to meet NSPS/MACT

RBLC Review

None of the RBLC entries for greenhouse gas control of large diesel-fired emergency generators requires the use of add-on control. The control methods listed are all based upon a properly designed engine that conforms to the requirements of 40 CFR 60, Subpart IIII. The NSPS ensures good design and proper combustion practices. OVR has an identical proposal.

Applicant Proposal

The applicant proposed the following as BACT:

(a) Compliance with 40 CFR 60, Subpart IIII; and
(b) Good combustion practices.

The control method proposed by the applicant represents top BACT.

Step 5: Select BACT

IDEM, OAQ has established GHG BACT for the diesel-fired emergency generator (EU-009) as:

(1) The hours of operation of the diesel-fired emergency generator (EU-009) shall not exceed 200 hours per twelve consecutive month period with compliance determined at the end of each month.

(2) GHG emissions shall be controlled by the use of good combustion practices.

(3) CO_2 emissions from the diesel-fired emergency generator (EU-009) shall not exceed 526.39 g/hp-hr, based on a three-hour average.

This analysis focuses on the emissions of CO_2 only. While other GHGs, such as methane and N_2O, are present in trace quantities, there are no known add on control technologies for these pollutants coming from combustion sources. To the extent measures are identified that reduce fuel use and thereby CO_2, the other GHGs will be reduced accordingly. Therefore, CO_2 serves as a useful surrogate for other GHGs in this regard.

(12) GHG BACT – Fugitive Emissions

Step 1: Identify Potential Control Technologies

The only potential control technology or operational practice to control fugitive greenhouse gas emissions is a leak detection and repair program.

Step 2: Eliminate Technically Infeasible Options

The source estimates fugitive greenhouse gas emissions of 1,215 tons as CO_2e will be emitted. The applicant estimates there will be small amounts of fugitive GHG emissions from equipment leaks, compressor leaks, valve and connector leaks, etc. These fugitive emissions are small in the overall operation of the facility but must be addressed. An LDAR program is technically feasible for the fugitive GHG emissions from this source.

Step 3: Rank the Remaining Control Technologies by Control Effectiveness

There is only one control option; therefore, a ranking or further analysis is not needed.

Step 4: Evaluate the Most Effective Controls and Document the Results

The following table lists the proposed GHG BACT determinations for similar emission units. All data in the table is based on the information obtained from the permit application submitted by Ohio Valley Resources, LLC, the U.S. EPA RACT/BACT/LAER Clearinghouse (RBLC), Indiana issued permits, and electronic versions of permits available at the websites of other permitting agencies.

RACT/BACT/LEAR CLEARINGHOUSE DATA
Fugitive Emissions – Greenhouse Gases

RBLC ID Permit #	Facility	Issued Date	Process Description	Capacity	Limitation	Control Method
T 147-32322-00062	**Ohio Valley Resources, LLC**	**Proposed**	**Fugitive GHG Emissions**	**NA**	**None**	**None**
FL-0330	Port Dolphin Energy, LLC	12/01/11	Fugitive GHG Emissions	NA	No Numerical Limits	Gas Leak Detection System
LA-0257	Sabine Pass LNG Terminal	12/06/11	Fugitive GHG Emissions	NA	89,629 TPY	LDAR Program
LA-0263	Phillips 66, Alliance Refinery	07/25/12	Fugitive GHG Emissions	NA	No Numerical Limits	LDAR, Monitor Total Hydrocarbon Instead of VOC
T147-30464-00060	Indiana Gasification, LLC	06/27/12	Fugitive GHG Emissions	NA	No Numerical Limits	LDAR, visual/audio inspection of compressors
T 147-32322-00062	**Ohio Valley Resources, LLC**	**Proposed**	**Fugitive GHG Emissions**	**NA**	**None**	**None**

RBLC Review
A review of the RBLC entries for the control of fugitive GHG emissions shows in all cases some sort of leak detection and control program is required. OVR is making an identical proposal.

Applicant Proposal
The applicant proposed an LDAR program. The applicant proposed top BACT. Only one entry contained a numerical limit on GHG emissions from fugitive sources. OVR estimates GHG emissions of 1,215 tons per year as CO_2e. This is approximately 0.05% of the total CO_2e PTE for the entire site. The Sabine Pass LNG Terminal permit has much higher emissions and a numerical limit for OVR is unnecessary. A numerical limit is not required because potential emissions are so small. It is not cost effective to implement an LDAR program for GHG emissions

Step 5: Select BACT
IDEM, OAQ has established GHG BACT for Fugitive Greenhouse Gas (GHG) Emissions from Equipment Leaks as the no control option. GHG emissions are insignificant from this emission unit.

(13) GHG BACT – Diesel-Fired Emergency Fire Water Pump (EU-016)

Step 1: Identify Potential Control Technologies
Today’s stationary diesel-fired emergency compression ignition internal combustion engines are sold as package units with an engineering design tailored to meet the emission limitations of 40 CFR 60, Subpart IIII and 40 CFR 63, Subpart ZZZZ. The manufacturer provides an engine that is in compliance with the applicable NSPS and NESHAP and the owner/operator is expected to maintain and operate the unit to guarantee compliance with applicable emission limitations. Based on the review of information for this BACT, IDEM has determined the only control method available for GHG for emergency stationary compression ignition internal combustion engines is good combustion practices.

Step 2: Eliminate Technically Infeasible Options

The only feasible control option for the diesel-fired emergency fire water pump (EU-016) is good combustion practices.

Step 3: Rank the Remaining Control Technologies by Control Effectiveness

There is only one control option; therefore, a ranking is not needed.

Step 4: Evaluate the Most Effective Controls and Document the Results

The following table lists the proposed GHG BACT determinations for similar emission units. All data in the table is based on the information obtained from the permit application submitted by Ohio Valley Resources, LLC, the U.S. EPA RACT/BACT/LAER Clearinghouse (RBLC), Indiana issued permits, and electronic versions of permits available at the websites of other permitting agencies.

RACT/BACT/LEAR CLEARINGHOUSE DATA
Diesel-Fired Fire Water Pump (EU-016) – Greenhouse Gases

RBLC ID	Facility	Issued Date	Process Description	Capacity	Limitation	Control Method
T147-32322-00062	**Ohio Valley Resources, LLC**	**Proposed**	**Fire Pump**	**481 HP**	**CO_2 – 527.40 g/hp-hr, 3 hr avg.**	**Combustion Practices, Use Limit**
IA-0105	Iowa Fertilizer Company	10/26/12	Fire Pump	235 KW	N_2O – None CO_2e – 91 TPY CO_2 – 1.55 g/KW-hr Methane – 0.0001 g/KW-hr	Good Combustion Practices
LA-0254	Ninemile Point Electric Generating Plant	08/16/11	Fire Pump	350 HP	CO_2 – 163 lb/MMBtu CH_4 – 0.0064 lb/MMBtu N_2O – 0.0014 lb/MMBtu	Proper Operation and Good Combustion
MD-0040	CPV St Charles	11/12/08	Fire Pump	300 HP	Methane - 3 g/Hp-hr	None

RBLC Review

None of the RBLC entries for greenhouse gas control of large diesel-fired emergency generators requires the use of add-on control. The control methods listed are all based upon a properly designed engine that conforms to the requirements of 40 CFR 60, Subpart IIII. The NSPS ensures good design and proper combustion practices. OVR has an identical proposal.

Applicant Proposal

The applicant proposed compliance with 40 CFR 60, Subpart IIII and Good combustion practices as BACT.

Step 5: Select BACT

IDEM, OAQ has established GHG BACT for the diesel-fired emergency fire water pump (EU-016) as:

(1) Operation of the Diesel-Fired Emergency Firewater Pump (EU-016) shall not exceed 200 hours per twelve consecutive month period with compliance determined at the end of each month.

(2) GHG emissions from the Diesel-Fired Emergency Firewater Pump (EU-016) shall be controlled by the use of good combustion practices.

(3) CO_2 emissions from the diesel-fired emergency firewater pump (EU-016) shall not exceed 527.40 g/hp-hr, based on a three-hour average.

This analysis focuses on the emissions of CO_2 only. While other GHGs, such as methane and N_2O, are present in trace quantities, there are no known add on control technologies for these pollutants coming from combustion sources. To the extent measures are identified that reduce fuel use and thereby CO_2, the other GHGs will be reduced accordingly. Therefore, CO_2 serves as a useful surrogate for other GHGs in this regard.

Indiana Department of Environmental Management
Office of Air Quality

Appendix C to the Technical Support Document (TSD)
Air Quality Impact Analysis

Source Background and Description

Source Name:	Ohio Valley Resources, LLC
Source Location:	300-400 East CR 350 North, Rockport, Indiana 47635
County:	Spencer
SIC Code:	2873
Permit No.:	T 147-32322-00062
Permit Reviewer:	David Matousek

Proposed Construction

Air Quality Analysis

Ohio Valley Resources, LLC

Rockport, Indiana (Spencer County)

Tracking and Plant ID: 147-32322-00062

Proposed Project

Ohio Valley Resources, (OVR) first submitted their Prevention of Significant Deterioration (PSD) modeling in October 2012. OVR proposes to construct and operate an anhydrous ammonia and urea ammonium nitrate (UAN) facility in Spencer County, in Rockport, Indiana.

Spirit Environmental (Spirit) was the consultant who prepared the modeling portion of the permit application for OVR. This technical support document provides the air quality analysis review of the submitted modeling by Spirit for OVR and by the Indiana Department of Environmental Management (IDEM).

Analysis Summary

Based on the potential emissions after controls, a PSD air quality analysis was triggered for PM_{10}, $PM_{2.5,}$ CO, NO_2, and Volatile Organic Compounds. (VOCs) The major source threshold was triggered for Hazardous Air Pollutants. (HAPs) The significant impact analysis for annual PM_{10}, CO, and annual $PM_{2.5}$ determined that modeling concentrations did not exceed the significant impact levels. A refined analysis was required for both NO_2 standards as well as the short-term PM_{10} and $PM_{2.5}$ standards. In this refined analysis, no NAAQS violations were modeled for the annual standard for NO_2, but there were exceedences for short-term NO_2 and $PM_{2.5}$. A cause and contribute analysis was performed for the short-term standards of NO_2 and $PM_{2.5}$ which showed OVR did not significantly contribute to those violations. HAP impacts were below the Hazard Quotient and Individual Cancer Risk thresholds. An additional impact analysis was conducted and showed no significant impact.

