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

Eric J. Holcomb
Governor

Bruno L. Pigott
Commissioner

NOTICE OF 30-DAY PERIOD
FOR PUBLIC COMMENT

Preliminary Findings Regarding the Renewal of a
Part 70 Operating Permit

for University of Notre Dame du Lac in St. Joseph County

Part 70 Operating Permit Renewal No.: T141-41227-00013

The Indiana Department of Environmental Management (IDEM) has received an application from University of Notre Dame du Lac located at 100 Facilities Building, Notre Dame, Indiana 46556 for a renewal of its Part 70 Operating Permit issued on March 19, 2019. If approved by IDEM's Office of Air Quality (OAQ), this proposed renewal would allow University of Notre Dame du Lac to continue to operate its existing source.

This draft permit does not contain any new equipment that would emit air pollutants; however, some conditions from previously issued permits/approvals have been corrected, changed, or removed. These corrections, changes, and removals may include Title I changes (e.g., changes that add or modify synthetic minor emission limits). This notice fulfills the public notice procedures to which those conditions are subject. IDEM has reviewed this application and has developed preliminary findings, consisting of a draft permit and several supporting documents, which would allow for these changes.

A copy of the permit application and IDEM's preliminary findings are available at:

Hesburgh Memorial Library
221 Hesburgh Memoria Library
Notre Dame, Indiana 46556

and

IDEM Northern Regional Office
300 North Dr. Martin Luther King Jr. Boulevard, Suite 450
South Bend, IN 46601-1295

A copy of the preliminary findings is available on the Internet at: http://www.in.gov/ai/appfiles/idem-caats/.

A copy of the preliminary findings is also available via IDEM's Virtual File Cabinet (VFC.) Please go to: http://www.in.gov/idem/ and enter VFC in the search box. You will then have the option to search for permit documents using a variety of criteria.

How can you participate in this process?

The date that this notice is posted on IDEM's website (https://www.in.gov/idem/5474.htm) marks the beginning of a 30-day public comment period. If the 30th day of the comment period falls on a day when IDEM offices are closed for business, all comments must be postmarked or delivered in person on the next business day that IDEM is open.

You may request that IDEM hold a public hearing about this draft permit. If adverse comments concerning the **air pollution impact** of this draft permit are received, with a request for a public hearing, IDEM will decide whether or not to hold a public hearing. IDEM could also decide to hold a public

meeting instead of, or in addition to, a public hearing. If a public hearing or meeting is held, IDEM will make a separate announcement of the date, time, and location of that hearing or meeting. At a hearing, you would have an opportunity to submit written comments and make verbal comments. At a meeting, you would have an opportunity to submit written comments, ask questions, and discuss any air pollution concerns with IDEM staff.

Comments and supporting documentation, or a request for a public hearing should be sent in writing to IDEM at the address below. If you comment via e-mail, please include your full U.S. mailing address so that you can be added to IDEM's mailing list to receive notice of future action related to this permit. If you do not want to comment at this time, but would like to receive notice of future action related to this permit application, please contact IDEM at the address below. Please refer to permit number T141-41227-00013 in all correspondence.

Comments should be sent to:

Tripurari Sinha, Ph. D.
IDEM, Office of Air Quality
100 North Senate Avenue
MC 61-53 IGCN 1003
Indianapolis, Indiana 46204-2251
(800) 451-6027, ask for Tripurari Sinha, Ph. D. or (317) 234-4907
Or dial directly: (317) 234-4907
Fax: (317) 232-6749 attn: Tripurari Sinha, Ph. D.
E-mail: tsinha@idem.IN.gov

All comments will be considered by IDEM when we make a decision to issue or deny the permit. Comments that are most likely to affect final permit decisions are those based on the rules and laws governing this permitting process (326 IAC 2), air quality issues, and technical issues. IDEM does not have legal authority to regulate zoning, odor, or noise. For such issues, please contact your local officials.

For additional information about air permits and how the public and interested parties can participate, refer to the IDEM Air Permits page on the Internet at: http://www.in.gov/idem/airquality/2356.htm; and the Citizens' Guide to IDEM on the Internet at: http://www.in.gov/idem/6900.htm.

What will happen after IDEM makes a decision?

Following the end of the public comment period, IDEM will issue a Notice of Decision stating whether the permit has been issued or denied. If the permit is issued, it may be different than the draft permit because of comments that were received during the public comment period. If comments are received during the public notice period, the final decision will include a document that summarizes the comments and IDEM's response to those comments. If you have submitted comments or have asked to be added to the mailing list, you will receive a Notice of the Decision. The notice will provide details on how you may appeal IDEM's decision, if you disagree with that decision. The final decision will also be available on the Internet at the address indicated above, at the local library indicated above, at the IDEM Regional Office indicated above, and the IDEM public file room on the 12th floor of the Indiana Government Center North, 100 N. Senate Avenue, Indianapolis, Indiana 46204-2251.

If you have any questions, please contact Tripurari Sinha, Ph. D. of my staff at the above address.

Ghassan Shalabi, Section Chief
Permits Branch
Office of Air Quality

INDIANA DEPARTMENT OF ENVIRONMENTAL MANAGEMENT
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Governor

Bruno L. Pigott
Commissioner

DRAFT

Part 70 Operating Permit Renewal
OFFICE OF AIR QUALITY

University of Notre Dame du Lac
100 Facilities Building
Notre Dame, Indiana 46556

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

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

This permit is issued in accordance with 326 IAC 2 and 40 CFR Part 70 Appendix A and contains the conditions and provisions specified in 326 IAC 2-7 as required by 42 U.S.C. 7401, et. seq. (Clean Air Act as amended by the 1990 Clean Air Act Amendments), 40 CFR Part 70.6, IC 13-15 and IC 13-17.
This permit also addresses certain new source review requirements for existing equipment and is intended to fulfill the new source review procedures pursuant to 326 IAC 2-7-10.5, applicable to those conditions

Operation Permit No.: T141-41227-00013 Master Agency Interest ID: 10812	
Issued by: Ghassan Shalabi, Section Chief Permits Branch Office of Air Quality	Issuance Date: Expiration Date:

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Attachment C - National Emissions Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines (40 CFR Part 63, Subpart ZZZZ)

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Attachment F - National Emission Standards for Hazardous Air Pollutants for Gasoline Dispensing Facilities (40 CFR Part 63, Subpart CCCCCC)

SECTION A SOURCE SUMMARY

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

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

The Permittee owns and operates a stationary University.

Source Address:	100 Facilities Building, Notre Dame, Indiana 46556
General Source Phone Number:	574-631-0142
SIC Code:	8221
County Location:	St Joseph
Source Location Status:	Attainment for all criteria pollutants
Source Status:	Part 70 Operating Permit Program Major Source, under PSD Rules Minor Source, Section 112 of the Clean Air Act Not 1 of 28 Source Categories

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

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

(a) One (1) No. 2 fuel oil or natural gas fired boiler, identified as B-1, constructed in 1961, with a single low NOx burner and economizer constructed in 2006, and with a maximum design capacity of 137 MMBtu per hour heat input, and exhausting to stack S-1.

[This is an existing affected source under 40 CFR Part 63, Subpart JJJJJJ.]

(b) Two (2) natural gas fired boilers, identified as B-2 and B-3, constructed in 1952, and modified in 2019 to remove coal firing capacity, with maximum design capacity of 96 MMBtu per hour heat input, each, each equipped with low NOx burners, and exhausting to stack S-1.

(c) One (1) natural gas or No. 2 fuel oil fired boiler, identified as B-4, constructed in 1966, and modified in 2018 to remove coal firing capacity, with a maximum design capacity of 234 MMBtu per hour heat input**,** and exhausting to stack S-2.

[This is an existing affected source under 40 CFR 63, Subpart JJJJJJ.]

(d) One (1) No. 2 fuel oil or natural gas fired boiler, identified as B-5, constructed in 1973, with a maximum design capacity of 244.5 MMBtu per hour heat input, equipped with low NOx burner for natural gas and fuel oil, and exhausting to stack S-3.

[This is an existing affected source under 40 CFR Part 63, Subpart JJJJJJ.]

(e) One (1) natural gas fired boiler, identified as B-6, constructed in 2006, with a maximum design capacity of 249 MMBtu per hour heat input, equipped with a low NOx burner and flue gas recirculation (FGR), using No. 2 fuel oil as a backup fuel, and exhausting to stack S-9, monitored by certified COM and NOx CEM.

[This is an affected source under 40 CFR Part 60, Subpart Db.]
[This is an existing affected source under 40 CFR Part 63, Subpart JJJJJJ.]

(f) Three (3) diesel-fired generators, identified as G-8, G-9 and G-10, constructed before July 11, 2005 (permitted in 2003), each with a maximum rated capacity of 2,593 brake horsepower, equipped with oxidation catalysts, and exhausting to stacks S-6, S-7 and S-8, respectively.

[These generators are an affected source under 40 CFR Part 63, Subpart ZZZZ.]

(g) Two (2) diesel-fired emergency generators, identified as G-3 and G-4, constructed in 1953, with maximum design capacity of 13.70 MMBtu per hour heat input, each, and exhausting to stacks S-4 and S-5, respectively.

(h) Two (2) natural gas-fired combustion turbines, identified as GT-1 and GT-2, each equipped with a heat recovery steam generator (HRSG), constructed in 2018. Each HRSG is equipped with a natural gas-fired duct burner, each turbine has a maximum capacity of 6.4 MW (75.4 MMBtu/hr), and each duct burner has a maximum capacity of 87.5 MMBtu/hr. During normal operation, the turbines and duct burners exhaust to a shared main stack.

*Note: The heat recovery steam generators are not a source of emissions. They have been included for clarity as they are part of the entire source and operate in conjunction with the duct burners and combustion turbines which are a source of emissions.

[These turbines are an affected source under 40 CFR Part 60, Subpart KKKK.]

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) Degreasing operations that do not exceed 145 gallons per 12 months, except if subject to 326 IAC 20-6.

(b) The following activities not resulting in the emission of HAPs: brazing equipment, cutting torches, soldering equipment, welding equipment.

(c) Grinding and machining operations controlled with fabric filters, scrubbers, mist collectors, wet collectors and electrostatic precipitators with a design grain loading of less than or equal to 0.03 grains per actual cubic foot and a gas flow rate less than or equal to 4000 actual cubic feet per minute, including the following: deburring, buffing, polishing, abrasive blasting, pneumatic conveying; and woodworking operations.

(d) Space heaters, process heaters, or boilers consisting of the following:

(1) Natural gas-fired combustion sources with heat input capacities equal to or less than 10.0 MMBtu per hour.

(A) Two (2) indirect natural gas fired heaters, identified as Irish Athletic Center Heaters, constructed in 2018 and 2019 with maximum capacity of 2.4 MMBtu, each.

(B) Three hundred (300) indirect natural gas fired heaters, constructed prior to 2020 with a maximum capacity of 40,000 Btu per hour, each.

(2) Propane, LPG, or butane-fired combustion sources with heat input capacities equal to or less than 6.0 MMBtu per hour.

(3) Fuel oil-fired combustion sources with heat input capacities equal to or less than 2.0 MMBtu per hour and firing fuel containing less than 0.5% sulfur by weight.

(4) Wood-fired combustion sources with heat input capacities equal to or less than 2.0 MMBtu per hour and firing fuel containing less than 0.5% sulfur by weight.

(e) Noncontact cooling tower systems with forced and induced draft cooling tower systems not regulated under a NESHAP.

(1) Five (5) non-contact, counterflow cooling towers; identified as Cooling Towers 1 through 5; each with a maximum water circulation rate of 10,400 gallons/minute; each cooling tower was constructed in 2000 and controlled by drift eliminators.

(2) Two (2) closed-loop, counterflow cooling towers; identified as Cooling Towers 6 and 7; each with a maximum cooling tower water circulation rate of 10,000 gallons/minute; each constructed in 2016 and controlled by drift eliminators.

(3) Two (2) closed-loop, counter flow cooling towers; identified as East Chiller Plant Cooling Towers 8 and 9; each with a maximum cooling tower water circulation rate of 5,000 gallons/minute; each constructed in 2016 and controlled by drift eliminators.

(f) Insignificant emergency engines consisting of the following:

(1) Diesel fired compression ignition emergency engines, each with a capacity less than or equal to 500 Hp, constructed/reconstructed before June 12, 2006.

Location	Engine Rating	Year of Manufacture
Old Security Building	27	1990
Haggar	20	1990
Loftus Center	20	1987
North Dining Hall	44	1988
Hesburgh Ctr. For Int. Studies	54	1991
Rec Sports	60	1997
Hammes Mowbray	74	2004
Material Storage	80	1990
Bond Hall/Morrissey	80	1997
South Dining Hall	80	1993
Eck Center/Ryan Hall	107	1999
DeBartolo	121	1992
Hanks Aquatics	134	1997
Guigliemino CVA	134	2004
O'Neill/Keough/Welsh McGlinn/Duncan	201	1996
Coleman Morse	201	1999
Performing Arts Center	201	2002
Geddes Hall	268	2005
COBA	469	1995
East Plant	201	2003

(2) Diesel fired compression ignition emergency engines, each with a capacity less than or equal to 500 Hp, manufactured/modified/ constructed/reconstructed on or after June 12, 2006.

Location	Engine Rating	Year of Manufacture
MVAP Complex	168	2009
Nanotechnology Research Ctr.	201	2006
Stayer Center	201	2012
Innovation Park Building 1	335	2009
Compton Ice Arena	335	2011
Eck Law School	402	2007
Morris Inn	235	2013
Jenkins-Nanovic Hall	385	2016
Sacred Heart Basilica	134	2019

[These are new affected source under 40 CFR Part 60, Subpart IIII]
[These are new affected source under 40 CFR Part 63, Subpart ZZZZ]

(3) Diesel fired compression ignition emergency engines, each with a capacity greater than 500 Hp and not exceeding 1600 Hp, constructed/reconstructed before December 19, 2002.

Location	Engine Rating	Year of Manufacture
Secondary Chilled Water Pumping Station	536	1996
Malloy Hall	536	2001
Flanner/Grace/Wells 1 & 2	671	1996
ITC	671	2002
Administration Bldg.	671	1997

(4) Diesel fired compression ignition emergency engines, each with a capacity greater than 500 HP and not exceeding 1600 Hp, manufactured/modified/constructed/ reconstructed on or after June 12, 2006.

Location	Generator Rating	Year of Manufacture
Well #9	536	2012
Joyce Center	671	2013
Hesburgh Library #1	671	2013
Hesburgh Library #2	671	2013
Galvin Life Sciences	755	2015
Nieuwland	755	2015
Stinson-Remick	1,073	2010
McCourtney Hall	1,220	2016
Stadium 1	1,474	2016
Stadium 2	1,474	2016
Stepan Chemistry	755	2019
Fitzpatrick	755	2019

[These are new affected source under 40 CFR Part 60, Subpart IIII]
[These are new affected source under 40 CFR Part 63, Subpart ZZZZ]

(5) Diesel fired compression ignition emergency engines, each with a capacity greater than 500 HP and not exceeding 1600 Hp, constructed/reconstructed on or after December 19, 2002 and manufactured/ modified/reconstructed before July 11, 2005.

Location	Engine Rating	Year of Manufacture
Galvin No. 3	805	2005
Jordan Hall of Science	805	2004

(6) Ten existing natural gas fired emergency engines with a total combined capacity of 802 HP.

(g) A gasoline fuel transfer dispensing operation 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.

[This is an affected unit under 40 CFR Part 63, Subpart CCCCCC]

(h) Paved and unpaved roads and parking lots with public access.

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, as defined in 326 IAC 2-7-1(21):

(a) One (1) underground diesel fuel storage tank constructed in 2005 for generators G-8, G-9, and G-10, identified as UST, with maximum storage capacity of 30,000 gallons and storing diesel fuel with a maximum true vapor pressure less than 15 kilo Pascal (kPa).

(b) Combustion source flame safety purging on startup.

(c) A petroleum fuel, other than gasoline dispensing facility, 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.

(d) Asbestos abatement projects regulated by 326 IAC 14-10.

(e) Ten (10) underground storage tanks: four (4) at 50,000 gallons for No.2 fuel oil, each constructed in 1973; five (5) at 20,000 gallons for No.2 fuel oil, each constructed in 1990, and one (1) at 20,000 gallons for diesel fuel, constructed in 1990.

(f) Two (2) above-ground, storage tanks for fuel oil #2, identified as AST-1 and AST-2; each constructed in 2016, each providing additional storage capacity for the University boilers; and each having a maximum storage capacity of 300,000 gallons.

(g) Five (5) 300-gallon diesel fuel day tanks for G-3, G-4, G-8, G-9, and G-10.

(h) The following VOC and HAP storage containers:

(1) Storage tanks with capacity less than or equal to one thousand (1,000) gallons and annual throughputs less than twelve thousand (12,000) gallons.

(2) Vessels storing hydraulic oils, lubricating oils, machining oils, machining fluids.

(i) Refractory storage not requiring air pollution control equipment.

(j) Equipment used exclusively for packaging greases and lubricants and filling drums, pails, or other packaging containers with greases, lubricating oils, and waxes.

(k) Repair activities, including the following:

(1) Replacement or repair of electrostatic precipitators, bags in baghouses, and filters in other air filtration equipment.

(2) Heat exchanger cleaning and repair.

(3) Process vessel degassing and cleaning to prepare for internal repairs.

(l) Routine maintenance and repair of buildings, structures, or vehicles at the source where air emissions from those activities would not be associated with any production process, including purging of gas lines and vessels.

(m) Equipment used to collect any material that might be released during a malfunction, process upset, or spill cleanup, including the following:

(1) Catch tanks.

(2) Temporary liquid separators.
(3) Tanks.
(4) Fluid handling equipment.

(n) Blowdown for the following:

(1) Sight glass.
(2) Boiler.
(3) Cooling tower.
(4) Compressors.
(5) Pumps.

(o) On-site fire training approved by the IDEM.

(p) Purge double block and bleed valves.

(q) Filter or coalescer media change out.

(r) Activities including a micro turbine associated with the following:

(1) Emissions from a laboratory as defined in 326 IAC 2-7-1(21)(G).

(2) Emissions from research and development activities as defined in 326 IAC 2-7-1(21)(H).

(3) Emissions from educational and teaching activities as defined in 326 IAC 2-7-1(21)(I).

(s) Water-based activities, including the following:

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

(2) Water based adhesives that are less than or equal to five percent (5%) by volume of VOCs excluding HAPs.

(t) One maintenance shop paint booth.

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

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

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

(b) It is a source in a source category designated by the United States Environmental Protection Agency (U.S. EPA) under 40 CFR 70.3 (Part 70 - Applicability).

SECTION B GENERAL CONDITIONS

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

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

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

(a) This permit, T141-41227-00013, is issued for a fixed term of five (5) years from the issuance date of this permit, as determined in accordance with IC 4-21.5-3-5(f) and IC 13-15-5-3. Subsequent revisions, modifications, or amendments of this permit do not affect the expiration date of this permit.

(b) If IDEM, OAQ, upon receiving a timely and complete renewal permit application, fails to issue or deny the permit renewal prior to the expiration date of this permit, this existing permit shall not expire and all terms and conditions shall continue in effect, including any permit shield provided in 326 IAC 2-7-15, until the renewal permit has been issued or denied.

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

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

(a) the condition is modified in a subsequent permit action pursuant to Title I of the Clean Air Act; or

(b) the emission unit to which the condition pertains permanently ceases operation.

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

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

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

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

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

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

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

(a) The Permittee shall furnish to IDEM, OAQ, within a reasonable time, any information that IDEM, OAQ may request in writing to determine whether cause exists for modifying, revoking and reissuing, or terminating this permit, or to determine compliance with this permit. Upon request, the Permittee shall also furnish to IDEM, OAQ copies of records required to be kept by this permit.

(b) For information furnished by the Permittee to IDEM, OAQ, the Permittee may include a claim of confidentiality in accordance with 326 IAC 17.1. When furnishing copies of requested records directly to U. S. EPA, the Permittee may assert a claim of confidentiality in accordance with 40 CFR 2, Subpart B.

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

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

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

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

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

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

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

(a) The Permittee shall annually submit a compliance certification report which addresses the status of the source's compliance with the terms and conditions contained in this permit, including emission limitations, standards, or work practices. All certifications shall cover the time period from January 1 to December 31 of the previous year, and shall be submitted no later than April 15 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 5
Air and Radiation Division, Air Enforcement Branch - Indiana (AE-17J)
77 West Jackson Boulevard
Chicago, Illinois 60604-3590

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

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

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

(2) The compliance status;

(3) Whether compliance was continuous or intermittent;

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

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

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

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

(a) A Preventive Maintenance Plan(PMP) meets the requirements of 326 IAC 1-6-3 if it includes, at a minimum:

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

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

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

The Permittee shall implement the PMPs.

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

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

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

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

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

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

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

The Permittee shall implement the PMPs.

(c) A copy of the PMPs shall be submitted to IDEM, OAQ upon request and within a reasonable time, and shall be subject to review and approval by IDEM, OAQ. IDEM, OAQ may require the Permittee to revise its PMPs whenever lack of proper maintenance causes or is the primary contributor to an exceedance of any limitation on emissions. The

PMPs and their submittal do not require a certification that meets the requirements of 326 IAC 2-7-6(1) by a "responsible official" as defined by 326 IAC 2-7-1(35).

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

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

(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 Northern 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
Northern Regional Office phone: (574) 245-4870; fax: (574) 245-4877.

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

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

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

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

(A) A description of the emergency;

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

(C) Corrective actions taken.

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

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

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

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

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

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

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

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

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

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

(b) If, after issuance of this permit, it is determined that the permit is in nonconformance with an applicable requirement that applied to the source on the date of permit issuance, IDEM, OAQ shall immediately take steps to reopen and revise this permit and issue a compliance order to the Permittee to ensure expeditious compliance with the applicable

requirement until the permit is reissued. The permit shield shall continue in effect so long as the Permittee is in compliance with the compliance order.

(c) No permit shield shall apply to any permit term or condition that is determined after issuance of this permit to have been based on erroneous information supplied in the permit application. Erroneous information means information that the Permittee knew to be false, or in the exercise of reasonable care should have been known to be false, at the time the information was submitted.

(d) Nothing in 326 IAC 2-7-15 or in this permit shall alter or affect the following:

(1) The provisions of Section 303 of the Clean Air Act (emergency orders), including the authority of the U.S. EPA under Section 303 of the Clean Air Act;

(2) The liability of the Permittee for any violation of applicable requirements prior to or at the time of this permit's issuance;

(3) The applicable requirements of the acid rain program, consistent with Section 408(a) of the Clean Air Act; and

(4) The ability of U.S. EPA to obtain information from the Permittee under Section 114 of the Clean Air Act.

(e) This permit shield is not applicable to any change made under 326 IAC 2-7-20(b)(2) (Sections 502(b)(10) of the Clean Air Act changes) and 326 IAC 2-7-20(c)(2) (trading based on State Implementation Plan (SIP) provisions).

(f) This permit shield is not applicable to modifications eligible for group processing until after IDEM, OAQ, has issued the modifications. [326 IAC 2-7-12(c)(7)]

(g) This permit shield is not applicable to minor Part 70 permit modifications until after IDEM, OAQ, has issued the modification. [326 IAC 2-7-12(b)(8)]

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

(a) All terms and conditions of permits established prior to T141-41227-00013 and issued pursuant to permitting programs approved into the state implementation plan have been either:

(1) incorporated as originally stated,

(2) revised under 326 IAC 2-7-10.5, or

(3) deleted under 326 IAC 2-7-10.5.

(b) Provided that all terms and conditions are accurately reflected in this combined permit, all previous registrations and permits are superseded by this combined new source review and Part 70 operating permit.

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

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

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

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

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

(1) That this permit contains a material mistake.

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

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

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

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

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

(a) The application for renewal shall be submitted using the application form or forms prescribed by IDEM, OAQ and shall include the information specified in 326 IAC 2-7-4. Such information shall be included in the application for each emission unit at this source, except those emission units included on the trivial or insignificant activities list contained in 326 IAC 2-7-1(21) and 326 IAC 2-7-1(42). The renewal application does require a certification that meets the requirements of 326 IAC 2-7-6(1) by a "responsible official" as defined by 326 IAC 2-7-1(35).

Request for renewal shall be submitted to:

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

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

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

(2) If the date postmarked on the envelope or certified mail receipt, or affixed by the shipper on the private shipping receipt, is on or before the date it is due. If the

document is submitted by any other means, it shall be considered timely if received by IDEM, OAQ on or before the date it is due.

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

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

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

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

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

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

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

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

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

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

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

(a) The Permittee may make any change or changes at the source that are described in 326 IAC 2-7-20(b) 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 5
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(37)) without a permit revision, subject to the constraint of 326 IAC 2-7-20(a). For each such Section 502(b)(10) of the Clean Air Act change, the required written notification shall include the following:

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

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

(3) Any change in emissions; and

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

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

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

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

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

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

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

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

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

(a) Enter upon the Permittee's premises where a Part 70 source is located, or emissions related activity is conducted, or where records must be kept under the conditions of this permit;

(b) As authorized by the Clean Air Act, IC 13-14-2-2, IC 13-17-3-2, and IC 13-30-3-1, have access to and copy any records that must be kept under the conditions of this permit;

(c) As authorized by the Clean Air Act, IC 13-14-2-2, IC 13-17-3-2, and IC 13-30-3-1, inspect any facilities, equipment (including monitoring and air pollution control equipment), practices, or operations regulated or required under this permit;

(d) As authorized by the Clean Air Act, IC 13-14-2-2, IC 13-17-3-2, and IC 13-30-3-1, sample or monitor substances or parameters for the purpose of assuring compliance with this permit or applicable requirements; and

(e) As authorized by the Clean Air Act, IC 13-14-2-2, IC 13-17-3-2, and IC 13-30-3-1, utilize any photographic, recording, testing, monitoring, or other equipment for the purpose of assuring compliance with this permit or applicable requirements.

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

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

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

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

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

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

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

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

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

(c) The Permittee may call the following telephone numbers: 1-800-451-6027 or 317-233-8590 (ask for OAQ, Billing, Licensing, and Training Section), to determine the appropriate permit fee.

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

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

SECTION C SOURCE OPERATION CONDITIONS

Entire Source

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

C.1 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 thirty percent (30%) 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 Part 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.2 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.3 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.4 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.5 Stack Height [326 IAC 1-7]

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

C.6 Asbestos Abatement Projects [326 IAC 14-10] [326 IAC 18] [40 CFR 61, Subpart M]

(a) Notification requirements apply to each owner or operator. If the combined amount of regulated asbestos containing material (RACM) to be stripped, removed or disturbed is at least 260 linear feet on pipes or 160 square feet on other facility components, or at least thirty-five (35) cubic feet on all facility components, then the notification requirements of 326 IAC 14-10-3 are mandatory. All demolition projects require notification whether or not asbestos is present.

(b) The Permittee shall ensure that a written notification is sent on a form provided by the Commissioner at least ten (10) working days before asbestos stripping or removal work or before demolition begins, per 326 IAC 14-10-3, and shall update such notice as necessary, including, but not limited to the following:

(1) When the amount of affected asbestos containing material increases or decreases by at least twenty percent (20%); or

(2) If there is a change in the following:

(A) Asbestos removal or demolition start date;

(B) Removal or demolition contractor; or

(C) Waste disposal site.

(c) The Permittee shall ensure that the notice is postmarked or delivered according to the guidelines set forth in 326 IAC 14-10-3(c).

(d) The notice to be submitted shall include the information enumerated in 326 IAC 14-10-3(d).

All required notifications shall be submitted to:

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

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

(e) Procedures for Asbestos Emission Control
The Permittee shall comply with the applicable emission control procedures in 326 IAC 14-10-4 and 40 CFR 61.145(c). Per 326 IAC 14-10-1, emission control requirements are applicable for any removal or disturbance of RACM greater than three (3) linear feet on pipes or three (3) square feet on any other facility components or a total of at least 0.75 cubic feet on all facility components.

(f) Demolition and Renovation
The Permittee shall thoroughly inspect the affected facility or part of the facility where the demolition or renovation will occur for the presence of asbestos pursuant to 40 CFR 61.145(a).

(g) Indiana Licensed Asbestos Inspector
The Permittee shall comply with 326 IAC 14-10-1(a) that requires the owner or operator, prior to a renovation/demolition, to use an Indiana Licensed Asbestos Inspector to thoroughly inspect the affected portion of the facility for the presence of asbestos. The requirement to use an Indiana Licensed Asbestos inspector is not federally enforceable.

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

C.7 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.8 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.9 Compliance Monitoring [326 IAC 2-7-5(3)][326 IAC 2-7-6(1)]

(a) For new units:
Unless otherwise specified in the approval for the new emission unit(s), compliance monitoring for new emission units shall be implemented on and after the date of initial start-up.

(b) For existing units:
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 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, 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).

C.10 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. The analog instrument shall be capable of measuring values outside of the normal range.

(b) The Permittee may request that the IDEM, OAQ approve the use of an instrument that does not meet the above specifications provided the Permittee can demonstrate that an alternative instrument specification will adequately ensure compliance with permit conditions requiring the measurement of the parameters.

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

C.11 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 maintain the most recently submitted written emergency reduction plans (ERPs) consistent with safe operating procedures.

(b) Upon direct notification by IDEM, OAQ that a specific air pollution episode level is in effect, the Permittee shall immediately put into effect the actions stipulated in the approved ERP for the appropriate episode level. [326 IAC 1-5-3]

C.12 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.13 Response to Excursions or Exceedances [326 IAC 2-7-5] [326 IAC 2-7-6]

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

(a) The Permittee shall take reasonable response steps to restore operation of the emissions unit (including any control device and associated capture system) to its normal or usual manner of operation as expeditiously as practicable in accordance with good air pollution control practices for minimizing excess emissions.

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

(1) initial inspection and evaluation;

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

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

(c) A determination of whether the Permittee has used acceptable procedures in response to an excursion or exceedance will be based on information available, which may include, but is not limited to, the following:

(1) monitoring results;

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

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

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

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

C.14 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.15 Emission Statement [326 IAC 2-7-5(3)(C)(iii)][326 IAC 2-7-5(7)][326 IAC 2-7-19(c)][326 IAC 2-6]

Pursuant to 326 IAC 2-6-3(b)(1), starting in 2004 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(33) (“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.16 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, where applicable:

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

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

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

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

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

(c) 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 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 (as defined in 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.17 General Reporting Requirements [326 IAC 2-7-5(3)(C)] [326 IAC 2-1.1-11] [326 IAC 2-2][326 IAC 2-3]

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

(b) The address for report submittal is:

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

(c) Unless otherwise specified in this permit, any notice, report, or other submission required by this permit shall be considered timely if the date postmarked on the envelope or certified mail receipt, or affixed by the shipper on the private shipping receipt, is on or before the date it is due. If the document is submitted by any other means, it shall be considered timely if received by IDEM, OAQ on or before the date it is due.

(d) Reporting periods are based on calendar years, unless otherwise specified in this permit. For the purpose of this permit "calendar year" means the twelve (12) month period from January 1 to December 31 inclusive.

(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 (oo) and/or 326 IAC 2-3-1 (jj)) 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 a 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.18 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) One (1) No. 2 fuel oil or natural gas fired boiler, identified as B-1, constructed in 1961, with a single low NOx burner and economizer constructed in 2006, and with a maximum design capacity of 137 MMBtu per hour heat input, and exhausting to stack S-1.

[This is an existing affected source under 40 CFR Part 63, Subpart JJJJJJ.]

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

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

D.1.1 Particulate Matter Limitation (PM) - St. Joseph County [326 IAC 6.5-7]

(a) Pursuant to 326 IAC 6.5-7-16 (Particulate emission limitations for sources in St. Joseph County), PM emissions from boiler B-1 shall not exceed 0.087 pounds per million British thermal units heat input.

(b) Pursuant to 326 IAC 6.5-7-16 (Particulate emission limitations for sources in St. Joseph County), PM emissions from boilers B-1 through B-5 shall not exceed a total of 118.7 tons per year.

D.1.2 Opacity [326 IAC 5-1]

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

(a) Opacity shall not exceed an average of thirty percent (30%) 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 Part 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.

D.1.3 Temporary Alternative Opacity Limitations [326 IAC 5-1]

Pursuant to 326 IAC 5-1-3, (Temporary Alternative Opacity Limitations):

(a) When building a new fire in a boiler, or shutting down a boiler, opacity may exceed thirty (30%); however, opacity levels shall not exceed sixty percent (60%) for any six (6) minute averaging period. Opacity in excess of thirty (30%) shall not continue for more than two (2) six (6) minute averaging periods in any twenty-four (24) hour period.

(b) When removing ashes from the fuel bed or furnace in a boiler or blowing tubes, opacity may exceed thirty (30%); however, opacity shall not exceed sixty percent (60%) for any six (6) minute averaging period and opacity in excess of thirty (30%) shall not continue for more than one (1) six (6) minute averaging period in any sixty (60) minute period. The averaging periods shall not be permitted for more than three (3) six (6) minute averaging periods in a twelve (12) hour period.

D.1.4 Sulfur Dioxide Emission Limitations [326 IAC 7-1.1][326 IAC 7-2-1]

Pursuant to 326 IAC 7-1.1-2(a)(3) (SO_2 Emissions Limitations), the SO_2 emissions from boiler B-1 shall not exceed five-tenths (0.5) pounds per MMBtu heat input when combusting No. 2 fuel oil only. Pursuant to 326 IAC 7-2-1, compliance shall be demonstrated on a calendar month average.

D.1.5 Preventive Maintenance Plan [326 IAC 2-7-5(12)]

A Preventive Maintenance Plan is required for this facility. Section B - Preventive Maintenance Plan contains the Permittee's obligation with regard to the preventive maintenance plan required by this condition.

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

D.1.6 Sulfur Dioxide Emissions and Sulfur Content [326 IAC 3][326 IAC 7-2][326 IAC 7-1.1-2]

In order to demonstrate compliance with Condition D.1.4, the Permittee shall determine SO2 emissions from boiler B-1 when using distillate oil (No. 2 fuel oil), or fuel oil in combination with natural gas, by using one of the following options.

(a) Pursuant to 326 IAC 3-7-4, the Permittee shall demonstrate that the sulfur dioxide emissions do not exceed five-tenths (0.5) pounds per MMBtu heat input by:

(1) Providing vendor analysis of fuel delivered, if accompanied by a certification, or analyses from approved modified procedures specified in 326 IAC 3-7-4(a), or the use of alternate equivalent procedures, as implemented;

(2) Analyzing the oil sample to determine the sulfur content of the oil via the procedures in 40 CFR Part 60, Appendix A, Method 19.

(A) Oil samples may be collected from the fuel tank immediately after the fuel tank is filled and before any oil is combusted; and

(B) If a partially empty fuel tank is refilled, a new sample and analysis would be required upon filling; or

(b) Conducting a stack test for sulfur dioxide emissions from boiler B-1 when using distillate fuel, using 40 CFR Part 60, Appendix A, Method 6 in accordance with the procedures in 326 IAC 3-6.

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

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

D.1.7 Visible Emissions Notations

(a) Visible emission (VE) notations from the boiler, identified as Boiler B-1 exhausting to stack S-1, shall be performed once per day during normal daylight operations when burning oil. A trained employee shall record whether emissions are normal or abnormal.

(b) For processes operated continuously, “normal” means those conditions prevailing, or expected to prevail, eighty percent (80%) of the time the process is in operation, not counting startup or shut down time.

(c) In the case of batch or discontinuous operations, readings shall be taken during that part of the operation that would normally be expected to cause the greatest emissions.

(d) A trained employee is an employee who has worked at the plant at least one (1) month and has been trained in the appearance and characteristics of normal visible emissions for the boiler.

(e) If abnormal emissions are observed, the Permittee shall take a reasonable response. Section C - Response to Excursions and Exceedances contains the Permittee's obligation with regard to the reasonable response steps required by this condition. Failure to take a reasonable response 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.1.8 Record Keeping Requirement

(a) To document the compliance status with Condition D.1.4, the Permittee shall maintain records in accordance with (1) through (6) below. Records maintained for (1) through (6) shall be taken monthly and shall be complete and sufficient to establish compliance with the SO_2 emission limit established in Condition D.1.4.

(1) Calendar dates covered in the compliance determination period;

(2) Actual fuel oil usage since last compliance determination period and equivalent sulfur dioxide emissions;

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

If the fuel supplier certification is used to demonstrate compliance the following, as a minimum, shall be maintained:

(4) Fuel supplier certifications;

(5) The name of the fuel supplier; and

(6) A statement from the fuel supplier that certifies the sulfur content and heat content of the fuel oil.

(b) To document the compliance status with Condition D.1.7, the Permittee shall maintain records of visible emission notations of stack exhaust from stack S-1. The Permittee shall include in its daily record when a visible emission notation is not taken and the reason for the lack of visible emission notation (e.g. the process did not operate that day).

(c) Section C - General Record Keeping Requirements contains the Permittee's obligations with regard to the records required by this condition.

SECTION D.2 EMISSIONS UNIT OPERATION CONDITIONS

Emissions Unit Description:

(b) Two (2) natural gas fired boilers, identified as B-2 and B-3, constructed in 1952, and modified in 2019 to remove coal firing capacity, with maximum design capacity of 96 MMBtu per hour heat input, each, each equipped with low NOx burners when using natural gas, and exhausting to stack S-1.

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

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

D.2.1 Particulate Matter Limitations Except Lake County [326 IAC 6.5-7]

(a) Pursuant to 326 IAC 6.5-7-16 (Particulate emission limitations for sources in St. Joseph County), PM emissions from each boiler B-2 and B-3 shall not exceed 0.28 pounds per million British thermal units heat input.

(b) Pursuant to 326 IAC 6.5-7-16 (Particulate emission limitations for sources in St. Joseph County), PM emissions from boilers B-1 through B-5 shall not exceed a total of 118.7 tons per year.

D.2.2 Opacity [326 IAC 5-1]

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

(a) Opacity shall not exceed an average of thirty percent (30%) 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 Part 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.

D.2.3 Temporary Alternative Opacity Limitations [326 IAC 5-1]

Pursuant to 326 IAC 5-1-3, (Temporary Alternative Opacity Limitations):

(a) When building a new fire in a boiler, or shutting down a boiler, opacity may exceed thirty (30%); however, opacity levels shall not exceed sixty percent (60%) for any six (6) minute averaging period. Opacity in excess of thirty (30%) shall not continue for more than two (2) six (6) minute averaging periods in any twenty-four (24) hour period.

(b) When removing ashes from the fuel bed or furnace in a boiler or blowing tubes, opacity may exceed thirty (30%); however, opacity shall not exceed sixty percent (60%) for any six (6) minute averaging period and opacity in excess of thirty (30%) shall not continue for more than one (1) six (6) minute averaging period in any sixty (60) minute period. The averaging periods shall not be permitted for more than three (3) six (6) minute averaging periods in a twelve (12) hour period.

D.2.4 Reserved

D.2.5 Preventive Maintenance Plan [326 IAC 2-7-5(12)]

A Preventive Maintenance Plan is required for this facility. Section B - Preventive Maintenance Plan contains the Permittee's obligation with regard to the preventive maintenance plan required by this condition.

SECTION D.3 EMISSIONS UNIT OPERATION CONDITIONS

Emissions Unit Description:

(c) One (1) natural gas or No. 2 fuel oil fired boiler, identified as B-4, constructed in 1966, and modified in 2018 to remove coal firing capacity, with a maximum design capacity of 234 MMBtu per hour heat input, and exhausting to stack S-2.

[This is an existing affected source under 40 CFR Part 63, Subpart JJJJJJ.]

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

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

D.3.1 Particulate Matter Limitations Except Lake County [326 IAC 6.5-7]

(a) Pursuant to 326 IAC 6.5-7-16 (Particulate emission limitations for sources in St. Joseph County), PM emission limitations for boiler B-4 shall not exceed 0.17 pounds per million British thermal units heat input.

(b) Pursuant to 326 IAC 6.5-7-16 (Particulate emission limitations for sources in St. Joseph County), PM emissions from boilers B-1 through B-5 shall not exceed a total of 118.7 tons per year.

D.3.2 Opacity [326 IAC 5-1]

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

(a) Opacity shall not exceed an average of thirty percent (30%) 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 Part 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.

D.3.3 Temporary Alternative Opacity Limitations [326 IAC 5-1]

Pursuant to 326 IAC 5-1-3, (Temporary Alternative Opacity Limitations):

(a) When building a new fire in a boiler, or shutting down a boiler, opacity may exceed thirty percent (30%); however, opacity levels shall not exceed sixty percent (60%) for any six (6) minute averaging period. Opacity in excess of thirty (30%) shall not continue for more than two (2) six (6) minute averaging periods in any twenty-four (24) hour period.

(b) When removing ashes from the fuel bed or furnace in a boiler or blowing tubes, opacity may exceed thirty percent (30%); however, opacity shall not exceed sixty percent (60%) for any six (6) minute averaging period and opacity in excess of thirty percent (30%) shall not continue for more than one (1) six (6) minute averaging period in any sixty (60) minute period. The averaging periods shall not be permitted for more than three (3) six (6) minute averaging periods in a twelve (12) hour period.

D.3.4 Sulfur Dioxide Emission Limitations [326 IAC 7-1.1-2][326 IAC 7-2-1]

Pursuant to 326 IAC 7-1.1(a)(3) (SO_2 Emissions Limitations), the SO_2 emissions from boiler B-4 shall not exceed five-tenths (0.5) pounds per MMBtu heat input when combusting No. 2 fuel oil only. Pursuant to 326 IAC 7-2-1, compliance shall be demonstrated on a calendar month average.

D.3.5 Preventive Maintenance Plan [326 IAC 2-7-5(12)]

A Preventive Maintenance Plan is required for this facility. Section B - Preventive Maintenance Plan contains the Permittee's obligation with regard to the preventive maintenance plan required by this condition.

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

D.3.6 Reserved

D.3.7 Reserved

D.3.8 Reserved

D.3.9 Reserved

D.3.10 Sulfur Dioxide Emissions and Sulfur Content [326 IAC 3][326 IAC 7-2][326 IAC 7-1.1-2]

In order to demonstrate compliance with Condition D.3.4, the Permittee shall determine SO2 emissions from boiler B-4 when using distillate oil (No.2 fuel oil), or fuel oil in combination with natural gas, by utilizing one of the following options.

(a) Pursuant to 326 IAC 3-7-4, the Permittee shall demonstrate that the sulfur dioxide emissions do not exceed five-tenths (0.5) pounds per MMBtu by:

(1) Providing vendor analysis of fuel delivered, if accompanied by a certification, or analyses from approved modified procedures specified in 326 IAC 3-7-4(a), or the use of alternate equivalent procedures, as implemented;

(2) Analyzing the oil sample to determine the sulfur content of the oil via the procedures in 40 CFR Part 60, Appendix A, Method 19.