Air Quality Impact Objectives

The purpose of the air quality impact analysis in the permit application is to accomplish the following objectives. Each objective is individually addressed in this document in each section outlined below.

A. Establish which pollutants require an air quality analysis based on PSD significant emission rates.

B. Provide analyses of actual stack heights with respect to Good Engineering Practice (GEP), the meteorological data used, a description of the model used in the analysis, and the receptor grid utilized for the analyses.

C. Determine the significant impact level, the area impacted by the source's emissions, and background air quality levels.

D. Demonstrate that the source will not cause or contribute to a violation of the National Ambient Air Quality Standard (NAAQS) or PSD increment if the applicant exceeds significant impact levels.

E. Perform a qualitative analysis of the source's impact on general growth, soils, vegetation, and visibility in the impact area with emphasis on any Class I areas. The nearest Class I area is Kentucky's Mammoth Cave National Park.

F. Analysis of Secondary Ozone formation

G. Analysis of Secondary $PM_{2.5}$ formation

H. HAP's Analysis

I. Summarize the Air Quality Analysis

Section A - Pollutants Analyzed for Air Quality Impact

Applicability

The PSD requirements, 326 IAC 2-2, apply in attainment and unclassifiable areas and require an air quality impact analysis of each regulated pollutant emitted in significant amounts by a major stationary source or modification. Significant emission levels for each pollutant are defined in 326 IAC 2-2-1 and in the Code of Federal Regulations (CFR) 52.21(b) (23) (i).

Proposed Project Emissions

PM_{10}, $PM_{2.5,}$ NO_x, SO_2, CO, VOCs and HAPs are the pollutants that will be emitted from OVR and are summarized below in Table 1. PM_{10}, $PM_{2.5,}$ NO_2, and CO potential emissions after controls exceed the PSD significant emission rates and therefore require an air quality analysis. Emissions for HAPs exceed the threshold that triggers an air quality analysis for IDEM.

TABLE 1
Facility Emission Rates

POLLUTANT	**SOURCE EMISSION RATE** (Facility totals in tons/year)	**EMISSION RATE THRESHOLD** (tons/year)	**PRELIMINARY AQ ANALYSIS REQUIRED**
PM_{10}	57.5	15	Yes
$PM_{2.5}$	55.0	10	Yes
NO_x	512.4	40	Yes
SO_2	6.37	40	No
CO	1047.9	100	Yes
VOC	93.8	40	Yes[2]
HAPs	26.69	25[1]	Yes[3]

[1] Total HAP emissions of 25 tons per year (TPY) or 10 TPY per pollutant trigger HAP analysis, but are not a PSD Significant Emission Rate (SER)
[2] VOC emissions are only included in a secondary pollutant analysis.
[3] HAP's analysis is not a federal requirement, but IDEM policy.

Section B – Good Engineering Practice (GEP), Met Data, Model Used, Receptor Grid and Terrain

Stack Height Compliance with Good Engineering Practice (GEP)

Stacks should comply with GEP requirements established in 326 IAC 1-7-4. If stacks are lower than GEP, excessive ambient concentrations due to aerodynamic downwash may occur. Dispersion modeling credit for stacks taller than 65 meters (213 feet) is limited to GEP for the purpose of establishing emission limitations. The GEP stack height takes into account the distance and dimensions of nearby structures, which affects the downwind wake of the stack. The downwind wake is considered to extend five times the lesser of the structure's height or width. A GEP stack height is determined for each nearby structure by the following formula:

$$Hg = H + 1.5L$$

Where:
Hg is the GEP stack height
H is the structure height
L is the structure's lesser dimension (height or width)

Meteorological Data

The National Weather Service (NWS) 1-minute Automated Surface Observation Station (ASOS) meteorological data used in the air quality analysis consisted of 2006 through 2010 surface data from Evansville, Indiana and upper air measurements taken at Lincoln, Illinois. The meteorological data was preprocessed using the latest versions of AERMINUTE, AERSURFACE, and AERMET.

Model Description

The Office of Air Quality (OAQ) used AERMOD version 12060 in their air quality analysis review to determine maximum off-property concentrations or impacts for each pollutant. All regulatory default options were utilized in the U.S. EPA approved model, as listed in the 40 Code of Federal Register Part 51, Appendix W "Guideline on Air Quality Models".

Receptor Grid

OAQ modeling used the same receptor grids generated by Spirit. The receptor grid is outlined below:

- 100 meter spacing from the property boundary to 2000 meters,
- 500 meters spacing from 2000 meters to 5000 meters,
- 1000 meters spacing from 5000 meters to 25 kilometers,
- 3000 meters spacing beyond 25 kilometers.

Treatment of Terrain

Receptor terrain elevation inputs were interpolated from NED (National Elevation Dataset) data obtained from the USGS. NED terrain data was preprocessed using AERMAP.

Section C - Significant Impact Level/Area (SIA) and Background Air Quality Levels

A significant impact analysis was conducted to determine if the source would exceed the PSD significant impact levels (concentrations). If the source's concentrations exceed these Significant Impact Levels, (SILs) further air quality analysis is required. Refined modeling for CO, $PM_{2.5}$, PM_{10}, and annual NO_2 was not required because the results did not exceed significant impact levels. The $PM_{2.5}$ and 1-hour NO_2 exceeded their significant impact levels and required refined modeling. Significant impact levels are defined by the following time periods in Table 2 below, with all maximum-modeled concentrations from the worst case operating scenarios. A Tier II 80% conversion of NO to NO_2 was assumed based on the March 01, 2011, Tyler Fox memorandum.

TABLE 2
Significant Impact Analysis[3]

POLLUTANT	TIME AVERAGING PERIOD	MAXIMUM MODELED IMPACTS ($\mu g/m^3$)	SIGNIFICANT IMPACT LEVEL ($\mu g/m^3$)	REFINED AQ ANALYSIS REQUIRED
NO_2	Annual[1]	0.97	1	No
NO_2	1-hour[2]	105.9	7.55	Yes
PM_{10}	Annual[1]	0.61	1	No
PM_{10}	24-hour[1]	3.91	5	No
$PM_{2.5}$	Annual[2]	0.26	0.3	No
$PM_{2.5}$	24-hour[2]	2.10	1.2	Yes
CO	1-hour[1]	1,521	2000	No
CO	8-hour[1]	247	500	No

[1] First highest values per EPA NSR manual October 1990.
[2] In accordance with recent U.S. EPA guidance, the highest modeled concentration may be averaged over the five years modeled for comparison with the 1-hour NO_2, 1-hour SO_2, 24-hour $PM_{2.5}$, and the annual $PM_{2.5}$ SIL. See the March 01, 2011 and the March 23, 2010 memorandums. [3] Impacts are from OVR only.

Pre-construction Monitoring Analysis

Applicability

The PSD rule, 326 IAC 2-2-4, requires an air quality analysis of the new source or the major modification to determine if the pre-construction monitoring threshold is triggered. In most cases, monitoring data taken from a similar geographic location can satisfy this requirement if the pre-construction monitoring threshold has been exceeded. Also, post construction monitoring could be required if the air quality in that area could be adversely impacted by applicant's emissions.

Modeling Results

The modeling results were compared to the PSD preconstruction monitoring thresholds. The results are shown in the table below.

TABLE 3
Preconstruction Monitoring Analysis

POLLUTANT	TIME AVERAGING PERIOD	MAXIMUM MODELED IMPACTS (µg/m^3)	DEMINIMIS LEVEL (µg/m^3)	ABOVE DE MINIMIS LEVEL
NO_2	Annual[1]	1.76	14	No
PM_{10}	24-hour[1]	3.91	10	No
$PM_{2.5}$	24-hour[2]	2.10	4	No
CO	8-hour	247	575	No

[1] First highest values per EPA NSR manual October 1990. Maximum modeled impacts are from OVR only.
[2] In accordance with recent U.S. EPA guidance, the highest modeled concentration may be averaged over the five years. See the March 01, 2011 and the March 23, 2010 memorandums from EPA.

For $NO_{2,}$ CO, $PM_{2.5}$ and PM_{10}, OVR did not trigger the preconstruction monitoring threshold level.

Background Concentrations

Applicability

EPA's "Ambient Monitoring Guidelines for Prevention of Significant Deterioration" (EPA-450/4-87-007) Section 2.4.1 is cited for approval of the monitoring sites chosen for this area.

Background Monitors

Background data was taken from representative monitoring stations for OVR. The background design value was used for $PM_{2.5}$. It was agreed between OVR and OAQ that this approach be used in place of the preconstruction monitoring requirement.

TABLE 4
Existing Monitoring Data Used For Background Concentrations *

Pollutant	Location	Monitoring Site	Averaging Period	Concentration (ug/m^3)
$PM_{2.5}$	Dale, IN	21-059-0005	24-hour	27.0
NO_2	Owensboro, KY	18-163-0021	Annual	27.8
NO_2	Owensboro, KY	21-059-0005	1-hour	66.5

* $PM_{2.5}$ and NO_2 used the design value.

Section D - NAAQS and PSD Increment

NAAQS Compliance Analysis and Results

OAQ supplied emission inventories of all point sources in Indiana within a 50-kilometer radius of OVR. The NAAQS inventories are generated from EMITS (Emission Inventory Tracking System) in accordance with 326 IAC 2-6. That inventory is in actual emissions while largest of nearby sources were modeled at actual. The $PM_{2.5}$ PSD increment inventories include sources that affect the increment and are compiled from permits issued by OAQ, while NAAQS inventories were used as a conservative measure for all other increment pollutants.

OAQ modeling results are shown in Table 5. All maximum-modeled concentrations were compared to the respective NAAQS limit. All receptors were below the NAAQS when OVR had an impact above the SIL. Every receptor over the standard was evaluated below the maximum modeled concentration for each scenario until there was no longer a NAAQS violation and showed OVR was below significance and did not cause or contribute to a violation of the NAAQS. Results were based on the worst operating scenario determined in Significant Impact Area (SIA) modeling.