(A) Oil samples may be collected from the fuel tank immediately after the fuel tank is filled and before any oil is combusted; and

(B) If a partially empty fuel tank is refilled, a new sample and analysis would be required upon filling; or

(b) Conducting a stack test for sulfur dioxide emissions from boiler B-4 when using distillate fuel, using 40 CFR Part 60, Appendix A, Method 6 in accordance with the procedures in 326 IAC 3-6.

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

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

D.3.11 Visible Emissions Notations

(a) Visible emission (VE) notations from the boiler, identified as Boiler B-4 exhausting to stack S-2, shall be performed once per day during normal daylight operations when burning oil. A trained employee shall record whether emissions are normal or abnormal.

(b) For processes operated continuously, “normal” means those conditions prevailing, or expected to prevail, eighty percent (80%) of the time the process is in operation, not counting startup or shut down time.

(c) In the case of batch or discontinuous operations, readings shall be taken during that part of the operation that would normally be expected to cause the greatest emissions.

(d) A trained employee is an employee who has worked at the plant at least one (1) month and has been trained in the appearance and characteristics of normal visible emissions for the boiler.

(e) If abnormal emissions are observed, the Permittee shall take a reasonable response. Section C - Response to Excursions and Exceedances contains the Permittee's obligation with regard to the reasonable response steps required by this condition. Failure to take a reasonable response shall be considered a deviation from this permit.

D.3.12 Reserved

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

D.3.13 Record Keeping Requirements

(a) To document the compliance status with Condition D.3.4, the Permittee shall maintain records in accordance with (1) through (6) below. Records maintained for (1) through (6) shall be taken monthly and shall be complete and sufficient to establish compliance with the SO_2 emission limit established in Condition D.3.4.

(1) Calendar dates covered in the compliance determination period;

(2) Calendar month average sulfur content, fuel consumption, and sulfur dioxide emission rate in pounds per MMBtu;

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

If the fuel supplier certification is used to demonstrate compliance the following, as a minimum, shall be maintained:

(4) Fuel supplier certifications;

(5) The name of the fuel supplier; and

(6) A statement from the fuel supplier that certifies the sulfur content, and heat content of the fuel oil.

(b) To document the compliance status with Condition D.3.11, the Permittee shall maintain a daily record of visible emission notations of stack exhaust from stack S-2. The Permittee shall include in its daily record when a visible emission notation is not taken and the

reason for the lack of visible emission notation (e.g. the process did not operate that day or did not operate on oil).

(c) Section C - General Reporting Requirements contains the Permittee's obligations with regard to the records required by this condition.

SECTION D.4 EMISSIONS UNIT OPERATION CONDITIONS

Emissions Unit Description:

(d) One (1) No. 2 fuel oil or natural gas fired boiler, identified as B-5, constructed in 1973, with a maximum design capacity of 244.5 MMBtu per hour heat input, equipped with low NOx burner for natural gas and fuel oil, and exhausting to stack S-3.

[This is an existing affected source under 40 CFR Part 63, Subpart JJJJJJ.]

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

D.4.1 Particulate Matter Limitation (PM) [326 IAC 6.5-7]

(a) Pursuant to 326 IAC 6.5-7-16 (Particulate emission limitations for sources in St. Joseph County), PM emission limitations for boiler B-5 shall not exceed 0.02 pounds per million British thermal units heat input.

(b) Pursuant to 326 IAC 6.5-7-16 (Particulate emission limitations for sources in St. Joseph County), PM emissions from boilers B-1 through B-5 shall not exceed a total of 118.7 tons per year.

D.4.2 Opacity [326 IAC 5-1]

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

(a) Opacity shall not exceed an average of thirty percent (30%) 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 Part 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.

D.4.3 Temporary Alternative Opacity Limitations [326 IAC 5-1]

Pursuant to 326 IAC 5-1-3, (Temporary Alternative Opacity Limitations):

(a) When building a new fire in a boiler, or shutting down a boiler, opacity may exceed thirty (30%); however, opacity levels shall not exceed sixty percent (60%) for any six (6) minute averaging period. Opacity in excess of thirty (30%) shall not continue for more than two (2) six (6) minute averaging periods in any twenty-four (24) hour period.

(b) When removing ashes from the fuel bed or furnace in a boiler or blowing tubes, opacity may exceed thirty (30%); however, opacity shall not exceed sixty percent (60%) for any six (6) minute averaging period and opacity in excess of thirty (30%) shall not continue for more than one (1) six (6) minute averaging period in any sixty (60) minute period. The averaging periods shall not be permitted for more than three (3) six (6) minute averaging periods in a twelve (12) hour period.

D.4.4 Sulfur Dioxide Emission Limitations [326 IAC 7-1.1-2][326 IAC 7-2-1]

Pursuant to 326 IAC 7-1.1(a)(3) (SO_2 Emissions Limitations), the SO_2 emissions from boiler B-5 shall not exceed five-tenths (0.5) pounds per MMBtu heat input when combusting No. 2 fuel oil only. Pursuant to 326 IAC 7-2-1, compliance shall be demonstrated on a calendar month average.

D.4.5 Preventive Maintenance Plan [326 IAC 2-7-5(12)]

A Preventive Maintenance Plan is required for this facility. Section B - Preventive Maintenance Plan contains the Permittee's obligation with regard to the preventive maintenance plan required by this condition.

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

D.4.6 Sulfur Dioxide Emissions and Sulfur Content [326 IAC 3][326 IAC 7-2][326 IAC 7-1.1-2]

In order to demonstrate compliance with Condition D.4.4 the Permittee shall determine SO2 emissions from boiler B-5, when using distillate oil (No.2 fuel oil), or fuel oil in combination with natural gas, by utilizing one of the following options.

(a) Pursuant to 326 IAC 3-7-4, the Permittee shall demonstrate that the sulfur dioxide emissions do not exceed five-tenths (0.5) pounds per MMBtu heat input by:

(1) Providing vendor analysis of fuel delivered, if accompanied by a certification, or analyses from approved modified procedures specified in 326 IAC 3-7-4(a), or the use of alternate equivalent procedures, as implemented;

(2) Analyzing the oil sample to determine the sulfur content of the oil via the procedures in 40 CFR Part 60, Appendix A, Method 19.

(A) Oil samples may be collected from the fuel tank immediately after the fuel tank is filled and before any oil is combusted; and

(B) If a partially empty fuel tank is refilled, a new sample and analysis would be required upon filling; or

(b) Conducting a stack test for sulfur dioxide emissions from boiler B-5 when using distillate fuel, using 40 CFR Part 60, Appendix A, Method 6 in accordance with the procedures in 326 IAC 3-6.

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

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

D.4.7 Visible Emissions Notations

(a) Visible emission (VE) notations from the boiler, identified as Boiler B-5 exhausting to stack S-3, shall be performed once per day during normal daylight operations when burning oil. A trained employee shall record whether emissions are normal or abnormal.

(b) For processes operated continuously, “normal” means those conditions prevailing, or expected to prevail, eighty percent (80%) of the time the process is in operation, not counting startup or shut down time.

(c) In the case of batch or discontinuous operations, readings shall be taken during that part of the operation that would normally be expected to cause the greatest emissions.

(d) A trained employee is an employee who has worked at the plant at least one (1) month and has been trained in the appearance and characteristics of normal visible emissions for the boiler.

(e) If abnormal emissions are observed, the Permittee shall take a reasonable response. Section C - Response to Excursions and Exceedances contains the Permittee's

obligation with regard to the reasonable response steps required by this condition. Failure to take a reasonable response 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.4.8 Record Keeping Requirements

(a) To document the compliance status with Condition D.4.4, the Permittee shall maintain records in accordance with (1) through (6) below. Records maintained for (1) through (6) shall be taken monthly and shall be complete and sufficient to establish compliance with the SO_2 emission limit established in Condition D.4.4.

(1) Calendar dates covered in the compliance determination period;

(2) Calendar month average sulfur content, fuel consumption, and sulfur dioxide emission rate in pounds per MMBtu;

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

If the fuel supplier certification is used to demonstrate compliance the following, as a minimum, shall be maintained:

(4) Fuel supplier certifications;

(5) The name of the fuel supplier; and

(6) A statement from the fuel supplier that certifies the sulfur content, and heat content of the fuel oil.

(b) To document the compliance status with Condition D.4.7, the Permittee shall maintain a daily record of visible emission notations of stack exhaust from stack S-3. The Permittee shall include in its daily record when a visible emission notation is not taken and the reason for the lack of visible emission notation (e.g. the process did not operate that day or did not operate on oil).

(c) Section C - General Reporting Requirements contains the Permittee's obligations with regard to the records required by this condition.

SECTION D.5 EMISSIONS UNIT OPERATION CONDITIONS

Emissions Unit Description:

(f) Three (3) diesel-fired generators, identified as G-8, G-9 and G-10, constructed before July 11, 2005 (permitted in 2003), each with a maximum rated capacity of 2,593 brake horsepower, equipped with oxidation catalysts, and exhausting to stacks S-6, S-7 and S-8, respectively.

[These generators are an affected source under 40 CFR Part 63, Subpart ZZZZ.]

Specifically Regulated Insignificant

(f) Specifically Regulated Insignificant emergency engines consisting of the following:

*****

(2) Diesel fired compression ignition emergency engines, each with a capacity less than or equal to 500 Hp, manufactured/modified/ constructed/reconstructed on or after June 12, 2006.

Location	Engine Rating	Year of Manufacture
MVAP Complex	168	2009
Nanotechnology Research Ctr.	201	2006
Stayer Center	201	2012
Innovation Park Building 1	335	2009
Compton Ice Arena	335	2011
Eck Law School	402	2007
Morris Inn	235	2013
Jenkins-Nanovic Hall	385	2016
Sacred Heart Basilica	134	2019

[These are new affected source under 40 CFR Part 60, Subpart IIII]
[These are new affected source under 40 CFR Part 63, Subpart ZZZZ]

*****

(4) Diesel fired compression ignition emergency engines, each with a capacity greater than 500 HP and not exceeding 1600 Hp, manufactured/modified/constructed/ reconstructed on or after June 12, 2006.

Location	Generator Rating	Year of Manufacture
Well #9	536	2012
Joyce Center	671	2013

Hesburgh Library #1	671	2013
Hesburgh Library #2	671	2013
Galvin Life Sciences	755	2015
Nieuwland	755	2015
Stinson-Remick	1,073	2010
McCourtney Hall	1,220	2016
Stadium 1	1,474	2016
Stadium 2	1,474	2016
Stepan Chemistry	755	2019
Fitzpatrick	755	2019

[These are new affected source under 40 CFR Part 60, Subpart IIII]
[These are new affected source under 40 CFR Part 63, Subpart ZZZZ]

*****

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

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

D.5.1 PSD Minor Limit for PM_{10} [326 IAC 2-2]

The Permittee shall comply with the following:

(a) The combined fuel usage from the diesel-fired generator units (G-8, G-9, and G-10) shall be limited to less than 3,076,600 gallons of diesel fuel per twelve (12) consecutive month period, with compliance determined at the end of each month.

(b) The PM_{10} emissions shall not exceed 0.0097 lb. PM_{10}/gallon diesel oil burned.

Compliance with these limits shall limit the potential to emit of PM_{10} (including filterable and condensable) emissions from the diesel-fired generators (G-8, G-9 and G-10), to less than fifteen (15) tons per twelve (12) consecutive month period and shall render the requirements of 326 IAC 2-2 (PSD) not applicable to G8, G9, and G10 permitted under SSM 141-15828-00013.

D.5.2 Prevention of Significant Deterioration (PSD) for NOx and SO_2 [326 IAC 2-2-5][326 IAC 2-2-6]

Pursuant to PSD Significant Source Modification 141-15828-00013, issued on April 30, 2003, and 326 IAC 2-2-5 and 2-2-6 (PSD Requirements: Air Quality Impacts and Increment Consumption);

(a) NO_X emissions from each diesel-fired generator unit (G-8, G-9, and G-10) shall be controlled using retarded ignition timing, and shall not exceed 37.44 pounds per hour.

(b) SO_2 emissions from each diesel-fired generator unit (G-8, G-9, and G-10) shall not exceed 6.7 pounds per hour.

D.5.3 Particulate Emission Limitations [326 IAC 6.5-1-2]

Pursuant to 326 IAC 6.5-1-2(a), particulate matter emissions from each of the generators listed above shall not exceed 0.03 grain per dry standard cubic foot (gr/dscf).

D.5.4 Particulate Emission Limitations [326 IAC 6-3-2]

Pursuant to the Agreed Order 04-A-J-3402 and 326 IAC 6-3-2, the particulate emission rate for generators G-3 and G-4 shall be determined by the table in 326 IAC 6-3-2(e) or the following equation:

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

D.5.5 Opacity [326 IAC 5-1]

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

(a) Opacity shall not exceed an average of thirty percent (30%) 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 Part 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.

D.5.6 Sulfur Dioxide Emission Limitations [326 IAC 7-1.1-1][326 IAC 7-2-1]

Pursuant to 326 IAC 7-1.1(a)(3) (SO_2 Emissions Limitations), the SO_2 emissions from each diesel-fired generator (G-8, G-9, and G-10) shall not exceed five-tenths (0.5) pounds per MMBtu heat input. Pursuant to 326 IAC 7-2-1, compliance shall be demonstrated on a calendar month average.

D.5.7 Preventive Maintenance Plan [326 IAC 2-7-5(12)]

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

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

D.5.8 Testing Requirements [326 IAC 2-1.1-11]

No testing for PM_{10} is required for these generators unless the fuel usage for generators G-8, G-9 and G-10 is greater than 2,461,280 gallons of diesel fuel per twelve (12) consecutive month period. If diesel fuel usage is greater than 2,461,280 gallons of diesel fuel per twelve (12) consecutive month period, not later than 180 days after the month in which it has exceeded the diesel fuel usage limit, the Permittee shall perform PM_{10} testing of on a representative number of diesel-fired generators, utilizing methods approved by the commissioner. In the event that the fuel usage threshold is re-triggered during any other 12 consecutive month period, retesting shall not be required, provided that no modifications have been made to the engines which may significantly change the emission profile. 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} includes filterable and condensable PM.

D.5.9 Sulfur Dioxide Emissions and Sulfur Content [326 IAC 3][326 IAC 7-2][326 IAC 7-1.1-2]

(a) Pursuant to 326 IAC 3-7-4, the Permittee shall demonstrate that the sulfur dioxide emissions from each of the diesel-fired generators (G-8, G-9, and G-10) do not exceed five-tenths (0.5) pounds per million Btu heat input by:

(1) Providing vendor analysis of fuel delivered, if accompanied by a vendor certification, or analyses from approved modified procedures specified in 326 IAC

3-7-4(a), or the use of alternate equivalent procedures, as implemented;

(2) Analyzing the oil sample to determine the sulfur content of the oil via the procedures in 40 CFR Part 60, Appendix A, Method 19.

(A) Oil samples may be collected from the fuel tank immediately after the fuel tank is filled and before any oil is combusted; and

(B) If a partially empty fuel tank is refilled, a new sample and analysis would be required upon filling.

(b) Compliance may also be determined by conducting a stack test for sulfur dioxide emissions from the diesel-fired generators (G-8, G-9 and G-10), using 40 CFR Part 60, Appendix A, Method 6 in accordance with the procedures in 326 IAC 3-6.

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

D.5.10 Sulfur Dioxide Emissions and Sulfur Content

In order to comply with Condition D.5.2(b), the Permittee shall combust diesel fuel containing sulfur content less than three-tenths (0.3) percent, in the generators (G-8, G-9, and G-10). Compliance can be demonstrated by the following:

(1) Providing vendor analysis of fuel delivered, if accompanied by a vendor certification, or analyses from approved modified procedures specified in 326 IAC 3-7-4(a), or the use of alternate equivalent procedures, as implemented;

(2) Analyzing the oil sample to determine the sulfur content of the oil via the procedures in 40 CFR Part 60, Appendix A, Method 19.

(A) Oil samples may be collected from the fuel tank immediately after the fuel tank is filled and before any oil is combusted; and
(B) If a partially empty fuel tank is refilled, a new sample and analysis would be required upon filling.

(b) Compliance may also be determined by conducting a stack test for sulfur dioxide emissions from the diesel-fired generators (G-8, G-9 and G-10), using 40 CFR Part 60, Appendix A, Method 6 in accordance with the procedures in 326 IAC 3-6.

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

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

D.5.11 Visible Emissions Notations [326 IAC 2-7-6(1)][326 IAC 2-7-5(1)]

(a) Visible emission (VE) notations from the diesel-fired generators, identified as G-8, G-9 and G-10, respectively exhausting to stacks (S-6, S-7 and S-8 respectively) shall be performed once per day during normal daylight operations. A trained employee shall record whether emissions are normal or abnormal.

(b) For processes operated continuously, “normal” means those conditions prevailing, or expected to prevail, eighty percent (80%) of the time the process is in operation, not counting startup or shut down time.

(c) In the case of batch or discontinuous operations, readings shall be taken during that part of the operation that would normally be expected to cause the greatest emissions.

(d) A trained employee is an employee who has worked at the plant at least one (1) month and has been trained in the appearance and characteristics of normal visible emissions for the boiler.

(e) If abnormal emissions are observed, the Permittee shall take a reasonable response. Section C - Response to Excursions and Exceedances contains the Permittee's obligation with regard to the reasonable response steps required by this condition. Failure to take a reasonable response 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.5.12 Record Keeping Requirements

(a) To document the compliance status with Condition D.5.1(a), the Permittee shall record the combined monthly fuel usage of the diesel-fired generators (G-8, G-9, and G-10).

(b) To document the compliance status with Condition D.5.6, the Permittee shall maintain records in accordance with (1) through (6) below. Records maintained for (1) through (6) shall be taken monthly and shall be complete and sufficient to establish compliance with the SO_2 emission limits established in Condition D.5.6.

(1) Calendar dates covered in the compliance determination period;

(2) Calendar month average sulfur content, fuel consumption, and sulfur dioxide emission rate in pounds per MMBtu;

(3) Actual diesel fuel usage since last compliance determination period and equivalent SO_2 emissions; and

If the fuel supplier certification is used to demonstrate compliance, when burning alternate fuels and not determining compliance pursuant to 326 IAC 3-7-4, the following, as a minimum, shall be maintained:

(4) Fuel supplier certifications;

(5) The name of the fuel supplier; and,

(6) A statement from the fuel supplier that certifies the sulfur content of the diesel fuel.

(c) To document the compliance status with Condition D.5.11, the Permittee shall maintain a daily record of visible emission notations of stack exhaust from stacks S-6, S-7, and S-8. The Permittee shall include in its daily record when a visible emission notation is not taken and the reason for the lack of visible emission notation (e.g. the process did not operate that day).

(d) To document the compliance status with Condition D.5.10, the Permittee shall maintain a record of sulfur content of diesel oil combusted in the generators G8, G9, and G10.

If the fuel supplier certification is used to demonstrate compliance, when burning alternate fuels and not determining compliance pursuant to 326 IAC 3-7-4, the following, as a minimum, shall be maintained:

(4) Fuel supplier certifications;

(5) The name of the fuel supplier; and,

(6) A statement from the fuel supplier that certifies the sulfur content of the diesel fuel.

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

D.5.13 Reporting Requirements

A quarterly summary of the information to document the compliance status with Condition D.5.1(a) shall be submitted using the reporting form located at the end of this permit, or its equivalent, not later than thirty (30) days after the end of the quarter being reported. Section C - General Reporting contains the Permittee's obligation with regard to the reporting required by this condition. The report submitted by the Permittee does require a certification that meets the requirements of 326 IAC 2-7-6(1) by a “responsible official” as defined by 326 IAC 2-7-1(35).

SECTION D.6 EMISSIONS UNIT OPERATION CONDITIONS

Emissions Unit Description:

(e) One (1) natural gas fired boiler, identified as B-6, constructed in 2006, with a maximum design capacity of 249 MMBtu per hour heat input, equipped with a low NOx burner and flue gas recirculation (FGR), using No. 2 fuel oil as a backup fuel, and exhausting to stack S-9, monitored by certified COM and NOx CEM.

[This is an affected source under CFR Part 60, Subpart Db.]

[This is an existing affected source under 40 CFR Part 63, Subpart JJJJJJ]

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

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

D.6.1 Particulate Matter Limitation (PM) [326 IAC 6.5-1-2]

Pursuant to 326 IAC 6.5-1-2 (b) (2) and (3), total PM emissions from Boiler B-6 shall not exceed 0.15 pounds per MMBtu heat input when combusting No. 2 fuel oil, or 0.01 grains per dry standard cubic foot when combusting natural gas, respectively.

D.6.2 Prevention of Significant Deterioration (PSD) for Particulate Matter (PM10) [326 IAC 2-2-5][326 IAC 2-2-6]

Pursuant to PSD Significant Source Modification 141-20012-00013, issued on August 24, 2005, and 326 IAC 2-2-5 and 2-2-6 (PSD Requirements: Air Quality Impacts and Increment Consumption); the PM_{10} emissions from Boiler B-6 shall be limited to less than 0.014 lb/MMBtu and 15.58 tons per twelve (12) month consecutive period when burning No. 2 fuel oil or 0.008 lb/MMBtu and 8.29 tons per twelve (12) month consecutive period when burning natural gas.

D.6.3 Opacity [326 IAC 5-1]

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

(a) Opacity shall not exceed an average of thirty percent (30%) 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 Part 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.

D.6.4 Temporary Alternative Opacity Limitations [326 IAC 5-1]

Pursuant to 326 IAC 5-1-3, (Temporary Alternative Opacity Limitations):

(a) When building a new fire in a boiler, or shutting down a boiler, opacity may exceed thirty (30%); however, opacity levels shall not exceed sixty percent (60%) for any six (6) minute averaging period. Opacity in excess of thirty (30%) shall not continue for more than two (2) six (6) minute averaging periods in any twenty-four (24) hour period.

(b) When removing ashes from the fuel bed or furnace in a boiler or blowing tubes, opacity may exceed thirty (30%); however, opacity shall not exceed sixty percent (60%) for any six (6) minute averaging period and opacity in excess of thirty (30%) shall not continue for

more than one (1) six (6) minute averaging period in any sixty (60) minute period. The averaging periods shall not be permitted for more than three (3) six (6) minute averaging periods in a twelve (12) hour period.

D.6.5 Preventive Maintenance Plan [326 IAC 2-7-5(12)]

A Preventive Maintenance Plan is required for this facility. Section B - Preventive Maintenance Plan contains the Permittee's obligation with regard to the preventive maintenance plan required by this condition.

D.6.6 Prevention of Significant Deterioration (PSD) for SO_2 [326 IAC 2-2-5][326 IAC 2-2-6][326 IAC 7-1.1]

Pursuant to PSD Significant Source Modification 141-20012-00013, issued on August 24, 2005, and 326 IAC 2-2-5 and 2-2-6 (PSD Requirements: Air Quality Impacts and Increment Consumption); and 326 IAC 7-1.1-2 (Sulfur Dioxide Emission Limitations), SO_2 emissions from Boiler B-6 shall be limited to less than 0.5 pounds per MMBtu and 545.31 tons per twelve month consecutive period when burning No. 2 fuel oil.

D.6.7 Prevention of Significant Deterioration (PSD) for CO [326 IAC 2-2-5][326 IAC 2-2-6]

Pursuant to 326 IAC 2-2-5 and 326 IAC 2-2-6 (PSD Requirements: Air Quality Impacts and Increment Consumption), CO emissions from Boiler B-6 shall be limited to 0.295 lb/MMBtu and 321.73 tons per twelve (12) month consecutive period when burning No. 2 fuel oil or 0.084 lb/MMBtu and 91.61 tons per twelve (12) month consecutive period when burning natural gas.

D.6.8 Emission Offset Minor Limit for NOx [326 IAC 2-3]

Pursuant to 326 IAC 2-3 (Emission Offset), NOx emissions from Boiler B-6, for gas and oil firing combined, shall be less than forty (40) tons per twelve (12) consecutive month period with compliance determined by the continuous emissions monitoring system (CEMS) or other means approved by the department.

When burning natural gas, the Boiler B-6 shall be operated with low NOX burners and a flue gas recirculation rate necessary to achieve a NOX emissions rate of 0.036 lb/MMBtu.

Compliance with this limit shall render 326 IAC 2-3 (Emission Offset) not applicable to the installation of Boiler B-6, permitted under SSM No.141-20012-00013.

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

D.6.9 Fuel Oil Sulfur Content Limit

To demonstrate compliance with condition D.6.6; when Boiler B-6 combusts fuel oil, the sulfur content of the fuel oil combusted shall not exceed 0.5 percent by weight. Sulfur content will be demonstrated to have met this limit pursuant to 326 IAC 3-7-4. During No. 2 fuel oil combustion, Boiler B-6 will combust only very low sulfur oil as defined in 40 CFR Part 60, Subpart Db.

D.6.10 Sulfur Dioxide Emissions and Sulfur Content [326 IAC 3][326 IAC 7-2][326 IAC 7-1.1-2]

(a) Pursuant to 326 IAC 7-2-1(c)(3), the Permittee shall demonstrate that when combusting fuel oil in Boiler B-6, the sulfur dioxide emissions do not exceed the equivalent of 0.5 pounds per MMBtu, using a calendar month average.

(b) Pursuant to 326 IAC 7-2-1(e) and 326 IAC 3-7-4, fuel sampling and analysis data shall be collected as follows:

(1) The Permittee may, with the prior approval of the department, modify the procedures specified in 326 IAC 3-7-4(a), use alternate equivalent procedures, or rely upon vendor analysis of fuel delivered, if accompanied by a vendor certification [326 IAC 3-7-4(b)]; or,

(2) The Permittee shall perform sampling and analysis of fuel oil samples in accordance with 326 IAC 3-7-4(a).

(A) Oil samples shall be collected from the tanker truck load prior to transferring fuel to the storage tank; or
(B) Oil samples shall be collected from the storage tank immediately after each addition of fuel to the tank.

D.6.11 Continuous Opacity Monitoring [326 IAC 3-5]

(a) Pursuant to 326 IAC 3-5 (Continuous Monitoring of Emissions), the continuous opacity monitoring system (COM) for boiler B-6, when combusting fuel oil, shall be calibrated, maintained, and operated for measuring opacity which meet all applicable performance specifications of 326 IAC 3-5-2.

(b) The continuous opacity monitoring system (COM) is subject to the monitor system certification requirements pursuant to 326 IAC 3-5-3.

(c) The Permittee shall install, calibrate, maintain, and operate all necessary continuous opacity monitoring systems (COM) and related equipment. The COMS shall be in operation at all times that the induced draft fan is in operation, except as provided otherwise in the Section D requirements.

(d) All COMS shall meet the performance specifications of 40 CFR Part 60, Appendix B, Performance Specification No. 1, and are subject to monitor system certification requirements pursuant to 326 IAC 3-5.

(e) In the event that a breakdown of a COMS occurs, a record shall be made of the times and reasons of the breakdown and efforts made to correct the problem.

(f) Whenever a COMS is malfunctioning or is down for maintenance or repairs for a period of twenty-four (24) hours or more and a backup COMS is not online within twenty-four (24) hours of shutdown or malfunction of the primary COMS, the Permittee shall provide a certified opacity reader, who may be an employee of the Permittee or an independent contractor, to self-monitor the emissions from the emission unit stack.

(1) Visible emission readings shall be performed in accordance with 40 CFR Part 60, Appendix A, Method 9, for a minimum of five (5) consecutive six (6) minute averaging periods beginning not more than twenty-four (24) hours after the start of the malfunction or down time.

(2) Method 9 opacity readings shall be repeated for a minimum of five (5) consecutive six (6) minute averaging periods at least twice per day during daylight operations, with at least four (4) hours between each set of readings, until a COMS is online.

(3) Method 9 readings may be discontinued once a COMS is online.

(4) Any opacity exceedances determined by Method 9 readings shall be reported with the Quarterly Opacity Exceedances Reports.

(g) Nothing in this permit shall excuse the Permittee from complying with the requirements to operate a continuous opacity monitoring system pursuant to 326 IAC 3-5, (and 40 CFR Part 60 and/or 40 CFR Part 63).

D.6.12 Continuous Emissions Monitoring [326 IAC 3-5]

(a) Pursuant to 326 IAC 3-5 (Continuous Monitoring of Emissions), the Permittee is required to calibrate, certify, operate, and maintain a continuous emission monitoring system (CEMS) for measuring NOx emissions rates from Boiler B-6 (stack S-9) in accordance with 326 IAC 3-5 to demonstrate compliance with Condition D.6.8.

(b) All continuous emission monitoring systems are subject to monitor system certification requirements pursuant to 326 IAC 3-5-3.

(c) Pursuant to 326 IAC 3-5-4(a), if revisions are made to the continuous monitoring standard operating procedures (SOP), the Permittee shall submit updates to the department within two (2) years of the revisions.

(d) The CEMS must operate and record data during all periods of operation of the affected facilities including periods of startup, shutdown, malfunction or emergency conditions, except for CEMS breakdown, repairs, calibration checks, and zero and span adjustments.

(e) Nothing in this permit shall excuse the Permittee from complying with the requirements to operate a continuous emission monitoring system pursuant to 326 IAC 3-5 and 40 CFR Part 60.

(f) Whenever a continuous emission monitor other than an opacity monitor is malfunctioning or is down for maintenance or repairs, the following shall be used as an alternative to continuous data collection:

(1) Whenever the NOx continuous emission monitoring system is malfunctioning or down for repairs or adjustments, the Permittee shall record appropriate operational data, (e.g., excess O_2 (%), fuel oil burner pressure, and gas burner pressure) to enable a demonstration of continual compliance with applicable emissions limitations during the monitor downtime. In the event of an extended period of monitor downtime and when possible based on operational needs, the Permittee will shut down the Boiler B-6.

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

D.6.13 Record Keeping Requirements

(a) To document the compliance status with Condition D.6.6, the Permittee shall maintain records in accordance with (1) through (6) below. Records maintained for (1) through (6) shall be taken monthly and shall be complete and sufficient to establish compliance with the SO_2 emission limit established in Condition D.6.6.

(1) Calendar dates covered in the compliance determination period;

(2) Actual fuel oil usage since last compliance determination period and equivalent sulfur dioxide emissions;

(3) A certification, signed by the owner or operator, that the records of the fuel supplier certifications represent all of the fuel combusted during the period; and if the fuel supplier certification is used to demonstrate compliance the following, as a minimum, shall be maintained:

(A) Fuel supplier certifications;

(B) The name of the fuel supplier; and

(C) A statement from the fuel supplier that certifies the sulfur content of the fuel oil.

(b) To document the compliance status with Conditions D.6.3, D.6.4, and D.6.11 the Permittee shall maintain records of the results of continuous opacity monitoring (COM) system, pursuant to 326 IAC 3-5-6.

(c) To document the compliance status with Condition D.6.12, the Permittee shall maintain records, including raw data of all monitoring data and supporting information, for a minimum of five (5) years from the date described in 326 IAC 3-5-7(a). The records shall include the information described in 326 IAC 3-5-7(b).

(d) To document the compliance status with Condition D.6.8, the Permittee shall maintain records of the NOx emissions from Boiler B-6 for each month.

(e) To document the compliance status with the NO_X requirements in Condition D.6.8, the Permittee shall maintain records of all NOx and CO_2 or O_2 continuous emissions monitoring data, pursuant to 326 IAC 3-5-6, 40 CFR 60.7, and 40 CFR 60.45. Records shall be complete and sufficient to establish compliance with the NOx limits as required in D.6.8.

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

D.6.14 Reporting Requirements

(a) A quarterly summary of the information to document the compliance status with Condition D.6.8 shall be submitted using the reporting form located at the end of this permit, or its equivalent, not later than thirty (30) days after the end of the quarter being reported. Section C - General Reporting contains the Permittee's obligation with regard to the reporting required by this condition. The report submitted by the Permittee does require a certification that meets the requirements of 326 IAC 2-7-6(1) by a “responsible official” as defined by 326 IAC 2-7-1(35).

(b) Pursuant to 326 IAC 3-5-7(5), reporting of continuous monitoring system instrument downtime, except for zero (0) and span checks, which shall be reported separately, shall include the following:

(1) Date of downtime.

(2) Time of commencement.

(3) Duration of each downtime.

(4) Reasons for each downtime.

(5) Nature of system repairs and adjustments.

The report submitted by the Permittee does require the certification by the "responsible official" as defined by 326 IAC 2-7-1(4).

(c) The Permittee shall prepare and submit to IDEM, OAQ a written report of the results of the calibration gas audits and relative accuracy test audits for each calendar quarter

within thirty (30) calendar days after the end of each quarter. The report must contain the information required by 326 IAC 3-5-5(e)(2).

SECTION D.7 EMISSIONS UNIT OPERATION CONDITIONS

Emissions Unit Description:

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

(a) Degreasing operations that do not exceed 145 gallons per 12 months, except if subject to 326 IAC 20-6.

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

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

D.7.1 Cold Cleaner Degreaser Control Equipment and Operating Requirements [326 IAC 8-3-2]

Pursuant to 326 IAC 8-3-2 (Cold Cleaner Degreaser Control and Equipment Operating Requirements), the Permittee shall:

(a) Ensure the following control equipment and operating requirements are met:

(1) Equip the degreaser with a cover.

(2) Equip the degreaser with a device for draining cleaned parts.

(3) Close the degreaser cover whenever parts are not being handled in the degreaser.

(4) Drain cleaned parts for at least fifteen (15) seconds or until dripping ceases;

(5) Provide a permanent, conspicuous label that lists the operating requirements in subdivisions (3), (4), (6), and (7).

(6) Store waste solvent only in closed containers.

(7) Prohibit the disposal or transfer of waste solvent in such a manner that could allow greater than twenty percent (20%) of the waste solvent (by weight) to evaporate into the atmosphere.

(b) Ensure the following additional control equipment and operating requirements are met:

(1) Equip the degreaser with one (1) of the following control devices if the solvent is heated to a temperature of greater than forty-eight and nine-tenths (48.9) degrees Celsius (one hundred twenty (120) degrees Fahrenheit):

(A) A freeboard that attains a freeboard ratio of seventy-five hundredths (0.75) or greater.
(B) A water cover when solvent used is insoluble in, and heavier than, water.
(C) A refrigerated chiller.
(D) Carbon adsorption.
(E) An alternative system of demonstrated equivalent or better control as those outlined in clauses (A) through (D) that is approved by the department. An alternative system shall be submitted to the U.S. EPA as a SIP revision.

(2) Ensure the degreaser cover is designed so that it can be easily operated with one (1) hand if the solvent is agitated or heated.

(3) If used, solvent spray:
(A) must be a solid, fluid stream; and
(B) shall be applied at a pressure that does not cause excessive splashing.

D.7.2 Material Requirements for Cold Cleaner Degreasers [326 IAC 8-3-8]

Pursuant to 326 IAC 8-3-8 (Material Requirements for Cold Cleaner Degreasers), the Permittee shall not operate a cold cleaning degreaser with a solvent that has a VOC composite partial vapor pressure that exceeds one (1) millimeter of mercury (nineteen-thousandths (0.019) pound per square inch) measured at twenty (20) degrees Celsius (sixty-eight (68) degrees Fahrenheit).

D.7.3 Preventive Maintenance Plan [326 IAC 2-7-5(12)]

A Preventive Maintenance Plan is required for this facility. Section B - Preventive Maintenance Plan contains the Permittee's obligation with regard to the preventive maintenance plan required by this condition.

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

D.7.4 Record Keeping Requirements

To document the compliance status with Condition D.7.2, the Permittee shall maintain the following records for each purchase of solvent used in the cold cleaner degreasing operations. These records shall be retained on-site or accessible electronically for the most recent three (3) year period and shall be reasonably accessible for an additional two (2) year period.

(a) The name and address of the solvent supplier.

(b) The date of purchase.

(c) The type of solvent purchased.

(d) The total volume of the solvent purchased.

(e) The true vapor pressure of the solvent measured in millimeters of mercury at twenty (20) degrees Celsius (sixty-eight (68) degrees Fahrenheit).

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

SECTION D.8 EMISSIONS UNIT OPERATION CONDITIONS

Emissions Unit Description:

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

(b) The following activities not resulting in the emission of HAPs: brazing equipment, cutting torches, soldering equipment, welding equipment.

(c) Grinding and machining operations controlled with fabric filters, scrubbers, mist collectors, wet collectors and electrostatic precipitators with a design grain loading of less than or equal to 0.03 grains per actual cubic foot and a gas flow rate less than or equal to 4000 actual cubic feet per minute, including the following: deburring, buffing, polishing, abrasive blasting, pneumatic conveying; and woodworking operations.

(d) Space heaters, process heaters, or boilers consisting of the following:

(1) Natural gas-fired combustion sources with heat input capacities equal to or less than 10.0 MMBtu per hour.

(A) Two (2) indirect natural gas fired heaters, identified as Irish Athletic Center Heaters, constructed in 2018 and 2019, with maximum capacity of 2.4 MMBtu, each.

(B) Three hundred (300) indirect natural gas fired heaters, constructed prior to 2020, with a maximum capacity of 40,000 Btu per hour, each.

(2) Propane, LPG, or butane-fired combustion sources with heat input capacities equal to or less than 6.0 MMBtu per hour.

(3) Fuel oil-fired combustion sources with heat input capacities equal to or less than 2.0 MMBtu per hour and firing fuel containing less than 0.5% sulfur by weight.

(4) Wood-fired combustion sources with heat input capacities equal to or less than 2.0 MMBtu per hour and firing fuel containing less than 0.5% sulfur by weight.

(e) Noncontact cooling tower systems with forced and induced draft cooling tower systems not regulated under a NESHAP.

(1) Five (5) non-contact, counter flow cooling towers; identified as Cooling Towers 1 through 5; each with a maximum water circulation rate of 10,400 gallons/minute; each cooling tower was constructed in 2000 and controlled by drift eliminators.

(2) Two (2) closed-loop, counter flow cooling towers; identified as Cooling Towers 6 and 7; each with a maximum cooling tower water circulation rate of 10,000 gallons/minute; each constructed in 2016 and controlled by drift eliminators.

(3) Two (2) closed-loop, counter flow cooling towers; identified as East Chiller Plant Cooling Towers 8 and 9; each with a maximum cooling tower water circulation rate of 5,000 gallons/minute; each constructed in 2016 and controlled by drift eliminators.

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

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

D.8.1 Particulate Matter Limitations Except Lake County [326 IAC 6.5-1-2]

Pursuant to 326 IAC 6.5-1-2(a), the particulate matter (PM) emissions from the emission units listed above except boilers, shall not exceed 0.03 grains per dry standard cubic foot, each.

D.8.2 Particulate Matter Limitations Except Lake County [326 IAC 6.5-1-2]

(a) Pursuant to 326 IAC 6.5-1-2(b)(3), the particulate matter (PM) emissions from the gaseous fuel fired boilers, shall not exceed one-hundredth (0.01) grain per dry standard cubic foot (dscf).

(b) Pursuant to 326 IAC 6.5-1-2(b)(2), the particulate matter (PM) emissions from the No. 2 fuel oil fired boilers, shall not exceed 0.15 pound per million Btu).

(c) Pursuant to 326 IAC 6.5-1-2(b)(1)(C), the particulate matter (PM) emissions from the wood-fired boilers, shall not exceed six-tenths (0.6) pound per million Btu.

D.8.3 Preventive Maintenance Plan [326 IAC 2-7-5(12)]

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

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

D.8.4 Particulate Control [326 IAC 2-7-6(6)]

In order to assure compliance with Condition D.8.1, grinding and machining operation and cooling tower controls for particulate control shall be in operation and control emissions from each grinding and machining operation and cooling tower at all times each grinding and machining operation and cooling towers are in operation.

SECTION D.9 EMISSIONS UNIT OPERATION CONDITIONS

Emissions Unit Description:

(h) Two (2) natural gas-fired combustion turbines, identified as GT-1 and GT-2, each equipped with a heat recovery steam generator (HRSG), constructed in 2018. Each HRSG is equipped with a natural gas-fired duct burner, each turbine has a maximum capacity of 6.4 MW (75.4 MMBtu/hr), and each duct burner has a maximum capacity of 87.5 MMBtu/hr. During normal operation, the turbines and duct burners exhaust to a shared main stack.

*Note: The heat recovery steam generators are not a source of emissions. They have been included for clarity as they are part of the entire source and operate in conjunction with the duct burners and combustion turbines which are a source of emissions.

[These turbines are an affected source under 40 CFR Part 60, Subpart KKKK]

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

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

D.9.1 Particulate Matter Limitations Except Lake County [326 IAC 6.5-1-2]

Pursuant to 326 IAC 6.5-1-2(a), the particulate matter (PM) emissions from the two (2) duct burners associated with turbines, GT-1 and GT-2, shall not exceed 0.03 grains per dry standard cubic foot, each.

D.9.2 Preventive Maintenance Plan [326 IAC 2-7-5(12)]

A Preventive Maintenance Plan is required for the duct burners. Section B - Preventive Maintenance Plan contains the Permittee's obligation with regard to the preventive maintenance plan required by this condition.

SECTION E.1 **NSPS**

Emissions Unit Description:

(e) One (1) natural gas fired boiler, identified as B-6, constructed in 2006, with a maximum design capacity of 249 MMBtu per hour heat input, equipped with a low NOx burner and flue gas recirculation (FGR), using No. 2 fuel oil as a backup fuel, and exhausting to stack S-9, monitored by certified COM and NOx CEM.

[This is an affected source under 40 CFR Part 60, Subpart Db.]
[This is an existing affected source under 40 CFR Part 63, Subpart JJJJJJ.]

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

New Source Performance Standards (NSPS) Requirements [326 IAC 2-7-5(1)]

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

(a) Pursuant to 40 CFR 60.1, the Permittee shall comply with the provisions of 40 CFR Part 60, Subpart A - General Provisions, which are incorporated by reference as 326 IAC 12-1, for the emission unit(s) listed above, except as otherwise specified in 40 CFR Part 60, Subpart Db.

(b) Pursuant to 40 CFR 60.4, the Permittee shall submit all required notifications and reports to:

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

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

The Permittee shall comply with the following provisions of 40 CFR Part 60, Subpart Db (included as Attachment A to the operating permit), which are incorporated by reference as 326 IAC 12, for the emission unit listed above:

(1) 40 CFR 60.40b
(2) 40 CFR 60.41b
(3) 40 CFR 60.42b (j)
(4) 40 CFR 60.42b (k)(2)
(5) 40 CFR 60.43b (h) (5)
(6) 40 CFR 60.44b(l)(1), (h), (i)
(7) 40 CFR 60.45b (j)
(8) 40 CFR 60.46b (a), (c), (e), (e)(1), (i)
(9) 40 CFR 60.47b(f)
(10) 40 CFR 60.48b (b), (c)-(e), (e)(2), (e)(3), (f), (g), (j)
(11) 40 CFR 60.49b (a), (a) (1), (a)(3), (b), (d), (g), (h), (i). (o), (r), (r)(1), (v), (w)

SECTION E.2 **NSPS**

Emissions Unit Description:

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

(f) Insignificant emergency engines consisting of the following:

(2) Compression ignition emergency engines, each with a capacity less than or equal to 500 HP, manufactured/modified/ constructed/ reconstructed on or after June 12, 2006.

Location	Generator Rating	Year of Manufacture
MVAP Complex	168	2009
Nanotechnology Research Center	201	2006
Stayer Center	201	2012
Innovation Park Building1	335	2009
Compton Ice Arena	335	2011
Eck Law School	402	2007
Morris Inn	235	2013
Jenkins-Nanovic Hall	385	2016
Sacred Heart Basilica	134	2019

[These are new affected source under 40 CFR Part 60, Subpart IIII]
[These are new affected source under 40 CFR Part 63, Subpart ZZZZ]

*****

(4) Compression ignition emergency engines, each with a capacity greater than 500 HP and not exceeding 1600 Hp, manufactured/modified/constructed/ reconstructed on or after June 12, 2006.

Location	Generator Rating	Year of Manufacture
Well #9	536	2012
Joyce Center	671	2013
Hesburgh Library #1	671	2013
Hesburgh Library #2	671	2013
Galvin Life Sciences	755	2015
Nieuwland	755	2015
Stinson-Remick	1,073	2010
McCourtney Hall	1,220	2016
Stadium 1	1,474	2016
Stadium 2	1,474	2016
Stepan Chemistry	755	2019
Fitzpatrick	755	2019

[These are new affected source under 40 CFR Part 60, Subpart IIII]
[These are new affected source under 40 CFR Part 63, Subpart ZZZZ]

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

New Source Performance Standards (NSPS) Requirements [326 IAC 2-7-5(1)]

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

(a) Pursuant to 40 CFR 60.1, the Permittee shall comply with the provisions of 40 CFR Part 60, Subpart A - General Provisions, which are incorporated by reference as 326 IAC 12-1, for the emission unit(s) listed above, except as otherwise specified in 40 CFR Part 60, Subpart IIII.

(b) Pursuant to 40 CFR 60.4, the Permittee shall submit all required notifications and reports to:

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

E.2.2 Standards of Performance for Stationary Compression Ignition Internal Combustion Engines NSPS [326 IAC 12][40 CFR Part 60, Subpart IIII]

The Permittee shall comply with the following provisions of 40 CFR Part 60, Subpart IIII (included as Attachment B to the operating permit), which are incorporated by reference as 326 IAC 12, for the emission unit(s) listed above:

(1) 40 CFR 60.4200(a)(2), (a)(2)(i), (a)(3), (a)(4)
(2) 40 CFR 60.4205(b), (d)(2)(i)
(3) 40 CFR 60.4206
(4) 40 CFR 60.4207(a), (b)
(5) 40 CFR 60.4209(a)
(6) 40 CFR 60.4211(a)(1-3), (c), (d)(1), (d)(2)(i-v), (f)(1), (f)(2)(i), (g)(2-3)
(7) 40 CFR 60.4212
(8) 40 CFR 60.4213
(9) 40 CFR 60.4214(b)
(10) 40 CFR 60.4218
(11) 40 CFR 60.4219
(12) 40 CFR 60, Table 8

SECTION E.3 **NESHAP**

Emissions Unit Description:

(f) Three (3) diesel-fired generators, identified as G-8, G-9 and G-10, constructed before July 11, 2005 (permitted in 2003), each with a maximum rated capacity of 2,593 brake horsepower, equipped with oxidation catalysts, and exhausting to stacks S-6, S-7 and S-8, respectively.

[These generators are an affected source under 40 CFR Part 63, Subpart ZZZZ.]

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

(f) Insignificant emergency engines consisting of the following:

*****

(2) Diesel fired compression ignition emergency engines, each with a capacity less than or equal to 500 Hp, manufactured/modified/ constructed/reconstructed on or after June 12, 2006.

Location	Engine Rating	Year of Manufacture
MVAP Complex	168	2009
Nanotechnology Research Ctr.	201	2006
Stayer Center	201	2012
Innovation Park Building 1	335	2009
Compton Ice Arena	335	2011
Eck Law School	402	2007
Morris Inn	235	2013
Jenkins-Nanovic Hall	385	2016
Sacred Heart Basilica	134	2019

[These are new affected source under 40 CFR Part 60, Subpart IIII]
[These are new affected source under 40 CFR Part 63, Subpart ZZZZ]

*****

(4) Diesel fired compression ignition emergency engines, each with a capacity greater than 500 HP and not exceeding 1600 Hp, manufactured/modified/constructed/ reconstructed on or after June 12, 2006.

Location	Generator Rating	Year of Manufacture
Well #9	536	2012
Joyce Center	671	2013
Hesburgh Library #1	671	2013
Hesburgh Library #2	671	2013
Galvin Life Sciences	755	2015
Nieuwland	755	2015
Stinson-Remick	1,073	2010
McCourtney Hall	1,220	2016
Stadium 1	1,474	2016
Stadium 2	1,474	2016
Stepan Chemistry	755	2019
Fitzpatrick	755	2019

[These are new affected source under 40 CFR Part 60, Subpart IIII]
[These are new affected source under 40 CFR Part 63, Subpart ZZZZ]

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

National Emission Standards for Hazardous Air Pollutants (NESHAP) Requirements [326 IAC 2-7-5(1)]

E.3.1 General Provisions Relating to National Emission Standards for Hazardous Air Pollutants under 40 CFR Part 63 [326 IAC 20-1][40 CFR Part 63, Subpart A]

(a) Pursuant to 40 CFR 63.1 the Permittee shall comply with the provisions of 40 CFR Part 63, Subpart A - General Provisions, which are incorporated by reference as 326 IAC 20-1, for the emission unit(s) listed above, except as otherwise specified in 40 CFR Part 63, Subpart ZZZZ.

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

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

E.3.2 National Emissions Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines NESHAP [40 CFR Part 63, Subpart ZZZZ]

The Permittee shall comply with the following provisions of 40 CFR Part 63, Subpart ZZZZ (included as Attachment C to the operating permit), which are incorporated by reference as 326 IAC 20-82 for the emission units listed above:

<u>Diesel generators G-8, G-9, and G-10</u>

(1) 40 CFR 63.6580
(2) 40 CFR 63.6585
(3) 40 CFR 63.6590(a)(1)(iii) and (iv)
(4) 40 CFR 63.6595 (a)(1), (b), and (c)
(5) 40 CFR 63.6603(a)
(6) 40 CFR 63.6604(a)

(7) 40 CFR 63.6605
(8) 40 CFR 63.6612
(9) 40 CFR 63.6615
(10) 40 CFR 63.6620
(11) 40 CFR 63.6625(g), and (h)
(12) 40 CFR 63.6630(a), (b), and (c)
(13) 40 CFR 63.6635
(14) 40 CFR 63.6640(a), (b), and (e)
(15) 40 CFR 63.6645 (a)(2), (g), and (h)
(16) 40 CFR 63.6650
(17) 40 CFR 63.6655
(18) 40 CFR 63.6660
(19) 40 CFR 63.6665
(20) 40 CFR 63.6670
(21) 40 CFR 63.6675
(22) 40 CFR 63, Table 2b
(23) 40 CFR 63, Table 2d (item 3)
(24) 40 CFR 63, Table 3 (item 4)
(25) 40 CFR 63, Table 4 (items 1 and 3)
(26) 40 CFR 63, Table 5
(27) 40 CFR 63, Table 6 (items 3, 10, and 11)
(28) 40 CFR 63, Table 7 (item 1)
(29) 40 CFR 63, Table 8

*****

(f) Insignificant emergency engines consisting of the following:

(2) Diesel fired compression ignition emergency engines, each with a capacity less than or equal to 500 Hp, manufactured/modified/ constructed/reconstructed on or after June 12, 2006.

Location	Engine Rating	Year of Manufacture
MVAP Complex	168	2009
Nanotechnology Research Ctr.	201	2006
Stayer Center	201	2012
Innovation Park Building 1	335	2009
Compton Ice Arena	335	2011
Eck Law School	402	2007
Morris Inn	235	2013
Jenkins-Nanovic Hall	385	2016
Sacred Heart Basilica	134	2019

*****

(4) Diesel fired compression ignition emergency engines, each with a capacity greater than 500 HP and not exceeding 1600 Hp, manufactured/modified/constructed/ reconstructed on or after June 12, 2006.

Location	Generator Rating	Year of Manufacture
Well #9	536	2012
Joyce Center	671	2013
Hesburgh Library #1	671	2013
Hesburgh Library #2	671	2013
Galvin Life Sciences	755	2015
Nieuwland	755	2015
Stinson-Remick	1,073	2010
McCourtney Hall	1,220	2016
Stadium 1	1,474	2016
Stadium 2	1,474	2016
Stepan Chemistry	755	2019
Fitzpatrick	755	2019

The diesel fired emergency engines are subject the following applicable portions of the NESHAP for new stationary RICE at an area source of HAP:

(1) 40 CFR 63.6580
(2) 40 CFR 63.6585
(3) 40 CFR 63.6590(a)(2)(iii) and (c)(1)
(4) 40 CFR 63.6595(a)(6) and (a)(7)
(5) 40 CFR 63.6665
(6) 40 CFR 63.6670
(7) 40 CFR 63.6675

SECTION E.4 NESHAP

Emissions Unit Description:

(a) One (1) No. 2 fuel oil or natural gas fired boiler, identified as B-1, constructed in 1961, with a single low NOx burner and economizer constructed in 2006, and with a maximum design capacity of 137 MMBtu per hour heat input, and exhausting to stack S-1.

[This is an existing affected source under 40 CFR Part 63, Subpart JJJJJJ.]

(c) One (1) natural gas or No. 2 fuel oil fired boiler, identified as B-4, constructed in 1966, and modified in 2018 to remove coal firing capacity, with a maximum design capacity of 234 MMBtu per hour heat input, and exhausting to stack S-2.

[This is an existing affected source under 40 CFR Part 63, Subpart JJJJJJ.]

(d) One (1) No. 2 fuel oil or natural gas fired boiler, identified as B-5, constructed in 1973, with a maximum design capacity of 244.5 MMBtu per hour heat input, equipped with low NOx burner for natural gas and fuel oil, and exhausting to stack S-3.

[This is an existing affected source under 40 CFR Part 63, Subpart JJJJJJ.]

(e) One (1) natural gas fired boiler, identified as B-6, constructed in 2006, with a maximum design capacity of 249 MMBtu per hour heat input, equipped with a low NOx burner and flue gas recirculation (FGR), using No. 2 fuel oil as a backup fuel, and exhausting to stack S-9, monitored by certified COM and NOx CEM.

[This is an affected source under 40 CFR Part 60, Subpart Db.]
[This is an existing affected source under 40 CFR Part 63, Subpart JJJJJJ.]

Specifically Regulated Insignificant Activities

(d) Space heaters, process heaters, or boilers consisting of the following:

(3) Fuel oil-fired combustion sources with heat input capacities equal to or less than 2.0 MMBtu per hour and firing fuel containing less than 0.5% sulfur by weight.

[These boilers are subject to the following portions of Subpart JJJJJJ:]

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

National Emission Standards for Hazardous Air Pollutants (NESHAP) Requirements [326 IAC 2-7-5(1)]

E.4.1 General Provisions Relating to National Emission Standards for Hazardous Air Pollutants under 40 CFR Part 63 [326 IAC 20-1][40 CFR Part 63, Subpart A]

(a) Pursuant to 40 CFR 63.1 the Permittee shall comply with the provisions of 40 CFR Part 63, Subpart A - General Provisions, which are incorporated by reference as 326 IAC 20-1, for the emission unit(s) listed above, except as otherwise specified in 40 CFR Part 63, Subpart JJJJJJ.

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

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

E.4.2 National Emission Standards for Hazardous Air Pollutants for Industrial, Commercial, and Institutional Boilers Area Sources-NESHAP [40 CFR Part 63, Subpart JJJJJJ]

The Permittee shall comply with the following provisions of 40 CFR Part 63, Subpart JJJJJJ (included as Attachment D to the operating permit), which are incorporated by reference as 326 IAC 20-1, for the emission units listed above:

(a) For Boiler B-1, B-4, B-5, and B-6

(1) 40 CFR 63.11193
(2) 40 CFR 63.11194(a), (b)
(3) 40 CFR 63.11200(c)
(4) 40 CFR 63.11201(b), (d)
(5) 40 CFR 63.11205(a)
(6) 40 CFR 63.11210 (c)
(7) 40 CFR 63.11214(b), (c)
(8) 40 CFR 63.11223(a), (b)
(9) 40 CFR 63.11225(a) (2), (b), (c), (d)
(10) 40 CFR 63.11235
(11) 40 CFR 63.11236
(12) 40 CFR 63.11237
(13) 40 CFR 63, Table 2 (Item 4 and item 16)
(14) 40 CFR 63, Table 8

(b) For Fuel oil-fired combustion sources with heat input capacities equal to or less than 2.0 MMBtu per hour and firing fuel containing less than 0.5% sulfur by weight.

(1) 40 CFR 63.11193
(2) 40 CFR 63.11194(a)
(3) 40 CFR 63.11195(e) and (f)
(4) 40 CFR 63.11200(c)
(5) 40 CFR 63.11201(b), and (d)
(6) 40 CFR 63.11205(a)
(7) 40 CFR 63.11210(c), (e), (f), (g)
(8) 40 CFR 63.11214(b)
(9) 40 CFR 63.11220 (b) (3) and (c) (2)
(10) 40 CFR 63.11223 (a), and (b)
(11) 40 CFR 63.11225 (a) (2), (b), (c), (d)
(12) 40 CFR 63.11235
(13) 40 CFR 63.11236
(14) 40 CFR 63.11237
(15) 40 CFR 63, Table 2
(16) 40 CFR 63, Table 8

E.4.3 Reserved .

SECTION E.5 NSPS

Emissions Unit Description:

(h) Two (2) natural gas-fired combustion turbines, identified as GT-1 and GT-2, each equipped with a heat recovery steam generator (HRSG), constructed in 2018. Each HRSG is equipped with a natural gas-fired duct burner, constructed in 2018. Each turbine has a maximum capacity of 6.4 MW (75.4 MMBtu/hr), and each duct burner has a maximum capacity of 87.5 MMBtu/hr. During normal operation, the turbines and duct burners exhaust to a shared main stack.

*Note: The heat recovery steam generators are not a source of emissions. They have been included for clarity as they are part of the entire source and operate in conjunction with the duct burners and combustion turbines which are a source of emissions.

[These turbines are an affected source under 40 CFR Part 60, Subpart KKKK]

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

New Source Performance Standards (NSPS) Requirements [326 IAC 2-7-5(1)]

E.5.1 General Provisions Relating to New Source Performance Standards [326 IAC 12-1][40 CFR Part 60, Subpart A]

(a) Pursuant to 40 CFR 60.1, the Permittee shall comply with the provisions of 40 CFR Part 60, Subpart A - General Provisions, which are incorporated by reference as 326 IAC 12, for the emission unit(s) listed above, except as otherwise specified in 40 CFR Part 60, Subpart KKKK.

(b) Pursuant to 40 CFR 60.4, the Permittee shall submit all required notifications and reports to:

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

E.5.2 Standards of Performance for Stationary Combustion Turbines NSPS [326 IAC 12][40 CFR Part 60, Subpart KKKK]

The Permittee shall comply with the following provisions of 40 CFR Part 60, Subpart KKKK (included as Attachment E to the operating permit), which are incorporated by reference as 326 IAC 12, for the emission units listed above:

(1) 40 CFR 60.4300
(2) 40 CFR 60.4305
(3) 40 CFR 60.4315
(4) 40 CFR 60.4320(a)
(5) 40 CFR 60.4330(a)(2)
(6) 40 CFR 60.4333(a)
(7) 40 CFR 60.4340(a)
(8) 40 CFR 60.4365(a)

(9) 40 CFR 60.4375(b)
(10) 40 CFR 60.4395
(11) 40 CFR 60.4400
(12) 40 CFR 60.4420
(13) 40 CFR 60, Table 1

SECTION E.6 NESHAP

Emissions Unit Description:

Specifically Regulated Insignificant Activities

(g) A gasoline fuel transfer dispensing operation 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.

[This is an affected unit under 40 CFR Part 63, Subpart CCCCCC]

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

National Emission Standards for Hazardous Air Pollutants (NESHAP) Requirements [326 IAC 2-7-5(1)]

E.6.1 General Provisions Relating to National Emission Standards for Hazardous Air Pollutants under 40 CFR Part 63 [326 IAC 20-1][40 CFR Part 63, Subpart A]

(a) Pursuant to 40 CFR 63.1 the Permittee shall comply with the provisions of 40 CFR Part 63, Subpart A - General Provisions, which are incorporated by reference as 326 IAC 20-1, for the emission unit(s) listed above, except as otherwise specified in 40 CFR Part 63, Subpart CCCCCC.

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

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

E.6.2 National Emission Standards for Hazardous Air Pollutants for Source Category: Gasoline Dispensing Facilities [40 CFR Part 63, Subpart CCCCCC][326 IAC-20]

The Permittee shall comply with the following provisions of 40 CFR Part 63, Subpart CCCCCC (included as Attachment F of this permit), for the emission units listed above:

(1) 40 CFR 63.11110
(2) 40 CFR 63.11111(a), (b), (c), (e), (h), (i), (j)
(3) 40 CFR 63.11112
(4) 40 CFR 63.11113
(5) 40 CFR 63.11115
(6) 40 CFR 63.11116
(7) 40 CFR 63.11117
(8) 40 CFR 63.11124(a)
(9) 40 CFR 63.11125(d)
(10) 40 CFR 63.11126(b)
(11) 40 CFR 63.11130
(12) 40 CFR 63.11131
(13) 40 CFR 63.11132
(14) 40 CFR 63, Table 3

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

Source Name: University of Notre Dame du Lac
Source Address: 100 Facilities Building, Notre Dame, Indiana 46556
Part 70 Permit No.: T141-41227-00013

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: University of Notre Dame du Lac
Source Address: 100 Facilities Building, Notre Dame, Indiana 46556
Part 70 Permit No.: T141-41227-00013

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**) daytime 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

Source Name: University of Notre Dame du Lac
Source Address: 100 Facilities Building, Notre Dame, Indiana 46556
Part 70 Permit No.: T141-41227-00013
Facility: Boiler B-6
Parameter: NOx
Limit: Less than 40 tons per 12 consecutive month period, with compliance determined at the end of each month.

QUARTER :_____ YEAR: _____

Month	Column 1	Column 2	Column 1 + Column 2
	This Month (tons)	Previous 11 Months (tons)	12 Month Total (tons)

☐ 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

Source Name: University of Notre Dame du Lac
Source Address: 100 Facilities Building, Notre Dame, Indiana 46556
Part 70 Permit No.: T141-41227-00013
Facility: G-8, G-9, and G-10
Parameter: Diesel Fuel
Limit: Total combined diesel fuel use shall not exceed 3,076,000 gallons per 12 consecutive month period, with compliance determined at the end of each month.

QUARTER :_____ YEAR: _____

Month	Column 1	Column 2	Column 1 + Column 2
	This Month (Gals)	Previous 11 Months (Gals)	12 Month Total (Gals)

☐ 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: University of Notre Dame du Lac
Source Address: 100 Facilities Building, Notre Dame, Indiana 46556
Part 70 Permit No.: T141-41227-00013

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:	

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: _____

Attachment A

Part 70 Operating Permit No: 141-41227-00013

[Downloaded from the eCFR on October 15, 2014]

Electronic Code of Federal Regulations

Title 40: Protection of Environment

PART 60—STANDARDS OF PERFORMANCE FOR NEW STATIONARY SOURCES

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 (SO2).

(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 (NOX).

(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:

	Nitrogen oxide emission limits (expressed as NO_2) heat input	
Fuel/steam generating unit type	**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

Fuel/steam generating unit type	Nitrogen oxide emission limits (expressed as NO_2) heat input	
	ng/J	lb/MMBTu
(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 ($E_{ho}°$) is used in Equation 19-19 of Method 19 of appendix A of this part to compute an adjusted 30-day average emission rate ($E_{ao}°$). The Eho° is computed using the following formula:

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

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 or Method 320 of appendix A of part 63 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, or 7E of appendix A of this part, Method 320 of appendix A of part 63 of this chapter, 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, or 7E of appendix A of this part, Method 320 of appendix A of part 63, 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.

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§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 sampling location for Method 6B of appendix A of this part. 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 or Method 320 of appendix A of part 63 of this chapter 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; 79 FR 11249, Feb. 27, 2014]

§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]

Attachment B

Part 70 Operating Permit No: 141-41227-00013

[Downloaded from the eCFR on September 6, 2016]

Electronic Code of Federal Regulations

Title 40: Protection of Environment

PART 60—STANDARDS OF PERFORMANCE FOR NEW STATIONARY SOURCES

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) Remote areas of Alaska; 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.

(h) Stationary CI ICE certified to the standards in 40 CFR part 1039 and equipped with auxiliary emission control devices (AECDs) as specified in 40 CFR 1039.665 must meet the Tier 1 certification emission standards for new nonroad CI engines in 40 CFR 89.112 while the AECD is activated during a qualified emergency situation. A qualified emergency situation is defined in 40 CFR 1039.665. When the qualified emergency situation has ended and the AECD is deactivated, the engine must resume meeting the otherwise applicable emission standard specified in this section.

[71 FR 39172, July 11, 2006, as amended at 76 FR 37967, June 28, 2011; 81 FR 44219, July 7, 2016]

§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) Remote areas of Alaska; 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; 81 FR 44219, July 7, 2016]

§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.

(f) Owners and operators of stationary CI ICE certified to the standards in 40 CFR part 1039 and equipped with AECDs as specified in 40 CFR 1039.665 must meet the Tier 1 certification emission standards for new nonroad CI engines in 40 CFR 89.112 while the AECD is activated during a qualified emergency situation. A qualified emergency situation is defined in 40 CFR 1039.665. When the qualified emergency situation has ended and the AECD is deactivated, the engine must resume meeting the otherwise applicable emission standard specified in this section.

[71 FR 39172, July 11, 2006, as amended at 76 FR 37968, June 28, 2011; 81 FR 44219, July 7, 2016]

§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 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]

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.

(j) Stationary CI ICE manufacturers may equip their stationary CI internal combustion engines certified to the emission standards in 40 CFR part 1039 with AECDs for qualified emergency situations according to the requirements of 40 CFR 1039.665. Manufacturers of stationary CI ICE equipped with AECDs as allowed by 40 CFR 1039.665 must meet all of the requirements in 40 CFR 1039.665 that apply to manufacturers. Manufacturers must document that the engine complies with the Tier 1 standard in 40 CFR 89.112 when the AECD is activated. Manufacturers must provide any relevant testing, engineering analysis, or other information in sufficient detail to support such statement when applying for certification (including amending an existing certificate) of an engine equipped with an AECD as allowed by 40 CFR 1039.665.

[71 FR 39172, July 11, 2006, as amended at 76 FR 37969, June 28, 2011; 81 FR 44219, July 7, 2016]

§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.

(h) The requirements for operators and prohibited acts specified in 40 CFR 1039.665 apply to owners or operators of stationary CI ICE equipped with AECDs for qualified emergency situations as allowed by 40 CFR 1039.665.

[71 FR 39172, July 11, 2006, as amended at 76 FR 37970, June 28, 2011; 78 FR 6695, Jan. 30, 2013; 81 FR 44219, July 7, 2016]

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:

$$\frac{C_i - C_o}{C_i} \times 100 = R \qquad \text{(Eq. 2)}$$

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]

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.

(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.

(e) Owners or operators of stationary CI ICE equipped with AECDs pursuant to the requirements of 40 CFR 1039.665 must report the use of AECDs as required by 40 CFR 1039.665(e).

[71 FR 39172, July 11, 2006, as amended at 78 FR 6696, Jan. 30, 2013; 81 FR 44219, July 7, 2016]

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 remote areas of Alaska 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 §§60.4201(f) and 60.4202(g).

(c) Manufacturers, owners and operators of stationary CI ICE that are located in remote areas of Alaska 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 remote areas of Alaska.

(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 remote areas of Alaska 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, as amended at 81 FR 44219, July 7, 2016]

§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.

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.

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.

Remote areas of Alaska means areas of Alaska that meet either paragraph (1) or (2) of this definition.

(1) Areas of Alaska that are not accessible by the Federal Aid Highway System (FAHS).

(2) Areas of Alaska that meet all of the following criteria:

(i) The only connection to the FAHS is through the Alaska Marine Highway System, or the stationary CI ICE 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 CI ICE on an annual basis is used for residential purposes.

(iii) The generating capacity of the source is less than 12 megawatts, or the stationary CI ICE is used exclusively for backup power for renewable energy.

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; 81 FR 44219, July 7, 2016]

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)

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
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:

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 number/location of traverse points at the inlet and outlet of the control device;		(a) For NO_X, O_2, and moisture measurement, ducts ≤6 inches in diameter may be sampled at a single point located at the duct centroid and ducts >6 and ≤12 inches in diameter may be sampled at 3 traverse points located at 16.7, 50.0, and 83.3% of the measurement line ('3-point long line'). If the duct is >12 inches in diameter *and* the sampling port location meets the two and half-diameter criterion of Section 11.1.1 of Method 1 of 40 CFR part 60, appendix A-1, the duct may be sampled at '3-point long line'; otherwise, conduct the stratification testing and select sampling points according to Section 8.1.2 of Method 7E of 40 CFR part 60, appendix A-4.
		ii. Measure O_2 at the inlet and outlet of the control device;	(1) Method 3, 3A, or 3B of 40 CFR part 60, appendix A-2	(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	(2) Method 4 of 40 CFR part 60, appendix A-3, 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.	(3) Method 7E of 40 CFR part 60, appendix A-4, 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.

Each	Complying with the requirement to	You must	Using	According to the following requirements
	b. Limit the concentration of NO_X in the stationary CI internal combustion engine exhaust.	i. Select the sampling port location and number/location of traverse points at the exhaust of the stationary internal combustion engine;		(a) For NO_X, O_2, and moisture measurement, ducts ≤6 inches in diameter may be sampled at a single point located at the duct centroid and ducts >6 and ≤12 inches in diameter may be sampled at 3 traverse points located at 16.7, 50.0, and 83.3% of the measurement line ('3-point long line'). If the duct is >12 inches in diameter *and* the sampling port location meets the two and half-diameter criterion of Section 11.1.1 of Method 1 of 40 CFR part 60, appendix A-1, the duct may be sampled at '3-point long line'; otherwise, conduct the stratification testing and select sampling points according to Section 8.1.2 of Method 7E of 40 CFR part 60, appendix A-4.
		ii. Determine the O_2 concentration of the stationary internal combustion engine exhaust at the sampling port location;	(1) Method 3, 3A, or 3B of 40 CFR part 60, appendix A-2	(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	(2) Method 4 of 40 CFR part 60, appendix A-3, 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; if using a control device, the sampling site must be located at the outlet of the control device.	(3) Method 7E of 40 CFR part 60, appendix A-4, 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-1	(a) Sampling sites must be located at the inlet and outlet of the control device.

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-2	(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-3	(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-3	(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-1	(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;	(2) Method 3, 3A, or 3B of 40 CFR part 60, appendix A-2	(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 of the stationary internal combustion engine exhaust at the sampling port location; and	(3) Method 4 of 40 CFR part 60, appendix A-3	(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-3	(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.

[79 FR 11251, Feb. 27, 2014]

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.

General Provisions citation	Subject of citation	Applies to subpart	Explanation
§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	

Attachment C

Part 70 Operating Permit No: 141-41227-00013

[Downloaded from the eCFR on July 23, 2014]

Electronic Code of Federal Regulations

Title 40: Protection of Environment

PART 63—NATIONAL EMISSION STANDARDS FOR HAZARDOUS AIR POLLUTANTS FOR SOURCE CATEGORIES

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.

(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]

§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]

§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]

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 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]

§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]

§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]

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, 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]

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. 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:

$$\frac{C_i - C_o}{C_i} \times 100 = R \quad (Eq.\ 1)$$

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:

$$F_o = \frac{0.209\ F_d}{F_c} \quad (Eq.\ 2)$$

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, dsm3/J (dscf/106 Btu).

F_c = Ratio of the volume of CO_2 produced to the gross calorific value of the fuel from Method 19, dsm3/J (dscf/106 Btu)

(ii) Calculate the CO_2 correction factor for correcting measurement data to 15 percent O_2, as follows:

$$X_{CO2} = \frac{5.9}{F_o} \quad (Eq. 3)$$

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:

$$C_{adj} = C_d \frac{X_{CO2}}{\%CO_2} \quad (Eq. 4)$$

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]

§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]

§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]

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, 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]

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).

(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]

§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]

§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]

§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:

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]

Table 1a 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]

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

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:

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]

Table 2a 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_2 until 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	

For each . . .	You must meet the following emission limitation, except during periods of startup . . .	During periods of startup you must . . .
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 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

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:

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	

For each . . .	You must meet the following operating limitation, except during periods of startup . . .
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]

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

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, 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	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]	
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]	

For each . . .	You must meet the following requirement, except during periods of startup . . .	During periods of startup you must . . .
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]

Table 2d 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] 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]	
	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.	

For each . . .	You must meet the following requirement, except during periods of startup . . .	During periods of startup you must . . .
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]	
	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	

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 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	
	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]

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 >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]

Table 4 to Subpart ZZZZ of Part 63—Requirements for Performance Tests

As stated in §§63.6610, 63.6611, 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. Select the sampling port location and the number/location of traverse points at the inlet and outlet of the control device; and		(a) For CO and O_2 measurement, ducts ≤6 inches in diameter may be sampled at a single point located at the duct centroid and ducts >6 and ≤12 inches in diameter may be sampled at 3 traverse points located at 16.7, 50.0, and 83.3% of the measurement line (`3-point long line'). If the duct is >12 inches in diameter *and* the sampling port location meets the two and half-diameter criterion of Section 11.1.1 of Method 1 of 40 CFR part 60, appendix A-1, the duct may be sampled at `3-point long line'; otherwise, conduct the stratification testing and select sampling points according to Section 8.1.2 of Method 7E of 40 CFR part 60, appendix A-4.
		ii. 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-2, or ASTM Method D6522-00 (Reapproved 2005)[ac] (heated probe not necessary)	(b) Measurements to determine O_2 must be made at the same time as the measurements for CO concentration.
		iii. Measure the CO at the inlet and the outlet of the control device	(1) ASTM D6522-00 (Reapproved 2005)[abc] (heated probe not necessary) or Method 10 of 40 CFR part 60, appendix A-4	(c) The CO concentration must be at 15 percent O_2, dry basis.

For each . . .	Complying with the requirement to . . .	You must . . .	Using . . .	According to the following requirements . . .
2. 4SRB stationary RICE	a. reduce formaldehyde emissions	i. Select the sampling port location and the number/location of traverse points at the inlet and outlet of the control device; and		(a) For formaldehyde, O_2, and moisture measurement, ducts ≤6 inches in diameter may be sampled at a single point located at the duct centroid and ducts >6 and ≤12 inches in diameter may be sampled at 3 traverse points located at 16.7, 50.0, and 83.3% of the measurement line (`3-point long line'). If the duct is >12 inches in diameter *and* the sampling port location meets the two and half-diameter criterion of Section 11.1.1 of Method 1 of 40 CFR part 60, appendix A, the duct may be sampled at `3-point long line'; otherwise, conduct the stratification testing and select sampling points according to Section 8.1.2 of Method 7E of 40 CFR part 60, appendix A.
		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-2, or ASTM Method D6522-00 (Reapproved 2005)[a] (heated probe not necessary)	(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-3, or 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 formalde-hyde 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-7	(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.

For each . . .	Complying with the requirement to . . .	You must . . .	Using . . .	According to the following requirements . . .
3. Stationary RICE	a. limit the concentra-tion of formalde-hyde or CO in the stationary RICE exhaust	i. Select the sampling port location and the number/location of traverse points at the exhaust of the stationary RICE; and		(a) For formaldehyde, CO, O_2, and moisture measurement, ducts ≤6 inches in diameter may be sampled at a single point located at the duct centroid and ducts >6 and ≤12 inches in diameter may be sampled at 3 traverse points located at 16.7, 50.0, and 83.3% of the measurement line (`3-point long line'). If the duct is >12 inches in diameter *and* the sampling port location meets the two and half-diameter criterion of Section 11.1.1 of Method 1 of 40 CFR part 60, appendix A, the duct may be sampled at `3-point long line'; otherwise, conduct the stratification testing and select sampling points according to Section 8.1.2 of Method 7E of 40 CFR part 60, appendix 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-2, or ASTM Method D6522-00 (Reapproved 2005)[a] (heated probe not necessary)	(a) Measurements to determine O_2 concentration must be made at the same time and location as the measurements for formaldehyde or CO concentration.
		iii. Measure moisture content of the station-ary RICE exhaust at the sampling port location; and	(1) Method 4 of 40 CFR part 60, appendix A-3, or 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 formalde-hyde at the exhaust of the station-ary 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 station-ary RICE	(1) Method 10 of 40 CFR part 60, appendix A-4, ASTM Method D6522-00 (2005)[ac], 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]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.

[b]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.

[79 FR 11290, Feb. 27, 2014]

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:

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_2 or CO_2 at 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_2 or CO_2 at 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	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

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); 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.
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.

For each . . .	Complying with the requirement to . . .	You have demonstrated initial compliance if . . .
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.
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]

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:

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
		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.

For each . . .	Complying with the requirement to . . .	You must demonstrate continuous compliance by . . .
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.
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.

For each . . .	Complying with the requirement to . . .	You must demonstrate continuous compliance by . . .
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.
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

For each . . .	Complying with the requirement to . . .	You must demonstrate continuous compliance by . . .
		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.
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]

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; 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.
		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).

For each . . .	You must submit a . . .	The report must contain . . .	You must submit the report . . .
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]

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.	

General provisions citation	Subject of citation	Applies to subpart	Explanation
§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.

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.
		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.	

General provisions citation	Subject of citation	Applies to subpart	Explanation
§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]

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											
″											
″											
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″											
Mean											
Refresh Phase											
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[78 FR 6721, Jan. 30, 2013]

Attachment D

Part 70 Operating Permit No: 141-41227-00013

[Downloaded from the eCFR on September 14, 2016]

Electronic Code of Federal Regulations

Title 40: Protection of Environment

PART 63—NATIONAL EMISSION STANDARDS FOR HAZARDOUS AIR POLLUTANTS FOR SOURCE CATEGORIES

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

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

What This Subpart Covers

§63.11193 Am I subject to this subpart?

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

§63.11194 What is the affected source of this subpart?

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

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

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

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

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

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

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

(f) If you are an owner or operator of an area source subject to this subpart, you are exempt from the obligation to obtain a permit under 40 CFR part 70 or part 71 as a result of this subpart. You may, however, be required to obtain a

title V permit due to another reason or reasons. *See* 40 CFR 70.3(a) and (b) or 71.3(a) and (b). Notwithstanding the exemption from title V permitting for area sources under this subpart, you must continue to comply with the provisions of this subpart.

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

§63.11195 Are any boilers not subject to this subpart?

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

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

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

(c) A boiler required to have a permit under section 3005 of the Solid Waste Disposal Act or covered by subpart EEE of this part (*e.g.,* hazardous waste boilers).

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

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

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

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

(h) Temporary boilers as defined in this subpart.

(i) Residential boilers as defined in this subpart.

(j) Electric boilers as defined in this subpart.

(k) An electric utility steam generating unit (EGU) as defined in this subpart.

[76 FR 15591, Mar. 21, 2011, as amended at 78 FR 7506, Feb. 1, 2013; 81 FR 63125, Sept. 14, 2016]

§63.11196 What are my compliance dates?

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

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

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

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

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

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

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

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

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

§63.11200 What are the subcategories of boilers?

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

(a) Coal.

(b) Biomass.

(c) Oil.

(d) Seasonal boilers.

(e) Oil-fired boilers with heat input capacity of equal to or less than 5 million British thermal units (Btu) per hour.

(f) Boilers with an oxygen trim system that maintains an optimum air-to-fuel ratio that would otherwise be subject to a biennial tune-up.

(g) Limited-use boilers.

[78 FR 7506, Feb. 1, 2013]

§63.11201 What standards must I meet?

(a) You must comply with each emission limit specified in Table 1 to this subpart that applies to your boiler.

(b) You must comply with each work practice standard, emission reduction measure, and management practice specified in Table 2 to this subpart that applies to your boiler. An energy assessment completed on or after January 1, 2008 that meets or is amended to meet the energy assessment requirements in Table 2 to this subpart satisfies the energy assessment requirement. A facility that operates under an energy management program established through energy management systems compatible with ISO 50001, that includes the affected units, also satisfies the energy assessment requirement.

(c) You must comply with each operating limit specified in Table 3 to this subpart that applies to your boiler.

(d) These standards apply at all times the affected boiler is operating, except during periods of startup and shutdown as defined in §63.11237, during which time you must comply only with Table 2 to this subpart.

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

General Compliance Requirements

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Initial Compliance Requirements

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

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

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

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

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

(e) For new or reconstructed oil-fired boilers that commenced construction or reconstruction on or before September 14, 2016, that combust only oil that contains no more than 0.50 weight percent sulfur or a mixture of 0.50 weight percent sulfur oil with other fuels not subject to a particulate matter (PM) emission limit under this subpart and that do not use a post-combustion technology (except a wet scrubber) to reduce PM or sulfur dioxide emissions, you are not subject to the PM emission limit in Table 1 of this subpart until September 14, 2019, providing you monitor and record on a monthly basis the type of fuel combusted. If you intend to burn a new type of fuel or fuel mixture that does not meet the requirements of this paragraph, you must conduct a performance test within 60 days of burning the new fuel. On and after September 14, 2019, you are subject to the PM emission limit in Table 1 of this subpart and you must demonstrate compliance with the PM emission limit in Table 1 no later than March 12, 2020.

(f) For new or reconstructed boilers that combust only ultra-low-sulfur liquid fuel as defined in §63.11237, you are not subject to the PM emission limit in Table 1 of this subpart providing you monitor and record on a monthly basis the type of fuel combusted. If you intend to burn a fuel other than ultra-low-sulfur liquid fuel or gaseous fuels as defined in §63.11237, you must conduct a performance test within 60 days of burning the new fuel.

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

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

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

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

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

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

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

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

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

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

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

[76 FR 15591, Mar. 21, 2011, as amended at 78 FR 7507, Feb. 1, 2013; 81 FR 63125, Sept. 14, 2016]

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

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

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

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

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

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

(4) The operating limit for boilers with fabric filters that demonstrate continuous compliance through bag leak detection systems is that a bag leak detection system be installed according to the requirements in §63.11224, and

that each fabric filter must be operated such that the bag leak detection system alarm does not sound more than 5 percent of the operating time during a 6-month period.

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

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

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

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

Where:

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

(a) If you own or operate an existing or new coal-fired boiler with a heat input capacity of less than 10 million Btu per hour, you must conduct a performance tune-up according to §63.11210(c) or (g), as applicable, and §63.11223(b). If you own or operate an existing coal-fired boiler 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 an initial tune-up of the boiler.

(b) If you own or operate an existing or new biomass-fired boiler or an existing or new oil-fired boiler, you must conduct a performance tune-up according to §63.11210(c) or (g), as applicable, and §63.11223(b). If you own or operate an existing biomass-fired boiler or existing oil-fired boiler, you must submit a signed statement in the Notification of Compliance Status report that indicates that you conducted an initial tune-up of the boiler.

(c) If you own or operate an existing affected boiler with a heat input capacity of 10 million Btu per hour or greater, you must submit a signed certification in the Notification of Compliance Status report that an energy assessment of the boiler and its energy use systems was completed according to Table 2 to this subpart and that the assessment is an accurate depiction of your facility at the time of the assessment or that the maximum number of on-site technical hours specified in the definition of energy assessment applicable to the facility has been expended.

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

[76 FR 15591, Mar. 21, 2011, as amended at 78 FR 7508, Feb. 1, 2013; 81 FR 63126, Sept. 14, 2016]

Continuous Compliance Requirements

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

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

(b) For new or reconstructed boilers that commenced construction or reconstruction on or before September 14, 2016, when demonstrating initial compliance with the PM emission limit, if your boiler's performance test results show

that your PM emissions are equal to or less than half of the PM emission limit, you do not need to conduct further performance tests for PM until September 14, 2021, but must continue to comply with all applicable operating limits and monitoring requirements and must comply with the provisions as specified in paragraphs (b)(1) through (4) of this section.

(1) A performance test for PM must be conducted by September 14, 2021.

(2) If your performance test results show that your PM emissions are equal to or less than half of the PM emission limit, you may choose to conduct performance tests for PM every fifth year. Each such performance test must be conducted no more than 61 months after the previous performance test.

(3) If you intend to burn a new type of fuel other than ultra-low-sulfur liquid fuel or gaseous fuels as defined in §63.11237, you must conduct a performance test within 60 days of burning the new fuel type.

(4) If your performance test results show that your PM emissions are greater than half of the PM emission limit, you must conduct subsequent performance tests on a triennial basis as specified in paragraph (a) of this section.

(c) For new or reconstructed boilers that commenced construction or reconstruction after September 14, 2016, when demonstrating initial compliance with the PM emission limit, if your boiler's performance test results show that your PM emissions are equal to or less than half of the PM emission limit, you may choose to conduct performance tests for PM every fifth year, but must continue to comply with all applicable operating limits and monitoring requirements and must comply with the provisions as specified in paragraphs (c)(1) through (3) of this section.

(1) Each such performance test must be conducted no more than 61 months after the previous performance test.

(2) If you intend to burn a new type of fuel other than ultra-low-sulfur liquid fuel or gaseous fuels as defined in §63.11237, you must conduct a performance test within 60 days of burning the new fuel type.

(3) If your performance test results show that your PM emissions are greater than half of the PM emission limit, you must conduct subsequent performance tests on a triennial basis as specified in paragraph (a) of this section.

(d) If you demonstrate compliance with the mercury emission limit based on fuel analysis, you must conduct a fuel analysis according to §63.11213 for each type of fuel burned as specified in paragraphs (d)(1) through (3) of this section. If you plan to burn a new type of fuel or fuel mixture, you must conduct a fuel analysis before burning the new type of fuel or mixture in your boiler. You must recalculate the mercury emission rate using Equation 1 of §63.11211. The recalculated mercury emission rate must be less than the applicable emission limit.

(1) For existing boilers and new or reconstructed boilers that commenced construction or reconstruction on or before September 14, 2016, when demonstrating initial compliance with the mercury emission limit, if the mercury constituents in the fuel or fuel mixture are measured to be equal to or less than half of the mercury emission limit, you do not need to conduct further fuel analysis sampling until September 14, 2017, but must continue to comply with all applicable operating limits and monitoring requirements and must comply with the provisions as specified in paragraphs (d)(1)(i) and (ii) of this section.

(i) Fuel analysis sampling for mercury must be conducted by September 14, 2017.

(ii) If your fuel analysis results show that the mercury constituents in the fuel or fuel mixture are equal to or less than half of the mercury emission limit, you may choose to conduct fuel analysis sampling for mercury every 12 months.