TABLE 5[1]
NAAQS Analysis

Pollutant	Year	Time-Averaging Period	Maximum Concentration (µg/m^3)	Background Concentration (µg/m^3)	Total (µg/m^3)	NAAQS Limit (µg/m^3)	NAAQS Violation
NO_2	2006-2010	1-hour	531.3[2]	66.5	**597.8**	188.6	Yes
$PM_{2.5}$	2006-2010	24-hour	26.2[2,3]	27.0	**49.2**	35	Yes
NO_2	2006-2010	Annual	7.58	27.8	**35.4**	100	No

[1] Any differences between the maximum concentration numbers in Tables 5 and 6 are due to different sources used for the NAAQS and the increment inventories.
[2] In accordance with recent U.S. EPA guidance, the highest modeled concentration may be averaged over the five years. See the March 23, 2010, memorandum from EPA.
[3] Listed in this table is the highest 1-hour period for any receptor at which the project was above the SIL. This did not include impacts from sources onto their own property.

Further modeling was conducted to determine if OVR was culpable during a NAAQS violation. The results are shown in Table 5a and 5b. OVR's highest impact at a receptor modeled above the 1-hour NO_2 NAAQS was 4.46 ug/m^3. The highest concentration where OVR had a significant impact was 119 ug/m^3.

Table 5a[1]
1-Hour Culpability Analysis For NO_2

Highest Predicted 1-hour NO_2 Concentration from Cumulative Analysis (μg/m^3)							
Concentration (modeled + background)	Contribution from Modeled OVR to Total	Is the Total Concentration ≥ NAAQS of 188.6 μg/m3?	Is the OVR contribution ≥ SIL of 7.55 μg/m3?	Greatest OVR contribution to any violation of NAAQS	Highest Concentration with OVR > SIL	Highest concentration with background	Any Concentration > NAAQS with OVR > SIL?
597.8	0.0006	Yes	No	4.46	119.4	185.9	No

[1]This follows the recent U.S. EPA guidance in the March 23, 2010, memorandum on page 8 which explains how to determine significant contributions to modeled violations.

Table 5b[1]
24-Hour Culpability Analysis For $PM_{2.5}$

Highest Predicted 24-hour $PM_{2.5}$ Concentration from Cumulative Analysis (μg/m^3)							
Concentration (modeled + background)	Contribution from Modeled OVR to Total	Is the Total Concentration ≥ NAAQS of 35.0 μg/m3?	Is the OVR contribution ≥ SIL of 1.2 μg/m3?	Greatest OVR contribution to any violation of NAAQS	Highest Concentration with OVR > SIL	Highest concentration with background	Any Concentration > NAAQS with OVR > SIL?
49.2	0.055	Yes	No	0.99	5.20	32.2	No

[1]This follows the recent U.S. EPA guidance in the March 23, 2010, memorandum on page 8 which explains how to determine significant contributions to modeled violations.

Even though the model predicts a NAAQS violation, OVR was not significant at the same receptor and time period. For $PM_{2.5}$ there was only one receptor at which OVR's impact averaged above the SIL. Therefore, OVR does not cause or contribute to a violation of the $PM_{2.5}$ NAAQS.

Analysis and Results of Source Impact on the PSD Increment

Applicability

Maximum allowable increases (PSD increments) are established by 326 IAC 2-2 for $PM_{2.5}$. This rule also limits a source to no more than 80 percent of available PSD increment to allow for future growth.

Source Impact

Since the impacts for 24-hour $PM_{2.5}$ and annual NO_2 modeled above SILs, a PSD increment analysis for OVR and surrounding sources was required. For NO_2, the NAAQS inventory was used as a conservative assumption. For $PM_{2.5}$, the only other increment consuming source was adjacent to the project. Results of the increment modeling are summarized in Table 6 below.

TABLE 6[1]
Increment Analysis

Pollutant	Year	Time-Averaging Period	Maximum Concentration (μg/m^3)	PSD Increment (μg/m^3)	Percent Impact on the PSD Increment	Increment Violation
$PM_{2.5}$	2006-2010	24-hour[2,3]	6.31	9	70.1 %	No
NO_2	2006-2010	Annual	2.04	25	8.0%	No

[1] Any differences between the maximum concentration numbers in Tables 5 and 6 are due to different sources used for the NAAQS and the increment inventories.
[2]In accordance with the Federal Register dated October 20, 2010; the high 2nd high is used.
[3]Listed in this table is the highest 1-hour period for any receptor at which the project was above the SIL. This did not include impacts from sources onto their own property.

The results of the increment analysis show all pollutants for all averaging periods were below 80% of the available increment. No further analysis is required.

Part E – Qualitative Analysis

Additional Impact Analysis

All PSD permit applicants must prepare an additional impact analysis for each pollutant subject to regulation under the Act. This analysis assesses the impacts on growth, soils and vegetation, endangered species, and visibility caused by any increase in emissions of any regulated pollutant from the source. The OVR modeling submittal provided an additional impact analysis performed by Spirit.

Economic Growth

The purpose of the growth analysis is to quantify project associated growth and estimate the air quality impacts from this growth either quantitatively or qualitatively.

Many of the permanent OVR employees will be drawn from the local area. Since the area is predominately rural, it is not expected the growth impacts will cause a violation of the NAAQS or the PSD increment.

Soils and Vegetation Analysis

Soil types included a variety of loamy soils. Due to the agricultural nature of the land, crops in the Spencer County area consist mainly of corn and soybeans. (2007 Agricultural Census for Spencer County). The maximum modeled concentrations for OVR are well below the threshold limits necessary to have adverse impacts on the surrounding vegetation. Livestock in Spencer County consist mainly of hogs, cattle and dairy (2007 Agricultural Census for Spencer County) and will not be adversely impacted from the facility. Trees in the area are mainly hardwoods. These are hardy trees and no significant adverse impacts are expected due to modeled concentrations.

Federal and State Endangered Species Analysis

Federal and state endangered species are listed by the U.S. Fish and Wildlife Service; Division of Endangered Species for Indiana, and includes 6 mammals, 27 birds, 10 fishes, 16 mollusks, 6 amphibians and 15 reptiles. Of the federal and state endangered species on the list, 2 mollusks, 1 bird, and 2 bats have an endangered habitat within Spencer County. The facility is not expected to have any additional adverse effects on the habitats of the species than what has already occurred from the industrial, farming, and residential activities in the area.

Visibility Analysis

Visibility analysis was performed for impacts on local visibility. The VISCREEN model is designed as a screening model to determine the visual impact using parameters from a single source's plume. It is used basically to determine whether or not a plume is visible as an object itself. The visibility impairment analysis considers the impacts that occur within the impact area of the source as defined by the user distances. The user distances are determined by the nearest interstate or airport. EPA has defined these locations in guidance to the state.

The PM_{10}, SO_2 and NO_x emissions limits were used to run a local visibility Level 1 analysis. VISCREEN Version 1.01 was used to determine if the color difference parameter (Delta-E) or the plume (green) contrast limits were exceeded. The Delta-E was developed to specify the perceived magnitude of color and brightness changes and is used as the primary basis for determining the perceptibility of plume visual impacts. The plume constant can be defined at any wavelength as the relative difference in the intensity (called spectral radiance) between the viewed object and its background. This is used to

determine how the human eye responds differently to different wavelengths of light. The Delta-E of 2.0 and the plume contrast of 0.05 were not exceeded at the Owensboro Airport.

TABLE 7
Level 1 Local Visibility Analysis

Background	Theta (degrees)	Azimuth (degrees)	Distance (km)	Alpha (degrees)	Delta E Critical	Delta E Plume	Contrast Critical	Contrast Plume
Sky	10	60	20.1	109	2.00	1.625	0.05	-0.002
Sky	140	60	20.1	109	2.00	0.512	0.05	-0.008
Terrain	10	60	19.2	109	2.00	0.427	0.05	0.005
Terrain	140	60	19.2	109	2.00	0.129	0.05	0.004

* This Class II location is above suggested critical value for Class I areas

Thus, it is concluded that there will be no visibility impacts at the closest location from the facility.

The Federal Class I areas include national parks and national wilderness areas and are considered environments for which minimal air quality degradation is allowed. The nearest Class 1 area to OVR is Mammoth Cave National Park which is 102 km from the plant. Pursuant to a new federal guidance document (Federal Land Managers' Air Quality Related Values Work Group (FLAG) Phase 1 Report – Revised November 2010), the OVR facility would not be required to conduct a Class 1 area analysis since the combined emissions of visibility impairing pollutants are less the screening threshold. The visual impact is equal to Q / D, the total emissions divided by distance for sources more than 50 km from a Class 1 area. If the number is less than 10, then a visibility analysis is not required.

The primary visibility impairment pollutants are PM_{10}, SO_2, H_2SO_4, and NO_x. The proposed potential emissions of these pollutants from OVR are Q = 57.5 + 6.3 + 0 + 512.4 TPY = 576.2 TPY. The distance to the nearest Class 1 area is D = 102 km. The source impact is Q / D = 576.2 / 102 = 5.6. 5.6 is less than 10, so this project will not affect visibility in the nearest Class 1 area.

Additional Analysis Conclusions

Finally, the results of the additional impact analysis conclude the operation of the facility will have no significant impact on economic growth, soils, vegetation, or visibility in the immediate vicinity or on any Class I area.

Part F - Secondary Ozone Formation Analysis

Because of the well established relationship between nitrogen oxides (NO_x), volatile organic compounds (VOCs), and the regional transport formation of ozone, U.S. EPA recently finalized the Cross State Air Pollution Rule (CSAPR) to assist states to meet the ozone NAAQS. This rule included extensive modeling to support the emissions reductions necessary in each state to achieve the ozone NAAQS in the eastern U.S. The source category responsible for these reductions is Electric Generating Units (EGUs). While the U.S. Court of Appeals for the D.C. Circuit issued a decision vacating CSAPR on August 21, 2012, the modeling analysis conducted by U.S. EPA is considered valid and will be used for the ozone analysis.

U.S. EPA used a regional model, Comprehensive Air Quality Model with extensions (CAMx), and the Air Quality Assessment Tool (AQAT) to determine levels of emissions reduction from EGUs necessary to achieve the NAAQS at every site. The documentation includes extensive tables showing impacts at all ozone monitors in the eastern U.S. and emission reduction levels necessary to achieve those results. To examine the possible impact of Ohio Valley Resources (OVR), results from the modeling U.S. EPA conducted to establish the 2012 and 2014 base case emissions in CSAPR were used for this analysis. The CSAPR website is located at http://www.epa.gov/crossstaterule/techinfo.html.