(2) For new or reconstructed boilers that commenced construction or reconstruction after September 14, 2016, when demonstrating initial compliance with the mercury emission limit, if the mercury constituents in the fuel or fuel mixture are measured to be equal to or less than half of the mercury emission limit, you may choose to conduct fuel analysis sampling for mercury every 12 months, but must continue to comply with all applicable operating limits and monitoring requirements.

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

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

[81 FR 63127, Sept. 14, 2016]

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

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

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

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

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

[78 FR 7508, Feb. 1, 2013, as amended at 81 FR 63127, Sept. 14, 2016]

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

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

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

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

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

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

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

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

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

[76 FR 15591, Mar. 21, 2011, as amended at 81 FR 63127, Sept. 14, 2016]

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

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

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

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

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

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

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

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

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

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

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

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

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

(c) Boilers with an oxygen trim system that maintains an optimum air-to-fuel ratio that would otherwise be subject to a biennial tune-up must conduct a tune-up of the boiler every 5 years as specified in paragraphs (b)(1) through (7) of this section. Each 5-year tune-up must be conducted no more than 61 months after the previous tune-up. For a new or reconstructed boiler with an oxygen trim system, the first 5-year tune-up must be no later than 61 months after the initial startup. You may delay the burner inspection specified in paragraph (b)(1) of this section and inspection of the system controlling the air-to-fuel ratio specified in paragraph (b)(3) of this section until the next scheduled unit shutdown, but you must inspect each burner and system controlling the air-to-fuel ratio at least once every 72 months. If an oxygen trim system is utilized on a unit without emission standards to reduce the tune-up frequency to once every 5 years, set the oxygen level no lower than the oxygen concentration measured during the most recent tune-up.

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

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

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

(g) If you own or operate a boiler subject to emission limits in Table 1 of this subpart, you must minimize the boiler's startup and shutdown periods following the manufacturer's recommended procedures, if available. If manufacturer's

recommended procedures are not available, you must follow recommended procedures for a unit of similar design for which manufacturer's recommended procedures are available. You must submit a signed statement in the Notification of Compliance Status report that indicates that you conducted startups and shutdowns according to the manufacturer's recommended procedures or procedures specified for a boiler of similar design if manufacturer's recommended procedures are not available.

[76 FR 15591, Mar. 21, 2011, as amended at 78 FR 7509, Feb. 1, 2013; 81 FR 63127, Sept. 14, 2016]

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

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

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

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

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

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

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

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

Where:

Hpvi = the hourly parameter value for hour i

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

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

(7) You must operate the oxygen analyzer system at or above the minimum oxygen level that is established as the operating limit according to Table 6 to this subpart when firing the fuel or fuel mixture utilized during the most recent

CO performance stack test. Operation of oxygen trim systems to meet these requirements shall not be done in a manner which compromises furnace safety.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

$$\text{30-day average} = \frac{\Sigma_{i=1}^{n} Hpvi}{n} \qquad \text{(Eq.3)}$$

Where:

Hpvi = the hourly parameter value for hour i

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

(4) You must submit the Notification of Compliance Status no later than 120 days after the applicable compliance date specified in §63.11196 unless you own or operate a new boiler subject only to a requirement to conduct a biennial or 5-year tune-up or you must conduct a performance stack test. If you own or operate a new boiler subject to a requirement to conduct a tune-up, you are not required to prepare and submit a Notification of Compliance Status for the tune-up. If you must conduct a performance stack test, you must submit the Notification of Compliance Status within 60 days of completing the performance stack test. You must submit the Notification of Compliance Status in accordance with paragraphs (a)(4)(i) and (vi) of this section. The Notification of Compliance Status must include the information and certification(s) of compliance in paragraphs (a)(4)(i) through (v) of this section, as applicable, and signed by a responsible official.

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

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

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

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

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

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

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

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

(1) Company name and address.

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

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

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

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

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

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

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

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

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

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

(ii) For operating units that combust non-hazardous secondary materials that have been determined not to be solid waste pursuant to §241.3(b)(1) of this chapter, you must keep a record which documents how the secondary material meets each of the legitimacy criteria under §241.3(d)(1). If you combust a fuel that has been processed from a discarded non-hazardous secondary material pursuant to §241.3(b)(4) of this chapter, you must keep records as to how the operations that produced the fuel satisfies the definition of processing in §241.2 and each of the legitimacy criteria in §241.3(d)(1) of this chapter. If the fuel received a non-waste determination pursuant to the petition process submitted under §241.3(c) of this chapter, you must keep a record that documents how the fuel satisfies the requirements of the petition process. For operating units that combust non-hazardous secondary materials as fuel per §241.4, you must keep records documenting that the material is a listed non-waste under §241.4(a).

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

(iv) For each boiler subject to an emission limit in Table 1 to this subpart, you must keep records of monthly fuel use by each boiler, including the type(s) of fuel and amount(s) used. For each new oil-fired boiler that meets the requirements of §63.11210(e) or (f), you must keep records, on a monthly basis, of the type of fuel combusted.

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

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

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

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

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

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

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

(ii) Person conducting the monitoring.

(iii) Technique or method used.

(iv) Operating conditions during the activity.

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

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

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

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

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

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

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

(e)(1) Within 60 days after the date of completing each performance test (as defined in §63.2) required by this subpart, you must submit the results of the performance tests, including any associated fuel analyses, following the procedure specified in either paragraph (e)(1)(i) or (ii) of this section.

(i) For data collected using test methods supported by the EPA's Electronic Reporting Tool (ERT) as listed on the EPA's ERT Web site (*https://www3.epa.gov/ttn/chief/ert/ert_info.html*) at the time of the test, you must submit the results of the performance test to the EPA via the Compliance and Emissions Data Reporting Interface (CEDRI). (CEDRI can be accessed through the EPA's Central Data Exchange (CDX) (*https://cdx.epa.gov/*).) Performance test data must be submitted in a file format generated through the use of the EPA's ERT or an alternate electronic file format consistent with the extensible markup language (XML) schema listed on the EPA's ERT Web site. If you claim that some of the performance test information being submitted is confidential business information (CBI), you must submit a complete file generated through the use of the EPA's ERT or an alternate electronic file consistent with the XML schema listed on the EPA's ERT Web site, including information claimed to be CBI, on a compact disc, flash drive, or other commonly used electronic storage media to the EPA. The electronic media must be clearly marked as CBI and mailed to U.S. EPA/OAQPS/CORE CBI Office, Attention: Group Leader, Measurement Policy Group, MD C404-02, 4930 Old Page Rd., Durham, NC 27703. The same ERT or alternate file with the CBI omitted must be submitted to the EPA via the EPA's CDX as described earlier in this paragraph.

(ii) For data collected using test methods that are not supported by the EPA's ERT as listed on the EPA's ERT Web site at the time of the test, you must submit the results of the performance test to the Administrator at the appropriate address listed in §63.13.

(2) Within 60 days after the date of completing each CEMS performance evaluation (as defined in §63.2), you must submit the results of the performance evaluation following the procedure specified in either paragraph (e)(2)(i) or (ii) of this section.

(i) For performance evaluations of continuous monitoring systems measuring relative accuracy test audit (RATA) pollutants that are supported by the EPA's ERT as listed on the EPA's ERT Web site at the time of the evaluation, you must submit the results of the performance evaluation to the EPA via the CEDRI. (CEDRI can be accessed through the EPA's CDX.) Performance evaluation data must be submitted in a file format generated through the use of the EPA's ERT or an alternate file format consistent with the XML schema listed on the EPA's ERT Web site. If you claim that some of the performance evaluation information being submitted is CBI, you must submit a complete file generated through the use of the EPA's ERT or an alternate electronic file consistent with the XML schema listed on the EPA's ERT Web site, including information claimed to be CBI, on a compact disc, flash drive, or other commonly used electronic storage media to the EPA. The electronic storage media must be clearly marked as CBI and mailed to U.S. EPA/OAQPS/CORE CBI Office, Attention: Group Leader, Measurement Policy Group, MD C404-02, 4930 Old Page Rd., Durham, NC 27703. The same ERT or alternate file with the CBI omitted must be submitted to the EPA via the EPA's CDX as described earlier in this paragraph.

(ii) For any performance evaluations of continuous monitoring systems measuring RATA pollutants that are not supported by the EPA's ERT as listed on the EPA's ERT Web site at the time of the evaluation, you must submit the results of the performance evaluation to the Administrator at the appropriate address listed in §63.13.

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

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

(2) The currently applicable subcategory under this subpart.

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

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

(g) If you have switched fuels or made a physical change to the boiler and the fuel switch or change resulted in the applicability of a different subcategory within this subpart, in the boiler becoming subject to this subpart, or in the boiler switching out of this subpart due to a fuel change that results in the boiler meeting the definition of gas-fired boiler, as defined in §63.11237, or you have taken a permit limit that resulted in you becoming subject to this subpart or no longer being subject to this subpart, you must provide notice of the date upon which you switched fuels, made the physical change, or took a permit limit within 30 days of the change. The notification must identify:

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

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

[76 FR 15591, Mar. 21, 2011, as amended at 78 FR 7511, Feb. 1, 2013; 81 FR 63127, Sept. 14, 2016]

§63.11226 [Reserved]

Other Requirements and Information

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

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

§63.11236 Who implements and enforces this subpart?

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

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

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

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

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

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

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

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

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

§63.11237 What definitions apply to this subpart?

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

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

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

Annual capacity factor means the ratio between the actual heat input to a boiler from the fuels burned during a calendar year and the potential heat input to the boiler 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.

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

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

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

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

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

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

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

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

limited to, solvent-refined coal, coal-oil mixtures, and coal-water mixtures. Coal derived gases are excluded from this definition.

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

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

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

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

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

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

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

(2) A deviation is not always a violation.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Federally enforceable means all limitations and conditions that are enforceable by the EPA Administrator, including, but not limited to, the requirements of 40 CFR parts 60, 61, 63, and 65, requirements within any applicable state implementation plan, and any permit requirements established under 40 CFR 52.21 or under 40 CFR 51.18 and 40 CFR 51.24.

Fluidized bed boiler means a boiler utilizing a fluidized bed combustion process that is not a pulverized coal boiler.

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

Fossil fuel means natural gas, oil, coal, and any form of solid, liquid, or gaseous fuel derived from such material.

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

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

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

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

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

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

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

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

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

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

Load fraction means the actual heat input of a boiler divided by heat input during the performance test that established the minimum sorbent injection rate or minimum activated carbon injection rate, expressed as a fraction (*e.g.,* for 50 percent load the load fraction is 0.5). For boilers that co-fire natural gas with a solid or liquid fuel, the load fraction is determined by the actual heat input of the solid or liquid fuel divided by heat input of the solid or liquid fuel fired during the performance test (*e.g.,* if the performance test was conducted at 100 percent solid fuel firing, for 100 percent load firing 50 percent solid fuel and 50 percent natural gas, the load fraction is 0.5).

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

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

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

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

Minimum sorbent injection rate means:

(1) The load fraction multiplied by the lowest hourly average sorbent injection rate for each sorbent measured according to Table 6 to this subpart during the most recent performance stack 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 6 to this subpart during the most recent performance stack test demonstrating compliance with the applicable emission limits.

Natural gas means:

(1) A naturally occurring mixture of hydrocarbon and nonhydrocarbon gases found in geologic formations beneath the earth's surface, of which the principal constituent is methane; or

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

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

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

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

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

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

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

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

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

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

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

Process heater means an enclosed device using controlled flame, and the unit's primary purpose is to transfer heat indirectly to a process material (liquid, gas, or solid) or to a heat transfer material (e.g., glycol or a mixture of glycol and water) for use in a process unit, instead of generating steam. Process heaters are devices in which the combustion gases do not come into direct contact with process materials. Process heaters include units that heat water/water mixtures for pool heating, sidewalk heating, cooling tower water heating, power washing, or oil heating.

Qualified energy assessor means:

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

(i) Boiler combustion management.

(ii) Boiler thermal energy recovery, including

(A) Conventional feed water economizer,

(B) Conventional combustion air preheater, and

(C) Condensing economizer.

(iii) Boiler blowdown thermal energy recovery.

(iv) Primary energy resource selection, including

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

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

(v) Insulation issues.

(vi) Steam trap and steam leak management.

(vii) Condensate recovery.

(viii) Steam end-use management.

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

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

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

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

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

(v) Boiler-steam turbine cogeneration systems.

(vi) Industry specific steam end-use systems.

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

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

(1) A dwelling containing four or fewer families, or

(2) A single unit residence dwelling that has since been converted or subdivided into condominiums or apartments.

Residual oil means crude oil, fuel oil that does not comply with the specifications under the definition of distillate oil, and all fuel oil numbers 4, 5, and 6, as defined by the American Society of Testing and Materials in ASTM D396-10 (incorporated by reference, see §63.14(b)).

Responsible official means responsible official as defined in §70.2.

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

Shutdown means the period in which cessation of operation of a boiler is initiated for any purpose. Shutdown begins when the boiler no longer supplies useful thermal energy (such as steam or hot water) for heating, cooling, or process purposes or generates electricity, or when no fuel is being fed to the boiler, whichever is earlier. Shutdown ends when the boiler no longer supplies useful thermal energy (such as steam or hot water) for heating, cooling, or process purposes or generates electricity, and no fuel is being combusted in the boiler.

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

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

Startup means:

(1) Either the first-ever firing of fuel in a boiler for the purpose of supplying useful thermal energy (such as steam or hot water) 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 useful thermal energy (such as steam or hot water) from the boiler is supplied for heating and/or producing electricity, or for any other purpose, or

(2) The period in which operation of a boiler is initiated for any purpose. Startup begins with either the first-ever firing of fuel in a boiler for the purpose of supplying useful thermal energy (such as steam or hot water) for heating, cooling or process purposes or producing electricity, or the firing of fuel in a boiler for any purpose after a shutdown event. Startup ends 4 hours after when the boiler supplies useful thermal energy (such as steam or hot water) for heating, cooling, or process purposes or generates electricity, whichever is earlier.

Temporary boiler means any gaseous or liquid fuel boiler that is designed to, and is capable of, being carried or moved from one location to another by means of, for example, wheels, skids, carrying handles, dollies, trailers, or platforms. A boiler is not a temporary boiler if any one of the following conditions exists:

(1) The equipment is attached to a foundation.

(2) The boiler or a replacement remains at a location within the facility and performs the same or similar function for more than 12 consecutive months, unless the regulatory agency approves an extension. An extension may be granted by the regulating agency upon petition by the owner or operator of a unit specifying the basis for such a request. Any temporary boiler that replaces a temporary boiler at a location within the facility and performs the same or similar function will be included in calculating the consecutive time period unless there is a gap in operation of 12 months or more.

(3) The equipment is located at a seasonal facility and operates during the full annual operating period of the seasonal facility, remains at the facility for at least 2 years, and operates at that facility for at least 3 months each year.

(4) The equipment is moved from one location to another within the facility but continues to perform the same or similar function and serve the same electricity, steam, and/or hot water system in an attempt to circumvent the residence time requirements of this definition.

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

Ultra-low-sulfur liquid fuel means a distillate oil that has less than or equal to 15 parts per million (ppm) sulfur.

Useful thermal energy means energy (*i.e.,* steam or hot water) that meets the minimum operating temperature, flow, and/or pressure required by any energy use system that uses energy provided by the affected boiler.

Vegetable oil means oils extracted from vegetation.

Voluntary Consensus Standards (VCS) mean technical standards (*e.g.,* materials specifications, test methods, sampling procedures, business practices) developed or adopted by one or more voluntary consensus bodies. EPA/Office of Air Quality Planning and Standards, by precedent, has only used VCS that are written in English. Examples of VCS bodies are: American Society of Testing and Materials (ASTM, 100 Barr Harbor Drive, P.O. Box CB700, West Conshohocken, Pennsylvania 19428-B2959, (800) 262-1373, *http://www.astm.org*), American Society of Mechanical Engineers (ASME, 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.standards.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 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 Air Resources Board (CARB) and Texas Commission on Environmental Quality (TCEQ); industry groups, such as American Petroleum Institute (API), Gas Processors Association (GPA), and Gas Research Institute (GRI); and other branches of the U.S. Government, *e.g.,* Department of Defense (DOD) and Department of Transportation (DOT). This does not preclude EPA from using standards developed by groups that are not VCS bodies within their rule. When this occurs, EPA has done searches and reviews for VCS equivalent to these non-EPA methods.

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

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

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

[76 FR 15591, Mar. 21, 2011, as amended at 78 FR 7513, Feb. 1, 2013; 81 FR 61328, Sept. 14, 2016]

Table 1 to Subpart JJJJJJ of Part 63—Emission Limits

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

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

[78 FR 7517, Feb. 1, 2013, as amended at 81 FR 63129, Sept. 14, 2016]

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

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

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

If your boiler is in this subcategory . . .	You must meet the following . . .
3. New coal-fired boilers with heat input capacity of less than 10 MMBtu/hr that do not meet the definition of limited-use boiler, or use an oxygen trim system that maintains an optimum air-to-fuel ratio	Conduct a tune-up of the boiler biennially as specified in §63.11223.
4. Existing oil-fired boilers with heat input capacity greater than 5 MMBtu/hr that do not meet the definition of seasonal boiler or limited-use boiler, or use an oxygen trim system that maintains an optimum air-to-fuel ratio	Conduct an initial tune-up as specified in §63.11214, and conduct a tune-up of the boiler biennially as specified in §63.11223.
5. New oil-fired boilers with heat input capacity greater than 5 MMBtu/hr that do not meet the definition of seasonal boiler or limited-use boiler, or use an oxygen trim system that maintains an optimum air-to-fuel ratio	Conduct a tune-up of the boiler biennially as specified in §63.11223.
6. Existing biomass-fired boilers that do not meet the definition of seasonal boiler or limited-use boiler, or use an oxygen trim system that maintains an optimum air-to-fuel ratio	Conduct an initial tune-up as specified in §63.11214, and conduct a tune-up of the boiler biennially as specified in §63.11223.
7. New biomass-fired boilers that do not meet the definition of seasonal boiler or limited-use boiler, or use an oxygen trim system that maintains an optimum air-to-fuel ratio	Conduct a tune-up of the boiler biennially as specified in §63.11223.
8. Existing seasonal boilers	Conduct an initial tune-up as specified in §63.11214, and conduct a tune-up of the boiler every 5 years as specified in §63.11223.
9. New seasonal boilers	Conduct a tune-up of the boiler every 5 years as specified in §63.11223.
10. Existing limited-use boilers	Conduct an initial tune-up as specified in §63.11214, and conduct a tune-up of the boiler every 5 years as specified in §63.11223.
11. New limited-use boilers	Conduct a tune-up of the boiler every 5 years as specified in §63.11223.
12. Existing oil-fired boilers with heat input capacity of equal to or less than 5 MMBtu/hr	Conduct an initial tune-up as specified in §63.11214, and conduct a tune-up of the boiler every 5 years as specified in §63.11223.
13. New oil-fired boilers with heat input capacity of equal to or less than 5 MMBtu/hr	Conduct a tune-up of the boiler every 5 years as specified in §63.11223.
14. Existing coal-fired, biomass-fired, or oil-fired boilers with an oxygen trim system that maintains an optimum air-to-fuel ratio that would otherwise be subject to a biennial tune-up	Conduct an initial tune-up as specified in §63.11214, and conduct a tune-up of the boiler every 5 years as specified in §63.11223.
15. New coal-fired, biomass-fired, or oil-fired boilers with an oxygen trim system that maintains an optimum air-to-fuel ratio that would otherwise be subject to a biennial tune-up	Conduct a tune-up of the boiler every 5 years as specified in §63.11223.

If your boiler is in this subcategory . . .	You must meet the following . . .
16. Existing coal-fired, biomass-fired, or oil-fired boilers (units with heat input capacity of 10 MMBtu/hr and greater), not including limited-use boilers	Must have a one-time energy assessment performed by a qualified energy assessor. An energy assessment completed on or after January 1, 2008, that meets or is amended to meet the energy assessment requirements in this table satisfies the energy assessment requirement. Energy assessor approval and qualification requirements are waived in instances where past or amended energy assessments are used to meet the energy assessment requirements. A facility that operated under an energy management program developed according to the ENERGY STAR guidelines for energy management or compatible with ISO 50001 for at least 1 year between January 1, 2008, and the compliance date specified in §63.11196 that includes the affected units also satisfies the energy assessment requirement. The energy assessment must include the following with extent of the evaluation for items (1) to (4) appropriate for the on-site technical hours listed in §63.11237:
	(1) A visual inspection of the boiler system,
	(2) An evaluation of operating characteristics of the affected boiler systems, specifications of energy use systems, operating and maintenance procedures, and unusual operating constraints,
	(3) An inventory of major energy use systems consuming energy from affected boiler(s) and which are under control of the boiler owner or operator,
	(4) A review of available architectural and engineering plans, facility operation and maintenance procedures and logs, and fuel usage,
	(5) A list of major energy conservation measures that are within the facility's control,
	(6) A list of the energy savings potential of the energy conservation measures identified, and
	(7) A comprehensive report detailing the ways to improve efficiency, the cost of specific improvements, benefits, and the time frame for recouping those investments.

[78 FR 7518, Feb. 1, 2013, as amended at 81 FR 63129, Sept. 14, 2016]

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

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

If you demonstrate compliance with applicable emission limits using . . .	You must meet these operating limits except during periods of startup and shutdown . . .
1. Fabric filter control	a. Maintain opacity to less than or equal to 10 percent opacity (daily block average); OR b. Install and operate a bag leak detection system according to §63.11224 and operate the fabric filter such that the bag leak detection system alarm does not sound more than 5 percent of the operating time during each 6-month period.
2. Electrostatic precipitator control	a. Maintain opacity to less than or equal to 10 percent opacity (daily block average); OR b. Maintain the 30-day rolling average total secondary electric power of the electrostatic precipitator at or above the minimum total secondary electric power as defined in §63.11237.

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

[78 FR 7519, Feb. 1, 2013]

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

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

To conduct a performance test for the following pollutant. . .	You must. . .	Using. . .
1. Particulate Matter	a. Select sampling ports location and the number of traverse points	Method 1 in appendix A-1 to part 60 of this chapter.
	b. Determine velocity and volumetric flow-rate of the stack gas	Method 2, 2F, or 2G in appendix A-2 to part 60 of this chapter.
	c. Determine oxygen and carbon dioxide concentrations of the stack gas	Method 3A or 3B in appendix A-2 to part 60 of this chapter, or ASTM D6522-00 (Reapproved 2005),[a] or ANSI/ASME PTC 19.10-1981.[a]
	d. Measure the moisture content of the stack gas	Method 4 in appendix A-3 to part 60 of this chapter.

To conduct a performance test for the following pollutant. . .	You must. . .	Using. . .
	e. Measure the particulate matter emission concentration	Method 5 or 17 (positive pressure fabric filters must use Method 5D) in appendix A-3 and A-6 to part 60 of this chapter and a minimum 1 dscm of sample volume per run.
	f. Convert emissions concentration to lb/MMBtu emission rates	Method 19 F-factor methodology in appendix A-7 to part 60 of this chapter.
2. Mercury	a. Select sampling ports location and the number of traverse points	Method 1 in appendix A-1 to part 60 of this chapter.
	b. Determine velocity and volumetric flow-rate of the stack gas	Method 2, 2F, or 2G in appendix A-2 to part 60 of this chapter.
	c. Determine oxygen and carbon dioxide concentrations of the stack gas	Method 3A or 3B in appendix A-2 to part 60 of this chapter, or ASTM D6522-00 (Reapproved 2005),[a] or ANSI/ASME PTC 19.10-1981.[a]
	d. Measure the moisture content of the stack gas	Method 4 in appendix A-3 to part 60 of this chapter.
	e. Measure the mercury emission concentration	Method 29, 30A, or 30B in appendix A-8 to part 60 of this chapter or Method 101A in appendix B to part 61 of this chapter or ASTM Method D6784-02.[a] Collect a minimum 2 dscm of sample volume with Method 29 of 101A per run. Use a minimum run time of 2 hours with Method 30A.
	f. Convert emissions concentration to lb/MMBtu emission rates	Method 19 F-factor methodology in appendix A-7 to part 60 of this chapter.
3. Carbon Monoxide	a. Select the sampling ports location and the number of traverse points	Method 1 in appendix A-1 to part 60 of this chapter.
	b. Determine oxygen and carbon dioxide concentrations of the stack gas	Method 3A or 3B in appendix A-2 to part 60 of this chapter, or ASTM D6522-00 (Reapproved 2005),[a] or ANSI/ASME PTC 19.10-1981.[a]
	c. Measure the moisture content of the stack gas	Method 4 in appendix A-3 to part 60 of this chapter.
	d. Measure the carbon monoxide emission concentration	Method 10, 10A, or 10B in appendix A-4 to part 60 of this chapter or ASTM D6522-00 (Reapproved 2005)[a] and a minimum 1 hour sampling time per run.

[a]Incorporated by reference, see §63.14.

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

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

To conduct a fuel analysis for the following pollutant . . .	You must. . .	Using . . .
1. Mercury	a. Collect fuel samples	Procedure in §63.11213(b) or ASTM D2234/D2234M[a] (for coal) or ASTM D6323[a] (for biomass) or equivalent.
	b. Compose fuel samples	Procedure in §63.11213(b) or equivalent.
	c. Prepare composited fuel samples	EPA SW-846-3050B[a] (for solid samples) or EPA SW-846-3020A[a] (for liquid samples) or 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 mercury concentration in fuel sample	ASTM D6722[a] (for coal) or EPA SW-846-7471B[a] (for solid samples) or EPA SW-846-7470A[a] (for liquid samples) or equivalent.
	g. Convert concentrations into units of lb/MMBtu of heat content	

[a]Incorporated by reference, see §63.14.

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

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

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

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 for each individual test run in the three-run performance stack test by computing the average of all the 15-minute readings taken during each test run.
2. Mercury	Dry sorbent or activated carbon injection rate operating parameters	Establish a site-specific minimum sorbent or activated carbon injection rate operating limit according to §63.11211(b)	Data from the sorbent or activated carbon injection rate monitors and the mercury performance stack tests	(a) You must collect sorbent or activated carbon injection rate data every 15 minutes during the entire period of the performance stack tests;
				(b) Determine the average sorbent or activated carbon injection rate for each individual test run in the three-run performance stack test by computing the average of all the 15-minute readings taken during each test run.
				(c) When your unit operates at lower loads, multiply your sorbent or activated carbon injection rate by the load fraction, as defined in §63.11237, to determine the required injection rate.
3. CO	Oxygen	Establish a unit-specific limit for minimum oxygen level	Data from the oxygen analyzer system specified in §63.11224(a)	(a) You must collect oxygen data every 15 minutes during the entire period of the performance stack tests;
				(b) Determine the average hourly oxygen concentration for each individual test run in the three-run performance stack test by computing the average of all the 15-minute readings taken during each test run.
4. Any pollutant for which compliance is demonstrated by a performance stack test	Boiler operating load	Establish a unit-specific limit for maximum operating load according to §63.11212(c)	Data from the operating load monitors (fuel feed monitors or steam generation monitors)	(a) You must collect operating load data (fuel feed rate or steam generation data) every 15 minutes during the entire period of the performance test.
				(b) Determine the average operating load by computing the hourly averages using all of the 15-minute readings taken during each performance test.

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.

[78 FR 7520, Feb. 1, 2013, as amended at 81 FR 63129, Sept. 14, 2016]

Table 7 to Subpart JJJJJJ of Part 63—Demonstrating Continuous Compliance

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

If you must meet the following operating limits . . .	You must demonstrate continuous compliance by . . .
1. Opacity	a. Collecting the opacity monitoring system data according to §63.11224(e) and §63.11221; and
	b. Reducing the opacity monitoring data to 6-minute averages; and
	c. Maintaining opacity to less than or equal to 10 percent (daily block average).
2. Fabric Filter Bag Leak Detection Operation	Installing and operating a bag leak detection system according to §63.11224(f) and operating the fabric filter such that the requirements in §63.11222(a)(4) are met.
3. Wet Scrubber Pressure Drop and Liquid Flow Rate	a. Collecting the pressure drop and liquid flow rate monitoring system data according to §§63.11224 and 63.11221; and
	b. Reducing the data to 30-day rolling averages; and
	c. Maintaining the 30-day rolling average pressure drop and liquid flow rate at or above the minimum pressure drop and minimum liquid flow rate according to §63.11211.
4. Dry Scrubber Sorbent or Activated Carbon Injection Rate	a. Collecting the sorbent or activated carbon injection rate monitoring system data for the dry scrubber according to §§63.11224 and 63.11221; and
	b. Reducing the data to 30-day rolling averages; and
	c. Maintaining the 30-day rolling average sorbent or activated carbon injection rate at or above the minimum sorbent or activated carbon injection rate according to §63.11211.
5. Electrostatic Precipitator Total Secondary Electric Power	a. Collecting the total secondary electric power monitoring system data for the electrostatic precipitator according to §§63.11224 and 63.11221; and
	b. Reducing the data to 30-day rolling averages; and
	c. Maintaining the 30-day rolling average total secondary electric power at or above the minimum total secondary electric power according to §63.11211.
6. Fuel Pollutant Content	a. Only burning the fuel types and fuel mixtures used to demonstrate compliance with the applicable emission limit according to §63.11213 as applicable; and
	b. Keeping monthly records of fuel use according to §§63.11222(a)(2) and 63.11225(b)(4).

If you must meet the following operating limits . . .	You must demonstrate continuous compliance by . . .
7. Oxygen content	a. Continuously monitoring the oxygen content of flue gas according to §63.11224 (This requirement does not apply to units that install an oxygen trim system since these units will set the trim system to the level specified in §63.11224(a)(7)); and
	b. Reducing the data to 30-day rolling averages; and
	c. Maintaining the 30-day rolling average oxygen content at or above the minimum oxygen level established during the most recent CO performance test.
8. CO emissions	a. Continuously monitoring the CO concentration in the combustion exhaust according to §§63.11224 and 63.11221; and
	b. Correcting the data to 3 percent oxygen, and reducing the data to 1-hour averages; and
	c. Reducing the data from the hourly averages to 10-day rolling averages; and
	d. Maintaining the 10-day rolling average CO concentration at or below the applicable emission limit in Table 1 to this subpart.
9. Boiler operating load	a. Collecting operating load data (fuel feed rate or steam generation data) every 15 minutes; and
	b. Reducing the data to 30-day rolling averages; and
	c. Maintaining the 30-day rolling average at or below the operating limit established during the performance test according to §63.11212(c) and Table 6 to this subpart.

[78 FR 7521, Feb. 1, 2013]

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

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

General provisions cite	Subject	Does it apply?
§63.1	Applicability	Yes.
§63.2	Definitions	Yes. Additional terms defined in §63.11237.
§63.3	Units and Abbreviations	Yes.
§63.4	Prohibited Activities and Circumvention	Yes.
§63.5	Preconstruction Review and Notification Requirements	No
§63.6(a), (b)(1)-(b)(5), (b)(7), (c), (f)(2)-(3), (g), (i), (j)	Compliance with Standards and Maintenance Requirements	Yes.
§63.6(e)(1)(i)	General Duty to minimize emissions	No. *See* §63.11205 for general duty requirement.
§63.6(e)(1)(ii)	Requirement to correct malfunctions ASAP	No.
§63.6(e)(3)	SSM Plan	No.
§63.6(f)(1)	SSM exemption	No.

General provisions cite	Subject	Does it apply?
§63.6(h)(1)	SSM exemption	No.
§63.6(h)(2) to (9)	Determining compliance with opacity emission standards	Yes.
§63.7(a), (b), (c), (d) , (e)(2)-(e)(9), (f), (g), and (h)	Performance Testing Requirements	Yes.
§63.7(e)(1)	Performance testing	No. *See* §63.11210.
§63.8(a), (b), (c)(1), (c)(1)(ii), (c)(2) to (c)(9), (d)(1) and (d)(2), (e),(f), and (g)	Monitoring Requirements	Yes.
§63.8(c)(1)(i)	General duty to minimize emissions and CMS operation	No.
§63.8(c)(1)(iii)	Requirement to develop SSM Plan for CMS	No.
§63.8(d)(3)	Written procedures for CMS	Yes, except for the last sentence, which refers to an SSM plan. SSM plans are not required.
§63.9	Notification Requirements	Yes, excluding the information required in §63.9(h)(2)(i)(B), (D), (E) and (F). See §63.11225.
§63.10(a) and (b)(1)	Recordkeeping and Reporting Requirements	Yes.
§63.10(b)(2)(i)	Recordkeeping of occurrence and duration of startups or shutdowns	No.
§63.10(b)(2)(ii)	Recordkeeping of malfunctions	No. *See* §63.11225 for recordkeeping of (1) occurrence and duration and (2) actions taken during malfunctions.
§63.10(b)(2)(iii)	Maintenance records	Yes.
§63.10(b)(2)(iv) and (v)	Actions taken to minimize emissions during SSM	No.
§63.10(b)(2)(vi)	Recordkeeping for CMS malfunctions	Yes.
§63.10(b)(2)(vii) to (xiv)	Other CMS requirements	Yes.
§63.10(b)(3)	Recordkeeping requirements for applicability determinations	No.
§63.10(c)(1) to (9)	Recordkeeping for sources with CMS	Yes.
§63.10(c)(10)	Recording nature and cause of malfunctions	No. *See* §63.11225 for malfunction recordkeeping requirements.
§63.10(c)(11)	Recording corrective actions	No. *See* §63.11225 for malfunction recordkeeping requirements.
§63.10(c)(12) and (13)	Recordkeeping for sources with CMS	Yes.
§63.10(c)(15)	Allows use of SSM plan	No.

General provisions cite	Subject	Does it apply?
§63.10(d)(1) and (2)	General reporting requirements	Yes.
§63.10(d)(3)	Reporting opacity or visible emission observation results	No.
§63.10(d)(4)	Progress reports under an extension of compliance	Yes.
§63.10(d)(5)	SSM reports	No. *See* §63.11225 for malfunction reporting requirements.
§63.10(e)	Additional reporting requirements for sources with CMS	Yes.
§63.10(f)	Waiver of recordkeeping or reporting requirements	Yes.
§63.11	Control Device Requirements	No.
§63.12	State Authority and Delegation	Yes.
§63.13-63.16	Addresses, Incorporation by Reference, Availability of Information, Performance Track Provisions	Yes.
§63.1(a)(5), (a)(7)-(a)(9), (b)(2), (c)(3)-(4), (d), 63.6(b)(6), (c)(3), (c)(4), (d), (e)(2), (e)(3)(ii), (h)(3), (h)(5)(iv), 63.8(a)(3), 63.9(b)(3), (h)(4), 63.10(c)(2)-(4), (c)(9)	Reserved	No.

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

Attachment E

Part 70 Operating Permit No: 141-41227-00013

[Downloaded from the eCFR on July 19, 2016]

Electronic Code of Federal Regulations

Title 40: Protection of Environment

PART 60—STANDARDS OF PERFORMANCE FOR NEW STATIONARY SOURCES

Subpart KKKK—Standards of Performance for Stationary Combustion Turbines

Source: 71 FR 38497, July 6, 2006, unless otherwise noted.

Introduction

§60.4300 What is the purpose of this subpart?

This subpart establishes emission standards and compliance schedules for the control of emissions from stationary combustion turbines that commenced construction, modification or reconstruction after February 18, 2005.

Applicability

§60.4305 Does this subpart apply to my stationary combustion turbine?

(a) If you are the owner or operator of a stationary combustion turbine with a heat input at peak load equal to or greater than 10.7 gigajoules (10 MMBtu) per hour, based on the higher heating value of the fuel, which commenced construction, modification, or reconstruction after February 18, 2005, your turbine is subject to this subpart. Only heat input to the combustion turbine should be included when determining whether or not this subpart is applicable to your turbine. Any additional heat input to associated heat recovery steam generators (HRSG) or duct burners should not be included when determining your peak heat input. However, this subpart does apply to emissions from any associated HRSG and duct burners.

(b) Stationary combustion turbines regulated under this subpart are exempt from the requirements of subpart GG of this part. Heat recovery steam generators and duct burners regulated under this subpart are exempted from the requirements of subparts Da, Db, and Dc of this part.

§60.4310 What types of operations are exempt from these standards of performance?

(a) Emergency combustion turbines, as defined in §60.4420(i), are exempt from the nitrogen oxides (NO_X) emission limits in §60.4320.

(b) Stationary combustion turbines engaged by manufacturers in research and development of equipment for both combustion turbine emission control techniques and combustion turbine efficiency improvements are exempt from the NO_X emission limits in §60.4320 on a case-by-case basis as determined by the Administrator.

(c) Stationary combustion turbines at integrated gasification combined cycle electric utility steam generating units that are subject to subpart Da of this part are exempt from this subpart.

(d) Combustion turbine test cells/stands are exempt from this subpart.

Emission Limits

§60.4315 What pollutants are regulated by this subpart?

The pollutants regulated by this subpart are nitrogen oxide (NO_X) and sulfur dioxide (SO_2).

§60.4320 What emission limits must I meet for nitrogen oxides (NOX)?

(a) You must meet the emission limits for NO_X specified in Table 1 to this subpart.

(b) If you have two or more turbines that are connected to a single generator, each turbine must meet the emission limits for NO_X.

§60.4325 What emission limits must I meet for NOX if my turbine burns both natural gas and distillate oil (or some other combination of fuels)?

You must meet the emission limits specified in Table 1 to this subpart. If your total heat input is greater than or equal to 50 percent natural gas, you must meet the corresponding limit for a natural gas-fired turbine when you are burning that fuel. Similarly, when your total heat input is greater than 50 percent distillate oil and fuels other than natural gas, you must meet the corresponding limit for distillate oil and fuels other than natural gas for the duration of the time that you burn that particular fuel.

§60.4330 What emission limits must I meet for sulfur dioxide (SO2)?

(a) If your turbine is located in a continental area, you must comply with either paragraph (a)(1), (a)(2), or (a)(3) of this section. If your turbine is located in Alaska, you do not have to comply with the requirements in paragraph (a) of this section until January 1, 2008.

(1) You must not cause to be discharged into the atmosphere from the subject stationary combustion turbine any gases which contain SO_2 in excess of 110 nanograms per Joule (ng/J) (0.90 pounds per megawatt-hour (lb/MWh)) gross output;

(2) You must not burn in the subject stationary combustion turbine any fuel which contains total potential sulfur emissions in excess of 26 ng SO_2/J (0.060 lb SO_2/MMBtu) heat input. If your turbine simultaneously fires multiple fuels, each fuel must meet this requirement; or

(3) For each stationary combustion turbine burning at least 50 percent biogas on a calendar month basis, as determined based on total heat input, you must not cause to be discharged into the atmosphere from the affected source any gases that contain SO_2 in excess of 65 ng SO_2/J (0.15 lb SO_2/MMBtu) heat input.

(b) If your turbine is located in a noncontinental area or a continental area that the Administrator determines does not have access to natural gas and that the removal of sulfur compounds would cause more environmental harm than benefit, you must comply with one or the other of the following conditions:

(1) You must not cause to be discharged into the atmosphere from the subject stationary combustion turbine any gases which contain SO_2 in excess of 780 ng/J (6.2 lb/MWh) gross output, or

(2) You must not burn in the subject stationary combustion turbine any fuel which contains total sulfur with potential sulfur emissions in excess of 180 ng SO_2/J (0.42 lb SO_2/MMBtu) heat input. If your turbine simultaneously fires multiple fuels, each fuel must meet this requirement.

[71 FR 38497, July 6, 2006, as amended at 74 FR 11861, Mar. 20, 2009]

General Compliance Requirements

§60.4333 What are my general requirements for complying with this subpart?

(a) You must operate and maintain your stationary combustion turbine, air pollution control equipment, and monitoring equipment in a manner consistent with good air pollution control practices for minimizing emissions at all times including during startup, shutdown, and malfunction.

(b) When an affected unit with heat recovery utilizes a common steam header with one or more combustion turbines, the owner or operator shall either:

(1) Determine compliance with the applicable NO_X emissions limits by measuring the emissions combined with the emissions from the other unit(s) utilizing the common heat recovery unit; or

(2) Develop, demonstrate, and provide information satisfactory to the Administrator on methods for apportioning the combined gross energy output from the heat recovery unit for each of the affected combustion turbines. The Administrator may approve such demonstrated substitute methods for apportioning the combined gross energy output measured at the steam turbine whenever the demonstration ensures accurate estimation of emissions related under this part.

Monitoring

§60.4335 How do I demonstrate compliance for NOX if I use water or steam injection?

(a) If you are using water or steam injection to control NO_X emissions, you must install, calibrate, maintain and operate a continuous monitoring system to monitor and record the fuel consumption and the ratio of water or steam to fuel being fired in the turbine when burning a fuel that requires water or steam injection for compliance.

(b) Alternatively, you may use continuous emission monitoring, as follows:

(1) Install, certify, maintain, and operate a continuous emission monitoring system (CEMS) consisting of a NO_X monitor and a diluent gas (oxygen (O_2) or carbon dioxide (CO_2)) monitor, to determine the hourly NO_X emission rate in parts per million (ppm) or pounds per million British thermal units (lb/MMBtu); and

(2) For units complying with the output-based standard, install, calibrate, maintain, and operate a fuel flow meter (or flow meters) to continuously measure the heat input to the affected unit; and

(3) For units complying with the output-based standard, install, calibrate, maintain, and operate a watt meter (or meters) to continuously measure the gross electrical output of the unit in megawatt-hours; and

(4) For combined heat and power units complying with the output-based standard, install, calibrate, maintain, and operate meters for useful recovered energy flow rate, temperature, and pressure, to continuously measure the total thermal energy output in British thermal units per hour (Btu/h).

§60.4340 How do I demonstrate continuous compliance for NOX if I do not use water or steam injection?

(a) If you are not using water or steam injection to control NO_X emissions, you must perform annual performance tests in accordance with §60.4400 to demonstrate continuous compliance. If the NO_X emission result from the performance test is less than or equal to 75 percent of the NO_X emission limit for the turbine, you may reduce the frequency of subsequent performance tests to once every 2 years (no more than 26 calendar months following the previous performance test). If the results of any subsequent performance test exceed 75 percent of the NO_X emission limit for the turbine, you must resume annual performance tests.

(b) As an alternative, you may install, calibrate, maintain and operate one of the following continuous monitoring systems:

(1) Continuous emission monitoring as described in §§60.4335(b) and 60.4345, or

(2) Continuous parameter monitoring as follows:

(i) For a diffusion flame turbine without add-on selective catalytic reduction (SCR) controls, you must define parameters indicative of the unit's NO_X formation characteristics, and you must monitor these parameters continuously.

(ii) For any lean premix stationary combustion turbine, you must continuously monitor the appropriate parameters to determine whether the unit is operating in low-NO_X mode.

(iii) For any turbine that uses SCR to reduce NO_X emissions, you must continuously monitor appropriate parameters to verify the proper operation of the emission controls.

(iv) For affected units that are also regulated under part 75 of this chapter, with state approval you can monitor the NO_X emission rate using the methodology in appendix E to part 75 of this chapter, or the low mass emissions methodology in §75.19, the requirements of this paragraph (b) may be met by performing the parametric monitoring described in section 2.3 of part 75 appendix E or in §75.19(c)(1)(iv)(H).

§60.4345 What are the requirements for the continuous emission monitoring system equipment, if I choose to use this option?

If the option to use a NO_X CEMS is chosen:

(a) Each NO_X diluent CEMS must be installed and certified according to Performance Specification 2 (PS 2) in appendix B to this part, except the 7-day calibration drift is based on unit operating days, not calendar days. With state approval, Procedure 1 in appendix F to this part is not required. Alternatively, a NO_X diluent CEMS that is installed and certified according to appendix A of part 75 of this chapter is acceptable for use under this subpart. The relative accuracy test audit (RATA) of the CEMS shall be performed on a lb/MMBtu basis.

(b) As specified in §60.13(e)(2), during each full unit operating hour, both the NO_X monitor and the diluent monitor must complete a minimum of one cycle of operation (sampling, analyzing, and data recording) for each 15-minute quadrant of the hour, to validate the hour. For partial unit operating hours, at least one valid data point must be obtained with each monitor for each quadrant of the hour in which the unit operates. For unit operating hours in which required quality assurance and maintenance activities are performed on the CEMS, a minimum of two valid data points (one in each of two quadrants) are required for each monitor to validate the NO_X emission rate for the hour.

(c) Each fuel flowmeter shall be installed, calibrated, maintained, and operated according to the manufacturer's instructions. Alternatively, with state approval, fuel flowmeters that meet the installation, certification, and quality assurance requirements of appendix D to part 75 of this chapter are acceptable for use under this subpart.

(d) Each watt meter, steam flow meter, and each pressure or temperature measurement device shall be installed, calibrated, maintained, and operated according to manufacturer's instructions.

(e) The owner or operator shall develop and keep on-site a quality assurance (QA) plan for all of the continuous monitoring equipment described in paragraphs (a), (c), and (d) of this section. For the CEMS and fuel flow meters, the owner or operator may, with state approval, satisfy the requirements of this paragraph by implementing the QA program and plan described in section 1 of appendix B to part 75 of this chapter.

§60.4350 How do I use data from the continuous emission monitoring equipment to identify excess emissions?

For purposes of identifying excess emissions:

(a) All CEMS data must be reduced to hourly averages as specified in §60.13(h).

(b) For each unit operating hour in which a valid hourly average, as described in §60.4345(b), is obtained for both NO_X and diluent monitors, the data acquisition and handling system must calculate and record the hourly NO_X emission rate in units of ppm or lb/MMBtu, using the appropriate equation from method 19 in appendix A of this part. For any hour in which the hourly average O_2 concentration exceeds 19.0 percent O_2 (or the hourly average CO_2 concentration is less than 1.0 percent CO_2), a diluent cap value of 19.0 percent O_2 or 1.0 percent CO_2 (as applicable) may be used in the emission calculations.

(c) Correction of measured NO_X concentrations to 15 percent O_2 is not allowed.

(d) If you have installed and certified a NO_X diluent CEMS to meet the requirements of part 75 of this chapter, states can approve that only quality assured data from the CEMS shall be used to identify excess emissions under this subpart. Periods where the missing data substitution procedures in subpart D of part 75 are applied are to be reported as monitor downtime in the excess emissions and monitoring performance report required under §60.7(c).

(e) All required fuel flow rate, steam flow rate, temperature, pressure, and megawatt data must be reduced to hourly averages.

(f) Calculate the hourly average NO_X emission rates, in units of the emission standards under §60.4320, using either ppm for units complying with the concentration limit or the following equation for units complying with the output based standard:

(1) For simple-cycle operation:

$$E = \frac{(NO_x)_h * (HI)_h}{P} \qquad \text{(Eq. 1)}$$

Where:

E = hourly NO_X emission rate, in lb/MWh,

$(NO_X)_h$ = hourly NO_X emission rate, in lb/MMBtu,

$(HI)_h$ = hourly heat input rate to the unit, in MMBtu/h, measured using the fuel flowmeter(s), *e.g.*, calculated using Equation D-15a in appendix D to part 75 of this chapter, and

P = gross energy output of the combustion turbine in MW.

(2) For combined-cycle and combined heat and power complying with the output-based standard, use Equation 1 of this subpart, except that the gross energy output is calculated as the sum of the total electrical and mechanical energy generated by the combustion turbine, the additional electrical or mechanical energy (if any) generated by the steam turbine following the heat recovery steam generator, and 100 percent of the total useful thermal energy output that is not used to generate additional electricity or mechanical output, expressed in equivalent MW, as in the following equations:

$$P = (Pe)_t + (Pe)_c + Ps + Po \qquad \text{(Eq. 2)}$$

Where:

P = gross energy output of the stationary combustion turbine system in MW.

$(Pe)_t$ = electrical or mechanical energy output of the combustion turbine in MW,

$(Pe)_c$ = electrical or mechanical energy output (if any) of the steam turbine in MW, and

$$Ps = \frac{Q * H}{3.413 \times 10^6 \text{ Btu/MWh}} \qquad \text{(Eq. 3)}$$

Where:

Ps = useful thermal energy of the steam, measured relative to ISO conditions, not used to generate additional electric or mechanical output, in MW,

Q = measured steam flow rate in lb/h,

H = enthalpy of the steam at measured temperature and pressure relative to ISO conditions, in Btu/lb, and 3.413 × 10_6 = conversion from Btu/h to MW.

Po = other useful heat recovery, measured relative to ISO conditions, not used for steam generation or performance enhancement of the combustion turbine.

(3) For mechanical drive applications complying with the output-based standard, use the following equation:

$$E = \frac{(NO_x)_m}{BL * AL} \qquad \text{(Eq. 4)}$$

Where:

E = NO_X emission rate in lb/MWh,

$(NO_X)_m$ = NO_X emission rate in lb/h,

BL = manufacturer's base load rating of turbine, in MW, and

AL = actual load as a percentage of the base load.

(g) For simple cycle units without heat recovery, use the calculated hourly average emission rates from paragraph (f) of this section to assess excess emissions on a 4-hour rolling average basis, as described in §60.4380(b)(1).

(h) For combined cycle and combined heat and power units with heat recovery, use the calculated hourly average emission rates from paragraph (f) of this section to assess excess emissions on a 30 unit operating day rolling average basis, as described in §60.4380(b)(1).

§60.4355 How do I establish and document a proper parameter monitoring plan?

(a) The steam or water to fuel ratio or other parameters that are continuously monitored as described in §§60.4335 and 60.4340 must be monitored during the performance test required under §60.8, to establish acceptable values and ranges. You may supplement the performance test data with engineering analyses, design specifications, manufacturer's recommendations and other relevant information to define the acceptable parametric ranges more precisely. You must develop and keep on-site a parameter monitoring plan which explains the procedures used to document proper operation of the NOX emission controls. The plan must:

(1) Include the indicators to be monitored and show there is a significant relationship to emissions and proper operation of the NOX emission controls,

(2) Pick ranges (or designated conditions) of the indicators, or describe the process by which such range (or designated condition) will be established,

(3) Explain the process you will use to make certain that you obtain data that are representative of the emissions or parameters being monitored (such as detector location, installation specification if applicable),

(4) Describe quality assurance and control practices that are adequate to ensure the continuing validity of the data,

(5) Describe the frequency of monitoring and the data collection procedures which you will use (e.g., you are using a computerized data acquisition over a number of discrete data points with the average (or maximum value) being used for purposes of determining whether an exceedance has occurred), and

(6) Submit justification for the proposed elements of the monitoring. If a proposed performance specification differs from manufacturer recommendation, you must explain the reasons for the differences. You must submit the data supporting the justification, but you may refer to generally available sources of information used to support the justification. You may rely on engineering assessments and other data, provided you demonstrate factors which assure compliance or explain why performance testing is unnecessary to establish indicator ranges. When establishing indicator ranges, you may choose to simplify the process by treating the parameters as if they were correlated. Using this assumption, testing can be divided into two cases:

(i) All indicators are significant only on one end of range (e.g., for a thermal incinerator controlling volatile organic compounds (VOC) it is only important to insure a minimum temperature, not a maximum). In this case, you may conduct your study so that each parameter is at the significant limit of its range while you conduct your emissions testing. If the emissions tests show that the source is in compliance at the significant limit of each parameter, then as long as each parameter is within its limit, you are presumed to be in compliance.

(ii) Some or all indicators are significant on both ends of the range. In this case, you may conduct your study so that each parameter that is significant at both ends of its range assumes its extreme values in all possible combinations of the extreme values (either single or double) of all of the other parameters. For example, if there were only two parameters, A and B, and A had a range of values while B had only a minimum value, the combinations would be A high with B minimum and A low with B minimum. If both A and B had a range, the combinations would be A high and B high, A low and B low, A high and B low, A low and B high. For the case of four parameters all having a range, there are 16 possible combinations.

(b) For affected units that are also subject to part 75 of this chapter and that have state approval to use the low mass emissions methodology in §75.19 or the NOX emission measurement methodology in appendix E to part 75, you may meet the requirements of this paragraph by developing and keeping on-site (or at a central location for unmanned facilities) a QA plan, as described in §75.19(e)(5) or in section 2.3 of appendix E to part 75 of this chapter and section 1.3.6 of appendix B to part 75 of this chapter.

§60.4360 How do I determine the total sulfur content of the turbine's combustion fuel?

You must monitor the total sulfur content of the fuel being fired in the turbine, except as provided in §60.4365. The sulfur content of the fuel must be determined using total sulfur methods described in §60.4415. Alternatively, if the total sulfur content of the gaseous fuel during the most recent performance test was less than half the applicable limit, ASTM D4084, D4810, D5504, or D6228, or Gas Processors Association Standard 2377 (all of which are incorporated by reference, see §60.17), which measure the major sulfur compounds, may be used.

§60.4365 How can I be exempted from monitoring the total sulfur content of the fuel?

You may elect not to monitor the total sulfur content of the fuel combusted in the turbine, if the fuel is demonstrated not to exceed potential sulfur emissions of 26 ng SO_2/J (0.060 lb SO_2/MMBtu) heat input for units located in continental areas and 180 ng SO_2/J (0.42 lb SO_2/MMBtu) heat input for units located in noncontinental areas or a continental area that the Administrator determines does not have access to natural gas and that the removal of sulfur compounds would cause more environmental harm than benefit. You must use one of the following sources of information to make the required demonstration:

(a) The fuel quality characteristics in a current, valid purchase contract, tariff sheet or transportation contract for the fuel, specifying that the maximum total sulfur content for oil use in continental areas is 0.05 weight percent (500 ppmw) or less and 0.4 weight percent (4,000 ppmw) or less for noncontinental areas, the total sulfur content for natural gas use in continental areas is 20 grains of sulfur or less per 100 standard cubic feet and 140 grains of sulfur

or less per 100 standard cubic feet for noncontinental areas, has potential sulfur emissions of less than less than 26 ng SO_2/J (0.060 lb SO_2/MMBtu) heat input for continental areas and has potential sulfur emissions of less than less than 180 ng SO_2/J (0.42 lb SO_2/MMBtu) heat input for noncontinental areas; or

(b) Representative fuel sampling data which show that the sulfur content of the fuel does not exceed 26 ng SO_2/J (0.060 lb SO_2/MMBtu) heat input for continental areas or 180 ng SO_2/J (0.42 lb SO_2/MMBtu) heat input for noncontinental areas. At a minimum, the amount of fuel sampling data specified in section 2.3.1.4 or 2.3.2.4 of appendix D to part 75 of this chapter is required.

§60.4370 How often must I determine the sulfur content of the fuel?

The frequency of determining the sulfur content of the fuel must be as follows:

(a) *Fuel oil.* For fuel oil, use one of the total sulfur sampling options and the associated sampling frequency described in sections 2.2.3, 2.2.4.1, 2.2.4.2, and 2.2.4.3 of appendix D to part 75 of this chapter (*i.e.*, flow proportional sampling, daily sampling, sampling from the unit's storage tank after each addition of fuel to the tank, or sampling each delivery prior to combining it with fuel oil already in the intended storage tank).

(b) *Gaseous fuel.* If you elect not to demonstrate sulfur content using options in §60.4365, and the fuel is supplied without intermediate bulk storage, the sulfur content value of the gaseous fuel must be determined and recorded once per unit operating day.

(c) *Custom schedules.* Notwithstanding the requirements of paragraph (b) of this section, operators or fuel vendors may develop custom schedules for determination of the total sulfur content of gaseous fuels, based on the design and operation of the affected facility and the characteristics of the fuel supply. Except as provided in paragraphs (c)(1) and (c)(2) of this section, custom schedules shall be substantiated with data and shall be approved by the Administrator before they can be used to comply with the standard in §60.4330.

(1) The two custom sulfur monitoring schedules set forth in paragraphs (c)(1)(i) through (iv) and in paragraph (c)(2) of this section are acceptable, without prior Administrative approval:

(i) The owner or operator shall obtain daily total sulfur content measurements for 30 consecutive unit operating days, using the applicable methods specified in this subpart. Based on the results of the 30 daily samples, the required frequency for subsequent monitoring of the fuel's total sulfur content shall be as specified in paragraph (c)(1)(ii), (iii), or (iv) of this section, as applicable.

(ii) If none of the 30 daily measurements of the fuel's total sulfur content exceeds half the applicable standard, subsequent sulfur content monitoring may be performed at 12-month intervals. If any of the samples taken at 12-month intervals has a total sulfur content greater than half but less than the applicable limit, follow the procedures in paragraph (c)(1)(iii) of this section. If any measurement exceeds the applicable limit, follow the procedures in paragraph (c)(1)(iv) of this section.

(iii) If at least one of the 30 daily measurements of the fuel's total sulfur content is greater than half but less than the applicable limit, but none exceeds the applicable limit, then:

(A) Collect and analyze a sample every 30 days for 3 months. If any sulfur content measurement exceeds the applicable limit, follow the procedures in paragraph (c)(1)(iv) of this section. Otherwise, follow the procedures in paragraph (c)(1)(iii)(B) of this section.

(B) Begin monitoring at 6-month intervals for 12 months. If any sulfur content measurement exceeds the applicable limit, follow the procedures in paragraph (c)(1)(iv) of this section. Otherwise, follow the procedures in paragraph (c)(1)(iii)(C) of this section.

(C) Begin monitoring at 12-month intervals. If any sulfur content measurement exceeds the applicable limit, follow the procedures in paragraph (c)(1)(iv) of this section. Otherwise, continue to monitor at this frequency.

(iv) If a sulfur content measurement exceeds the applicable limit, immediately begin daily monitoring according to paragraph (c)(1)(i) of this section. Daily monitoring shall continue until 30 consecutive daily samples, each having a sulfur content no greater than the applicable limit, are obtained. At that point, the applicable procedures of paragraph (c)(1)(ii) or (iii) of this section shall be followed.

(2) The owner or operator may use the data collected from the 720-hour sulfur sampling demonstration described in section 2.3.6 of appendix D to part 75 of this chapter to determine a custom sulfur sampling schedule, as follows:

(i) If the maximum fuel sulfur content obtained from the 720 hourly samples does not exceed 20 grains/100 scf, no additional monitoring of the sulfur content of the gas is required, for the purposes of this subpart.

(ii) If the maximum fuel sulfur content obtained from any of the 720 hourly samples exceeds 20 grains/100 scf, but none of the sulfur content values (when converted to weight percent sulfur) exceeds half the applicable limit, then the minimum required sampling frequency shall be one sample at 12 month intervals.

(iii) If any sample result exceeds half the applicable limit, but none exceeds the applicable limit, follow the provisions of paragraph (c)(1)(iii) of this section.

(iv) If the sulfur content of any of the 720 hourly samples exceeds the applicable limit, follow the provisions of paragraph (c)(1)(iv) of this section.

Reporting

§60.4375 What reports must I submit?

(a) For each affected unit required to continuously monitor parameters or emissions, or to periodically determine the fuel sulfur content under this subpart, you must submit reports of excess emissions and monitor downtime, in accordance with §60.7(c). Excess emissions must be reported for all periods of unit operation, including start-up, shutdown, and malfunction.

(b) For each affected unit that performs annual performance tests in accordance with §60.4340(a), you must submit a written report of the results of each performance test before the close of business on the 60th day following the completion of the performance test.

§60.4380 How are excess emissions and monitor downtime defined for NOX?

For the purpose of reports required under §60.7(c), periods of excess emissions and monitor downtime that must be reported are defined as follows:

(a) For turbines using water or steam to fuel ratio monitoring:

(1) An excess emission is any unit operating hour for which the 4-hour rolling average steam or water to fuel ratio, as measured by the continuous monitoring system, falls below the acceptable steam or water to fuel ratio needed to demonstrate compliance with §60.4320, as established during the performance test required in §60.8. Any unit operating hour in which no water or steam is injected into the turbine when a fuel is being burned that requires water or steam injection for NO_X control will also be considered an excess emission.

(2) A period of monitor downtime is any unit operating hour in which water or steam is injected into the turbine, but the essential parametric data needed to determine the steam or water to fuel ratio are unavailable or invalid.

(3) Each report must include the average steam or water to fuel ratio, average fuel consumption, and the combustion turbine load during each excess emission.

(b) For turbines using continuous emission monitoring, as described in §§60.4335(b) and 60.4345:

(1) An excess emissions is any unit operating period in which the 4-hour or 30-day rolling average NO_X emission rate exceeds the applicable emission limit in §60.4320. For the purposes of this subpart, a "4-hour rolling average NO_X emission rate" is the arithmetic average of the average NO_X emission rate in ppm or ng/J (lb/MWh) measured by the continuous emission monitoring equipment for a given hour and the three unit operating hour average NO_X emission rates immediately preceding that unit operating hour. Calculate the rolling average if a valid NO_X emission rate is obtained for at least 3 of the 4 hours. For the purposes of this subpart, a "30-day rolling average NO_X emission rate" is the arithmetic average of all hourly NO_X emission data in ppm or ng/J (lb/MWh) measured by the continuous emission monitoring equipment for a given day and the twenty-nine unit operating days immediately preceding that unit operating day. A new 30-day average is calculated each unit operating day as the average of all hourly NO_X emissions rates for the preceding 30 unit operating days if a valid NO_X emission rate is obtained for at least 75 percent of all operating hours.

(2) A period of monitor downtime is any unit operating hour in which the data for any of the following parameters are either missing or invalid: NO_X concentration, CO2 or O_2 concentration, fuel flow rate, steam flow rate, steam temperature, steam pressure, or megawatts. The steam flow rate, steam temperature, and steam pressure are only required if you will use this information for compliance purposes.

(3) For operating periods during which multiple emissions standards apply, the applicable standard is the average of the applicable standards during each hour. For hours with multiple emissions standards, the applicable limit for that hour is determined based on the condition that corresponded to the highest emissions standard.

(c) For turbines required to monitor combustion parameters or parameters that document proper operation of the NO_X emission controls:

(1) An excess emission is a 4-hour rolling unit operating hour average in which any monitored parameter does not achieve the target value or is outside the acceptable range defined in the parameter monitoring plan for the unit.

(2) A period of monitor downtime is a unit operating hour in which any of the required parametric data are either not recorded or are invalid.

§60.4385 How are excess emissions and monitoring downtime defined for SO2?

If you choose the option to monitor the sulfur content of the fuel, excess emissions and monitoring downtime are defined as follows:

(a) For samples of gaseous fuel and for oil samples obtained using daily sampling, flow proportional sampling, or sampling from the unit's storage tank, an excess emission occurs each unit operating hour included in the period beginning on the date and hour of any sample for which the sulfur content of the fuel being fired in the combustion turbine exceeds the applicable limit and ending on the date and hour that a subsequent sample is taken that demonstrates compliance with the sulfur limit.

(b) If the option to sample each delivery of fuel oil has been selected, you must immediately switch to one of the other oil sampling options (i.e., daily sampling, flow proportional sampling, or sampling from the unit's storage tank) if the sulfur content of a delivery exceeds 0.05 weight percent. You must continue to use one of the other sampling options until all of the oil from the delivery has been combusted, and you must evaluate excess emissions according to paragraph (a) of this section. When all of the fuel from the delivery has been burned, you may resume using the as-delivered sampling option.

(c) A period of monitor downtime begins when a required sample is not taken by its due date. A period of monitor downtime also begins on the date and hour of a required sample, if invalid results are obtained. The period of monitor downtime ends on the date and hour of the next valid sample.

§60.4390 What are my reporting requirements if I operate an emergency combustion turbine or a research and development turbine?

(a) If you operate an emergency combustion turbine, you are exempt from the NO_X limit and must submit an initial report to the Administrator stating your case.

(b) Combustion turbines engaged by manufacturers in research and development of equipment for both combustion turbine emission control techniques and combustion turbine efficiency improvements may be exempted from the NO_X limit on a case-by-case basis as determined by the Administrator. You must petition for the exemption.

§60.4395 When must I submit my reports?

All reports required under §60.7(c) must be postmarked by the 30th day following the end of each 6-month period.

Performance Tests

§60.4400 How do I conduct the initial and subsequent performance tests, regarding NOX?

(a) You must conduct an initial performance test, as required in §60.8. Subsequent NO_X performance tests shall be conducted on an annual basis (no more than 14 calendar months following the previous performance test).

(1) There are two general methodologies that you may use to conduct the performance tests. For each test run:

(i) Measure the NO_X concentration (in parts per million (ppm)), using EPA Method 7E or EPA Method 20 in appendix A of this part. For units complying with the output based standard, concurrently measure the stack gas flow rate, using EPA Methods 1 and 2 in appendix A of this part, and measure and record the electrical and thermal output from the unit. Then, use the following equation to calculate the NO_X emission rate:

$$E = \frac{1.194 \times 10^{-7} * (NO_x)_c * Q_{std}}{P} \qquad \text{(Eq. 5)}$$

Where:

E = NO_X emission rate, in lb/MWh

1.194×10^{-7} = conversion constant, in lb/dscf-ppm

$(NO_X)_c$ = average NO_X concentration for the run, in ppm

Q_{std} = stack gas volumetric flow rate, in dscf/hr

P = gross electrical and mechanical energy output of the combustion turbine, in MW (for simple-cycle operation), for combined-cycle operation, the sum of all electrical and mechanical output from the combustion and steam turbines, or, for combined heat and power operation, the sum of all electrical and mechanical output from the combustion and steam turbines plus all useful recovered thermal output not used for additional electric or mechanical generation, in MW, calculated according to §60.4350(f)(2); or

(ii) Measure the NO_X and diluent gas concentrations, using either EPA Methods 7E and 3A, or EPA Method 20 in appendix A of this part. Concurrently measure the heat input to the unit, using a fuel flowmeter (or flowmeters), and measure the electrical and thermal output of the unit. Use EPA Method 19 in appendix A of this part to calculate the NO_X emission rate in lb/MMBtu. Then, use Equations 1 and, if necessary, 2 and 3 in §60.4350(f) to calculate the NO_X emission rate in lb/MWh.

(2) Sampling traverse points for NO_X and (if applicable) diluent gas are to be selected following EPA Method 20 or EPA Method 1 (non-particulate procedures), and sampled for equal time intervals. The sampling must be performed with a traversing single-hole probe, or, if feasible, with a stationary multi-hole probe that samples each of the points sequentially. Alternatively, a multi-hole probe designed and documented to sample equal volumes from each hole may be used to sample simultaneously at the required points.

(3) Notwithstanding paragraph (a)(2) of this section, you may test at fewer points than are specified in EPA Method 1 or EPA Method 20 in appendix A of this part if the following conditions are met:

(i) You may perform a stratification test for NO_X and diluent pursuant to

(A) [Reserved], or

(B) The procedures specified in section 6.5.6.1(a) through (e) of appendix A of part 75 of this chapter.

(ii) Once the stratification sampling is completed, you may use the following alternative sample point selection criteria for the performance test:

(A) If each of the individual traverse point NO_X concentrations is within ±10 percent of the mean concentration for all traverse points, or the individual traverse point diluent concentrations differs by no more than ±5ppm or ±0.5 percent CO_2 (or O_2) from the mean for all traverse points, then you may use three points (located either 16.7, 50.0 and 83.3 percent of the way across the stack or duct, or, for circular stacks or ducts greater than 2.4 meters (7.8 feet) in diameter, at 0.4, 1.2, and 2.0 meters from the wall). The three points must be located along the measurement line that exhibited the highest average NO_X concentration during the stratification test; or

(B) For turbines with a NO_X standard greater than 15 ppm @ 15% O_2, you may sample at a single point, located at least 1 meter from the stack wall or at the stack centroid if each of the individual traverse point NO_X concentrations is within ±5 percent of the mean concentration for all traverse points, or the individual traverse point diluent concentrations differs by no more than ±3ppm or ±0.3 percent CO_2 (or O_2) from the mean for all traverse points; or

(C) For turbines with a NO_X standard less than or equal to 15 ppm @ 15% O_2, you may sample at a single point, located at least 1 meter from the stack wall or at the stack centroid if each of the individual traverse point NO_X concentrations is within ±2.5 percent of the mean concentration for all traverse points, or the individual traverse point diluent concentrations differs by no more than ±1ppm or ±0.15 percent CO_2 (or O_2) from the mean for all traverse points.

(b) The performance test must be done at any load condition within plus or minus 25 percent of 100 percent of peak load. You may perform testing at the highest achievable load point, if at least 75 percent of peak load cannot be achieved in practice. You must conduct three separate test runs for each performance test. The minimum time per run is 20 minutes.

(1) If the stationary combustion turbine combusts both oil and gas as primary or backup fuels, separate performance testing is required for each fuel.

(2) For a combined cycle and CHP turbine systems with supplemental heat (duct burner), you must measure the total NO_X emissions after the duct burner rather than directly after the turbine. The duct burner must be in operation during the performance test.

(3) If water or steam injection is used to control NO_X with no additional post-combustion NO_X control and you choose to monitor the steam or water to fuel ratio in accordance with §60.4335, then that monitoring system must be operated concurrently with each EPA Method 20 or EPA Method 7E run and must be used to determine the fuel consumption and the steam or water to fuel ratio necessary to comply with the applicable §60.4320 NO_X emission limit.

(4) Compliance with the applicable emission limit in §60.4320 must be demonstrated at each tested load level. Compliance is achieved if the three-run arithmetic average NO_X emission rate at each tested level meets the applicable emission limit in §60.4320.

(5) If you elect to install a CEMS, the performance evaluation of the CEMS may either be conducted separately or (as described in §60.4405) as part of the initial performance test of the affected unit.

(6) The ambient temperature must be greater than 0 °F during the performance test.

§60.4405 How do I perform the initial performance test if I have chosen to install a NOX-diluent CEMS?

If you elect to install and certify a NO_X-diluent CEMS under §60.4345, then the initial performance test required under §60.8 may be performed in the following alternative manner:

(a) Perform a minimum of nine RATA reference method runs, with a minimum time per run of 21 minutes, at a single load level, within plus or minus 25 percent of 100 percent of peak load. The ambient temperature must be greater than 0 °F during the RATA runs.

(b) For each RATA run, concurrently measure the heat input to the unit using a fuel flow meter (or flow meters) and measure the electrical and thermal output from the unit.

(c) Use the test data both to demonstrate compliance with the applicable NO_X emission limit under §60.4320 and to provide the required reference method data for the RATA of the CEMS described under §60.4335.

(d) Compliance with the applicable emission limit in §60.4320 is achieved if the arithmetic average of all of the NO_X emission rates for the RATA runs, expressed in units of ppm or lb/MWh, does not exceed the emission limit.

§60.4410 How do I establish a valid parameter range if I have chosen to continuously monitor parameters?

If you have chosen to monitor combustion parameters or parameters indicative of proper operation of NO_X emission controls in accordance with §60.4340, the appropriate parameters must be continuously monitored and recorded during each run of the initial performance test, to establish acceptable operating ranges, for purposes of the parameter monitoring plan for the affected unit, as specified in §60.4355.

§60.4415 How do I conduct the initial and subsequent performance tests for sulfur?

(a) You must conduct an initial performance test, as required in §60.8. Subsequent SO_2 performance tests shall be conducted on an annual basis (no more than 14 calendar months following the previous performance test). There are three methodologies that you may use to conduct the performance tests.

(1) If you choose to periodically determine the sulfur content of the fuel combusted in the turbine, a representative fuel sample would be collected following ASTM D5287 (incorporated by reference, see §60.17) for natural gas or ASTM D4177 (incorporated by reference, see §60.17) for oil. Alternatively, for oil, you may follow the procedures for manual pipeline sampling in section 14 of ASTM D4057 (incorporated by reference, see §60.17). The fuel analyses of this section may be performed either by you, a service contractor retained by you, the fuel vendor, or any other qualified agency. Analyze the samples for the total sulfur content of the fuel using:

(i) For liquid fuels, ASTM D129, or alternatively D1266, D1552, D2622, D4294, or D5453 (all of which are incorporated by reference, see §60.17); or

(ii) For gaseous fuels, ASTM D1072, or alternatively D3246, D4084, D4468, D4810, D6228, D6667, or Gas Processors Association Standard 2377 (all of which are incorporated by reference, see §60.17).

(2) Measure the SO_2 concentration (in parts per million (ppm)), using EPA Methods 6, 6C, 8, or 20 in appendix A of this part. In addition, the American Society of Mechanical Engineers (ASME) standard, ASME PTC 19-10-1981-Part 10, “Flue and Exhaust Gas Analyses,” manual methods for sulfur dioxide (incorporated by reference, see §60.17) can be used instead of EPA Methods 6 or 20. For units complying with the output based standard, concurrently measure the stack gas flow rate, using EPA Methods 1 and 2 in appendix A of this part, and measure and record the electrical and thermal output from the unit. Then use the following equation to calculate the SO_2 emission rate:

$$E = \frac{1.664 \times 10^{-7} * (SO_2)_c * Q_{sd}}{P} \qquad \text{(Eq. 6)}$$

Where:

E = SO_2 emission rate, in lb/MWh

1.664×10^{-7} = conversion constant, in lb/dscf-ppm

$(SO_2)_c$ = average SO_2 concentration for the run, in ppm

Q_{std} = stack gas volumetric flow rate, in dscf/hr

P = gross electrical and mechanical energy output of the combustion turbine, in MW (for simple-cycle operation), for combined-cycle operation, the sum of all electrical and mechanical output from the combustion and steam turbines, or, for combined heat and power operation, the sum of all electrical and mechanical output from the combustion and steam turbines plus all useful recovered thermal output not used for additional electric or mechanical generation, in MW, calculated according to §60.4350(f)(2); or

(3) Measure the SO_2 and diluent gas concentrations, using either EPA Methods 6, 6C, or 8 and 3A, or 20 in appendix A of this part. In addition, you may use the manual methods for sulfur dioxide ASME PTC 19-10-1981-Part 10 (incorporated by reference, see §60.17). Concurrently measure the heat input to the unit, using a fuel flowmeter (or flowmeters), and measure the electrical and thermal output of the unit. Use EPA Method 19 in appendix A of this part to calculate the SO_2 emission rate in lb/MMBtu. Then, use Equations 1 and, if necessary, 2 and 3 in §60.4350(f) to calculate the SO_2 emission rate in lb/MWh.

(b) [Reserved]

Definitions

§60.4420 What definitions apply to this subpart?

As used in this subpart, all terms not defined herein will have the meaning given them in the Clean Air Act and in subpart A (General Provisions) of this part.

Biogas means gas produced by the anaerobic digestion or fermentation of organic matter including manure, sewage sludge, municipal solid waste, biodegradable waste, or any other biodegradable feedstock, under anaerobic conditions. Biogas is comprised primarily of methane and CO_2.

Combined cycle combustion turbine means any stationary combustion turbine which recovers heat from the combustion turbine exhaust gases to generate steam that is only used to create additional power output in a steam turbine.

Combined heat and power combustion turbine means any stationary combustion turbine which recovers heat from the exhaust gases to heat water or another medium, generate steam for useful purposes other than additional electric generation, or directly uses the heat in the exhaust gases for a useful purpose.

Combustion turbine model means a group of combustion turbines having the same nominal air flow, combustor inlet pressure, combustor inlet temperature, firing temperature, turbine inlet temperature and turbine inlet pressure.

Combustion turbine test cell/stand means any apparatus used for testing uninstalled stationary or uninstalled mobile (motive) combustion turbines.

Diffusion flame stationary combustion turbine means any stationary combustion turbine where fuel and air are injected at the combustor and are mixed only by diffusion prior to ignition.

Duct burner means a device that combusts fuel and that is placed in the exhaust duct from another source, such as a stationary combustion turbine, internal combustion engine, kiln, etc., to allow the firing of additional fuel to heat the exhaust gases before the exhaust gases enter a heat recovery steam generating unit.

Efficiency means the combustion turbine manufacturer's rated heat rate at peak load in terms of heat input per unit of power output—based on the higher heating value of the fuel.

Emergency combustion turbine means any stationary combustion turbine which operates in an emergency situation. Examples include stationary combustion turbines used to produce power for critical networks or equipment, including power supplied to portions of a facility, when electric power from the local utility is interrupted, or stationary combustion turbines used to pump water in the case of fire or flood, etc. Emergency stationary combustion turbines do not include stationary combustion turbines used as peaking units at electric utilities or stationary combustion turbines at industrial facilities that typically operate at low capacity factors. Emergency combustion turbines may be operated for the purpose of maintenance checks and readiness testing, provided that the tests are required by the manufacturer, the vendor, or the insurance company associated with the turbine. Required testing of such units should be minimized, but there is no time limit on the use of emergency combustion turbines.

Excess emissions means a specified averaging period over which either (1) the NO_X emissions are higher than the applicable emission limit in §60.4320; (2) the total sulfur content of the fuel being combusted in the affected facility exceeds the limit specified in §60.4330; or (3) the recorded value of a particular monitored parameter is outside the acceptable range specified in the parameter monitoring plan for the affected unit.

Gross useful output means the gross useful work performed by the stationary combustion turbine system. For units using the mechanical energy directly or generating only electricity, the gross useful work performed is the gross electrical or mechanical output from the turbine/generator set. For combined heat and power units, the gross useful work performed is the gross electrical or mechanical output plus the useful thermal output (i.e., thermal energy delivered to a process).

Heat recovery steam generating unit means a unit where the hot exhaust gases from the combustion turbine are routed in order to extract heat from the gases and generate steam, for use in a steam turbine or other device that utilizes steam. Heat recovery steam generating units can be used with or without duct burners.

Integrated gasification combined cycle electric utility steam generating unit means a coal-fired electric utility steam generating unit that burns a synthetic gas derived from coal in a combined-cycle gas turbine. No solid coal is directly burned in the unit during operation.

ISO conditions means 288 Kelvin, 60 percent relative humidity and 101.3 kilopascals pressure.

Lean premix stationary combustion turbine means any stationary combustion turbine where the air and fuel are thoroughly mixed to form a lean mixture before delivery to the combustor. Mixing may occur before or in the combustion chamber. A lean premixed turbine may operate in diffusion flame mode during operating conditions such as startup and shutdown, extreme ambient temperature, or low or transient load.

Natural gas means a naturally occurring fluid mixture of hydrocarbons (e.g., methane, ethane, or propane) produced in geological formations beneath the Earth's surface that maintains a gaseous state at standard atmospheric temperature and pressure under ordinary conditions. Additionally, natural gas must either be composed of at least 70 percent methane by volume or have a gross calorific value between 950 and 1,100 British thermal units (Btu) per standard cubic foot. Natural gas does not include the following gaseous fuels: landfill gas, digester gas, refinery gas, sour gas, blast furnace gas, coal-derived gas, producer gas, coke oven gas, or any gaseous fuel produced in a process which might result in highly variable sulfur content or heating value.

Noncontinental area means the State of Hawaii, the Virgin Islands, Guam, American Samoa, the Commonwealth of Puerto Rico, the Northern Mariana Islands, or offshore platforms.

Peak load means 100 percent of the manufacturer's design capacity of the combustion turbine at ISO conditions.

Regenerative cycle combustion turbine means any stationary combustion turbine which recovers heat from the combustion turbine exhaust gases to preheat the inlet combustion air to the combustion turbine.

Simple cycle combustion turbine means any stationary combustion turbine which does not recover heat from the combustion turbine exhaust gases to preheat the inlet combustion air to the combustion turbine, or which does not

recover heat from the combustion turbine exhaust gases for purposes other than enhancing the performance of the combustion turbine itself.

Stationary 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), heat recovery system, and any ancillary components and sub-components comprising any simple cycle stationary combustion turbine, any regenerative/recuperative cycle stationary combustion turbine, any combined cycle combustion turbine, and any combined heat and power combustion turbine based system. Stationary means that the combustion turbine is not self propelled or intended to be propelled while performing its function. It may, however, be mounted on a vehicle for portability.

Unit 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 unit. It is not necessary for fuel to be combusted continuously for the entire 24-hour period.

Unit operating hour means a clock hour during which any fuel is combusted in the affected unit. If the unit combusts fuel for the entire clock hour, it is considered to be a full unit operating hour. If the unit combusts fuel for only part of the clock hour, it is considered to be a partial unit operating hour.

Useful thermal output means the thermal energy made available for use in any industrial or commercial process, or used in any heating or cooling application, i.e., total thermal energy made available for processes and applications other than electrical or mechanical generation. Thermal output for this subpart means the energy in recovered thermal output measured against the energy in the thermal output at 15 degrees Celsius and 101.325 kilopascals of pressure.

[71 FR 38497, July 6, 2006, as amended at 74 FR 11861, Mar. 20, 2009]

Table 1 to Subpart KKKK of Part 60—Nitrogen Oxide Emission Limits for New Stationary Combustion Turbines

Combustion turbine type	Combustion turbine heat input at peak load (HHV)	NO_X emission standard
New turbine firing natural gas, electric generating	≤ 50 MMBtu/h	42 ppm at 15 percent O_2 or 290 ng/J of useful output (2.3 lb/MWh).
New turbine firing natural gas, mechanical drive	≤ 50 MMBtu/h	100 ppm at 15 percent O_2 or 690 ng/J of useful output (5.5 lb/MWh).
New turbine firing natural gas	> 50 MMBtu/h and ≤ 850 MMBtu/h	25 ppm at 15 percent O_2 or 150 ng/J of useful output (1.2 lb/MWh).
New, modified, or reconstructed turbine firing natural gas	> 850 MMBtu/h	15 ppm at 15 percent O_2 or 54 ng/J of useful output (0.43 lb/MWh)
New turbine firing fuels other than natural gas, electric generating	≤ 50 MMBtu/h	96 ppm at 15 percent O_2 or 700 ng/J of useful output (5.5 lb/MWh).
New turbine firing fuels other than natural gas, mechanical drive	≤ 50 MMBtu/h	150 ppm at 15 percent O_2 or 1,100 ng/J of useful output (8.7 lb/MWh).

Combustion turbine type	**Combustion turbine heat input at peak load (HHV)**	**NO_X emission standard**
New turbine firing fuels other than natural gas	> 50 MMBtu/h and ≤ 850 MMBtu/h	74 ppm at 15 percent O_2 or 460 ng/J of useful output (3.6 lb/MWh).
New, modified, or reconstructed turbine firing fuels other than natural gas	> 850 MMBtu/h	42 ppm at 15 percent O_2 or 160 ng/J of useful output (1.3 lb/MWh).
Modified or reconstructed turbine	≤ 50 MMBtu/h	150 ppm at 15 percent O_2 or 1,100 ng/J of useful output (8.7 lb/MWh).
Modified or reconstructed turbine firing natural gas	> 50 MMBtu/h and ≤ 850 MMBtu/h	42 ppm at 15 percent O_2 or 250 ng/J of useful output (2.0 lb/MWh).
Modified or reconstructed turbine firing fuels other than natural gas	> 50 MMBtu/h and ≤ 850 MMBtu/h	96 ppm at 15 percent O_2 or 590 ng/J of useful output (4.7 lb/MWh).
Turbines located north of the Arctic Circle (latitude 66.5 degrees north), turbines operating at less than 75 percent of peak load, modified and reconstructed offshore turbines, and turbine operating at temperatures less than 0 °F	≤ 30 MW output	150 ppm at 15 percent O_2 or 1,100 ng/J of useful output (8.7 lb/MWh).
Turbines located north of the Arctic Circle (latitude 66.5 degrees north), turbines operating at less than 75 percent of peak load, modified and reconstructed offshore turbines, and turbine operating at temperatures less than 0 °F	> 30 MW output	96 ppm at 15 percent O_2 or 590 ng/J of useful output (4.7 lb/MWh).
Heat recovery units operating independent of the combustion turbine	All sizes	54 ppm at 15 percent O_2 or 110 ng/J of useful output (0.86 lb/MWh).

Attachment F

Part 70 Operating Permit No: 141-41227-00013

[Downloaded from the eCFR on May 13, 2013]

Electronic Code of Federal Regulations

Title 40: Protection of Environment

PART 63—NATIONAL EMISSION STANDARDS FOR HAZARDOUS AIR POLLUTANTS FOR SOURCE CATEGORIES

Subpart CCCCCC—National Emission Standards for Hazardous Air Pollutants for Source Category: Gasoline Dispensing Facilities

Source: 73 FR 1945, Jan. 10, 2008, unless otherwise noted.

What This Subpart Covers

§ 63.11110 What is the purpose of this subpart?

This subpart establishes national emission limitations and management practices for hazardous air pollutants (HAP) emitted from the loading of gasoline storage tanks at gasoline dispensing facilities (GDF). This subpart also establishes requirements to demonstrate compliance with the emission limitations and management practices.

§ 63.11111 Am I subject to the requirements in this subpart?

(a) The affected source to which this subpart applies is each GDF that is located at an area source. The affected source includes each gasoline cargo tank during the delivery of product to a GDF and also includes each storage tank.

(b) If your GDF has a monthly throughput of less than 10,000 gallons of gasoline, you must comply with the requirements in § 63.11116.

(c) If your GDF has a monthly throughput of 10,000 gallons of gasoline or more, you must comply with the requirements in § 63.11117.

(d) If your GDF has a monthly throughput of 100,000 gallons of gasoline or more, you must comply with the requirements in § 63.11118.

(e) An affected source shall, upon request by the Administrator, demonstrate that their monthly throughput is less than the 10,000-gallon or the 100,000-gallon threshold level, as applicable. For new or reconstructed affected sources, as specified in § 63.11112(b) and (c), recordkeeping to document monthly throughput must begin upon startup of the affected source. For existing sources, as specified in § 63.11112(d), recordkeeping to document monthly throughput must begin on January 10, 2008. For existing sources that are subject to this subpart only because they load gasoline into fuel tanks other than those in motor vehicles, as defined in § 63.11132, recordkeeping to document monthly throughput must begin on January 24, 2011. Records required under this paragraph shall be kept for a period of 5 years.