Information regarding the NO_x emissions modeled for CSAPR can be found in the "EmissionsSummaries.xlsx" spreadsheet under the Emissions Inventory Final Rule TSD section at EPA's CSAPR website for technical information http://www.epa.gov/crossstaterule/techinfo.html. The spreadsheet shows the base case annual NO_x emissions for Indiana in 2012 at 455,325 tons and base case annual NO_x emissions by 2014 at 431,342 tons. Indiana's total NO_x emission reduction between these scenarios totals 23,983 tons. All surrounding states make similar significant reductions. OVR's proposed emissions would be 512.43 tons per year of NO_x and 93.81 tons per year of VOCs for a total of 606.24 tons per year of NO_x and VOCs from OVR.

8-Hour Ozone Modeling Results

The nearest ozone monitor to OVR, located in Spencer County, is the Leopold ozone monitor in Perry County, considered downwind of OVR. The current design value for 2010-2012 at the Leopold ozone monitor is 75 parts per billion (ppb), at the 8-hour NAAQS of 75 ppb. The U.S. EPA CSAPR results show the maximum modeled 8-hour ozone concentration for Perry County is 75.1 ppb for the 2012 base case and 73.1 ppb for the 2014 base case. This is a decrease of 2.0 ppb as a result of NO_x emission adjustments between 2012 and 2014 base case emission calculations, based on emission growth factors. In order for this modeled 8-hour ozone concentration reduction to occur, Indiana's 2014 NO_x emissions were reduced from the 2012 base case emissions by 23,983 tons. The Perry County monitoring site is not necessarily impacted by every EGU in Indiana, but in the surrounding states, thousands of tons of annual NO_x emission reductions are projected to occur by 2014, many of which would impact this site. Therefore, to estimate the impact of OVR on modeled concentrations, the ratio of OVR's NO_x and VOC emissions to Indiana's 2012 to 2014 base case NO_x emission reduction was calculated. This ratio was then compared to the modeled ozone impact from the difference between the CSAPR 2012 and 2014 base case modeling results.

1) **606.24 tons** OVR NO_x and VOC emissions / **23,983 tons** of Indiana's NO_x base case emissions reduced from 2012 to 2014 = **2.53%** ratio of OVR's NO_x and VOC emissions compared to Indiana's NO_x emissions

2) **2.53%** OVR emission ratio * **2.0 ppb** maximum 8-hour 2012 to 2014 Base Case modeled results on Perry County monitor = **0.051 ppb** of OVR 8-hour ozone impact

3) **0.051 ppb** of OVR 8-hour ozone impact / **73.1 ppb** at Perry County ozone monitor from 2014 base case maximum modeled results = **0.0692%** OVR's impact on the 2014 base case modeled concentration.

Tables are located in CSAPR_AQModeling.pdf, Appendix B, pages B-10 and B-12, for 8-hour ozone design values that show the base case 2012 ozone concentrations at surrounding monitoring sites versus projected base case 2014 ozone concentrations. 2012 Base Case represents modeled results taken from the 2012 and 2014 Base Case emissions, represents the 2014 Base emissions with emission adjustments from growth factors factored into the modeling. Table 8 below shows the CSAPR modeling results for the Perry County monitor and the potential impact from OVR.

Table 8
EPA's Cross-State Air Pollution Rule - 8-Hour Ozone Modeling Results

Monitor ID	County	2012 Base (ppb)	2014 Base (ppb)	2012-2014 Base (ppb)	Anticipated Source Impact (ppb)	Source Impact on 2014 Base Results (%)
181230009	Perry - Leopold	75.1	73.1	2.0	0.051	0.069%
181730008	Warrick - Boonville	73.4	71.6	1.8	0.046	0.064%
181730009	Warrick - Lynnville	67.4	65.7	1.7	0.043	0.065%
181730011	Warrick - Dayville	70.8	69.0	1.8	0.046	0.066%

Summary of Ozone Results

Ohio Valley Resources' NO_x and VOC emissions were compared with the U.S. EPA CSAPR modeling for 8-hour ozone to determine what impacts may occur as a result of ozone formation. When OVR emissions were compared with the amount of NO_x emission reductions realized from emission estimates associated with base case emissions for CSAPR and compared with CSAPR modeling results for 8-hour ozone, the impacts from OVR on the Leopold ozone monitor in Perry County are anticipated to be minimal and not have a significant impact on the attainment status of Perry County and any surrounding counties, including Spencer County.

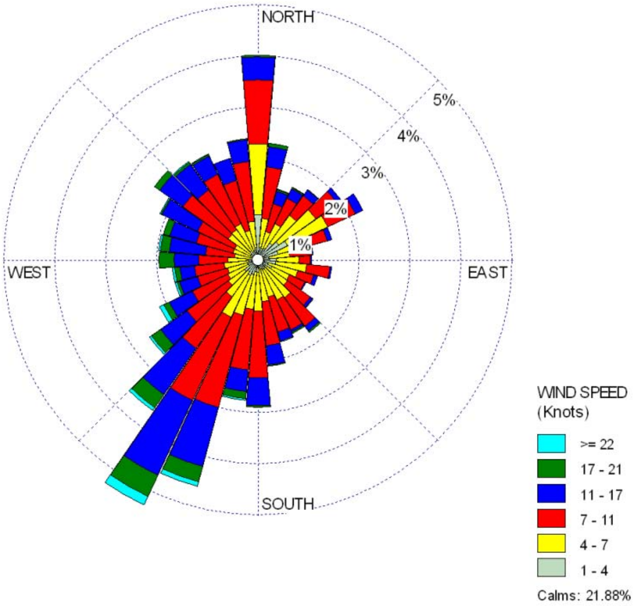
Part G - Secondary $PM_{2.5}$ formation Analysis

In addition to direct emissions of $PM_{2.5}$; other pollutants, chiefly NO_x and SO_2, can lead to formation of $PM_{2.5}$ further downwind. The photochemical reactions that transform these pollutants into particulate nitrates and sulfates, which become the major species of $PM_{2.5}$, take place over hours or days. Dispersion modeling for these two primary pollutants shows that concentrations are below Significant Impact Levels (SIL) for their respective NAAQS and further diminish within the modeling domain of 50 km. Since the NO_x and SO_2 standards are extremely restrictive, a typical source being below the SILs would likely prevent the pollutants from impacting secondary formation significantly enough to result in a violation of the $PM_{2.5}$ standards.

However, it is possible that some transformation into nitrates and sulfates from this source may occur and be transported downwind. No peer-reviewed regulatory model presently exists to examine the photochemical impacts of an individual source of SO_2 and NO_x. All photochemical models are regional scale and a source of this size would not show any measurable impact. Therefore, other available information from emissions inventories, meteorological analyses, and other modeling projects can be used to estimate the impact from this source.

The nearest active $PM_{2.5}$ monitor to OVR is the Dale monitor in Spencer County. The 2011 wind rose taken from the Evansville Airport in Evansville, Vanderburgh County shows the winds typically blow from the southwest. OVR would be considered upwind of the Dale monitor.

Evansville 2011



The 2009 – 2011 annual $PM_{2.5}$ design value at the Dale monitor in Spencer County is 12.4 µg/m^3, well below the annual $PM_{2.5}$ NAAQS of 15.0 µg/m^3. The 2009 – 2011 24-hour $PM_{2.5}$ design value at the Dale monitor is 27.0 µg/m^3, below the 24-hour $PM_{2.5}$ NAAQS of 35.0 µg/$m^{3.}$

Secondary $PM_{2.5}$ Weight of Evidence Analysis based on EPA's CSAPR Modeling

Because of the established relationship between NO_x and SO_2, and the regional transport and formation of $PM_{2.5}$, the U.S. EPA recently finalized the Cross State Air Pollution Rule (CSAPR) to assist states to meet the $PM_{2.5}$ NAAQS. This rule included extensive modeling to support the emissions reductions necessary in each state to achieve the $PM_{2.5}$ NAAQS in the eastern U.S. The source category responsible for these reductions is Electric Generating Units (EGUs). While the U.S. Court of Appeals for the D.C. Circuit issued a decision vacating CSAPR on August 21, 2012, the modeling analysis conducted by U.S. EPA is considered valid and will be used for the secondary $PM_{2.5}$ analysis.

U.S. EPA used a regional model, Comprehensive Air Quality Model with extensions (CAMx), and the Air Quality Assessment Tool (AQAT) to determine levels of reduction from EGUs necessary to achieve the NAAQS at every site. The documentation includes extensive tables showing impacts at all $PM_{2.5}$ monitoring sites in the eastern U.S. and emission reduction levels necessary to achieve those results. To examine the possible impact of OVR, results from the modeling U.S. EPA conducted to establish the final 2014 budgets in CSAPR and were used for this analysis. The CSAPR website is located at http://www.epa.gov/crossstaterule/techinfo.html.

Information regarding SO_2 and NO_x emission reductions necessary to achieve the future year modeled design values can be found in the "EmissionsSummaries.xlsx" spreadsheet under the Emissions Inventory Final Rule TSD section at U.S. EPA's CSAPR website for technical information: http://www.epa.gov/crossstaterule/techinfo.html. The spreadsheet shows the base case annual SO_2 and NO_x emissions for Indiana in 2012 and 2014. Indiana's total SO_2 and NO_x emission reductions between these two base-case scenarios are 89,222 tons, summarized in Table 9 below. All surrounding states make similar significant reductions. Potentials-to-emit after controls for OVR are 512.43 tons per year of NO_x and 6.37 tons per year of SO_2 for a total of 518.8 tons per year of NO_x and SO_2 emissions.

Table 9
EPA's Cross-State Air Pollution Rule Emission Summary for Indiana

	Pollutant	**2012 Base Case Emissions (tons/year)**	**2014 Base Case Emissions (tons/year)**	**2012-2014 Difference (tons/year)**
Indiana	SO_2	929,162	863,923	65,239
Indiana	NO_x	455,325	431,342	23,983
TOTAL				**89,222**

Annual $PM_{2.5}$ Modeling Results

The latest annual $PM_{2.5}$ design value (2009-2011) for the nearest $PM_{2.5}$ monitor to OVR is the Dale monitor in Spencer County is 12.4 μg/m^3. The maximum annual $PM_{2.5}$ modeled concentration for the Dale $PM_{2.5}$ monitor is 13.27 μg/m^3 for the 2012 base case and 12.66 μg/m^3 for the 2014 base case results. This is a decrease of 0.61 μg/m^3. Indiana's 2014 SO_2 emissions from EGUs were adjusted by 65,239 tons from the 2012 base case emissions and 2014 NO_x emissions were reduced by 23,983 for a total of 89,222 tons of SO_2 and NO_x. This particular monitoring site is not necessarily impacted by every EGU in Indiana, but in the surrounding states, hundreds of thousands of tons of annual SO_2 and NO_x emission reductions would occur by 2014, many of which would impact the Spencer County monitor. Therefore, to estimate the impact of OVR on modeled concentrations, the ratio of OVR's SO_2 and NO_x emissions to Indiana's SO_2 and NO_x decreases from 2012 and 2014 base case CSAPR emissions was calculated. This ratio was then compared to the modeled annual $PM_{2.5}$ impact from the difference between the CSAPR 2012 and 2014 base case annual $PM_{2.5}$ modeling results.

1) **518.8 tons** OVR's SO_2 and NO_x emissions / **89,222** tons of SO_2 and NO_x emissions reduced through CSAPR modeling = **0.581%**

2) **0.581%** OVR SO_2/NO_x emission ratio * **0.61 μg/m^3** modeled annual $PM_{2.5}$ CSAPR results on Spencer County monitor = **0.0036 μg/m^3** of OVR annual $PM_{2.5}$ impact

3) **0.0035 μg/m^3** OVR's annual $PM_{2.5}$ impact /**12.66 μg/m^3** of 2014 Base Case annual $PM_{2.5}$ modeled results = **0.028%** OVR's impact on the 2014 modeled Base Case annual $PM_{2.5}$ results.

Tables showing projected base case 2014 $PM_{2.5}$ concentrations at existing monitoring sites versus control strategy $PM_{2.5}$ concentrations are located in CSAPR_AQModeling.pdf, Appendix B, pages B-41 and B-42 for annual design values and pages B-70 to B-72 for 24-hour design values. 2014 Base represents anticipated 2014 emissions. 2014 Remedy represents the 2014 Base emissions with emission reductions from CSAPR factored into the modeling. Table 10 below shows the CSAPR annual $PM_{2.5}$ modeled concentrations at the Spencer County $PM_{2.5}$ monitor and surrounding monitors and OVR's anticipated impacts on those monitors.

Table 10
EPA's Cross-State Air Pollution Rule - Annual $PM_{2.5}$ Modeling Results

Monitor ID	County	2012 Base ($\mu g/m^3$)	2014 Base ($\mu g/m^3$)	2012 - 2014 Base ($\mu g/m^3$)	Anticipated Source Impact ($\mu g/m^3$)	Source Impact on 2014 Base Case Results (%)
181470009	Spencer	13.27	12.66	0.61	0.0035	0.028%
180372001	Dubois	14.35	13.72	0.63	0.0037	0.025%

24-Hour $PM_{2.5}$ Modeling Results

The same emissions and impact analysis methodology used for the annual $PM_{2.5}$ impacts were used to determine the 24-hour $PM_{2.5}$ impacts from OVR. The latest 24-hour $PM_{2.5}$ design value (2009-2011) for the nearest $PM_{2.5}$ monitor to OVR is Dale monitor in Spencer County is 27.0 $\mu g/m^3$. The maximum 24-hour $PM_{2.5}$ modeled concentration for the Dale $PM_{2.5}$ monitor is 31.3 $\mu g/m^3$ for the 2012 base case and 29.5 $\mu g/m^3$ for the 2014 base case. This is a reduction of modeled concentration of 1.8 $\mu g/m^3$. To estimate the 24-hour impact of OVR on modeled concentrations, the ratio of OVR SO_2 and NO_x emissions and the CSAPR SO_2 and NO_x emission reductions was calculated. This ratio was then compared to the modeled 24-hour $PM_{2.5}$ impact from the difference between the CSAPR 2012 and 2014 base case 24-hour $PM_{2.5}$ modeling results.

1) **518.8 tons** OVR SO_2 and NO_x emissions / **89,222 tons** of SO_2 and NO_x emissions reduced through CSAPR modeling = **0.581%**

2) **0.581%** OVR SO_2/NO_x emission ratio *** 1.8 $\mu g/m^3$** modeled 24-hour $PM_{2.5}$ CSAPR results on Spencer County monitor = **0.0105 $\mu g/m^3$** of OVR 24-hour $PM_{2.5}$ impact

3) **0.0105 $\mu g/m^3$** OVR 24-hour $PM_{2.5}$ impact /**29.5 $\mu g/m^3$** of 2014 Base Case 24-hour $PM_{2.5}$ modeled results = **0.036%** OVR's impact on the 2014 modeled Base Case 24-hour $PM_{2.5}$ concentration.

Modeling results below in Table 11 show 2012 and 2014 Base Case modeled 24-hour concentrations and the anticipated OVR impacts, based on the emissions comparison and estimated impacts.

Table 11
EPA's Cross-State Air Pollution Rule - 24-Hour $PM_{2.5}$ Modeling Results

Monitor ID	County	2012 Base ($\mu g/m^3$)	2014 Base ($\mu g/m^3$)	2012 - 2014 Base ($\mu g/m^3$)	Anticipated Source Impact ($\mu g/m^3$)	Source Impact on 2014 Base Case Results (%)
181470009	Spencer	31.3	29.5	1.8	0.0105	0.036%
180372001	Dubois	34.8	33.4	1.4	0.0081	0.025%

Summary Annual and 24-Hour $PM_{2.5}$

Ohio Valley Resources' SO_2 and NO_x emissions were compared with U.S. EPA CSAPR modeling for annual and 24-hour $PM_{2.5}$ to determine what impacts on $PM_{2.5}$ may occur as a result of secondary $PM_{2.5}$ formation. When the OVR emissions were compared with the amount of SO_2 and NO_x emission reductions realized from the CSAPR modeling analysis and compared with CSAPR modeling results for annual and 24-hour, the impacts from OVR on the nearest $PM_{2.5}$ monitor is anticipated to be minimal and will not have an effect on the attainment status of any $PM_{2.5}$ monitors in the area.

Part H – HAPs Analysis

OAQ currently requests data concerning the emission of 189 HAPs listed in the 1990 Clean Air Act Amendments (CAAA) that are either carcinogenic or otherwise considered toxic and may be used by industries in the State of Indiana. These substances are listed as air toxic compounds on the State of Indiana, Department of Environmental Management, Office of Air Quality's construction permit application Form GSD-08.

The single HAP with the highest emissions is methanol, with estimated annual emissions of 18 tons per year. Potential emissions of aggregate HAPs are estimated to be 29.7 tons per year.

For OVR, a full HAP analysis was completed comparing the maximum estimated concentrations of each pollutant with the Unit Risk Factor (URF) or Inhalation Unit Risk and the Reference Concentration (RfC). This analysis offers a refined, up to date site specific analysis that takes into account the different potencies and health effects that each pollutant presents to the public.

The URF is the upper-bound excess lifetime cancer risk estimated to result from continuous inhalation exposure to a pollutant over a 70 year lifetime. Multiplying the estimated concentration by the URF will produce a cancer risk estimate. The cancer risk estimate is the conservative probability of developing cancer from exposure to a pollutant or a mixture of pollutants over a 70 year lifetime, usually expressed as the number of additional cancer cases in a given number of people, e.g., one in a million. For screening purposes at OVR, the cancer estimates for each pollutant are considered to be additive when deriving the cumulative maximum individual cancer risk.

Non-cancer health effects are determined using the Reference Concentration (RfC). The RfC is an estimate 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. Dividing the estimated pollutant concentration by the RfC will determine the pollutant's Hazard Quotient (HQ). All of the HAPs' Hazard Quotients were added together to determine OVR's Hazard Index (HI).

This HAP screening analysis uses health protective assumptions that overestimate the actual risk associated with emissions from OVR. Estimates 1) assume a 70 year exposure time, 2) assume that all carcinogens cause the same type of cancer, 3) assume that all non-carcinogens have additive health effects, 4) assume maximum permit allowable emissions from the facility, and 5) use conservatively derived dose-response information. The risk analysis cannot accurately predict whether there will be observed health problems around the site; rather it identifies possible avenues of risk.

The results of the HAP modeling are in Table 12.

TABLE 12
Hazardous Air Pollutant Modeling Results

Compound	**CAS Number**	**Emission Rate (tons/ year)**	**Annual Concentration (µg/m3)**	**Cancer URF, (µg/m3)-1**	**Cancer Risk**	**Non-Cancer Chronic RfC, µg/m3**	**Hazard Quotient**
1,3-Butadiene	106990	8.80E-05	2.18E-05	3.00E-05	6.53E-10	2.0	1.09E-5
2-Methylnaphthalene	91576	1.47E-04	3.33E-07	N/A	N/A	N/A	N/A
Acetaldehyde	75070	1.73E-03	4.27E-04	2.20E-06	9.40E-10	9.0	4.75E-05
Acrolein	107028	2.08E-04	5.15E-05	N/A	N/A	0.02	2.58E-03
Arsenic compounds	7440382	1.23E-03	2.78E-06	4.30E-03	1.19E-08	0.015	1.85E-04
Benzene	71432	2.63E-02	8.56E-02	7.80E-06	6.68E-07	30	5.70E-03
Cadmium compounds	7440439	6.75E-03	1.53E-05	1.80E-03	2.75E-08	0.01	1.53E-03
Chromium (VI) compounds	7440473	8.59E-03	1.94E-05	1.20E-02	2.33E-07	0.10	1.94E-04
Cobalt	7440484	5.16E-04	1.17E-06	N/A	N/A	0.10	1.17E-05
Dichlorobenzene	95501	7.37E-03	1.67E-05	1.10E-05	1.83E-10	800	2.08E-08
Ethylbenzene	100424	9.06E-03	6.84E-02	2.50E-06	1.71E-07	1000	6.84E-05
Fluoranthene	206440	1.84E-05	4.17E-08	N/A	N/A	N/A	N/A
Fluorene	86737	1.71E-05	3.84E-08	N/A	N/A	N/A	N/A
Formaldehyde	50000	4.63E-01	1.41E-03	1.30E-05	1.83E-08	9.80	1.44E-04
Manganese compounds	7439965	2.33E-03	5.28E-06	N/A	N/A	0.05	1.06E-04
Mercury compounds	7439976	1.60E-03	3.61E-06	N/A	N/A	0.30	1.20E-05
Methanol	67561	17.99	7.60E-02	N/A	N/A	4000	1.90E-05
Naphthalene	91203	3.95E-03	2.75E-04	3.40E-05	9.35E-09	3.0	9.17E-05
n-Hexane	110543	11.09	3.66E-01	N/A	N/A	700	5.22E-04
Nickel compounds	7440020	1.29E-02	2.92E-05	N/A	N/A	0.09	3.24E-04
Phenanthrene	85018	1.04E-04	2.36E-07	N/A	N/A	N/A	N/A
Propylene	115071	5.81E-03	1.44E-03	N/A	N/A	N/A	N/A
Pyrene	129000	3.07E-05	6.94E-08	N/A	N/A	N/A	N/A
Toluene	108883	3.54E-02	1.03E-01	N/A	N/A	5000	2.05E-05
Xylenes	1330207	1.36E-02	1.03E-01	N/A	N/A	100	1.03E-03
				∑ Cancer Risk	**1.14E-06**	**Hazard Index (HI)**	**1.26E-02**
				IDEM Standard	**1.0000E-06**	**IDEM Standard**	**1.0000**
				Comparison	**Above**		**Below**

The additive cancer risk estimate is 1.14 additional cancer causes in one million people. This means if an individual was exposed to these HAPs continuously for 70 years, the risk of getting cancer from this exposure would be 1.14 in one million. The U.S. EPA considers one in ten thousand (1.0E-04) excess cancer risks to be the upper range of acceptability with an ample margin of safety. The probability for the general public to be exposed to these HAP's for 24 hours a day, seven days a week, and 52 weeks a year for 70 years is minimal.