(f) If you are an owner or operator of affected sources, as defined in paragraph (a) of this section, you are not required to obtain a permit under 40 CFR part 70 or 40 CFR part 71 as a result of being subject to this subpart. However, you must still apply for and obtain a permit under 40 CFR part 70 or 40 CFR part 71 if you meet one or more of the applicability criteria found in 40 CFR 70.3(a) and (b) or 40 CFR 71.3(a) and (b).

(g) The loading of aviation gasoline into storage tanks at airports, and the subsequent transfer of aviation gasoline within the airport, is not subject to this subpart.

(h) Monthly throughput is the total volume of gasoline loaded into, or dispensed from, all the gasoline storage tanks located at a single affected GDF. If an area source has two or more GDF at separate locations within the area source, each GDF is treated as a separate affected source.

(i) If your affected source's throughput ever exceeds an applicable throughput threshold, the affected source will remain subject to the requirements for sources above the threshold, even if the affected source throughput later falls below the applicable throughput threshold.

(j) The dispensing of gasoline from a fixed gasoline storage tank at a GDF into a portable gasoline tank for the on-site delivery and subsequent dispensing of the gasoline into the fuel tank of a motor vehicle or other gasoline-fueled engine or equipment used within the area source is only subject to § 63.11116 of this subpart.

(k) For any affected source subject to the provisions of this subpart and another Federal rule, you may elect to comply only with the more stringent provisions of the applicable subparts. You must consider all provisions of the rules, including monitoring, recordkeeping, and reporting. You must identify the affected source and provisions with which you will comply in your Notification of Compliance Status required under § 63.11124. You also must demonstrate in your Notification of Compliance Status that each provision with which you will comply is at least as stringent as the otherwise applicable requirements in this subpart. You are responsible for making accurate determinations concerning the more stringent provisions, and noncompliance with this rule is not excused if it is later determined that your determination was in error, and, as a result, you are violating this subpart. Compliance with this rule is your responsibility and the Notification of Compliance Status does not alter or affect that responsibility.

[73 FR 1945, Jan. 10, 2008, as amended at 76 FR 4181, Jan. 24, 2011]

§ 63.11112 What parts of my affected source does this subpart cover?

(a) The emission sources to which this subpart applies are gasoline storage tanks and associated equipment components in vapor or liquid gasoline service at new, reconstructed, or existing GDF that meet the criteria specified in § 63.11111. Pressure/Vacuum vents on gasoline storage tanks and the equipment necessary to unload product from cargo tanks into the storage tanks at GDF are covered emission sources. The equipment used for the refueling of motor vehicles is not covered by this subpart.

(b) An affected source is a new affected source if you commenced construction on the affected source after November 9, 2006, and you meet the applicability criteria in § 63.11111 at the time you commenced operation.

(c) An affected source is reconstructed if you meet the criteria for reconstruction as defined in § 63.2.

(d) An affected source is an existing affected source if it is not new or reconstructed.

§ 63.11113 When do I have to comply with this subpart?

(a) If you have a new or reconstructed affected source, you must comply with this subpart according to paragraphs (a)(1) and (2) of this section, except as specified in paragraph (d) of this section.

(1) If you start up your affected source before January 10, 2008, you must comply with the standards in this subpart no later than January 10, 2008.

(2) If you start up your affected source after January 10, 2008, you must comply with the standards in this subpart upon startup of your affected source.

(b) If you have an existing affected source, you must comply with the standards in this subpart no later than January 10, 2011.

(c) If you have an existing affected source that becomes subject to the control requirements in this subpart because of an increase in the monthly throughput, as specified in § 63.11111(c) or § 63.11111(d), you must comply with the standards in this subpart no later than 3 years after the affected source becomes subject to the control requirements in this subpart.

(d) If you have a new or reconstructed affected source and you are complying with Table 1 to this subpart, you must comply according to paragraphs (d)(1) and (2) of this section.

(1) If you start up your affected source from November 9, 2006 to September 23, 2008, you must comply no later than September 23, 2008.

(2) If you start up your affected source after September 23, 2008, you must comply upon startup of your affected source.

(e) The initial compliance demonstration test required under § 63.11120(a)(1) and (2) must be conducted as specified in paragraphs (e)(1) and (2) of this section.

(1) If you have a new or reconstructed affected source, you must conduct the initial compliance test upon installation of the complete vapor balance system.

(2) If you have an existing affected source, you must conduct the initial compliance test as specified in paragraphs (e)(2)(i) or (e)(2)(ii) of this section.

(i) For vapor balance systems installed on or before December 15, 2009, you must test no later than 180 days after the applicable compliance date specified in paragraphs (b) or (c) of this section.

(ii) For vapor balance systems installed after December 15, 2009, you must test upon installation of the complete vapor balance system.

(f) If your GDF is subject to the control requirements in this subpart only because it loads gasoline into fuel tanks other than those in motor vehicles, as defined in § 63.11132, you must comply with the standards in this subpart as specified in paragraphs (f)(1) or (f)(2) of this section.

(1) If your GDF is an existing facility, you must comply by January 24, 2014.

(2) If your GDF is a new or reconstructed facility, you must comply by the dates specified in paragraphs (f)(2)(i) and (ii) of this section.

(i) If you start up your GDF after December 15, 2009, but before January 24, 2011, you must comply no later than January 24, 2011.

(ii) If you start up your GDF after January 24, 2011, you must comply upon startup of your GDF.

[73 FR 1945, Jan. 10, 2008, as amended at 73 FR 35944, June 25, 2008; 76 FR 4181, Jan. 24, 2011]

Emission Limitations and Management Practices

§ 63.11115 What are my general duties to minimize emissions?

Each owner or operator of an affected source under this subpart must comply with the requirements of paragraphs (a) and (b) of this section.

(a) You must, at all times, 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 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.

(b) You must keep applicable records and submit reports as specified in § 63.11125(d) and § 63.11126(b).

[76 FR 4182, Jan. 24, 2011]

§ 63.11116 Requirements for facilities with monthly throughput of less than 10,000 gallons of gasoline.

(a) You must not allow gasoline to be handled in a manner that would result in vapor releases to the atmosphere for extended periods of time. Measures to be taken include, but are not limited to, the following:

(1) Minimize gasoline spills;

(2) Clean up spills as expeditiously as practicable;

(3) Cover all open gasoline containers and all gasoline storage tank fill-pipes with a gasketed seal when not in use;

(4) Minimize gasoline sent to open waste collection systems that collect and transport gasoline to reclamation and recycling devices, such as oil/water separators.

(b) You are not required to submit notifications or reports as specified in § 63.11125, § 63.11126, or subpart A of this part, but you must have records available within 24 hours of a request by the Administrator to document your gasoline throughput.

(c) You must comply with the requirements of this subpart by the applicable dates specified in § 63.11113.

(d) Portable gasoline containers that meet the requirements of 40 CFR part 59, subpart F, are considered acceptable for compliance with paragraph (a)(3) of this section.

[73 FR 1945, Jan. 10, 2008, as amended at 76 FR 4182, Jan. 24, 2011]

§ 63.11117 Requirements for facilities with monthly throughput of 10,000 gallons of gasoline or more.

(a) You must comply with the requirements in section § 63.11116(a).

(b) Except as specified in paragraph (c) of this section, you must only load gasoline into storage tanks at your facility by utilizing submerged filling, as defined in § 63.11132, and as specified in paragraphs (b)(1), (b)(2), or (b)(3) of this section. The applicable distances in paragraphs (b)(1) and (2) shall be measured from the point in the opening of the submerged fill pipe that is the greatest distance from the bottom of the storage tank.

(1) Submerged fill pipes installed on or before November 9, 2006, must be no more than 12 inches from the bottom of the tank.

(2) Submerged fill pipes installed after November 9, 2006, must be no more than 6 inches from the bottom of the tank.

(3) Submerged fill pipes not meeting the specifications of paragraphs (b)(1) or (b)(2) of this section are allowed if the owner or operator can demonstrate that the liquid level in the tank is always above the entire opening of the fill pipe. Documentation providing such demonstration must be made available for inspection by the Administrator's delegated representative during the course of a site visit.

(c) Gasoline storage tanks with a capacity of less than 250 gallons are not required to comply with the submerged fill requirements in paragraph (b) of this section, but must comply only with all of the requirements in § 63.11116.

(d) You must have records available within 24 hours of a request by the Administrator to document your gasoline throughput.

(e) You must submit the applicable notifications as required under § 63.11124(a).

(f) You must comply with the requirements of this subpart by the applicable dates contained in § 63.11113.

[73 FR 1945, Jan. 10, 2008, as amended at 73 FR 12276, Mar. 7, 2008; 76 FR 4182, Jan. 24, 2011]

§ 63.11118 Requirements for facilities with monthly throughput of 100,000 gallons of gasoline or more.

(a) You must comply with the requirements in §§ 63.11116(a) and 63.11117(b).

(b) Except as provided in paragraph (c) of this section, you must meet the requirements in either paragraph (b)(1) or paragraph (b)(2) of this section.

(1) Each management practice in Table 1 to this subpart that applies to your GDF.

(2) If, prior to January 10, 2008, you satisfy the requirements in both paragraphs (b)(2)(i) and (ii) of this section, you will be deemed in compliance with this subsection.

(i) You operate a vapor balance system at your GDF that meets the requirements of either paragraph (b)(2)(i)(A) or paragraph (b)(2)(i)(B) of this section.

(A) Achieves emissions reduction of at least 90 percent.

(B) Operates using management practices at least as stringent as those in Table 1 to this subpart.

(ii) Your gasoline dispensing facility is in compliance with an enforceable State, local, or tribal rule or permit that contains requirements of either paragraph (b)(2)(i)(A) or paragraph (b)(2)(i)(B) of this section.

(c) The emission sources listed in paragraphs (c)(1) through (3) of this section are not required to comply with the control requirements in paragraph (b) of this section, but must comply with the requirements in § 63.11117.

(1) Gasoline storage tanks with a capacity of less than 250 gallons that are constructed after January 10, 2008.

(2) Gasoline storage tanks with a capacity of less than 2,000 gallons that were constructed before January 10, 2008.

(3) Gasoline storage tanks equipped with floating roofs, or the equivalent.

(d) Cargo tanks unloading at GDF must comply with the management practices in Table 2 to this subpart.

(e) You must comply with the applicable testing requirements contained in § 63.11120.

(f) You must submit the applicable notifications as required under § 63.11124.

(g) You must keep records and submit reports as specified in §§ 63.11125 and 63.11126.

(h) You must comply with the requirements of this subpart by the applicable dates contained in § 63.11113.

[73 FR 1945, Jan. 10, 2008, as amended at 73 FR 12276, Mar. 7, 2008]

Testing and Monitoring Requirements

§ 63.11120 What testing and monitoring requirements must I meet?

(a) Each owner or operator, at the time of installation, as specified in § 63.11113(e), of a vapor balance system required under § 63.11118(b)(1), and every 3 years thereafter, must comply with the requirements in paragraphs (a)(1) and (2) of this section.

(1) You must demonstrate compliance with the leak rate and cracking pressure requirements, specified in item 1(g) of Table 1 to this subpart, for pressure-vacuum vent valves installed on your gasoline storage tanks using the test methods identified in paragraph (a)(1)(i) or paragraph (a)(1)(ii) of this section.

(i) California Air Resources Board Vapor Recovery Test Procedure TP-201.1E,—Leak Rate and Cracking Pressure of Pressure/Vacuum Vent Valves, adopted October 8, 2003 (incorporated by reference, see § 63.14).

(ii) Use alternative test methods and procedures in accordance with the alternative test method requirements in § 63.7(f).

(2) You must demonstrate compliance with the static pressure performance requirement specified in item 1(h) of Table 1 to this subpart for your vapor balance system by conducting a static pressure test on your gasoline storage tanks using the test methods identified in paragraphs (a)(2)(i), (a)(2)(ii), or (a)(2)(iii) of this section.

(i) California Air Resources Board Vapor Recovery Test Procedure TP-201.3,—Determination of 2-Inch WC Static Pressure Performance of Vapor Recovery Systems of Dispensing Facilities, adopted April 12, 1996, and amended March 17, 1999 (incorporated by reference, see § 63.14).

(ii) Use alternative test methods and procedures in accordance with the alternative test method requirements in § 63.7(f).

(iii) Bay Area Air Quality Management District Source Test Procedure ST-30—Static Pressure Integrity Test—Underground Storage Tanks, adopted November 30, 1983, and amended December 21, 1994 (incorporated by reference, *see* § 63.14).

(b) Each owner or operator choosing, under the provisions of § 63.6(g), to use a vapor balance system other than that described in Table 1 to this subpart must demonstrate to the Administrator or delegated authority under paragraph § 63.11131(a) of this subpart, the equivalency of their vapor balance system to that described in Table 1 to this subpart using the procedures specified in paragraphs (b)(1) through (3) of this section.

(1) You must demonstrate initial compliance by conducting an initial performance test on the vapor balance system to demonstrate that the vapor balance system achieves 95 percent reduction using the California Air Resources Board Vapor Recovery Test Procedure TP-201.1,—Volumetric Efficiency for Phase I Vapor Recovery Systems, adopted April 12, 1996, and amended February 1, 2001, and October 8, 2003, (incorporated by reference, see § 63.14).

(2) You must, during the initial performance test required under paragraph (b)(1) of this section, determine and document alternative acceptable values for the leak rate and cracking pressure requirements specified in item 1(g) of Table 1 to this subpart and for the static pressure performance requirement in item 1(h) of Table 1 to this subpart.

(3) You must comply with the testing requirements specified in paragraph (a) of this section.

(c) Conduct of performance tests. Performance tests conducted for this subpart shall be conducted under such conditions as the Administrator specifies to the owner or operator based on representative performance (*i.e.,* performance based on normal operating conditions) of the affected source. Upon request, the owner or operator shall make available to the Administrator such records as may be necessary to determine the conditions of performance tests.

(d) Owners and operators of gasoline cargo tanks subject to the provisions of Table 2 to this subpart must conduct annual certification testing according to the vapor tightness testing requirements found in § 63.11092(f).

[73 FR 1945, Jan. 10, 2008, as amended at 76 FR 4182, Jan. 24, 2011]

Notifications, Records, and Reports

§ 63.11124 What notifications must I submit and when?

(a) Each owner or operator subject to the control requirements in § 63.11117 must comply with paragraphs (a)(1) through (3) of this section.

(1) You must submit an Initial Notification that you are subject to this subpart by May 9, 2008, or at the time you become subject to the control requirements in § 63.11117, unless you meet the requirements in paragraph (a)(3) of this section. If your affected source is subject to the control requirements in § 63.11117 only because it loads gasoline into fuel tanks other than those in motor vehicles, as defined in § 63.11132, you must submit the Initial Notification by May 24, 2011. The Initial Notification must contain the information specified in paragraphs (a)(1)(i) through (iii) of this section. The notification must be submitted to the applicable EPA Regional Office and delegated State authority as specified in § 63.13.

(i) The name and address of the owner and the operator.

(ii) The address (i.e., physical location) of the GDF.

(iii) A statement that the notification is being submitted in response to this subpart and identifying the requirements in paragraphs (a) through (c) of § 63.11117 that apply to you.

(2) You must submit a Notification of Compliance Status to the applicable EPA Regional Office and the delegated State authority, as specified in § 63.13, within 60 days of the applicable compliance date specified in § 63.11113, unless you meet the requirements in paragraph (a)(3) of this section. The Notification of Compliance Status must be signed by a responsible official who must certify its accuracy, must indicate whether the source has complied with the requirements of this subpart, and must indicate whether the facilities' monthly throughput is calculated based on the volume of gasoline loaded into all storage tanks or on the volume of gasoline dispensed from all storage tanks. If your facility is in compliance with the requirements of this subpart at the time the Initial Notification required under paragraph (a)(1) of this section is due, the Notification of Compliance Status may be submitted in lieu of the Initial Notification provided it contains the information required under paragraph (a)(1) of this section.

(3) If, prior to January 10, 2008, you are operating in compliance with an enforceable State, local, or tribal rule or permit that requires submerged fill as specified in § 63.11117(b), you are not required to submit an Initial Notification or a Notification of Compliance Status under paragraph (a)(1) or paragraph (a)(2) of this section.

(b) Each owner or operator subject to the control requirements in § 63.11118 must comply with paragraphs (b)(1) through (5) of this section.

(1) You must submit an Initial Notification that you are subject to this subpart by May 9, 2008, or at the time you become subject to the control requirements in § 63.11118. If your affected source is subject to the control requirements in § 63.11118 only because it loads gasoline into fuel tanks other than those in motor vehicles, as defined in § 63.11132, you must submit the Initial Notification by May 24, 2011. The Initial Notification must contain the information specified in paragraphs (b)(1)(i) through (iii) of this section. The notification must be submitted to the applicable EPA Regional Office and delegated State authority as specified in § 63.13.

(i) The name and address of the owner and the operator.

(ii) The address (i.e., physical location) of the GDF.

(iii) A statement that the notification is being submitted in response to this subpart and identifying the requirements in paragraphs (a) through (c) of § 63.11118 that apply to you.

(2) You must submit a Notification of Compliance Status to the applicable EPA Regional Office and the delegated State authority, as specified in § 63.13, in accordance with the schedule specified in § 63.9(h). The Notification of

Compliance Status must be signed by a responsible official who must certify its accuracy, must indicate whether the source has complied with the requirements of this subpart, and must indicate whether the facility's throughput is determined based on the volume of gasoline loaded into all storage tanks or on the volume of gasoline dispensed from all storage tanks. If your facility is in compliance with the requirements of this subpart at the time the Initial Notification required under paragraph (b)(1) of this section is due, the Notification of Compliance Status may be submitted in lieu of the Initial Notification provided it contains the information required under paragraph (b)(1) of this section.

(3) If, prior to January 10, 2008, you satisfy the requirements in both paragraphs (b)(3)(i) and (ii) of this section, you are not required to submit an Initial Notification or a Notification of Compliance Status under paragraph (b)(1) or paragraph (b)(2) of this subsection.

(i) You operate a vapor balance system at your gasoline dispensing facility that meets the requirements of either paragraphs (b)(3)(i)(A) or (b)(3)(i)(B) of this section.

(A) Achieves emissions reduction of at least 90 percent.

(B) Operates using management practices at least as stringent as those in Table 1 to this subpart.

(ii) Your gasoline dispensing facility is in compliance with an enforceable State, local, or tribal rule or permit that contains requirements of either paragraphs (b)(3)(i)(A) or (b)(3)(i)(B) of this section.

(4) You must submit a Notification of Performance Test, as specified in § 63.9(e), prior to initiating testing required by § 63.11120(a) and (b).

(5) You must submit additional notifications specified in § 63.9, as applicable.

[73 FR 1945, Jan. 10, 2008, as amended at 73 FR 12276, Mar. 7, 2008; 76 FR 4182, Jan. 24, 2011]

§ 63.11125 What are my recordkeeping requirements?

(a) Each owner or operator subject to the management practices in § 63.11118 must keep records of all tests performed under § 63.11120(a) and (b).

(b) Records required under paragraph (a) of this section shall be kept for a period of 5 years and shall be made available for inspection by the Administrator's delegated representatives during the course of a site visit.

(c) Each owner or operator of a gasoline cargo tank subject to the management practices in Table 2 to this subpart must keep records documenting vapor tightness testing for a period of 5 years. Documentation must include each of the items specified in § 63.11094(b)(2)(i) through (viii). Records of vapor tightness testing must be retained as specified in either paragraph (c)(1) or paragraph (c)(2) of this section.

(1) The owner or operator must keep all vapor tightness testing records with the cargo tank.

(2) As an alternative to keeping all records with the cargo tank, the owner or operator may comply with the requirements of paragraphs (c)(2)(i) and (ii) of this section.

(i) The owner or operator may keep records of only the most recent vapor tightness test with the cargo tank, and keep records for the previous 4 years at their office or another central location.

(ii) Vapor tightness testing records that are kept at a location other than with the cargo tank must be instantly available (*e.g.,* via e-mail or facsimile) to the Administrator's delegated representative during the course of a site visit or within a mutually agreeable time frame. Such records must be an exact duplicate image of the original paper copy record with certifying signatures.

(d) Each owner or operator of an affected source under this subpart shall keep records as specified in paragraphs (d)(1) and (2) of this section.

(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 § 63.11115(a), including corrective actions to restore malfunctioning process and air pollution control and monitoring equipment to its normal or usual manner of operation.

[73 FR 1945, Jan. 10, 2008, as amended at 76 FR 4183, Jan. 24, 2011]

§ 63.11126 What are my reporting requirements?

(a) Each owner or operator subject to the management practices in § 63.11118 shall report to the Administrator the results of all volumetric efficiency tests required under § 63.11120(b). Reports submitted under this paragraph must be submitted within 180 days of the completion of the performance testing.

(b) Each owner or operator of an affected source under this subpart shall report, by March 15 of each year, the number, duration, and a brief description of each type of malfunction which occurred during the previous calendar year 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 § 63.11115(a), including actions taken to correct a malfunction. No report is necessary for a calendar year in which no malfunctions occurred.

[76 FR 4183, Jan. 24, 2011]

Other Requirements and Information

§ 63.11130 What parts of the General Provisions apply to me?

Table 3 to this subpart shows which parts of the General Provisions apply to you.

§ 63.11131 Who implements and enforces this subpart?

(a) This subpart can be implemented and enforced by the U.S. EPA or a delegated authority such as the applicable State, local, or tribal agency. If the U.S. EPA Administrator has delegated authority to a State, local, or tribal agency, then that agency, in addition to the U.S. EPA, has the authority to implement and enforce this subpart. Contact the applicable U.S. EPA Regional Office to find out if implementation and enforcement of this subpart is delegated to a State, local, or tribal agency.

(b) In delegating implementation and enforcement authority of this subpart to a State, local, or tribal agency under subpart E of this part, the authorities contained in paragraph (c) of this section are retained by the Administrator of U.S. EPA and cannot be transferred to the State, local, or tribal agency.

(c) The authorities that cannot be delegated to State, local, or tribal agencies are as specified in paragraphs (c)(1) through (3) of this section.

(1) Approval of alternatives to the requirements in §§ 63.11116 through 63.11118 and 63.11120.

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

(3) Approval of major alternatives to recordkeeping and reporting under § 63.10(f), as defined in § 63.90, and as required in this subpart.

§ 63.11132 What definitions apply to this subpart?

As used in this subpart, all terms not defined herein shall have the meaning given them in the Clean Air Act (CAA), or in subparts A and BBBBBB of this part. For purposes of this subpart, definitions in this section supersede definitions in other parts or subparts.

Dual-point vapor balance system means a type of vapor balance system in which the storage tank is equipped with an entry port for a gasoline fill pipe and a separate exit port for a vapor connection.

Gasoline means any petroleum distillate or petroleum distillate/alcohol blend having a Reid vapor pressure of 27.6 kilopascals or greater, which is used as a fuel for internal combustion engines.

Gasoline cargo tank means a delivery tank truck or railcar which is loading or unloading gasoline, or which has loaded or unloaded gasoline on the immediately previous load.

Gasoline dispensing facility (GDF) means any stationary facility which dispenses gasoline into the fuel tank of a motor vehicle, motor vehicle engine, nonroad vehicle, or nonroad engine, including a nonroad vehicle or nonroad engine used solely for competition. These facilities include, but are not limited to, facilities that dispense gasoline into on- and off-road, street, or highway motor vehicles, lawn equipment, boats, test engines, landscaping equipment, generators, pumps, and other gasoline-fueled engines and equipment.

Monthly throughput means the total volume of gasoline that is loaded into, or dispensed from, all gasoline storage tanks at each GDF during a month. Monthly throughput is calculated by summing the volume of gasoline loaded into, or dispensed from, all gasoline storage tanks at each GDF during the current day, plus the total volume of gasoline loaded into, or dispensed from, all gasoline storage tanks at each GDF during the previous 364 days, and then dividing that sum by 12.

Motor vehicle means any self-propelled vehicle designed for transporting persons or property on a street or highway.

Nonroad engine means an internal combustion engine (including the fuel system) that is not used in a motor vehicle or a vehicle used solely for competition, or that is not subject to standards promulgated under section 7411 of this title or section 7521 of this title.

Nonroad vehicle means a vehicle that is powered by a nonroad engine, and that is not a motor vehicle or a vehicle used solely for competition.

Submerged filling means, for the purposes of this subpart, the filling of a gasoline storage tank through a submerged fill pipe whose discharge is no more than the applicable distance specified in § 63.11117(b) from the bottom of the tank. Bottom filling of gasoline storage tanks is included in this definition.

Vapor balance system means a combination of pipes and hoses that create a closed system between the vapor spaces of an unloading gasoline cargo tank and a receiving storage tank such that vapors displaced from the storage tank are transferred to the gasoline cargo tank being unloaded.

Vapor-tight means equipment that allows no loss of vapors. Compliance with vapor-tight requirements can be determined by checking to ensure that the concentration at a potential leak source is not equal to or greater than 100 percent of the Lower Explosive Limit when measured with a combustible gas detector, calibrated with propane, at a distance of 1 inch from the source.

Vapor-tight gasoline cargo tank means a gasoline cargo tank which has demonstrated within the 12 preceding months that it meets the annual certification test requirements in § 63.11092(f) of this part.

[73 FR 1945, Jan. 10, 2008, as amended at 76 FR 4183, Jan. 24, 2011]

Table 1 to Subpart CCCCCC of Part 63—Applicability Criteria and Management Practices for Gasoline Dispensing Facilities With Monthly Throughput of 100,000 Gallons of Gasoline or More1

If you own or operate	Then you must
1. A new, reconstructed, or existing GDF subject to § 63.11118	Install and operate a vapor balance system on your gasoline storage tanks that meets the design criteria in paragraphs (a) through (h).
	(a) All vapor connections and lines on the storage tank shall be equipped with closures that seal upon disconnect.
	(b) The vapor line from the gasoline storage tank to the gasoline cargo tank shall be vapor-tight, as defined in § 63.11132.
	(c) The vapor balance system shall be designed such that the pressure in the tank truck does not exceed 18 inches water pressure or 5.9 inches water vacuum during product transfer.
	(d) The vapor recovery and product adaptors, and the method of connection with the delivery elbow, shall be designed so as to prevent the over-tightening or loosening of fittings during normal delivery operations.
	(e) If a gauge well separate from the fill tube is used, it shall be provided with a submerged drop tube that extends the same distance from the bottom of the storage tank as specified in § 63.11117(b).
	(f) Liquid fill connections for all systems shall be equipped with vapor-tight caps.
	(g) Pressure/vacuum (PV) vent valves shall be installed on the storage tank vent pipes. The pressure specifications for PV vent valves shall be: a positive pressure setting of 2.5 to 6.0 inches of water and a negative pressure setting of 6.0 to 10.0 inches of water. The total leak rate of all PV vent valves at an affected facility, including connections, shall not exceed 0.17 cubic foot per hour at a pressure of 2.0 inches of water and 0.63 cubic foot per hour at a vacuum of 4 inches of water.
	(h) The vapor balance system shall be capable of meeting the static pressure performance requirement of the following equation:
	$Pf = 2e^{-500.887/v}$
	Where:
	Pf = Minimum allowable final pressure, inches of water.
	v = Total ullage affected by the test, gallons.
	e = Dimensionless constant equal to approximately 2.718.
	2 = The initial pressure, inches water.
2. A new or reconstructed GDF, or any storage tank(s) constructed after November 9, 2006, at an existing affected facility subject to § 63.11118	Equip your gasoline storage tanks with a dual-point vapor balance system, as defined in § 63.11132, and comply with the requirements of item 1 in this Table.

[1] The management practices specified in this Table are not applicable if you are complying with the requirements in § 63.11118(b)(2), except that if you are complying with the requirements in § 63.11118(b)(2)(i)(B), you must operate using management practices at least as stringent as those listed in this Table.

[73 FR 1945, Jan. 10, 2008, as amended at 73 FR 35944, June 25, 2008; 76 FR 4184, Jan. 24, 2011]

Table 2 to Subpart CCCCCC of Part 63—Applicability Criteria and Management Practices for Gasoline Cargo Tanks Unloading at Gasoline Dispensing Facilities With Monthly Throughput of 100,000 Gallons of Gasoline or More

If you own or operate	Then you must
A gasoline cargo tank	Not unload gasoline into a storage tank at a GDF subject to the control requirements in this subpart unless the following conditions are met:
	(i) All hoses in the vapor balance system are properly connected,
	(ii) The adapters or couplers that attach to the vapor line on the storage tank have closures that seal upon disconnect,
	(iii) All vapor return hoses, couplers, and adapters used in the gasoline delivery are vapor-tight,
	(iv) All tank truck vapor return equipment is compatible in size and forms a vapor-tight connection with the vapor balance equipment on the GDF storage tank, and
	(v) All hatches on the tank truck are closed and securely fastened.
	(vi) The filling of storage tanks at GDF shall be limited to unloading from vapor-tight gasoline cargo tanks. Documentation that the cargo tank has met the specifications of EPA Method 27 shall be carried with the cargo tank, as specified in § 63.11125(c).

[73 FR 1945, Jan. 10, 2008, as amended at 76 FR 4184, Jan. 24, 2011]

Table 3 to Subpart CCCCCC of Part 63—Applicability of General Provisions

Citation	Subject	Brief description	Applies to subpart CCCCCC
§ 63.1	Applicability	Initial applicability determination; applicability after standard established; permit requirements; extensions, notifications	Yes, specific requirements given in § 63.11111.
§ 63.1(c)(2)	Title V Permit	Requirements for obtaining a title V permit from the applicable permitting authority	Yes, § 63.11111(f) of subpart CCCCCC exempts identified area sources from the obligation to obtain title V operating permits.
§ 63.2	Definitions	Definitions for part 63 standards	Yes, additional definitions in § 63.11132.
§ 63.3	Units and Abbreviations	Units and abbreviations for part 63 standards	Yes.
§ 63.4	Prohibited Activities and Circumvention	Prohibited activities; Circumvention, severability	Yes.
§ 63.5	Construction/Reconstruction	Applicability; applications; approvals	Yes, except that these notifications are not required for facilities subject to § 63.11116
§ 63.6(a)	Compliance with Standards/Operation & Maintenance—Applicability	General Provisions apply unless compliance extension; General Provisions apply to area sources that become major	Yes.

Citation	Subject	Brief description	Applies to subpart CCCCCC
§ 63.6(b)(1)-(4)	Compliance Dates for New and Reconstructed Sources	Standards apply at effective date; 3 years after effective date; upon startup; 10 years after construction or reconstruction commences for CAA section 112(f)	Yes.
§ 63.6(b)(5)	Notification	Must notify if commenced construction or reconstruction after proposal	Yes.
§ 63.6(b)(6)	[Reserved]		
§ 63.6(b)(7)	Compliance Dates for New and Reconstructed Area Sources That Become Major	Area sources that become major must comply with major source standards immediately upon becoming major, regardless of whether required to comply when they were an area source	No.
§ 63.6(c)(1)-(2)	Compliance Dates for Existing Sources	Comply according to date in this subpart, which must be no later than 3 years after effective date; for CAA section 112(f) standards, comply within 90 days of effective date unless compliance extension	No, § 63.11113 specifies the compliance dates.
§ 63.6(c)(3)-(4)	[Reserved]		
§ 63.6(c)(5)	Compliance Dates for Existing Area Sources That Become Major	Area sources That become major must comply with major source standards by date indicated in this subpart or by equivalent time period (e.g., 3 years)	No.
§ 63.6(d)	[Reserved]		
63.6(e)(1)(i)	General duty to minimize emissions	Operate to minimize emissions at all times; information Administrator will use to determine if operation and maintenance requirements were met.	No.*See*§ 63.11115 for general duty requirement.
63.6(e)(1)(ii)	Requirement to correct malfunctions ASAP	Owner or operator must correct malfunctions as soon as possible.	No.
§ 63.6(e)(2)	[Reserved]		
§ 63.6(e)(3)	Startup, Shutdown, and Malfunction (SSM) Plan	Requirement for SSM plan; content of SSM plan; actions during SSM	No.
§ 63.6(f)(1)	Compliance Except During SSM	You must comply with emission standards at all times except during SSM	No.
§ 63.6(f)(2)-(3)	Methods for Determining Compliance	Compliance based on performance test, operation and maintenance plans, records, inspection	Yes.
§ 63.6(g)(1)-(3)	Alternative Standard	Procedures for getting an alternative standard	Yes.
§ 63.6(h)(1)	Compliance with Opacity/Visible Emission (VE) Standards	You must comply with opacity/VE standards at all times except during SSM	No.
§ 63.6(h)(2)(i)	Determining Compliance with Opacity/VE Standards	If standard does not State test method, use EPA Method 9 for opacity in appendix A of part 60 of this chapter and EPA Method 22 for VE in appendix A of part 60 of this chapter	No.
§ 63.6(h)(2)(ii)	[Reserved]		

Citation	Subject	Brief description	Applies to subpart CCCCCC
§ 63.6(h)(2)(iii)	Using Previous Tests To Demonstrate Compliance With Opacity/VE Standards	Criteria for when previous opacity/VE testing can be used to show compliance with this subpart	No.
§ 63.6(h)(3)	[Reserved]		
§ 63.6(h)(4)	Notification of Opacity/VE Observation Date	Must notify Administrator of anticipated date of observation	No.
§ 63.6(h)(5)(i), (iii)-(v)	Conducting Opacity/VE Observations	Dates and schedule for conducting opacity/VE observations	No.
§ 63.6(h)(5)(ii)	Opacity Test Duration and Averaging Times	Must have at least 3 hours of observation with 30 6-minute averages	No.
§ 63.6(h)(6)	Records of Conditions During Opacity/VE Observations	Must keep records available and allow Administrator to inspect	No.
§ 63.6(h)(7)(i)	Report Continuous Opacity Monitoring System (COMS) Monitoring Data From Performance Test	Must submit COMS data with other performance test data	No.
§ 63.6(h)(7)(ii)	Using COMS Instead of EPA Method 9	Can submit COMS data instead of EPA Method 9 results even if rule requires EPA Method 9 in appendix A of part 60 of this chapter, but must notify Administrator before performance test	No.
§ 63.6(h)(7)(iii)	Averaging Time for COMS During Performance Test	To determine compliance, must reduce COMS data to 6-minute averages	No.
§ 63.6(h)(7)(iv)	COMS Requirements	Owner/operator must demonstrate that COMS performance evaluations are conducted according to § 63.8(e); COMS are properly maintained and operated according to § 63.8(c) and data quality as § 63.8(d)	No.
§ 63.6(h)(7)(v)	Determining Compliance with Opacity/VE Standards	COMS is probable but not conclusive evidence of compliance with opacity standard, even if EPA Method 9 observation shows otherwise. Requirements for COMS to be probable evidence-proper maintenance, meeting Performance Specification 1 in appendix B of part 60 of this chapter, and data have not been altered	No.
§ 63.6(h)(8)	Determining Compliance with Opacity/VE Standards	Administrator will use all COMS, EPA Method 9 (in appendix A of part 60 of this chapter), and EPA Method 22 (in appendix A of part 60 of this chapter) results, as well as information about operation and maintenance to determine compliance	No.
§ 63.6(h)(9)	Adjusted Opacity Standard	Procedures for Administrator to adjust an opacity standard	No.
§ 63.6(i)(1)-(14)	Compliance Extension	Procedures and criteria for Administrator to grant compliance extension	Yes.
§ 63.6(j)	Presidential Compliance Exemption	President may exempt any source from requirement to comply with this subpart	Yes.

Citation	Subject	Brief description	Applies to subpart CCCCCC
§ 63.7(a)(2)	Performance Test Dates	Dates for conducting initial performance testing; must conduct 180 days after compliance date	Yes.
§ 63.7(a)(3)	CAA Section 114 Authority	Administrator may require a performance test under CAA section 114 at any time	Yes.
§ 63.7(b)(1)	Notification of Performance Test	Must notify Administrator 60 days before the test	Yes.
§ 63.7(b)(2)	Notification of Re-scheduling	If have to reschedule performance test, must notify Administrator of rescheduled date as soon as practicable and without delay	Yes.
§ 63.7(c)	Quality Assurance (QA)/Test Plan	Requirement to submit site-specific test plan 60 days before the test or on date Administrator agrees with; test plan approval procedures; performance audit requirements; internal and external QA procedures for testing	Yes.
§ 63.7(d)	Testing Facilities	Requirements for testing facilities	Yes.
63.7(e)(1)	Conditions for Conducting Performance Tests	Performance test must be conducted under representative conditions	No, § 63.11120(c) specifies conditions for conducting performance tests.
§ 63.7(e)(2)	Conditions for Conducting Performance Tests	Must conduct according to this subpart and EPA test methods unless Administrator approves alternative	Yes.
§ 63.7(e)(3)	Test Run Duration	Must have three test runs of at least 1 hour each; compliance is based on arithmetic mean of three runs; conditions when data from an additional test run can be used	Yes.
§ 63.7(f)	Alternative Test Method	Procedures by which Administrator can grant approval to use an intermediate or major change, or alternative to a test method	Yes.
§ 63.7(g)	Performance Test Data Analysis	Must include raw data in performance test report; must submit performance test data 60 days after end of test with the Notification of Compliance Status; keep data for 5 years	Yes.
§ 63.7(h)	Waiver of Tests	Procedures for Administrator to waive performance test	Yes.
§ 63.8(a)(1)	Applicability of Monitoring Requirements	Subject to all monitoring requirements in standard	Yes.
§ 63.8(a)(2)	Performance Specifications	Performance Specifications in appendix B of 40 CFR part 60 apply	Yes.
§ 63.8(a)(3)	[Reserved]		
§ 63.8(a)(4)	Monitoring of Flares	Monitoring requirements for flares in § 63.11 apply	Yes.
§ 63.8(b)(1)	Monitoring	Must conduct monitoring according to standard unless Administrator approves alternative	Yes.

Citation	Subject	Brief description	Applies to subpart CCCCCC
§ 63.8(b)(2)-(3)	Multiple Effluents and Multiple Monitoring Systems	Specific requirements for installing monitoring systems; must install on each affected source or after combined with another affected source before it is released to the atmosphere provided the monitoring is sufficient to demonstrate compliance with the standard; if more than one monitoring system on an emission point, must report all monitoring system results, unless one monitoring system is a backup	No.
§ 63.8(c)(1)	Monitoring System Operation and Maintenance	Maintain monitoring system in a manner consistent with good air pollution control practices	No.
§ 63.8(c)(1)(i)-(iii)	Operation and Maintenance of Continuous Monitoring Systems (CMS)	Must maintain and operate each CMS as specified in § 63.6(e)(1); must keep parts for routine repairs readily available; must develop a written SSM plan for CMS, as specified in § 63.6(e)(3)	No.
§ 63.8(c)(2)-(8)	CMS Requirements	Must install to get representative emission or parameter measurements; must verify operational status before or at performance test	No.
§ 63.8(d)	CMS Quality Control	Requirements for CMS quality control, including calibration, etc.; must keep quality control plan on record for 5 years; keep old versions for 5 years after revisions	No.
§ 63.8(e)	CMS Performance Evaluation	Notification, performance evaluation test plan, reports	No.
§ 63.8(f)(1)-(5)	Alternative Monitoring Method	Procedures for Administrator to approve alternative monitoring	No.
§ 63.8(f)(6)	Alternative to Relative Accuracy Test	Procedures for Administrator to approve alternative relative accuracy tests for continuous emissions monitoring system (CEMS)	No.
§ 63.8(g)	Data Reduction	COMS 6-minute averages calculated over at least 36 evenly spaced data points; CEMS 1 hour averages computed over at least 4 equally spaced data points; data that cannot be used in average	No.
§ 63.9(a)	Notification Requirements	Applicability and State delegation	Yes.
§ 63.9(b)(1)-(2), (4)-(5)	Initial Notifications	Submit notification within 120 days after effective date; notification of intent to construct/reconstruct, notification of commencement of construction/reconstruction, notification of startup; contents of each	Yes.
§ 63.9(c)	Request for Compliance Extension	Can request if cannot comply by date or if installed best available control technology or lowest achievable emission rate	Yes.

Citation	Subject	Brief description	Applies to subpart CCCCCC
§ 63.9(d)	Notification of Special Compliance Requirements for New Sources	For sources that commence construction between proposal and promulgation and want to comply 3 years after effective date	Yes.
§ 63.9(e)	Notification of Performance Test	Notify Administrator 60 days prior	Yes.
§ 63.9(f)	Notification of VE/Opacity Test	Notify Administrator 30 days prior	No.
§ 63.9(g)	Additional Notifications when Using CMS	Notification of performance evaluation; notification about use of COMS data; notification that exceeded criterion for relative accuracy alternative	Yes, however, there are no opacity standards.
§ 63.9(h)(1)-(6)	Notification of Compliance Status	Contents due 60 days after end of performance test or other compliance demonstration, except for opacity/VE, which are due 30 days after; when to submit to Federal vs. State authority	Yes, however, there are no opacity standards.
§ 63.9(i)	Adjustment of Submittal Deadlines	Procedures for Administrator to approve change when notifications must be submitted	Yes.
§ 63.9(j)	Change in Previous Information	Must submit within 15 days after the change	Yes.
§ 63.10(a)	Recordkeeping/Reporting	Applies to all, unless compliance extension; when to submit to Federal vs. State authority; procedures for owners of more than one source	Yes.
§ 63.10(b)(1)	Recordkeeping/Reporting	General requirements; keep all records readily available; keep for 5 years	Yes.
§ 63.10(b)(2)(i)	Records related to SSM	Recordkeeping of occurrence and duration of startups and shutdowns	No.
§ 63.10(b)(2)(ii)	Records related to SSM	Recordkeeping of malfunctions	No.*See*§ 63.11125(d) for recordkeeping of (1) occurrence and duration and (2) actions taken during malfunction.
§ 63.10(b)(2)(iii)	Maintenance records	Recordkeeping of maintenance on air pollution control and monitoring equipment	Yes.
§ 63.10(b)(2)(iv)	Records Related to SSM	Actions taken to minimize emissions during SSM	No.
§ 63.10(b)(2)(v)	Records Related to SSM	Actions taken to minimize emissions during SSM	No.
§ 63.10(b)(2)(vi)-(xi)	CMS Records	Malfunctions, inoperative, out-of-control periods	No.
§ 63.10(b)(2)(xii)	Records	Records when under waiver	Yes.
§ 63.10(b)(2)(xiii)	Records	Records when using alternative to relative accuracy test	Yes.
§ 63.10(b)(2)(xiv)	Records	All documentation supporting Initial Notification and Notification of Compliance Status	Yes.
§ 63.10(b)(3)	Records	Applicability determinations	Yes.
§ 63.10(c)	Records	Additional records for CMS	No.