Part I - Summary of Air Quality Analysis

Spirit prepared the modeling portion of the PSD application. Spencer County is designated as attainment for all criteria pollutants except for the new 1-hour SO_2 standard which is unclassified. PM_{10}, NO_2, CO, $PM_{2.5}$, VOC and HAP emission rates associated with the proposed facility exceeded the respective significant emission rates. Modeling results taken from AERMOD model showed that CO, annual PM_{10}, and annual $PM_{2.5}$ impacts were less than significance levels. Refined modeling showed that the NO_2 and $PM_{2.5}$ increments were maintained. NAAQS modeling showed that both the PM_{10} standards along with the annual NO_2 and $PM_{2.5}$ standards were not exceeded. NAAQS modeling showed the 1-hour NO_2, and the 24-hour $PM_{2.5}$ standards were not adversely impacted by OVR. A secondary analysis for $PM_{2.5}$ and ozone showed minimal impact. OVR did not trigger the preconstruction monitoring threshold level. OVR's impact was below 80% of the available PM_{10} and $PM_{2.5}$ increment. The nearest Class I area is Mammoth Cave National Park in Kentucky 102 kilometers away from the source. An additional impact analysis was required but the operation of the proposed facility will have no significant impact.

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Michael R. Pence
Governor

Thomas W. Easterly
Commissioner

SENT VIA U.S. MAIL: CONFIRMED DELIVERY AND SIGNATURE REQUESTED

TO: Doug Wilson
Ohio Valley Resources
PO Box 667
Fairfield, IN 62837

DATE: September 25, 2013

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

SUBJECT: Final Decision
New Source Title V
147 - 32322 - 00062

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:
Brad Herrin Spirit Environmental
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.

Final Applicant Cover letter.dot 6/13/2013

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Michael R. Pence
Governor

Thomas W. Easterly
Commissioner

TO: Spencer County Public Library

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

Subject: **Important Information for Display Regarding a Final Determination**

Applicant Name: Ohio Valley Resources, LLC
Permit Number: 147-32322-00062

You previously received information to make available to the public during the public comment period of a draft permit. Enclosed is a copy of the final decision and supporting materials for the same project. Please place the enclosed information along with the information you previously received. To ensure that your patrons have ample opportunity to review the enclosed permit, **we ask that you retain this document for at least 60 days.**

The applicant is responsible for placing a copy of the application in your library. If the permit application is not on file, or if you have any questions concerning this public review process, please contact Joanne Smiddie-Brush, OAQ Permits Administration Section at 1-800-451-6027, extension 3-0185.

Enclosures
Final Library.dot 6/13/2013

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Michael R. Pence
Governor

Thomas W. Easterly
Commissioner

TO: Interested Parties / Applicant

DATE: September 25, 2013

RE: Ohio Valley Resources / 147 - 32322 - 00062

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

In order to conserve paper and reduce postage costs, IDEM's Office of Air Quality is now sending many permit decisions on CDs in Adobe PDF format. The enclosed CD contains information regarding the company named above.

This permit is also available on the IDEM website at:
http://www.in.gov/ai/appfiles/idem-caats/

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

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

Please Note: *If you feel you have received this information in error, or would like to be removed from the Air Permits mailing list, please contact Patricia Pear with the Air Permits Administration Section at 1-800-451-6027, ext. 3-6875 or via e-mail at PPEAR@IDEM.IN.GOV.*

Enclosures
CD Memo.dot 6/13/2013

Mail Code 61-53

IDEM Staff	DPABST 9/25/2013 Ohio Valley Resources LLC 147-32322-00062 (Final)			AFFIX STAMP HERE IF USED AS CERTIFICATE OF MAILING
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2		Doug Wilson Sole Owner Ohio Valley Resources LLC PO Box 667 Fairfield IL 62837 *(RO CAATS)*									
3		Ms. Francis Lueken 223 W. 10th Street, P.O. Box 206 Ferdinand IN 47532 *(Affected Party)*									
4		Ms. Linda Hamilton 3823 S Hampton Rd Philpot KY 42366-9027 *(Affected Party)*									
5		Mary Lee Vogel Richland Branch Public Library PO Box 155, SR 161 Richland IN 47634 *(Library)*									
6		Rockport City Council and Mayors Office P.O. Box 151 Rockport IN 47635 *(Local Official)*									
7		Spencer Co Public Library 210 N Walnut St Rockport IN 47635-1398 *(Library)*									
8		Mr. Thomas Utter Lincolnland Economical Development Corporation PO Box 400 Santa Claus IN 47579 *(Affected Party)*									
9		Lincoln Heritage public Library Hammond and Wallace Sts, P.O. Box 564 Dale IN 47523-0564 *(Library)*									
10		Ms. Kathy Tretter Dubois-Spencer Counties Publishing Co, Inc P.O. Box 38 Ferdinand IN 47532-0038 *(Affected Party)*									
11		Mr. Rex Winchell 715 W. Old SR 45 Rockport IN 47635 *(Affected Party)*									
12		Willard & Nan Hardin 210 West Jennings St Newburgh IN 47630 *(Affected Party)*									
13		Spencer County Commissioners 200 Main St., Courthouse Rockport IN 47635 (Local Official)									
14		Spencer County Health Department Main Street Courthouse, 1st Floor, Room 1 Roackport IN 47635-1492 *(Health Department)*									
15		Mr. Mark Wilson Evansville Courier & Press P.O. Box 268 Evansville IN 47702-0268 *(Affected Party)*									

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Mail Code 61-53

IDEM Staff	DPABST 9/25/2013 Ohio Valley Resources LLC 32322 (final)			AFFIX STAMP HERE IF USED AS CERTIFICATE OF MAILING
Name and address of Sender	▶	Indiana Department of Environmental Management Office of Air Quality – Permits Branch 100 N. Senate Indianapolis, IN 46204	Type of Mail: **CERTIFICATE OF MAILING ONLY**	

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		Spencer County Public Library 210 Walnut St. Rockport IN 47635 (Library)									
2		Gregory & Mary James 1062 N. SR 66 Rockport IN 47635 *(Affected Party)*									
3		Ronald Barnes 1342 W 200 N Rockport IN 47635 *(Affected Party)*									
4		Norfolk Southern 7315 Nelson Rd Fort Wayne IN 46803 *(Affected Party)*									
5		Hurm Farms Inc 371 E CR 200 N Rockport IN 47635 *(Affected Party)*									
6		Michael & Janice Cochenour 349 E CR 350 N Rockport IN 47635 *(Affected Party)*									
7		Ms. Jennifer Thompson 13585 Opera Rd Leopold IN 47551 *(Affected Party)*									
8		Rock Blanchard 6539 W CR 400 N Richland City IN 47634 *(Affected Party)*									
9		James Lacy Kamuf 117 E 18th St PMB #125 Owensboro KY 42301 *(Affected Party)*									
10		Mickey Toler 1617 N CR 312 W Rockport IN 47635 *(Affected Party)*									
11		Harold Goffinet 105 Seminar St Rockport IN 47635 *(Affected Party)*									
12		Chuck Botsko 12540 N Base Rd Gentryville IN 47537 *(Affected Party)*									
13		Brandon Ferguson 1124 Ravenswood Dr Evansville IN 47714 (Affected Party)									
14		Paul Morsey 2437 Pleasant Valley Rd Owensboro KY 42303 *(Affected Party)*									
15		David Boggs 216 Western Hills Dr Mt Vernon IN 47620 *(Affected Party)*									

Total number of pieces Listed by Sender	Total number of Pieces Received at Post Office	Postmaster, Per (Name of Receiving employee)	The full declaration of value is required on all domestic and international registered mail. The maximum indemnity payable for the reconstruction of nonnegotiable documents under Express Mail document reconstructing insurance is $50,000 per piece subject to a limit of $50, 000 per occurrence. The maximum indemnity payable on Express mil merchandise insurance is $500. The maximum indemnity payable is $25,000 for registered mail, sent with optional postal insurance. See ***Domestic Mail Manual*** **R900, S913**, and **S921** for limitations of coverage on inured and COD mail. See ***International Mail Manual*** for limitations o coverage on international mail. Special handling charges apply only to Standard Mail (A) and Standard Mail (B) parcels.

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											Remarks
1		Brad Spirit Environmental 17350 SH 249, Ste 249 Houston TX 77064 (Consultant)									
2		American Electric Power Co 2791 N US Hwy 231 Rockport IN 47635 *(Affected Party)*									
3		Mr. Frank Ingram 876 N Rebel Square Rockport IN 47635 *(Affected Party)*									
4		Ms. Rosemary Flamion 19414 Old State Road 37 Branchville IN 47514 *(Affected Party)*									
5		Mr. Gilbert Hartig 7824 Middle Mt Vernon Rd Evansville IN 47712 *(Affected Party)*									
6		Mr. Jeff Lindsey 217 Main St Rockport IN 47635 *(Affected Party)*									
7		Kathryn Williams & Laurel Montgomery 1837 Torrington St Raliegh NC 27615 *(Affected Party)*									
8		Jerry L & Mary C Revocable Living Trust 86 E CR 350 N Rockport IN 47635 *(Affected Party)*									
9		Charles & Theresa Garrett 358 S CR 350 N Rockport IN 47635 *(Affected Party)*									
10		Leslie J & Gay A Banks 388 E CR 350 N Rockport IN 47635 *(Affected Party)*									
11		MLF Properties 250 Westview Plaza Atlanta GA 30314 *(Affected Party)*									
12		John Blair 800 Adams Ave Evansville IN 47713 *(Affected Party)*									
13		Ellen Stauffer 2631 E Poplar Drive Bloomington IN 47401 (Affected Party)									
14		Mark Hallett 6430 E State Road 45 Bloomington IN 47408 *(Affected Party)*									
15		Jo Ann Gauthier 2102 N 5th Ave Evansville IN 47710 *(Affected Party)*									

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1		Robert 4345 Autumn Ridge Bend Owensboro KY 42303 (Affected Party)									
2		Derek Green 14200 Worthington Ct Evansville IN 47725 *(Affected Party)*									
3		Elaine Sorensen 10001 N Stones Ln Evanston IN 47531 *(Affected Party)*									
4		Richard Ullrich 403 Main St Aurora IN 47001 *(Affected Party)*									
5		Charlotte Reitz 901 Irvin Ave Evansville IN 47715 *(Affected Party)*									
6		Ricki Newman 617 Prince Dr Newburgh IN 47630 *(Affected Party)*									
7		Jennifer Knable Thompson 13585 Opera Rd Leopold IN 47551 *(Affected Party)*									
8		Robert Stoll 1405 E Prairie Dr Bloomington IN 47408 *(Affected Party)*									
9		Rick Fowler 222 E 21st St Owensboro KY 42303 *(Affected Party)*									
10		Greg Edwards 8455 Yorkridge Ct Newburgh IN 47630 *(Affected Party)*									
11		Elaine Sorensen 10001 N Stones Lane Evanston IN 47531 *(Affected Party)*									
12		Sara Dunn 2105 College Ave Vincennes IN 47591 *(Affected Party)*									
13		Kim Schiavone 1401 W. Bnvl New Har Road Evansville IN 47720 (Affected Party)									
14		Rhonda Kohl 42 Wildwood Rd Jeffersonville IN 47130 *(Affected Party)*									
15		Kelly Morrison 1220 Weed Ln Vincennes IN 47591 *(Affected Party)*									

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1		Hans 740 S Shady Side Dr Bloomington IN 47401 (Affected Party)									
2		Jeffrey Cottingham 417 4th St Aurora IN 47001 *(Affected Party)*									
3		Rick Honeycutt 8735 N Spades Rd Milan IN 47031 *(Affected Party)*									
4		Daniel Burnham 6775 N Hudoff Rd Bloomington IN 47408 *(Affected Party)*									
5		David Motz 1608 Southeast Blvd Evansville IN 47714 *(Affected Party)*									
6		Imogene Burkhart 328 Adams Ave Evansville IN 47713 *(Affected Party)*									
7		Yvonne French 322 E Kirkwood Ave Bloomington IN 47408 *(Affected Party)*									
8		Wes Milner 7109 E Chestnut St Evansville IN 47715 *(Affected Party)*									
9		Georgia Sumner 2409 E Rock Creek Dr Bloomington IN 47401 *(Affected Party)*									
10		Rebecca Brookman 1742 N Old Petersburg Rd Princeton IN 47670 *(Affected Party)*									
11		Shari Caldwell 13101 Caldwell Ln Dillsboro IN 47018 *(Affected Party)*									
12		Dorothy Wilson 4500 N Northwoods Lane Bloomington IN 47404 *(Affected Party)*									
13		Ashley Verkamp 22125 Blue Ridge Rd Bristow IN 47515 (Affected Party)									
14		Stephen Arnold 627 W 7th St Bloomington IN 47404 *(Affected Party)*									
15		Kristen Hackman 521 E 7th St Apt 4 Bloomington IN 47408 *(Affected Party)*									

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1		Philip 720 S College Mall Rd Apt H6 Bloomington IN 47401 (Affected Party)									
2		Karisha Kirk 3231 S Bradshire Ct Bloomington IN 47401 *(Affected Party)*									
3		Stephen Simonds 1305 Timberlake Rd Evansville IN 47710 *(Affected Party)*									
4		George Oglesby 9607 Darmstadt Rd Evansville IN 47710 *(Affected Party)*									
5		Joan Keeler 3927 S Cramer Cir Bloomington IN 47403 *(Affected Party)*									
6		Tracy Fox 11900 N County Road 50 W Batesville IN 47006 *(Affected Party)*									
7		Jan Reynolds 1412 W 12th St Bloomington IN 47404 *(Affected Party)*									
8		Elizabeth Izzo 815 S Rogers St Bloomington IN 47403 *(Affected Party)*									
9		Darrel Joy 4 Arbor Pl New Albany IN 47150 *(Affected Party)*									
10		Bruce Pearson 1025 S Graywell Dr Bloomington IN 47401 *(Affected Party)*									
11		Jean Webb 2105 E. Columbia St Evansville IN 47711 *(Affected Party)*									
12		Patrick Coppage 612 Mulberry St Madison IN 47250 *(Affected Party)*									
13		James Ashcraft 200 E Center St Lawrenceburg IN 47025 (Affected Party)									
14		Pamela Schrantz 12281 N Hogan Rd Aurora IN 47001 *(Affected Party)*									
15		Raymond Minton 1531 E State Road 356 Scottsburg IN 47170 *(Affected Party)*									

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											Remarks
1		Patricia 1015 W Van Trees St Washington IN 47501 (Affected Party)									
2		Tad Legler 4630 N Chatham Dr Bloomington IN 47404 *(Affected Party)*									
3		Steve Harrison 871 Chandler Dr Elletsville IN 47429 *(Affected Party)*									
4		June Tomastick 215 E 2nd St Bloomington IN 47401 *(Affected Party)*									
5		Kara Hortsman 3957 Terra Trace Ct Evansville IN 47715 *(Affected Party)*									
6		Anthony Schmitt 4308 Aj Dr N Wadesville IN 47638 *(Affected Party)*									
7		Paul Lukey 3600 E Morningside Dr Bloomington IN 47408 *(Affected Party)*									
8		Thomas Lehr 8948 W County Road 57 N Richland IN 47634 *(Affected Party)*									
9		Anne Fraker 2606 E Windemere Woods Dr Bloomington IN 47401 *(Affected Party)*									
10		Michael Caldie 618 S Lincoln St Bloomington IN 47401 *(Affected Party)*									
11		Annita Mason 1511 Beechwood Ave New Albany IN 47150 *(Affected Party)*									
12		W Jake Lindauer 2532 S Lindauer Rd Eckerty IN 47116 *(Affected Party)*									
13		Paola Quadrini 327 W 1st St Bloomington IN 47403 (Affected Party)									
14		Richard Ullrich 403 Main St Aurora IN 47001 *(Affected Party)*									
15		Jessica Cresseveur 2834 Charlestown Rd Apt 6 New Albany IN 47150 *(Affected Party)*									

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											Remarks
1		Bronwyn 3169 E Braeside Dr Bloomington IN 47408 (Affected Party)									
2		Paul Schneller 1500 E Richland Dr Bloomington IN 47408 *(Affected Party)*									
3		Donald Rhoads 1000 W Williams Rd Bloomington IN 47404 *(Affected Party)*									
4		Tonya Dale 2461 S Old US 41 Vincennes IN 47591 *(Affected Party)*									
5		Diane Seltz 3199 N Thompson Rd Madison IN 47250 *(Affected Party)*									
6		Matt Baucco 2500 S Ford Ave Bloomington IN 47403 *(Affected Party)*									
7		Steven Wilson 4026 E State Road 258 Seymour IN 47274 *(Affected Party)*									
8		Shannon Wenger PO Box 3512 Bloomington IN 47402 *(Affected Party)*									
9		Mark Roeder 225 E 20th St Apt 4 Bloomington IN 47408 *(Affected Party)*									
10		Ray Crittenden 8587 W Rice Rd Bloomington IN 47403 *(Affected Party)*									
11		Barbara Russell 914 Pfeiffer Rd Evansville IN 47711 *(Affected Party)*									
12		Jeanne Melchior 880 Church Ave Jasper IN 47546 *(Affected Party)*									
13		Ellie Macfarlane 1008 S Meadowbrook Dr Bloomington IN 47401 (Affected Party)									
14		Margee Stone 5633 Kenwood Dr Newburgh IN 47630 *(Affected Party)*									
15		Deborah Schade 8100 Upper Mount Vernon Rd Evansville IN 47712 *(Affected Party)*									

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1		Lawrence 1228 E Maxwell Ln Bloomington IN 47401 (Affected Party)									
2		Linda Greene 7487 N John Young Rd Unionville IN 47468 *(Affected Party)*									
3		Sherry Kraus 6161 Abbott Rd Tell City IN 47586 *(Affected Party)*									
4		Charles Kozak 1153 N Valleyview Dr West Baden Springs IN 47469 *(Affected Party)*									
5		Paul Hill 3800 W H and H Rustic Ln Madison IN 47250 *(Affected Party)*									
6		Rene Rezvan 9687 W State Road 48 Bloomington IN 47404 *(Affected Party)*									
7		Whitney Arvin 5048c Amstel Dr Evansville IN 47715 *(Affected Party)*									
8		Herman Gudino Indiana Flame Service PO Box 771 Portage IN 46368 *(Affected Party)*									
9		Martha Murphy 2536 N Main St Evansville IN 47711 *(Affected Party)*									
10		Kaleb Jeffries 2308 Scheips Ln Evansville IN 47720 *(Affected Party)*									
11		Joe Weisman 5156 N Brummetts Creek Rd Bloomington IN 47408 *(Affected Party)*									
12		Linda Dean 955 S Basswood Cir Bloomington IN 47403 *(Affected Party)*									
13		Suzanne Merriman 125 S Jaclyn Dr Bloomington IN 47401 (Affected Party)									
14		Vincent Desjardins 505 E Dixie St Bloomington IN 47401 *(Affected Party)*									
15		Robert Stoll 1405 E Prairie Dr Bloomington IN 47408 *(Affected Party)*									