Citation	Subject	Brief description	Applies to subpart CCCCCC
§ 63.10(d)(1)	General Reporting Requirements	Requirement to report	Yes.
§ 63.10(d)(2)	Report of Performance Test Results	When to submit to Federal or State authority	Yes.
§ 63.10(d)(3)	Reporting Opacity or VE Observations	What to report and when	No.
§ 63.10(d)(4)	Progress Reports	Must submit progress reports on schedule if under compliance extension	Yes.
§ 63.10(d)(5)	SSM Reports	Contents and submission	No.*See*§ 63.11126(b) for malfunction reporting requirements.
§ 63.10(e)(1)-(2)	Additional CMS Reports	Must report results for each CEMS on a unit; written copy of CMS performance evaluation; two-three copies of COMS performance evaluation	No.
§ 63.10(e)(3)(i)-(iii)	Reports	Schedule for reporting excess emissions	No.
§ 63.10(e)(3)(iv)-(v)	Excess Emissions Reports	Requirement to revert to quarterly submission if there is an excess emissions and parameter monitor exceedances (now defined as deviations); provision to request semiannual reporting after compliance for 1 year; submit report by 30th day following end of quarter or calendar half; if there has not been an exceedance or excess emissions (now defined as deviations), report contents in a statement that there have been no deviations; must submit report containing all of the information in §§ 63.8(c)(7)-(8) and 63.10(c)(5)-(13)	No.
§ 63.10(e)(3)(iv)-(v)	Excess Emissions Reports	Requirement to revert to quarterly submission if there is an excess emissions and parameter monitor exceedances (now defined as deviations); provision to request semiannual reporting after compliance for 1 year; submit report by 30th day following end of quarter or calendar half; if there has not been an exceedance or excess emissions (now defined as deviations), report contents in a statement that there have been no deviations; must submit report containing all of the information in §§ 63.8(c)(7)-(8) and 63.10(c)(5)-(13)	No, § 63.11130(K) specifies excess emission events for this subpart.
§ 63.10(e)(3)(vi)-(viii)	Excess Emissions Report and Summary Report	Requirements for reporting excess emissions for CMS; requires all of the information in §§ 63.10(c)(5)-(13) and 63.8(c)(7)-(8)	No.
§ 63.10(e)(4)	Reporting COMS Data	Must submit COMS data with performance test data	No.
§ 63.10(f)	Waiver for Recordkeeping/Reporting	Procedures for Administrator to waive	Yes.

Citation	Subject	Brief description	Applies to subpart CCCCCC
§ 63.11(b)	Flares	Requirements for flares	No.
§ 63.12	Delegation	State authority to enforce standards	Yes.
§ 63.13	Addresses	Addresses where reports, notifications, and requests are sent	Yes.
§ 63.14	Incorporations by Reference	Test methods incorporated by reference	Yes.
§ 63.15	Availability of Information	Public and confidential information	Yes.

[73 FR 1945, Jan. 10, 2008, as amended at 76 FR 4184, Jan. 24, 2011]

Indiana Department of Environmental Management

Office of Air Quality

Technical Support Document (TSD) for a Part 70 Operating Permit Renewal

Source Description and Location

Source Name:	**University of Notre Dame du Lac**
Source Location:	**100 Facilities Building, Notre Dame, IN 46556**
County:	**St. Joseph (Portage Township)**
SIC Code:	**8221 (Colleges, Universities, and Professional Schools)**
Permit Renewal No.:	**T 141-41227-00013**
Permit Reviewer:	**Tripurari Sinha, Ph. D.**

On March 19, 2019, University of Notre Dame du Lac submitted an application to the Office of Air Quality (OAQ) requesting to renew its operating permit. OAQ has reviewed the operating permit renewal application from University of Notre Dame du Lac relating to the operation of a university power plant, baseload generators, several heaters and emergency generators for various buildings on the campus. The University also operates two turbines for generating steam and electricity. University of Notre Dame du Lac was issued its second Part 70 Operating Permit Renewal T 141-33677-00013 on December 30, 2014.

Existing Approvals

The source was issued Part 70 Operating Permit Renewal No. T 141-33677-00013 on December 30, 2014. The source has since received the following approvals:

Permit Type	Permit Number	Issuance Date
Minor Source Modification	141-35739-00013	August 5, 2015
Significant Permit Modification	141-35763-00013	October 6, 2015
Administrative Amendment	141-37766-00013	December 21, 2016
Minor Source Modification	141-37597 -00013	December 22, 2016
Significant Source Modification	141-38402-00013	February 16, 2018
Significant Permit Modification	141-38426-00013	March 6, 2018
Administrative Amendment	141-40444-00013	December 19, 2018

All terms and conditions of previous permits issued pursuant to permitting programs approved into the State Implementation Plan have been either incorporated as originally stated, revised, or deleted by this permit. All previous registrations and permits are superseded by this permit.

Emission Units and Pollution Control Equipment

The source consists of the following permitted emission units:

(a) One (1) No. 2 fuel oil or natural gas fired boiler, identified as B-1, constructed in 1961, with a single low NOx burner and economizer constructed in 2006, and with a maximum design capacity of 137 MMBtu per hour heat input, and exhausting to stack S-1.

[This is an existing affected source under 40 CFR Part 63, Subpart JJJJJJ.]

(b) Two (2) natural gas fired boilers, identified as B-2 and B-3, constructed in 1952, and modified in 2019 to remove coal firing capacity, with maximum design capacity of 96 MMBtu per hour heat input, each, each equipped with low NOx burners, and exhausting to stack S-1.

(c) One (1) natural gas or No. 2 fuel oil fired boiler, identified as B-4, constructed in 1966, and modified in 2018 to remove coal firing capacity, with a maximum design capacity of 234 MMBtu per hour heat input**,** and exhausting to stack S-2.

[This is an existing affected source under 40 CFR Part 63, Subpart JJJJJJ.]

(d) One (1) No. 2 fuel oil or natural gas fired boiler, identified as B-5, constructed in 1973, with a maximum design capacity of 244.5 MMBtu per hour heat input, equipped with low NOx burner for natural gas and fuel oil, and exhausting to stack S-3.

[This is an existing affected source under 40 CFR Part 63, Subpart JJJJJJ.]

(e) One (1) natural gas fired boiler, identified as B-6, constructed in 2006, with a maximum design capacity of 249 MMBtu per hour heat input, equipped with a low NOx burner and flue gas recirculation (FGR), using No. 2 fuel oil as a backup fuel, and exhausting to stack S-9, monitored by certified COM and NOx CEM.

[This is an affected source under 40 CFR Part 60, Subpart Db.]
[This is an existing affected source under 40 CFR Part 63, Subpart JJJJJJ.]

(f) Three (3) diesel-fired generators, identified as G-8, G-9 and G-10, constructed before July 11, 2005 (permitted in 2003), each with a maximum rated capacity of 2,593 brake horsepower, equipped with oxidation catalysts, and exhausting to stacks S-6, S-7 and S-8, respectively.

[These generators are an affected source under 40 CFR Part 63, Subpart ZZZZ.]

(g) Two (2) diesel-fired emergency generators, identified as G-3 and G-4, constructed in 1953, with maximum design capacity of 13.70 MMBtu per hour heat input, each, and exhausting to stacks S-4 and S-5, respectively.

(h) Two (2) natural gas-fired combustion turbines, identified as GT-1 and GT-2, each equipped with a heat recovery steam generator (HRSG), constructed in 2018. Each HRSG is equipped with a natural gas-fired duct burner, each turbine has a maximum capacity of 6.4 MW (75.4 MMBtu/hr), and each duct burner has a maximum capacity of 87.5 MMBtu/hr. During normal operation, the turbines and duct burners exhaust to a shared main stack.

*Note: The heat recovery steam generators are not a source of emissions. They have been included for clarity as they are part of the entire source and operate in conjunction with the duct burners and combustion turbines which are a source of emissions.

[These turbines are an affected source under 40 CFR Part 60, Subpart KKKK]

Emission Units and Pollution Control Equipment Removed From the Source

The source has removed the following emission units:

(a) Other existing activities or categories not previously identified that have emissions equal to or less than insignificant thresholds [326 IAC 6.5-1]

(1) Long and short term coal storage piles, totaling 10.33 acres;

(2) One (1) 1200 ton coal handling facility, consisting of conveyors, crushers, and other equipment that are enclosed or underground;

(3) One (1) 450 ton coal bunker for boilers B-2 and B-3;

(4) One (1) 250 ton coal bunker for boiler B-4; and

(5) Covered conveyors for solid raw material, including coal or coke conveying of less than or equal to 360 tons per day.

(6) Underground conveyors.

(7) Coal bunker and coal scale exhausts and associated dust collector vents.

(b) One (1) lime sorbent storage silo, identified as Silo 1, constructed in 2008 and approved in 2015 for modification, with an increased throughput rate of 629 lb/hr to SI-1 and 699 lb/hr to SI-2 from 410 lb/hr to SI-1 and 575 lb/hr to SI-2 , equipped with one (1) bin vent filter (BVF-1). [326 IAC 6.5-1]

(c) One (1) powdered activated carbon (PAC) sorbent storage silo, identified as Silo 2, constructed in 2008 and approved in 2015 for modification, with an increased throughput rate of 50 lb/hr to SI-1 and 25 lb/hr to SI-2 from 5 lb/hr to SI-1 and 8 lb/hr to SI-2, equipped with one (1) bin vent filter (BVF-2). [326 IAC 6.5-1]

(d) One (1) lime sorbent storage silo, identified as Silo 3, constructed in 2008 and approved in 2015 for modification, with an increased throughput rate of 1,171 lb/hr to SI-1 and 1,301 lb/hr to SI-2 from an ash throughput of 17,327 ton per year, equipped with one (1) bin vent filter (BVF-3). [326 IAC 6.5-1]

(e) One (1) ash storage silo, identified as Silo 4, approved in 2015 for construction, with a throughput of 29,973 tons/yr, equipped with one (1) bin vent filter (BVF-4). [326 IACV 6.5-1]

(f) Vents from ash transport systems not operated at positive pressure. [326 IAC 6.5-1]

(g) Emergency Generators:

Location	Engine Rating	Year of Manufacture
Sacred Heart Basilica	19	1989
Band Bldg.	27	1990
Pasquerilla center (ROTC)	40	1990
Holy Cross House	134	1999
Fitzpatrick/Cushing/O'Shag/ Snite	402	1978
Stepan Chemistry/Nieuwland	402	1982

Insignificant Activities

This stationary source also includes the following insignificant activities:

(a) Degreasing operations that do not exceed 145 gallons per 12 months, except if subject to 326 IAC 20-6.

(b) The following equipment not resulting in the emission of HAPs: brazing equipment, cutting torches, soldering equipment, welding equipment.

(c) Grinding and machining operations controlled with fabric filters, scrubbers, mist collectors, wet collectors and electrostatic precipitators with a design grain loading of less than or equal to 0.03 grains per actual cubic foot and a gas flow rate less than or equal to 4000 actual cubic feet per minute, including the following: deburring, buffing, polishing, abrasive blasting, pneumatic conveying; and woodworking operations.

(d) Space heaters, process heaters, or boilers consisting of the following:

(1) Natural gas-fired combustion sources with heat input capacities equal to or less than 10.0 MMBtu per hour.

(2) Propane, LPG, or butane-fired combustion sources with heat input capacities equal to or less than 6.0 MMBtu per hour.

(3) Fuel oil-fired combustion sources with heat input capacities equal to or less than 2.0 MMBtu per hour and firing fuel containing less than 0.5% sulfur by weight.

(4) Wood-fired combustion sources with heat input capacities equal to or less than 2.0 MMBtu per hour and firing fuel containing less than 0.5% sulfur by weight.

(e) Noncontact cooling tower systems with forced and induced draft cooling tower systems not regulated under a NESHAP.

(1) Five (5) non-contact, counterflow cooling towers; identified as Cooling Towers 1 through 5; each with a maximum water circulation rate of 10,400 gallons/minute; each cooling tower was constructed in 2000 and controlled by drift eliminators.

(2) Two (2) closed-loop, counterflow cooling towers; identified as Cooling Towers 6 and 7; each with a maximum cooling tower water circulation rate of 10,000 gallons/minute; each constructed in 2016 and controlled by drift eliminators.

(3) Two (2) closed-loop, counter flow cooling towers; identified as East Chiller Plant Cooling Towers 8 and 9; each with a maximum cooling tower water circulation rate of 5,000 gallons/minute; each constructed in 2016 and controlled by drift eliminators.

(f) Insignificant emergency engines consisting of the following:

(1) Diesel fired compression ignition emergency engines, each with a capacity less than or equal to 500 Hp, constructed/reconstructed before June 12, 2006.

Location	Engine Rating	Year of Manufacture
Old Security Building	27	1990
Haggar	20	1990
Loftus Center	20	1987
North Dining Hall	44	1988
Hesburgh Ctr. For Int. Studies	54	1991
Rec Sports	60	1997
Hammes Mowbray	74	2004
Material Storage	80	1990
Bond Hall/Morrissey	80	1997
South Dining Hall	80	1993
Eck Center/Ryan Hall	107	1999
DeBartolo	121	1992
Hanks Aquatics	134	1997
Guigliemino CVA	134	2004
O'Neill/Keough/Welsh McGlinn/Duncan	201	1996
Coleman Morse	201	1999
Performing Arts Center	201	2002
Geddes Hall	268	2005
COBA	469	1995

(2) Diesel fired compression ignition emergency engines, each with a capacity less than or equal to 500 Hp, manufactured/modified/ constructed/reconstructed on or after June 12, 2006.

Location	Engine Rating	Year of Manufacture
MVAP Complex	168	2009
Nanotechnology Research Ctr.	201	2006
Stayer Center	201	2012
Innovation Park Building 1	335	2009
Compton Ice Arena	335	2011
Eck Law School	402	2007
Morris Inn	235	2013
Jenkins-Nanovic Hall	385	2016

[These are new affected source under 40 CFR Part 60, Subpart IIII]
[These are new affected source under 40 CFR Part 63, Subpart ZZZZ]

(3) Diesel fired compression Emergency engines, each with a capacity greater than 500 Hp and not exceeding 1600 Hp, constructed/reconstructed before December 19, 2002.

Location	Engine Rating	Year of Manufacture
Secondary Chilled Water Pumping Station	536	1996
Malloy Hall	536	2001
Flanner/Grace/Wells 1 & 2	671	1996
ITC	671	2002
Administration Bldg.	671	1997

(4) Diesel fired compression ignition emergency engines, each with a capacity greater than 500 HP and not exceeding 1600 Hp, manufactured/modified/constructed/ reconstructed on or after June 12, 2006.

Location	Generator Rating	Year of Manufacture
Well #9	536	2012
Joyce Center	671	2013
Hesburgh Library #1	671	2013
Hesburgh Library #2	671	2013
Galvin Life Sciences	755	2015
Nieuwland	755	2015
Stinson-Remick	1,073	2010
McCourtney Hall	1,220	2016
Stadium 1	1,474	2016
Stadium 2	1,474	2016

[These are new affected source under 40 CFR Part 60, Subpart IIII]
[These are new affected source under 40 CFR Part 63, Subpart ZZZZ]

(5) Diesel fired compression Emergency engines, each with a capacity greater than 500 HP and not exceeding 1600 Hp, constructed/reconstructed on or after December 19, 2002 and manufactured/ modified/reconstructed before July 11, 2005.

Location	Engine Rating	Year of Manufacture
Galvin No. 3	805	2005
Jordan Hall of Science	805	2004

(6) Ten existing natural gas fired emergency engines, identified as identified as (GEN-01), with a total combined capacity of 802 HP.

(g) A gasoline fuel transfer dispensing operation 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.

[This is an affected unit under 40 CFR Part 63, Subpart CCCCCC.]

(h) Paved and unpaved roads and parking lots with public access.

(i) One (1) underground diesel fuel storage tank constructed in 2005 for generators G-8, G-9, and G-10, identified as UST, with maximum storage capacity of 30,000 gallons and storing diesel fuel with a maximum true vapor pressure less than 15 kilo Pascal (kPa).

(j) Combustion source flame safety purging on startup.

(k) A petroleum fuel, other than gasoline dispensing facility, 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.

(l) Asbestos abatement projects regulated by 326 IAC 14-10.

(m) Ten (10) underground storage tanks: four (4) at 50,000 gallons for No.2 fuel oil, each constructed in 1973; five (5) at 20,000 gallons for No.2 fuel oil, each constructed in 1990, and one (1) at 20,000 gallons for diesel fuel, constructed in 1990.

(n) Two (2) above-ground, storage tanks for fuel oil #2, identified as AST-1 and AST-2; each constructed in 2016, each providing additional storage capacity for the University boilers; and each having a maximum storage capacity of 300,000 gallons.

(o) Five (5) 300 gallon diesel fuel day tanks for G-3, G-4, G-8, G-9, and G-10.

(p) The following VOC and HAP storage containers:

(1) Storage tanks with capacity less than or equal to one thousand (1,000) gallons and annual throughputs less than twelve thousand (12,000) gallons.

(2) Vessels storing hydraulic oils, lubricating oils, machining oils, machining fluids.

(q) Refractory storage not requiring air pollution control equipment.

(r) Equipment used exclusively for packaging greases and lubricants and filling drums, pails, or other packaging containers with greases, lubricating oils, and waxes.

(s) Repair activities, including the following:

(1) Replacement or repair of electrostatic precipitators, bags in baghouses, and filters in other air filtration equipment.

(2) Heat exchanger cleaning and repair.

(3) Process vessel degassing and cleaning to prepare for internal repairs.

(t) Routine maintenance and repair of buildings, structures, or vehicles at the source where air emissions from those activities would not be associated with any production process, including purging of gas lines and vessels.

(u) Equipment used to collect any material that might be released during a malfunction, process upset, or spill cleanup, including the following:

(1) Catch tanks.
(2) Temporary liquid separators.
(3) Tanks.
(4) Fluid handling equipment.

(v) Blowdown for the following:

(1) Sight glass.
(2) Boiler.
(3) Cooling tower.
(4) Compressors.
(5) Pumps.

(w) On-site fire training approved by the IDEM.

(x) Purge double block and bleed valves.

(y) Filter or coalescer media change out.

(z) Activities including a micro turbine associated with the following:

(1) Emissions from a laboratory as defined in 326 IAC 2-7-1(21)(G).

(2) Emissions from research and development activities as defined in 326 IAC 2-7-1(21)(H).

(3) Emissions from educational and teaching activities as defined in 326 IAC 2-7-1(21)(I).

(aa) Water-based activities, including the following:

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

(2) Water based adhesives that are less than or equal to five percent (5%) by volume of VOCs excluding HAPs.

(bb) One maintenance shop paint booth.

Emission Units and Pollution Control Equipment
Constructed Under the Provisions of 326 IAC 2-1.1-3 (Exemptions)

The following existing emissions unit(s), constructed under the provisions of 326 IAC 2-1.1-3 (Exemptions), are being incorporated in the permit as part of this permitting action:

Project 1:

Natural gas-fired combustion sources with heat input capacities equal to or less than 10.0 MMBtu per hour consisting of the following:

Two (2) indirect natural gas fired heaters, identified as Irish Athletic Center Heaters, constructed in 2018 and 2019, with maximum capacity of 2.4 MMBtu, each.

These emission units are identified under 326 IAC 2-1.1-3(e)(5)(A).

Project 2:

Natural gas-fired combustion sources with heat input capacities equal to or less than 10.0 MMBtu per hour consisting of the following:

Three hundred (300) indirect natural gas fired heaters, constructed prior to 2020, with a maximum capacity of 40,000 Btu per hour, each.

The University does not maintain an inventory of these small heaters. For the purposes of potential emissions calculations, the University conservatively assumed that the typical natural gas-fired unit is rated at 40,000 Btu/hr, and that there are 300 such heaters on campus.

Each heater qualifies as an independent project because each was budgeted separately and constructed at a separate location. The heaters have been installed gradually over time as the campus has grown.

These emission units are identified under 326 IAC 2-1.1-3(e)(5)(A).

Project 3:
Insignificant emergency Diesel generator not exceeding one thousand six hundred (1,600) horsepower:

Location	Engine Rating	Year of Manufacture
East Plant	201	2003

This emission unit is identified under 326 IAC 2-1.1-3(e)(25)(B)(ii).

Project 4
Insignificant emergency Diesel generator not exceeding one thousand six hundred (1,600) horsepower:

Location	Engine Rating	Year of Manufacture
Sacred Heart Basilica	134	2019

This emission unit is identified under 326 IAC 2-1.1-3(e)(25)(B)(ii).

Project 5

Insignificant emergency Diesel generator not exceeding one thousand six hundred (1,600) horsepower:

Location	Engine Rating	Year of Manufacture
Stepan Chemistry	755	2019
Fitzpatrick	755	2019

These emission units are identified under 326 IAC 2-1.1-3(e)(25)(B)(ii).

Project 1 and Project 2 are identified under 326 IAC 2-1.1-3(e)(5)(A)(Exemptions). Project 3, Project 4, and Project 5 are identified under 326 IAC 2-1.1-3(e)(25)(B)(ii) (Exemptions). The addition of the emission units did not require the source to transition to a higher operation permit level. Therefore, pursuant to 326 IAC 2-1.1-3(e)(5)(A) and (25)(B)(ii), the modification approval requirements under 326 IAC 2-7-10.5 , including the requirement to submit an application, do not apply to these emission units.

Enforcement Issue

There are no enforcement actions pending.

Emission Calculations

See Appendix A of this Technical Support Document for detailed emission calculations.

County Attainment Status

The source is located in St. Joseph County.

Pollutant	Designation
SO_2	Better than national standards.
CO	Unclassifiable or attainment effective November 15, 1990.
O_3	Unclassifiable or attainment effective August 3, 2018, for the 2015 8-hour ozone standard.
$PM_{2.5}$	Unclassifiable or attainment effective April 15, 2015, for the 2012 annual $PM_{2.5}$ standard.
$PM_{2.5}$	Unclassifiable or attainment effective December 13, 2009, for the 2006 24-hour $PM_{2.5}$ standard.
PM_{10}	Unclassifiable effective November 15, 1990.
NO_2	Unclassifiable or attainment effective January 29, 2012, for the 2010 NO_2 standard.
Pb	Unclassifiable or attainment effective December 31, 2011, for the 2008 lead standard.

(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. St. Joseph 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) $PM_{2.5}$

St. Joseph County has been classified as attainment for $PM_{2.5}$. Therefore, direct $PM_{2.5}$, SO_2, and NOx emissions were reviewed pursuant to the requirements for Prevention of Significant Deterioration (PSD), 326 IAC 2-2.

(c) Other Criteria Pollutants
St. Joseph County has been classified as attainment or unclassifiable in Indiana for all the other criteria pollutants. Therefore, these emissions were reviewed pursuant to the requirements for Prevention of Significant Deterioration (PSD), 326 IAC 2-2.

Fugitive Emissions

Since the existing source includes fossil fuel-fired boilers (or combination thereof) totaling more than two hundred fifty million (250,000,000) British thermal units per hour heat input, the boilers are considered one (1) of the twenty-eight (28) listed source categories, as specified in 326 IAC 2-2-1(ff)(1), 326 IAC 2-3-2(g), or 326 IAC 2-7-1(22)(B), and are considered "nested" within a non-listed source; therefore fugitive emissions are counted toward the determination of PSD, Emission Offset, and Part 70 Permit applicability, from the boilers.

Because the primary operation of the existing source is not in the one of 28 listed source categories under 326 IAC 2-2-1(ff)(1), 326 IAC 2-3-2(g), or 326 IAC 2-7-1(22)(B), and there is no applicable New Source Performance Standard or National Emission Standard for Hazardous Air Pollutants that was in effect on August 7, 1980, fugitive emissions are not counted toward the determination of PSD, Emission Offset, and Part 70 Permit applicability.

Greenhouse Gas (GHG) Emissions

On June 23, 2014, in the case of *Utility Air Regulatory Group v. EPA*, Cause No. 12-1146, (available at http://www.supremecourt.gov/opinions/13pdf/12-1146_4g18.pdf) the United States Supreme Court ruled that the U.S. EPA does not have the authority to treat greenhouse gases (GHGs) as an air pollutant for the purpose of determining operating permit applicability or PSD Major source status. On July 24, 2014, the U.S. EPA issued a memorandum to the Regional Administrators outlining next steps in permitting decisions in light of the Supreme Court's decision. U.S. EPA's guidance states that U.S. EPA will no longer require PSD or Title V permits for sources “previously classified as ‘Major' based solely on greenhouse gas emissions.”

The Indiana Environmental Rules Board adopted the GHG regulations required by U.S. EPA at 326 IAC 2-2-1(zz), pursuant to Ind. Code § 13-14-9-8(h) (Section 8 rulemaking). A rule, or part of a rule, adopted under Section 8 is automatically invalidated when the corresponding federal rule, or part of the rule, is invalidated. Due to the United States Supreme Court Ruling, IDEM, OAQ cannot consider GHG emissions to determine operating permit applicability or PSD applicability to a source or modification.

Unrestricted Potential Emissions

This table reflects the unrestricted potential emissions of the source.

	Unrestricted Potential Emissions (ton/year)								
	PM[1]	**PM_{10}[1]**	**$PM_{2.5}$[1, 2]**	**SO_2**	**NO_X**	**VOC**	**CO**	**Single HAP (Hexane)**	**Total HAPs**
Total PTE of Entire Source Excluding Fugitive Emissions*	90.76	103.71	84.77	1,848.30	1,422.2	59.72	797.44	9.65	12.83
Total PTE of Entire Source	90.76	103.71	84.77	1,848.3	1,422.2	59.72	797.44	9.65	12.83
Title V Major Source Thresholds	NA	100	100	100	100	100	100	10	25
PSD Major Source Thresholds	250	250	250	250	250	250	250	--	--

[1]Under the Part 70 Permit program (40 CFR 70), PM_{10} and $PM_{2.5}$, not particulate matter (PM), are each considered as a "regulated air pollutant."

[2]$PM_{2.5}$ listed is direct $PM_{2.5}$.

*Fugitive HAP emissions are always included in the source-wide emissions.

Appendix A of this TSD reflects the detailed unrestricted potential emissions of the source.

(a) The potential to emit (as defined in 326 IAC 2-7-1(30)) of PM10, SO_2, NOx, and CO is equal to or greater than one hundred (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 Renewal.

(b) The potential to emit (as defined in 326 IAC 2-7-1(30)) of any single HAP is less than ten (10) tons per year and the potential to emit (as defined in 326 IAC 2-7-1(30)) of a combination of HAPs is less than twenty-five (25) tons per year. Therefore, this source is an area source under Section 112 of the Clean Air Act (CAA).

Permit Level Determination - PSD Emissions Increase

The table below summarizes the potential to emit of the modification, reflecting all limits, of the emission units. Any control equipment is considered federally enforceable only after issuance of the Part 70 administrative amendment, and only to the extent that the effect of the control equipment is made practically enforceable in the permit. If the control equipment has been determined to be integral, the table reflects the potential to emit (PTE) after consideration of the integral control device.

Project 1

	Project Emissions (ton/year)						
Process / Emission Unit	**PM**	**PM_{10}**	**$PM_{2.5}$[1]**	**SO_2**	**NO_X**	**VOC**	**CO**
Two (2) indirect natural gas fired heaters, identified as Irish Athletic Center Heaters, constructed in 2018 and 2019, with maximum capacity of 2.4 MMBtu, each.	0.04	0.16	0.16	0.01	2.06	0.11	1.73
Total for Modification	0.04	0.16	0.16	0.01	2.06	0.11	1.73
PSD Significant Levels	25	15	10	40	40	40	100
[1]$PM_{2.5}$ listed is direct $PM_{2.5}$.							

This modification to an existing major PSD stationary source is not major because the emissions increase of each PSD regulated pollutant is less than the PSD significant level. Therefore, pursuant to 326 IAC 2-2, the PSD requirements do not apply.

Project 2

	Project Emissions (ton/year)						
Process / Emission Unit	**PM**	**PM_{10}**	**$PM_{2.5}$[1]**	**SO_2**	**NO_X**	**VOC**	**CO**
Three hundred (300) indirect natural gas fired heaters, constructed prior to 2020, with a maximum capacity of 40,000 Btu per hour, each.	0.10	0.39	0.39	0.03	5.15	0.28	4.33
Total for Modification	0.10	0.39	0.39	0.03	5.15	0.28	4.33
PSD Significant Levels	25	15	10	40	40	40	100
[1]$PM_{2.5}$ listed is direct $PM_{2.5}$.							

This modification to an existing major PSD stationary source is not major because the emissions increase of each PSD regulated pollutant is less than the PSD significant level. Therefore, pursuant to 326 IAC 2-2, the PSD requirements do not apply.

Project 3

	Project Emissions (ton/year)						
Process / Emission Unit	**PM**	**PM_{10}**	**$PM_{2.5}$[1]**	**SO_2**	**NO_X**	**VOC**	**CO**
East Plant Engine	0.11	0.11	0.11	0.10	1.56	0.13	0.34
Total for Modification	0.11	0.11	0.11	0.10	1.56	0.13	0.34
PSD Significant Levels	25	15	10	40	40	40	100
[1]$PM_{2.5}$ listed is direct $PM_{2.5}$.							

This modification to an existing major PSD stationary source is not major because the emissions increase of each PSD regulated pollutant is less than the PSD significant level. Therefore, pursuant to 326 IAC 2-2, the PSD requirements do not apply.

Project 4

	Project Emissions (ton/year)						
Process / Emission Unit	**PM**	**PM_{10}**	**$PM_{2.5}$[1]**	**SO_2**	**NO_X**	**VOC**	**CO**
Sacred Heart Basilica Engines	0.07	0.07	0.07	0.07	1.04	0.08	0.22
Total for Modification	0.07	0.07	0.07	0.07	1.04	0.08	0.22
PSD Significant Levels	25	15	10	40	40	40	100
[1]$PM_{2.5}$ listed is direct $PM_{2.5}$.							

This modification to an existing major PSD stationary source is not major because the emissions increase of each PSD regulated pollutant is less than the PSD significant level. Therefore, pursuant to 326 IAC 2-2, the PSD requirements do not apply.

Project 5

	Project Emissions (ton/year)						
Process / Emission Unit	**PM**	**PM_{10}**	**$PM_{2.5}$[1]**	**SO_2**	**NO_X**	**VOC**	**CO**
Stepan & Fitzpatrick Engines	0.07	0.07	0.07	4.58E-05	4.29	0.15	0.39
Total for Modification	0.07	0.07	0.07	4.58E-05	4.29	0.15	0.39
PSD Significant Levels	25	15	10	40	40	40	100
[1]$PM_{2.5}$ listed is direct $PM_{2.5}$.							

This modification to an existing major PSD stationary source is not major because the emissions increase of each PSD regulated pollutant is less than the PSD significant level. Therefore, pursuant to 326 IAC 2-2, the PSD requirements do not apply.

Actual Emissions

The following table shows the actual emissions as reported by the source. This information reflects the Year 2017 OAQ emission data.

Actual Emissions (tons/year)							
PM_{10}	**$PM_{2.5}$**	**SO_2**	**NO_X**	**VOC**	**CO**	**Lead (Pb)***	**Ammonia (NH_3)**
3	3	310	260	7	116	0.06	1
*Lead and lead compounds, including any unique chemical substance that contains lead.							

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 renewal, and only to the extent that the effect of the control equipment is made practically enforceable in the permit.

	Potential To Emit of the Entire Source After Issuance of Renewal (tons/year)								
	PM[1]	**PM_{10}[1]**	**$PM_{2.5}$[1, 2]**	**SO_2**	**NOx**	**VOC**	**CO**	**Single HAP[3] (Hexane)**	**Total HAPs**
Total PTE of Entire Source Excluding Fugitive Emissions*	90.76	101.37	84.77	1,798.5	1,355.3	59.72	797.44	9.65	12.83
Title V Major Source Thresholds	NA	100	100	100	100	100	100	10	25
PSD Major Source Thresholds	250	250	250	250	250	250	250	NA	NA

[1]Under the Part 70 Permit program (40 CFR 70), PM_{10} and $PM_{2.5}$, not particulate matter (PM), are each considered as a "regulated air pollutant."
[2]$PM_{2.5}$ listed is direct $PM_{2.5}$.
[3]Single highest source-wide HAP.
*Fugitive HAP emissions are always included in the source-wide emissions.

Appendix A of this TSD reflects the detailed potential to emit of the entire source after issuance.

(a) This existing source is a major stationary source, under PSD (326 IAC 2-2), because PSD regulated pollutants SO_2, NOx, and CO, are emitted at a rate of 250 tons per year or more, and it is not one of the twenty-eight (28) listed source categories, as specified in 326 IAC 2-2-1(ff)(1).

(b) This source is not a major source of HAP, as defined in 40 CFR 63.2, because HAP emissions are less than ten (10) tons per year for any single HAP and less than twenty-five (25) tons per year of a combination of HAPs. Therefore, this source is an area source under Section 112 of the Clean Air Act (CAA).

Federal Rule Applicability

Federal rule applicability for this source has been reviewed as follows:

New Source Performance Standards (NSPS):

(a) The requirements of the New Source Performance Standard for Industrial-commercial-Institutional Steam Generating Units, 40 CFR Part 60, Subpart Db and 326 IAC 12, are not included in the permit for Boilers B-1, B-4, and B-5, because, although these boilers have a maximum ratings of more than 100 MMBtu per hour, they were constructed prior to June 19, 1984.

(b) Boiler B-6 is subject to the New Source Performance Standards for Industrial-commercial-Institutional Steam Generating Unit, 40 CFR Part 60, Subpart Db and 326 IAC 12, because it has maximum heat input rating of more than 100 MMBtu and less than 250 MMBtu per hour; and it was constructed after June 19, 1984. The emission unit subject to this rule includes the following:

One (1) natural gas fired boiler, identified as B-6, constructed in 2006, with a maximum design capacity of 249 MMBtu per hour heat input, equipped with a low NOx burner and flue gas recirculation (FGR), using No. 2 fuel oil as a backup fuel, using no controls and exhausting to stack S-9, monitored by certified COM and NOx CEM.

Boiler 6 is subject to the following portions of Subpart Db.

(1) 40 CFR 60.40b
(2) 40 CFR 60.41b
(3) 40 CFR 60.42b (j)
(4) 40 CFR 60.42b (k)(2)
(5) 40 CFR 60.43b (h) (5)
(6) 40 CFR 60.44b(l)(1), (h), (i)
(7) 40 CFR 60.45b (j)
(8) 40 CFR 60.46b (a), (c), (e), (e)(1), (i)
(9) 40 CFR 60.47b(f)
(10) 40 CFR 60.48b (b), (c)-(e),(e)(2), (e)(3), (f), (g), (j)
(11) 40 CFR 60.49b (a), (a) (1), (a)(3), (b), (d), (g), (h), (i). (o), (r), (r)(1), (v), (w)

The requirements of 40 CFR Part 60, Subpart A - General Provisions, which are incorporated as 326 IAC 12-1, apply to the Boiler 6 except as otherwise specified in 40 CFR 60, Subpart Db.

(c) The requirements of the New Source Performance Standard for Small Industrial-Commercial-Institutional Steam Generating Units, 40 CFR Part 60, Subpart Dc and 326 IAC 12, are not included in the permit for Boilers B2 and B3, because although these boilers have maximum ratings of more than 10 and less than 100 MMBtu per hour, they were constructed prior to June 9, 1989.

(d) The requirements of the New Source Performance Standard for Storage Vessels for Petroleum Liquids for Which Construction, Reconstruction, or Modification Commenced After June 11, 1973, and Prior to May 19, 1978, 40 CFR Part 60, Subpart K and 326 IAC 12, are not included in the permit for four (4) 50,000 gallon underground storage tanks, because they have capacities greater than 151,416 liters (40,000 gallons), but not exceeding 246,052 liters (65,000 gallons), and commenced construction before March 8, 1974.

(e) The requirements of the New Source Performance Standard for Storage Vessels for Petroleum Liquids for Which Construction, Reconstruction, or Modification Commenced After May 18, 1978, and Prior to July 23, 1984, 40 CFR Part 60, Subpart Ka and 326 IAC 12, are not included in the permit for four (4) 50,000 gallon underground storage tanks, because they commenced construction before May 18, 1978.

(f) The requirements of the New Source Performance Standard 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 and 326 IAC 12, are not included in the permit for the four (4) 50,000 gallon underground storage tanks, because these storage tanks were constructed in 1973.

(g) The requirements of the New Source Performance Standard 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 and 326 IAC 12, are not included in the permit for the six (6) 20,000 gallon tanks, and one (1) 30,000 gallon underground storage tank, UST, storing fuel oil and diesel oil, respectively, because they have capacities greater than or equal to 75 m^3 but less than 151 m^3 storing a liquid with a maximum true vapor pressure less than 15.0 kPa

(h) The requirements of the New Source Performance Standard 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 and 326 IAC 12, are not included in the permit for the two (2) above-ground fuel oil storage tanks, AST-1 and AST-2. Pursuant to 40 CFR 60.110(b), the storage tanks, AST-1 and AST-2, are not subject to the requirements of the rule because the capacity of each tank is greater than 75 cubic meters and the fuel oil has a maximum true vapor pressure less than 3.5 kPa.

(i) The requirements of the New Source Performance Standard 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 and 326 IAC 12, are not included in the permit for the five (5) 300-gallon diesel fuel day tanks and 10,500 gallon petroleum fuel tank. Pursuant to 40 CFR 60.110(b), the five (5) 300-gallon diesel fuel day tanks and 10,500 petroleum storage tank, are not subject to the requirements of the rule because the capacity of each tank is less than 75 cubic meters.

(j) The requirements of the New Source Performance Standard for Stationary Compression Ignition Internal Combustion Engines, 40 CFR Part 60, Subpart IIII and 326 IAC 12, are not included in the permit for diesel generators, G-3, G-4, G-8, G-9 and G-10, because they were constructed prior to July 11, 2005.

(k) Insignificant diesel fired emergency generators are subject to the New Source Performance Standards for Stationary Compression Ignition Internal Combustion Engines, 40 CFR 60, Subpart IIII and 326 IAC 12, because each emergency generator commenced construction after July 11, 2005, and were manufactured after April 1, 2006, and none of the generators is a fire pump engine.

The emergency generators subject to this rule include the following:

Compression Ignition emergency engines, each with a capacity less than or equal to 500 HP, manufactured/modified/ constructed/ reconstructed on or after June 12, 2006.

Location	Generator Rating	Year of Manufacture
MVAP Complex	168	2009
Nanotechnology Research Center	201	2006
Stayer Center	201	2012
Innovation Park Building1	335	2009
Compton Ice Arena	335	2011
Eck Law School	402	2007
Morris Inn	235	2013

Jenkins-Nanovic Hall	385	2016
Sacred Heart Basilica	134	2019

Compression Ignition emergency engines, each with a capacity greater than 500 HP, and not exceeding 1600 HP, manufactured/modified/ constructed/ reconstructed on or after June 12, 2006.

Location	Generator Rating	Year of Manufacture
Well #9	536	2012
Joyce Center	671	2013
Hesburgh Library #1	671	2013
Hesburgh Library #2	671	2013
Galvin Life Sciences	755	2015
Nieuwland	755	2015
Stinson-Remick	1,073	2010
McCourtney Hall	1,220	2016
Stadium 1	1,474	2016
Stadium 2	1,474	2016
Stepan Chemistry	755	2019
Fitzpatrick	755	2019

These emission units are subject to the following portions of Subpart IIII:

(1) 40 CFR 60.4200(a)(2), (a)(2)(i), (a)(3), (a)(4)
(2) 40 CFR 60.4205(b), (d)(2)(i)
(3) 40 CFR 60.4206
(4) 40 CFR 60.4207(a), (b)
(5) 40 CFR 60.4209(a)
(6) 40 CFR 60.4211(a)(1-3), (c), (d)(1), (d)(2)(i-v), (f)(1), (f)(2)(i), (g)(2-~~3)~~
(7) 40 CFR 60.4212
(8) 40 CFR 60.4213
(9) 40 CFR 60.4214(b)
(10) 40 CFR 60.4218
(11) 40 CFR 60.4219
(12) 40 CFR 60, Table 8

The requirements of 40 CFR Part 60, Subpart A - General Provisions, which are incorporated as 326 IAC 12-1, apply to the emission units except as otherwise specified in 40 CFR Part 60, Subpart IIII.

Based on this evaluation **or** Based on the existing permit, this source is subject to 40 CFR Part 60, Subpart IIII. On May 4, 2016, the U.S. Court of Appeals for the D.C. Circuit issued a mandate vacating paragraphs 40 CFR 60.4211(f)(2)(ii) - (iii) of NSPS Subpart IIII. Therefore, these paragraphs no longer have any legal effect and any engine that is operated for purposes specified in these paragraphs becomes a non-emergency engine and must comply with all applicable requirements for a non-emergency engine.

For additional information, please refer to the USEPA's Guidance Memo: https://www.epa.gov/sites/production/files/2016-06/documents/ricevacaturguidance041516.pdf

Since the federal rule has not been updated to remove these vacated requirements, the text below shows the vacated language as ~~strikethrough~~ text. At this time, IDEM is not making any changes to the permit's attachment due to this vacatur. However, the permit will not reference the vacated requirements, as applicable.

40 CFR 60.4211(f)(2)
You may operate your emergency stationary ICE for any combination of the purposes specified in paragraph~~s~~ (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~~

~~(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.~~

(l) The ten (10) natural gas-fired emergency generators are not subject to the New Source Performance Standards for Stationary Spark Ignition Internal Combustion Engines, 40 CFR Part 60, Subpart JJJJ and 326 IAC 12, because the natural gas-fired emergency generators (GEN-01) were constructed before June 12, 2006.

(m) The requirements of the New Source Performance Standard for Small Industrial-Commercial-Institutional Steam Generating Units, 40 CFR Part 60, Subpart Dc and 326 IAC 12, are not included in the permit for the duct burners associated with the two (2) natural gas fired combustion turbines (GT-1 and GT-2), because 40 CFR 60.4305(b) exempts the associated duct burners from 40 CFR Part 60, Subpart Dc, when they are subject to 40 CFR 60, Subpart KKKK.

(n) The requirements of the New Source Performance Standard for Stationary Gas Turbines, 40 CFR Part 60, Subpart GG and 326 IAC 12, are not included in the permit for the two (2) natural gas fired combustion turbines (GT-1 and GT-2) and the associated duct burners, because 40 CFR 60.4305(b) exempts the natural gas fired combustion turbines and the associated duct burners from 40 CFR 60, Subpart GG, when they are subject 40 CFR 60, Subpart KKKK.

(o) The two (2) natural gas fired combustion turbines (GT-1 and GT-2) and the associated duct burners are subject to the New Source Performance Standards for Stationary Combustion Turbines 40 CFR Part 60, Subpart KKKK and 326 IAC 12, because the turbines were constructed after February 18, 2005 and have a heat input at peak load greater than 10 MMBtu per hour. The emission units subject to this rule include the following:

(1) Two (2) natural gas-fired combustion turbines, identified as GT-1 and GT-2, each equipped with a heat recovery steam generator (HRSG), were constructed in 2018. Each HRSG is equipped with a natural gas-fired duct burner, and each turbine has a maximum capacity of 6.4 MW (75.4 MMBtu/hr). Each duct burner has a maximum capacity of 87.5

MMBtu/hr. During normal operation, the turbines and duct burners exhaust to a shared main stack.

Note: The heat recovery steam generators are not a source of emissions. They have been included for clarity as they are part of the entire source and operate in conjunction with the duct burners and combustion turbines which are a source of emissions.