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1		Nancy 1207 W Green Tree Ln Bloomington IN 47403 (Affected Party)									
2		Kurt Singleton 2117 E Virginia St Evansville IN 47711 *(Affected Party)*									
3		Steven Black 3511 S Roxbury Cir Bloomington IN 47401 *(Affected Party)*									
4		Mary & Phil Mininger 1171 S Paoli Unionville Rd Paoli IN 47454 *(Affected Party)*									
5		Laura & jerry Hunter 8550 E Doe Run Rd Madison IN 47250 *(Affected Party)*									
6		Terri Greene 9510 S Snow Rd Bloomington IN 47403 *(Affected Party)*									
7		Antonia Matthew 1307 S Grant Ave Bloomington IN 47401 *(Affected Party)*									
8		Jennifer Knable Thompson 13585 Opera Rd Leopold IN 47551 *(Affected Party)*									
9		Kent Pellerite 2224 S Sussex Dr Bloomington IN 47401 *(Affected Party)*									
10		Marlene Beachy 925 W Oakwood Ln Paoli IN 47454 *(Affected Party)*									
11		Robert Bieder 2010 S Grovesnor Pl Bloomington IN 47401 *(Affected Party)*									
12		Mary Connors 3722 W Parkview Dr Bloomington IN 47404 *(Affected Party)*									
13		Nelvin Gaba 1750 N Range Rd Apt K104 Bloomington IN 47408 (Affected Party)									
14		Linda Richardson 7756 S Locust Grove Rd Hardinsburg IN 47125 *(Affected Party)*									
15		Emily Frazier 3974 S Bushmill Dr Bloomington IN 47403 *(Affected Party)*									

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1		Henry 1101 S Fess Ave Bloomington IN 47401 (Affected Party)									
2		Helen Templeton 208 S Taft Ave Evansville IN 47714 *(Affected Party)*									
3		Mark Hallett 6430 E State Road 45 Bloomington IN 47408 *(Affected Party)*									
4		Claire Gregory 2949 N Ramble Rd E Bloomington IN 47408 *(Affected Party)*									
5		James Hettmer 7455 S Rockport Rd Bloomington IN 47403 *(Affected Party)*									
6		Scott Sinclair 930 Blum St Tell City IN 47586 *(Affected Party)*									
7		Kathryn Marlett 3636 E Park Ln Bloomington IN 47408 *(Affected Party)*									
8		Mark Beard 6575 Heathervale Ct Newburgh IN 47630 *(Affected Party)*									
9		Michael Falkenstein 643 S Englewood Ave Evansville IN 47714 *(Affected Party)*									
10		Bill Kempf 3764 Woodbridge Dr Evansville IN 47710 *(Affected Party)*									
11		Bethany Martinez 3501 Wellington Dr Bloomington IN 47401 *(Affected Party)*									
12		Michael Schneider 6214 Appleleaf Ln Sellersburg IN 47172 *(Affected Party)*									
13		M Burton 309 N Hay St Bloomington IN 47404 (Affected Party)									
14		Christian Joyce 1220 Weed Ln Vincennes IN 47591 *(Affected Party)*									
15		Bret Daugherty 111 N Chestnut St Seymour IN 47274 *(Affected Party)*									

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											Remarks
1		Ruth 151 Winding Way Batesville IN 47006 (Affected Party)									
2		Robert McDonald 6458 W Eureka Rd Rockport IN 47635 *(Affected Party)*									
3		Paul Eisenburg 1005 S Hawthorne Dr Bloomington IN 47401 *(Affected Party)*									
4		Steve Kreuzburg 386 Brentwood Dr Madison IN 47250 *(Affected Party)*									
5		Erik Hitchcock 4104 W Daniel Ave Bloomington IN 47403 *(Affected Party)*									
6		Eric Ellis 4345 Country View Dr Floyds Knobs IN 47119 *(Affected Party)*									
7		Kaye Hill 704 N Park Ridge Rd Bloomington IN 47408 *(Affected Party)*									
8		Robert Mayton 4345 Autumn Ridge Bnd Owensboro KY 42303 *(Affected Party)*									
9		Rick Fowler 222 E 21st St Owensboro KY 42303 *(Affected Party)*									
10		Jennifer Schultz 2978 State Route 140 E Utica KY 42376 *(Affected Party)*									
11		Tammi Payne 2940 Salem Rd Olaton KY 42361 *(Affected Party)*									
12		Eva Atkinson 717 Frederica St Owensboro KY 42301 *(Affected Party)*									
13		Betsy Cockrum 610 N Burkhardt Rd Evansville IN 47715 (Affected Party)									
14		Hon. E. Woodford Sigler, KY Colonel 192 Melwood Pl Henderson KY 42420 *(Affected Party)*									
15		Bill Spaetti 182 S 400 W Rockport IN 47635 *(Affected Party)*									

Total number of pieces Listed by Sender	Total number of Pieces Received at Post Office	Postmaster, Per (Name of Receiving employee)	The full declaration of value is required on all domestic and international registered mail. The maximum indemnity payable for the reconstruction of nonnegotiable documents under Express Mail document reconstructing insurance is $50,000 per piece subject to a limit of $50, 000 per occurrence. The maximum indemnity payable on Express mil merchandise insurance is $500. The maximum indemnity payable is $25,000 for registered mail, sent with optional postal insurance. See ***Domestic Mail Manual*** **R900, S913**, and **S921** for limitations of coverage on inured and COD mail. See ***International Mail Manual*** for limitations o coverage on international mail. Special handling charges apply only to Standard Mail (A) and Standard Mail (B) parcels.

FACSIMILIE OF PS Form 3877

Mail Code 61-53

IDEM Staff	DPABST 9/25/2013 Ohio Valley Resources LLC 32322 (final)			AFFIX STAMP HERE IF USED AS CERTIFICATE OF MAILING
Name and address of Sender	▶	Indiana Department of Environmental Management Office of Air Quality – Permits Branch 100 N. Senate Indianapolis, IN 46204	Type of Mail: **CERTIFICATE OF MAILING ONLY**	

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		Mary 1309 Allen St Owensboro KY 42303 (Affected Party)									
2		Gary McCoy 2800 Liberty Rd Providence KY 42450 *(Affected Party)*									
3		Peggy White 431 Booth Ave Owensboro KY 42301 *(Affected Party)*									
4		Jeff Vogel 3124 N 200 W Rockport IN 47635 *(Affected Party)*									
5		Stella Payne 9978 State Route 456 Owensboro KY 42301 *(Affected Party)*									
6		James Russell 737 Cumberland St Owensboro KY 42303 *(Affected Party)*									
7		Lee Anderson 4325 Brookhill Dr Owensboro KY 42303 *(Affected Party)*									
8		Gene Steinkamp 3339 W Ridgewood Dr Rockport IN 47635 *(Affected Party)*									
9		Mike Ledbetter 7277 Marywood Newburgh IN 47638 *(Affected Party)*									
10		Barbara Montgomery 1933 Lydia Dr Owensboro KY 42301 *(Affected Party)*									
11		Sharon Tiahrt 2229 Yewells Lndg S Owensboro KY 42303 *(Affected Party)*									
12		James Mattingly 11881 Hwy 144 Philpot KY 42366 *(Affected Party)*									
13		Derek Kratzer 721 N Fairview St Bloomington IN 47404 (Affected Party)									
14		Terry Kindred 533 Panther Creek Ch. Rd. Philpot KY 42366 *(Affected Party)*									
15		Ralph Hirsbrunner PO Box 143 Madison IN 47250-0143 *(Affected Party)*									

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											Remarks
1		Gail 359 Brey Ln Hartford KY 42347-9525 (Affected Party)									
2		Ed Cupp 1309 Allen St Owensboro KY 42303-3034 *(Affected Party)*									
3		David Lindsey 313 Valley View Dr Beaver Dam KY 42320-1635 *(Affected Party)*									
4		Ron Mayhew 2504 SR 1554 Owensboro KY 42301-9557 *(Affected Party)*									
5		Tina Beier 1544 W 23rd St Ferdinand IN 47532-9499 *(Affected Party)*									
6		Rhonda Moers 5401 Wesbriar Ln Evansville IN 47720-7875 *(Affected Party)*									
7		Sarah Tull 1108 E Elm St New Albany IN 47150-3058 *(Affected Party)*									
8		Victoria Bedford 1701 E Circle Dr Bloomington IN 47401-6027 *(Affected Party)*									
9		Sam Rich 1250 Uniontown Rd Uniontown KY 42461-5240 *(Affected Party)*									
10		Jeff Poling 144 N Park Ridge Rd Bloomington IN 47408-3113 *(Affected Party)*									
11		Patrick Niese 5109 E Morris Mill St Batesville IN 47006-8207 *(Affected Party)*									
12		Marcia Droege 205 Krietenstein Rd S Wadesville IN 47638-8708 *(Affected Party)*									
13		Janet Altman 3209 E 10th St Apt D37 Bloomington IN 47408-2484 (Affected Party)									
14		Jean Smith 610 S 7th St Petersburg IN 47567-1811 *(Affected Party)*									
15		Elaine Sorenson 10001 N Stones Ln Evanston IN 47531 *(Affected Party)*									

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1		Melissa 372 N Barclay Dr Vincennes IN 47591 (Affected Party)									
2		James Wolcott 527 N Green River Rd pmb 325 Evansbille IN 47715 *(Affected Party)*									
3		Jean Robertson 618 E Jennings St Newburgh IN 47630 *(Affected Party)*									
4		John Reynolds 9325 Darnell School Rd Mount Vernon IN 47620 *(Affected Party)*									
5		Steve Amos 610 W Jennings St Newburgh IN 47630 *(Affected Party)*									
6		Abbi Surles 2755 W Popcorn Rd Springville IN 47462 *(Affected Party)*									
7		William Estes 623 E Emerson St Princeton IN 47670 *(Affected Party)*									
8		Evelyn Hunter One Adams Ave Apt A Evansville IN 47713 *(Affected Party)*									
9		Emilie Schwen 821 S Hawthorne Dr Bloomington IN 47401 *(Affected Party)*									
10		Ana Hernandez 660 E Old Hwy 50 Wheatland IN 47597 *(Affected Party)*									
11		Chris Huntington 1923 Mimosa Trl Florence KY 41042 *(Affected Party)*									
12											
13											
14											
15											

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