The two (2) natural gas fired combustion turbines (GT-1 and GT-2) and the associated duct burners are subject to the following portions of Subpart KKKK.

(1) 40 CFR 60.4300
(2) 40 CFR 60.4305
(3) 40 CFR 60.4315
(4) 40 CFR 60.4320(a)
(5) 40 CFR 60.4330(a)(2)
(6) 40 CFR 60.4333(a)
(7) 40 CFR 60.4340(a)
(8) 40 CFR 60.4365(a)
(9) 40 CFR 60.4375(b)
(10) 40 CFR 60.4395
(11) 40 CFR 60.4400
(12) 40 CFR 60.4420
(13) 40 CFR 60Table 1

The requirements of 40 CFR Part 60, Subpart A - General Provisions, which are incorporated as 326 IAC 12-1, apply to the two (2) natural gas fired combustion turbines (GT-1 and GT-2) and the associated duct burners except as otherwise specified in 40 CFR Part 60, Subpart KKKK.

(p) The requirements of the New Source Performance Standard for Small Industrial-Commercial Institutional Steam Generating Units, 40 CFR Part 60, Subpart Dc and 326 IAC 12, are not included in the permit for two (2) natural gas fired Irish Athletic Center Heaters, and three hundred (300) natural gas fired heaters, since these heaters are not steam generating units.

(q) The requirements of the New Source Performance Standard for Small Industrial-Commercial Institutional Steam Generating Units, 40 CFR Part 60, Subpart Dc and 326 IAC 12, are not included in the permit for the following emission units, since the heat capacity of each emission unit is less than 10 MMBtu/hr.

(1) Propane, LPG, or butane-fired combustion sources with heat input capacities equal to or less than 6.0 MMBtu per hour,

(2) Fuel oil-fired combustion sources with heat input capacities equal to or less than 2.0 MMBtu per hour and firing fuel containing less than 0.5% sulfur by weight, and

(3) Wood-fired combustion sources with heat input capacities equal to or less than 2.0 MMBtu per hour and firing fuel containing less than 0.5% sulfur by weight.

(r) There are no other New Source Performance Standards (40 CFR Part 60) and 326 IAC 12 included in the permit.

National Emission Standards for Hazardous Air Pollutants (NESHAP):

(a) The requirements of the National Emission Standards for Hazardous Air Pollutants (NESHAPs) for Industrial Process Cooling Towers 40 CFR Part 63, Subpart Q and 326 IAC 20 are not included in the permit for the five (5) non-contact, counterflow cooling towers; identified as Cooling Towers 1 through 5; replacement Cooling Towers identified as 6 and 7; and the Cooling

Towers identified as 8 and 9, since these cooling towers are not operated with chromium-based water treatment chemicals.

(b) (1) The three (3) diesel-fired generators, G-8, G-9, and G-10 are subject to the National Emission Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines, 40 CFR Part 63, Subpart ZZZZ, and 326 IAC 20-82, because they are considered existing stationary reciprocating internal combustion engines (RICE) construction commenced before June 12, 2006) at an area source of hazardous air pollutants (HAP). Construction of the three (3) diesel-fired generators, identified as G-8, G-9, and G-10 commended in 2005

The diesel generators G-8, G-9, and G-10 are subject the following applicable portions of the NESHAP for existing non-emergency stationary RICE (construction commenced before June 12, 2006), which has a site rating of greater than 500 brake horsepower at an area source of HAP:

(1) 40 CFR 63.6580
(2) 40 CFR 63.6585
(3) 40 CFR 63.6590(a)(1)(iii) and (iv)
(4) 40 CFR 63.6595 (a)(1), (b), and (c)
(5) 40 CFR 63.6603(a)
(6) 40 CFR 63.6604(a)
(7) 40 CFR 63.6605
(8) 40 CFR 63.6612
(9) 40 CFR 63.6615
(10) 40 CFR 63.6620
(11) 40 CFR 63.6625(g), and (h)
(12) 40 CFR 63.6630(a), (b), and (c)
(13) 40 CFR 63.6635
(14) 40 CFR 63.6640(a), (b), and (e)
(15) 40 CFR 63.6645 (a)(2), (g), and (h)
(16) 40 CFR 63.6650
(17) 40 CFR 63.6655
(18) 40 CFR 63.6660
(19) 40 CFR 63.6665
(20) 40 CFR 63.6670
(21) 40 CFR 63.6675
(22) 40 CFR 63, Table 2b
(23) 40 CFR 63, Table 2d (item 3)
(24) 40 CFR 63, Table 3 (item 4)
(25) 40 CFR 63, Table 4 (items 1 and 3)
(26) 40 CFR 63, Table 5
(27) 40 CFR 63, Table 6 (items 3, 10, and 11)
(28) 40 CFR 63, Table 7 (item 1)
(29) 40 CFR 63, Table 8

The requirements of 40 CFR Part 63, Subpart A - General Provisions, which are incorporated as 326 IAC 20-1, apply to the above emission units except as otherwise specified in 40 CFR Part 63, Subpart ZZZZ.

(2) The following emergency engines are subject to the National Emission Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines, 40 CFR Part 63, Subpart ZZZZ and 326 IAC 20-82, because they are considered new (construction commenced on or after June 12, 2006) stationary reciprocating internal combustion engine (RICE) at an area source of hazardous air pollutants (HAP). The emission units subject to this rule include the following:

(A) The diesel fired compression ignition emergency engines, each with a capacity less than or equal to 500 Hp, manufactured/modified/ constructed/reconstructed on or after June 12, 2006.

Location	Engine Rating	Year of Manufacture
MVAP Complex	168	2009
Nanotechnology Research Ctr.	201	2006
Stayer Center	201	2012
Innovation Park Building 1	335	2009
Compton Ice Arena	335	2011
Eck Law School	402	2007
Morris Inn	235	2013
Jenkins-Nanovic Hall	385	2016
Sacred Heart Basilica	134	2019

(B) Diesel fired compression ignition emergency engines, each with a capacity greater than 500 HP and not exceeding 1600 Hp, manufactured/modified/constructed/ reconstructed on or after June 12, 2006.

Location	Generator Rating	Year of Manufacture
Well #9	536	2012
Joyce Center	671	2013
Hesburgh Library #1	671	2013
Hesburgh Library #2	671	2013
Galvin Life Sciences	755	2015
Nieuwland	755	2015
Stinson-Remick	1,073	2010
McCourtney Hall	1,220	2016
Stadium 1	1,474	2016
Stadium 2	1,474	2016
Stepan Chemistry	755	2019
Fitzpatrick	755	2019

The diesel fired emergency engines are subject the following applicable portions of the NESHAP for new stationary RICE at an area source of HAP:

(1) 40 CFR 63.6580
(2) 40 CFR 63.6585
(3) 40 CFR 63.6590(a)(2)(iii) and (c)(1)
(4) 40 CFR 63.6595(a)(6) and (a)(7)
(5) 40 CFR 63.6665
(6) 40 CFR 63.6670
(7) 40 CFR 63.6675

Pursuant to 40 CFR 63.6665, the diesel fired emergency engines do not have to meet the requirements of 40 CRF Part 63, Subpart A (General Provisions), since they are considered new stationary RICE located at an area source of HAP emissions.

Based on this evaluation **or** Based on the existing permit, this source is subject to 40 CFR Part 63, Subpart ZZZZ. On May 4, 2016, the U.S. Court of Appeals for the D.C. Circuit issued a mandate vacating paragraphs 40 CFR 63.6640(f)(2)(ii) - (iii) of NESHAP Subpart ZZZZ. Therefore, these paragraphs no longer have any legal effect and any engine that is operated for purposes specified in these paragraphs becomes a non-emergency engine and must comply with all applicable requirements for a non-emergency engine.

For additional information, please refer to the USEPA's Guidance Memo: https://www.epa.gov/sites/production/files/2016-06/documents/ricevacaturguidance041516.pdf

Since the federal rule has not been updated to remove these vacated requirements, the text below shows the vacated language as ~~strikethrough~~ text. At this time, IDEM is not making any changes to the permit's attachment due to this vacatur. However, the permit will not reference the vacated requirements, as applicable.

40 CFR 63.6640(f)(2)
You may operate your emergency stationary RICE for any combination of the purposes specified in paragraph~~s~~ (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.~~

(c) The requirements of the National Emission Standards for Hazardous Air Pollutants (NESHAPs) for Stationary Reciprocating Internal Combustion Engines 40 CFR Part 63, Subpart ZZZZ and 326 IAC 20-82 are not included in the permit for the following emergency engines, since, these existing diesel-fired and natural gas fired emergency generators commenced construction before June 12, 2006 at an area source for HAPs and meet the definition of institutional emergency stationary RICE as defined in 40 CFR 63.6675, operate according to the provisions specified in 40 CFR 63.6640(f) and that do not operate for the purpose specified in § 63.6640(f)(4)(ii). Therefore, pursuant to 40 CFR 63.6585(f)(3), the requirements of 40 CFR Part 63, Subpart ZZZZ are not applicable to the following diesel and natural gas fired existing emergency generators.

This source operates under SIC Code 8062 (General Medical and Surgical Hospitals) and North American Industry Classification System (NAICS) Code 622110 (General Medical and Surgical Hospitals). Pursuant to an August 9, 2010, EPA Memorandum entitled "Guidance Regarding Definition of Residential, Commercial, and Institutional Emergency Stationary RICE in the NESHAP for Stationary RICE" (currently located on the internet at: https://www.epa.gov/sites/production/files/2014-03/documents/9_30_2010_guidance_emergency_engine_def.pdf, the operations at this source would fall under the category of "institutional" since this source operates under NAICS Code 622110.

(1) Two (2) diesel-fired emergency generators, identified as G-3 and G-4, constructed in 1953, with maximum design capacity of 13.70 MMBtu per hour heat input, each, and exhausting to stacks S-4 and S-5, respectively.

(2) Insignificant emergency engines consisting of the following:

(A) Diesel fired compression ignition emergency engines, each with a capacity less than or equal to 500 Hp, constructed/reconstructed before June 12, 2006.

Location	Engine Rating	Year of Manufacture
Old Security Building	27	1990
Haggar	20	1990
Loftus Center	20	1987
North Dining Hall	44	1988
Hesburgh Ctr. For Int. Studies	54	1991
Rec Sports	60	1997
Hammes Mowbray	74	2004
Material Storage	80	1990
Bond Hall/Morrissey	80	1997
South Dining Hall	80	1993
Eck Center/Ryan Hall	107	1999
DeBartolo	121	1992
Hanks Aquatics	134	1997
Guigliemino CVA	134	2004
O'Neill/Keough/Welsh McGlinn/Duncan	201	1996
Coleman Morse	201	1999
Performing Arts Center	201	2002
Geddes Hall	268	2005
COBA	469	1995
East Plant	201	2003

(B) Diesel fired compression Emergency engines, each with a capacity greater than 500 Hp and not exceeding 1600 Hp, constructed/reconstructed before December 19, 2002.

Location	Engine Rating	Year of Manufacture
Secondary Chilled Water Pumping Station	536	1996
Malloy Hall	536	2001
Flanner/Grace/Wells 1 & 2	671	1996
ITC	671	2002
Administration Bldg.	671	1997

(C) Diesel fired compression ignition emergency engines, each with a capacity greater than 500 HP and not exceeding 1600 Hp, constructed/reconstructed on or after December 19, 2002 and manufactured/ modified/reconstructed before July 11, 2005.

Location	Engine Rating	Year of Manufacture
Galvin No. 3	805	2005
Jordan Hall of Science	805	2004

(3) Ten existing natural gas fired emergency engines, identified as (GEN-01) with a total combined capacity of 802 HP.

(d) The following boilers are subject to the National Emission Standards for Hazardous Air Pollutants for Industrial, Commercial, and Institutional Boilers Area Sources, 40 CFR Part 63, Subpart JJJJJJ, which is incorporated by reference as 326 IAC 20, because these institutional boilers are existing emission units located within a subcategory, as listed in 40 CFR 63.11200 and defined in 40 CFR 63.11237, located at an area source.

The boilers subject to this rule include the following:

(1) One (1) No. 2 fuel oil or natural gas fired boiler, identified as B-1, constructed in 1961, with a single low NOx burner and economizer constructed in 2006, and with a maximum design capacity of 137 MMBtu per hour heat input, and exhausting to stack S-1.

(2) One (1) natural gas or No. 2 fuel oil fired boiler, identified as B-4, constructed in 1966, and modified in 2018 to remove coal firing capacity, with a maximum design capacity of 234 MMBtu per hour heat input**,** and exhausting to stack S-2.

(3) One (1) No. 2 fuel oil or natural gas fired boiler, identified as B-5, constructed in 1973, with a maximum design capacity of 244.5 MMBtu per hour heat input, equipped with low NOx burner for natural gas and fuel oil, and exhausting to stack S-3.

(4) One (1) natural gas fired boiler, identified as B-6, constructed in 2006, with a maximum design capacity of 249 MMBtu per hour heat input, equipped with a low NOx burner and flue gas recirculation (FGR), using No. 2 fuel oil as a backup fuel, and exhausting to stack S-9, monitored by certified COM and NOx CEM.

The Boilers B-1, B-4, B-5, and B-6 are subject to the following portions of Subpart JJJJJJ:

(1) 40 CFR 63.11193
(2) 40 CFR 63.11194(a), (b)
(3) 40 CFR 63.11200(c)
(4) 40 CFR 63.11201(b), (d)
(5) 40 CFR 63.11205(a)

(6) 40 CFR 63.11210 (c)
(7) 40 CFR 63.11214(b), (c)
(8) 40 CFR 63.11223(a), (b)
(9) 40 CFR 63.11225(a) (2), (b), (c), (d)
(10) 40 CFR 63.11235
(11l) 40 CFR 63.11236
(12) 40 CFR 63.11237
(13) 40 CFR 63, Table 2 (Item 4 and Item 16)
(14) 40 CFR 63, Table 8

The requirements of 40 CFR Part 63, Subpart A - General Provisions, which are incorporated as 326 IAC 20-1, apply to the above emission units except as otherwise specified in 40 CFR Part 63, Subpart JJJJJJ.

Specifically Regulated Insignificant Activities

(1) Space heaters, process heaters, or boilers consisting of the following:

(A) Fuel oil-fired boilers with heat input capacities equal to or less than 2.0 MMBtu per hour and firing fuel containing less than 0.5% sulfur by weight.

[This is an existing affected units under 40 CFR Part 63, Subpart JJJJJJ]

These boilers are subject to the following portions of Subpart JJJJJJ:

(1) 40 CFR 63.11193
(2) 40 CFR 63.11194(a)
(3) 40 CFR 63.11195(e) and (f)
(4) 40 CFR 63.11200(c)
(5) 40 CFR 63.11201(b, and (d)
(6) 40 CFR 63.11205(a)
(7) 40 CFR 63.11210(c), (e), (f), (g)
(8) 40 CFR 63.11214(b)
(9) 40 CFR 63.11220 (b) (3) and (c) (2)
(10) 40 CFR 63.11223 (a), and (b)
(11) 40 CFR 63.11225(a) (2), (b), (c), (d)
(12) 40 CFR 63.11235
(13) 40 CFR 63.11236
(14) 40 CFR 63.11237
(15) 40 CFR 63, Table 2
(16) 40 CFR 63, Table 8

The requirements of 40 CFR Part 63, Subpart A - General Provisions, which are incorporated as 326 IAC 20-1, apply to the above emission units except as otherwise specified in 40 CFR Part 63, Subpart JJJJJJ.

(e) The requirements of the National Emission Standards for Hazardous Air Pollutants (NESHAPs) for Industrial, Commercial, and Institutional Boilers at Area Sources, 40 CFR Part 63, Subpart JJJJJJ, and 326 IAC 12 are not included in the permit for the natural gas fired boilers B-2 and B-3 because they are located at an area source for HAPs and they meet the definition of gas boilers in 40 CFR 63.11237- "Gas-fired boiler includes any boiler that burns gaseous fuels not combined with any solid fuels", which are exempt from this rule as noted in 40 CFR 63.11195.

(f) The requirements of the National Emission Standards for Hazardous Air Pollutants (NESHAPs) for Industrial, Commercial, and Institutional Boilers Area Sources, 40 CFR Part 63, Subpart JJJJJJ, are not included in the permit for two (2) natural gas fired Irish Athletic Center Heaters, and three hundred (300) natural gas fired heaters since none of them is considered a boiler as defined by 40 CFR 63.11237.

(g) The requirements of the National Emission Standards for Hazardous Air Pollutants (NESHAPs) for Industrial, Commercial, and Institutional Boilers Area Sources, 40 CFR Part 63, Subpart JJJJJJ, are not included in the permit for the following boilers since each boiler is considered a gas-fired boiler as defined by 40 CFR 63.11237- "Gas-fired boiler includes any boiler that burns gaseous fuels not combined with any solid fuels", which are exempt from this rule as noted in 40 CFR 63.11195(e).

(1) Propane, LPG, or butane-fired combustion sources with heat input capacities equal to or less than 6.0 MMBtu per hour.

(h) A gasoline fuel transfer dispensing operation is subject to the National Emission Standards for Hazardous Air Pollutants for Gasoline Dispensing Facilities 40 CFR Part 63, Subpart CCCCCC, because hazardous air pollutants (HAP) are emitted from the loading of gasoline storage tanks at gasoline dispensing facilities (GDF) and the source is an area source for HAPs. The emission unit subject to this rule include the following:

(1) A gasoline fuel transfer dispensing operation handling less than or equal to one thousand three hundred (11,300) 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.

[This is an affected unit under 40 CFR Part 63, Subpart CCCCCC.]

This emission unit is subject to the following portions of Subpart CCCCCC:

(1) 40 CFR 63.11110
(2) 40 CFR 63.11111(a), (b), (c), (e), (h), (i), (j)
(3) 40 CFR 63.11112
(4) 40 CFR 63.11113
(5) 40 CFR 63.11115
(6) 40 CFR 63.11116
(7) 40 CFR 63.11117
(8) 40 CFR 63.11124(a)
(9) 40 CFR 63.11125(d)
(10) 40 CFR 63.11126(b)
(11) 40 CFR 63.11130
(12) 40 CFR 63.11131
(13) 40 CFR 63.11132
(14) 40 CFR 63 Table 3

The requirements of 40 CFR Part 63, Subpart A - General Provisions, which are incorporated as 326 IAC 20-1, apply to the unit except as otherwise specified in 40 CFR Part 63, Subpart CCCCCC.

(i) The requirements of the National Emission Standards for Hazardous Air Pollutants for Halogenated Solvent Cleaning, 40 CFR Part 63, Subpart T and 326 IAC 20-6, are not included for the degreaser because the degreaser does not use halogenated solvents.

(j) The requirements of the National Emission Standards for Hazardous Air Pollutants (NESHAPs) for Industrial Process Cooling Towers, 40 CFR Part 63, Subpart Q, and 326 IAC 14 or 326 IAC 20, are not included in the permit for the cooling towers 1 through 7 because these cooling towers do not use chromium-based water treatment chemicals.

(k) No other National Emission Standards for Hazardous Air Pollutants under 40 CFR Part 63, 326 IAC 14 and 326 IAC 20 included in the permit.

Compliance Assurance Monitoring (CAM):

(a) Pursuant to 40 CFR 64.2, Compliance Assurance Monitoring (CAM) is applicable to each existing pollutant-specific emission unit that meets the following criteria:

(1) has a potential to emit before controls equal to or greater than the major source threshold for the regulated pollutant involved;

(2) is subject to an emission limitation or standard for that pollutant (or a surrogate thereof); and

(3) uses a control device, as defined in 40 CFR 64.1, to comply with that emission limitation or standard.

(b) Pursuant to 40 CFR 64.2(b)(1)(i), emission limitations or standards proposed after November 15, 1990 pursuant to a NSPS or NESHAP under Section 111 or 112 of the Clean Air Act are exempt from the requirements of CAM. Therefore, an evaluation was not conducted for any emission limitations or standards proposed after November 15, 1990 pursuant to a NSPS or NESHAP under Section 111 or 112 of the Clean Air Act.

The following table is used to identify the applicability of CAM to each emission unit and each emission limitation or standard for a specified pollutant based on the criteria specified under 40 CFR 64.2:

Emission Unit / Pollutant	Control Device	Applicable Emission Limitation	Uncontrolled PTE (tons/year)	Controlled PTE (tons/year)	CAM Applicable (Y/N)	Large Unit (Y/N)
Grinding and machining operations including deburring, buffing, polishing, abrasive blasting, pneumatic conveying; and woodworking operations controlled with a design grain loading of less than or equal with a design grain loading of less than or equal to 0.03 grains per actual cubic foot and a gas flow rate less than or equal to 4000 actual cubic feet per minute	BH, WS and ESP	326 IAC 6.5	<100	<100	N	N
Under the Part 70 Permit program (40 CFR 70), PM is not a regulated pollutant. Uncontrolled PTE (tpy) and controlled PTE (tpy) are evaluated against the Major Source Threshold for each pollutant. Major Source Threshold for criteria pollutants (PM10, PM2.5, SO2, NOx, VOC, and CO) is 100 tpy, for a single HAP ten (10) tpy, and for total HAPs twenty-five (25) tpy.						
PM* For limitations under 326 IAC 6-3-2, 326 IAC 6.5, and 326 IAC 6.8, IDEM OAQ uses PM as a surrogate for the regulated air pollutant PM10. Therefore, uncontrolled PTE and controlled PTE reflect the emissions of the regulated air pollutant PM10.						
Controls: BH = Baghouse, C = Cyclone, DC = Dust Collection System, RTO = Regenerative or Recuperative Thermal Oxidizer, WS = Wet Scrubber, ESP = Electrostatic Preciptator						
Emission units without air pollution controls are not subject to CAM. Therefore, they are not listed in this table.						

Based on this evaluation, the requirements of 40 CFR Part 64, CAM, are not applicable to any emission unit, since either they do not have potential to emit before controls equal to or greater than the major source threshold for the regulated pollutant involved or use a control device, as defined in 40 CFR 64.1, to comply with that emission limitation or standard.

State Rule Applicability - Entire Source

State rule applicability for this source has been reviewed as follows:

326 IAC 1-6-3 (Preventive Maintenance Plan)
The source is subject to 326 IAC 1-6-3.

326 IAC 2-2 (PSD) and 326 IAC 2-3 (Emission Offset)
PSD and Emission Offset applicability is discussed under the Potential to Emit After Issuance section of this document.

PSD Minor Source Limits

2003 Modification

The Permittee shall comply with the following:

(a) The combined fuel usage from the diesel-fired generator units (G-8, G-9, and G-10) shall be limited to less than 3,076,600 gallons of diesel fuel per twelve (12) consecutive month period, with compliance determined at the end of each month.

(b) The PM_{10} emissions shall not exceed 0.0097 lb. PM_{10}/gallon diesel oil burned.

Compliance with these limits shall limit the potential to emit of PM_{10} (including filterable and condensable) emissions from the diesel-fired generators (G-8, G-9 and G-10), to less than fifteen (15) tons per twelve (12) consecutive month period and shall render the requirements of 326 IAC 2-2 (PSD) not applicable to G8, G9, and G10 permitted under SSM 141-15828-00013.

Emission Offset Minor Source Limit

2005 Modification

Pursuant to 326 IAC 2-3 (Emission Offset), NOx emissions from Boiler B-6, for gas and oil firing combined, shall be less than forty (40) tons per twelve (12) consecutive month period with compliance determined by the continuous emissions monitoring system (CEMS) or other means approved by the department.

When burning natural gas, the Boiler B-6 shall be operated with low NOX burners and a flue gas recirculation rate necessary to achieve a NOX emissions rate of 0.036 lb/MMBtu.

Compliance with this limit shall render 326 IAC 2-3 (Emission Offset) not applicable to the Installation of Boiler B-6.

326 IAC 2-4.1 (Major Sources of Hazardous Air Pollutants (HAP))
The provisions of 326 IAC 2-4.1 apply to any owner or operator who constructs or reconstructs a major source of hazardous air pollutants (HAP), as defined in 40 CFR 63.41, after July 27, 1997, unless the major source has been specifically regulated under or exempted from regulation under a NESHAP that was issued pursuant to Section 112(d), 112(h), or 112(j) of the Clean Air Act (CAA) and incorporated under 40 CFR 63. On and after June 29, 1998, 326 IAC 2-4.1 is intended to implement the requirements of Section 112(g)(2)(B) of the Clean Air Act (CAA).

The operation of Boiler B-6, Diesel generators G8, G9, and G10, Turbines GT-1 and GT-2, and all insignificant emission units, constructed after 1997, each, will emit less than ten (10) tons per year for a single HAP and less than twenty-five (25) tons per year for a combination of HAPs. Therefore, 326 IAC 2-4.1 does not apply.

326 IAC 2-6 (Emission Reporting)
This source, not located in Lake, Porter, or LaPorte County, is subject to 326 IAC 2-6 (Emission Reporting) because it is required to have an operating permit pursuant to 326 IAC 2-7 (Part 70). The potential to emit of VOC and PM10 is less than 250 tons per year; and the potential to emit of CO, NOx, and SO_2 is less than 2,500 tons per year. Therefore, pursuant to 326 IAC 2-6-3(a)(2), triennial reporting is required. An emission statement shall be submitted in accordance with the compliance schedule in 326 IAC 2-6-3 and 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 source is subject to the opacity limitations specified in 326 IAC 5-1-2(A)

326 IAC 6-4 (Fugitive Dust Emissions Limitations)
The source is subject to the requirements of 326 IAC 6-4, because the roads, have the potential to emit fugitive particulate emissions. Pursuant to 326 IAC 6-4 (Fugitive Dust Emissions Limitations), the source shall not allow fugitive dust to escape beyond the property line or boundaries of the property, right-of-way, or easement on which the source is located, in a manner that would violate 326 IAC 6-4.

326 IAC 6-5 (Fugitive Particulate Matter Emission Limitations)
This source is not subject to the requirements of 326 IAC 6-5, because the source has potential fugitive particulate emissions of less than twenty-five (25) tons per year.

326 IAC 6.5 (Particulate Matter Limitations Except Lake County)
This source (located in St. Joseph County) is located in one of the counties listed in 326 IAC 6.5 and it is one of the sources specifically listed in 326 IAC 6.5-16. Therefore, the facilities specifically identified in 326 IAC 6.5-16 are subject to the requirements of 326 IAC 6.5-16. All other facilities not specifically identified in 326 IAC 6.5-16 have a combined PTE of PM of 10 tons per year or more; therefore, the actual emissions of PM from these facilities can exceed 10 tons per year. Therefore, all other facilities not specifically identified in 326 IAC 6.5-16 are subject to the requirements of 326 IAC 6.5-1-2 because these facilities can have a combined actual emission of PM of 10 tons per year or more.

326 IAC 6.8 (Particulate Matter Limitations for Lake County)
Pursuant to 326 IAC 6.8-1-1(a), this source (located in St. Joseph County) is not subject to the requirements of 326 IAC 6.8 because it is not located in Lake County.

326 IAC 6.8 (Lake County: Fugitive Particulate Matter)
Pursuant to 326 IAC 6.8-10-1, this source (located in St. Joseph County) is not subject to the requirements of 326 IAC 6.8-10 because it is not located in Lake County.

State Rule Applicability - Individual Facilities

State rule applicability has been reviewed as follows:

326 IAC 6-2-1 (Particulate Emission Limitations for Sources of Indirect Heating)

(a) Pursuant to 326 IAC 6-2-1(e), the Boilers B-1, B-2, B-3, B-4, and B-5 are not subject to the provisions of 326 IAC 326 IAC 6-2-2, since the Boilers B-1, B-2, B-3, B-4, and B-5 are subject to particulate matter emission limits under 326 IAC 6.5.

(b) Pursuant to 326 IAC 6-2-1(e), the Boiler B-6 is not subject to the provisions of 326 IAC 326 IAC 6-2-4, since the Boiler B-6 is subject to particulate matter emission limit under 326 IAC 6.5.

(c) Pursuant to 326 IAC 6-2-1(e), the two (2) duct burners associated with two (2) natural gas fired combustion turbines are not subject to the provisions of 326 IAC 326 IAC 6-2-4, since the duct burners associated with two (2) natural gas fired combustion turbines are subject to more stringent particulate matter emission limits under 326 IAC 6.5.

326 IAC 6-3 (Particulate Emission Limitations)
Pursuant to the Agreed Order 04-A-J-3402 and 326 IAC 6-3-2, the particulate emission rate for generators G-3 and G-4 shall be determined by the table in 326 IAC 6-3-2(e) or the following equation:

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

326 IAC 6.5 (Particulate Matter Limitations Except Lake County)
Pursuant to 6.5-7-16, the source shall meet the following emission limitations:

Table 1: Emissions Limits - Particulate Matter			
Boiler:	MMBtu/hr	lb/MMBtu	Tons/year
B-1	137	0.087	118.7
B-2 & B-3	96 each	0.28	
B-4	234	0.17	
B-5	244.5	0.02	

326 IAC 6.5 (Particulate Matter Limitations Except Lake County)
This source (located in St. Joseph County) is located in one of the counties listed in 326 IAC 6.5 and it is one of the sources specifically listed in 326 IAC 6.5-7-16. Therefore, the facilities specifically identified in 326 IAC 6.5-7-16 are subject to the requirements of 326 IAC 6.5-7-16. All other facilities not specifically identified in 326 IAC 6.5-7-16 should comply with 6.5-1-2 if the source or facility has a PTE of PM of 100 tons or actual emissions of PM from these facilities can exceed 10 tons per year. Therefore, all other facilities not specifically identified in 326 IAC 6.5-7-16 are subject to the requirements of 326 IAC 6.5-1-2 because these facilities can have a combined actual emissions of PM of 10 tons per year or more.

(a) Pursuant to 326 IAC 6.5-1-2(b)(3), the particulate matter (PM) emissions from the gaseous fuel fired boilers, shall not exceed one-hundredth (0.01) grain per dry standard cubic foot (dscf).

(b) Pursuant to 326 IAC 6.5-1-2(b)(2), the particulate matter (PM) emissions from the No.2 fuel oil fired boilers, shall not exceed 0.15 pound per million Btu).

(c) Pursuant to 326 IAC 6.5-1-2(b)(1)(C), the particulate matter (PM) emissions from the wood fired boilers, shall not exceed six-tenths (0.6) pound per million Btu.

(d) One maintenance shop paint booth is not subject to the requirements of 326 IAC 6.5-1-2(h), because it is not a manufacturing process.

(e) The limitations in 326 IAC 6.5-2 through 326 IAC 6.5-10 of this rule conflict with or are inconsistent with limitations established in 326 IAC 12, then the more stringent limitation shall apply.

There is no PM limit for Boiler B-6 established by New Source Performance Standard for Industrial-Commercial-Institutional Steam Generating Unit, 40 CFR 60.43b(h)(5), Subpart Db and 326 IAC 12. Therefore, the Boiler B-6 is subject to 326 IAC 6.5.

As discussed in the State Rule Applicability - Entire Source, this source is subject to the requirements of 326 IAC 6.5.

Pursuant to 326 IAC 6.5-1-1(b), Boiler B-6 is subject to the provisions of 326 IAC 6.5-1-2.

Pursuant to 326 IAC 6.5-1-2 (b) (2) and (3), the PM emissions from Boiler B-6 shall not exceed 0.15 pounds per MMBtu heat input when combusting No. 2 fuel oil, or 0.01 grains per dry standard cubic foot when combusting natural gas, respectively.

(f) Pursuant to 326 IAC 6.5-1-2(a), particulate matter emissions from the following emission units shall not exceed 0.03 grain per dry standard cubic foot (gr/dscf).

(1) Three (3) diesel-fired generators, constructed in 2005, identified as G-8, G-9 and G-10, each with a maximum rated capacity of 2,593 brake horsepower, exhausting to stacks S-6, S-7 and S-8, respectively.

(2) Two (2) diesel-fired emergency generators constructed in 1953, identified as G-3 and G-4, with maximum design ratings of 13.70 MMBtu per hour heat input each, exhausting to stacks S-4 and S-5, respectively.

(3) The two (2) duct burners associated with the turbines, GT-1, and GT-2,

(4) The following equipment not resulting in the emission of HAPs: brazing equipment, cutting torches, soldering equipment, welding equipment.

(5) Grinding and machining operations controlled with fabric filters, scrubbers, mist collectors, wet collectors and electrostatic precipitators with a design grain loading of less than or equal to 0.03 grains per actual cubic foot and a gas flow rate less than or equal to 4000 actual cubic feet per minute, including the following: deburring, buffing, polishing, abrasive blasting, pneumatic conveying; and woodworking operations.

(6) Space heaters, process heaters, or boilers consisting of the following:

(i) Natural gas-fired combustion sources with heat input capacities equal to or less than 10.0 MMBtu per hour.

(A) Two (2) indirect natural gas fired heaters, identified as Irish Athletic Center Heaters, constructed in 2018 and 2019, with maximum capacity of 2.4 MMBtu, each.

(B) Three hundred (300) indirect natural gas fired heaters,constructed prior to 2020 with a maximum capacity of 40,000 Btu per hour, each.

(ii) Propane, LPG, or butane-fired combustion sources with heat input capacities equal to or less than 6.0 MMBtu per hour.

(iii) Fuel oil-fired combustion sources with heat input capacities equal to or less than 2.0 MMBtu per hour and firing fuel containing less than 0.5% sulfur by weight.

(iv) Wood-fired combustion sources with heat input capacities equal to or less than 2.0 MMBtu per hour and firing fuel containing less than 0.5% sulfur by weight.

(7) Noncontact cooling tower systems with forced and induced draft cooling tower systems not regulated under a NESHAP.

(i) Five (5) non-contact, counter flow cooling towers; identified as Cooling Towers 1 through 5; each with a maximum water circulation rate of 10,400 gallons/minute; each cooling tower was constructed in 2000 and controlled by drift eliminators.

(ii) Two (2) closed-loop, counter flow cooling towers; identified as Cooling Towers 6 and 7; each with a maximum cooling tower water circulation rate of 10,000 gallons/minute; each constructed in 2016 and controlled by drift eliminators.

(iii) Two (2) closed-loop, counter flow cooling towers; identified as East Chiller Plant Cooling Towers 8 and 9; each with a maximum cooling tower water circulation rate of 5,000 gallons/minute; each constructed in 2016 and controlled by drift eliminators.

(8) Insignificant emergency engines consisting of the following:

(i) Diesel fired compression ignition emergency engines, each with a capacity less than or equal to 500 Hp, constructed/reconstructed before June 12, 2006.

Location	Engine Rating	Year of Manufacture
Old Security Building	27	1990
Haggar	20	1990
Loftus Center	20	1987
North Dining Hall	44	1988
Hesburgh Ctr. For Int. Studies	54	1991
Rec Sports	60	1997
Hammes Mowbray	74	2004
Material Storage	80	1990
Bond Hall/Morrissey	80	1997
South Dining Hall	80	1993
Eck Center/Ryan Hall	107	1999
DeBartolo	121	1992
Hanks Aquatics	134	1997
Guigliemino CVA	134	2004
O'Neill/Keough/Welsh McGlinn/Duncan	201	1996
Coleman Morse	201	1999
Performing Arts Center	201	2002
Geddes Hall	268	2005
COBA	469	1995
East Plant	201	2003

(ii) Diesel fired compression ignition emergency engines, each with a capacity less than or equal to 500 Hp, manufactured/modified/ constructed/reconstructed on or after June 12, 2006.

Location	Engine Rating	Year of Manufacture
MVAP Complex	168	2009
Nanotechnology Research Ctr.	201	2006
Stayer Center	201	2012
Innovation Park Building 1	335	2009
Compton Ice Arena	335	2011
Eck Law School	402	2007
Morris Inn	235	2013
Jenkins-Nanovic Hall	385	2016

Sacred Heart Basilica	134	2019

[These are new affected source under 40 CFR Part 60, Subpart IIII]
[These are new affected source under 40 CFR Part 63, Subpart ZZZZ]

(iii) Diesel fired compression ignition emergency engines, each with a capacity greater than 500 Hp and not exceeding 1600 Hp, constructed/reconstructed before December 19, 2002.

Location	Engine Rating	Year of Manufacture
Secondary Chilled Water Pumping Station	536	1996
Malloy Hall	536	2001
Flanner/Grace/Wells 1 & 2	671	1996
ITC	671	2002
Administration Bldg.	671	1997

(iv) Diesel fired compression ignition emergency engines, each with a capacity greater than 500 HP and not exceeding 1600 Hp, manufactured/modified/constructed/ reconstructed on or after June 12, 2006.

Location	Generator Rating	Year of Manufacture
Well #9	536	2012
Joyce Center	671	2013
Hesburgh Library #1	671	2013
Hesburgh Library #2	671	2013
Galvin Life Sciences	755	2015
Nieuwland	755	2015
Stinson-Remick	1,073	2010
McCourtney Hall	1,220	2016
Stadium 1	1,474	2016
Stadium 2	1,474	2016
Stepan Chemistry	755	2019
Fitzpatrick	755	2019

[These are new affected source under 40 CFR Part 60, Subpart IIII]
[These are new affected source under 40 CFR Part 63, Subpart ZZZZ]

(v) Diesel fired compression ignition emergency engines, each with a capacity greater than 500 HP and not exceeding 1600 Hp, constructed/reconstructed on or after December 19, 2002 and manufactured/ modified/reconstructed before July 11, 2005.

Location	Engine Rating	Year of Manufacture
Galvin No. 3	805	2005
Jordan Hall of Science	805	2004

(vi) Ten existing natural gas fired emergency engines, identified as (GEN-01), with a total combined capacity of 802 HP.

26 IAC 7-1.1 Sulfur Dioxide Emission Limitations

(a) The following emission units are subject to 326 IAC 326 IAC 7-1.1 because each emission unit has potential to emit sulfur dioxide (SO_2) equal to or greater than 25 tons per year or 10 pounds per hour.

Pursuant to 7-1.1-2, the sulfur dioxide emissions from the fuel combustion emissions units shall be limited as follows:

Table 2: Sulfur Dioxide Emission Limitations (lb/MMBtu)	
Unit:	Distillate Oil (No. 2)
B-1	0.5
B-4	0.5
B-5	0.5
B-6	0.5
G-8	0.5
G-9	0.5
G-10	0.5

(b) None of the other emission units are subject to 326 IAC 326 IAC 7-1.1 because each emission unit has potential to emit sulfur dioxide (SO_2) of less than 25 tons per year or 10 pounds per hour.

326 IAC 8-1-6 (VOC Rules: General Reduction Requirements for New Facilities)
The Boilers B-1, B-2, B-3, B-4, B-5, G-3, and G-4 are not subject to the requirements of 326 IAC 8-1-6 because they were constructed before January 1, 1980.

326 IAC 8-1-6 (VOC Rules: General Reduction Requirements for New Facilities)
Boiler B-6 and all other emission units that were constructed after January 1, 1980, they are not subject to the requirements of 326 IAC 8-1-6, because their unlimited VOC potential emissions are less than twenty-five (25) tons per year.

326 IAC 8-3-2 (Cold Cleaner Degreaser Control Equipment and Operating Requirements)
The cold degreaser constructed before July1, 1990 and located in St. Joseph County, uses a VOC containing solvent. Therefore, the degreaser is subject to the requirements of 326 IAC 8-3-2.

326 IAC 8-3-8 (Material Requirements for Cold Cleaner Degreasers
The degreaser uses VOC-containing solvent, which is not used to clean electronic components. Therefore, the degreaser is subject to the requirements of 326 IAC 8-3-8.

326 IAC 9-1 (Carbon Monoxide Emission Limits)
The requirements of 326 IAC 9-1 do not apply to any emission unit, because this source does not operate a catalyst regeneration petroleum cracking system or a petroleum fluid coker, grey iron cupola, blast furnace, basic oxygen steel furnace, or other ferrous metal smelting equipment.

326 IAC 10-3 (Nitrogen Oxide Reduction Program for Specific Source Categories)
The requirements of 326 IAC 10-3 do not apply to any emission unit, since this unit is not a blast furnace gas-fired boiler, a Portland cement kiln, or a facility specifically listed under 326 IAC 10-3-1(a)(2).

Compliance Determination and Monitoring Requirements

Permits issued under 326 IAC 2-72-8 are required to assure 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 2-7-52-8-4. 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.

(a) The Compliance Determination Requirements applicable to this source are as follows:

Testing Requirements:

There are no testing conditions included in this permit.

(b) The Compliance Monitoring Requirements applicable to this source are as follows:

Control Device	Type of Parametric Monitoring	Frequency	Range or Specification
B-1, B-4 & B-5	Visible Emissions (when combusting fuel oil only)	Once per Day	Normal/Abnormal
B-6 (COMS)	Opacity	Continuous	<20%
B-6 (CEMS)	NOx	Continuous	< 40 tpy
G8, G9, and G10	Visible Emissions	Once per Day	Normal/Abnormal

Visible Emissions (when combusting fuel oil only) for Boilers identified as B-1, B-4, and B-5, are necessary because the Boilers B-1, B-4, and B-5 must operate properly to assure compliance with 326 IAC 5-1-2-2, Opacity Limitations.

Opacity monitoring for Boiler, identified as B-6, is necessary because Boiler B-6 must operate properly to assure compliance with 326 IAC 5-1-2-2, Opacity Limitations. Opacity monitoring is also required by 40 CFR Part 60, Subpart Db.

NOx monitoring for Boiler, identified as B-6, is necessary because the Boiler B-6 must operate properly to assure compliance with 326 IAC 2-3 (Emission Offset). NOx monitoring is also required by 40 CFR Part 60, Subpart Db.

Visible Emissions for Generators, identified as G8, G9, and G10 are necessary because the Generators, G8, G9, and G10 must operate properly to assure compliance with 326 IAC 5-1-2-2, Opacity Limitations.

Proposed Changes

As part of this permit approval, the permit may contain new or different permit conditions and some conditions from previously issued permits/approvals may have been corrected, changed, or removed. These corrections, changes, and removals may include Title I changes.

The following changes were made to conditions contained previously issued permits/approvals (these changes may include Title I changes):

(1) Removed PM testing requirements for Boilers B-2 and B-3, as they have ceased burning coal since November 1, 2019.

(2) All conditions related to coal combustion for Boilers B-2 and B3; and associated coal handling, coal conveyors, coal piles and silos have been removed.

The boilers B-2 and B-3, each rated at less than 100 MMBtu/hr, are not required to install and operate COMS, because the rule 326 IAC 3-5-1 is only applicable to boilers rated at 100 MMBtu/hr or more.

Although boiler B-4 is rated at 234 MMBtu/hr, pursuant to 326 IAC 3-5-1(b)(2)(ii), emission units combusting oil or a mix of gas and oil, are exempt from the requirement to install a COM, provided that the unit is able to demonstrate compliance with 326 IAC 5-1 without a control device. In addition, per Administrative Amendment 141-40444-00013, issued on December 19, 2018, B-4 no longer requires controls.

(3) The 40 CFR 60, Subpart Db applicable requirements for boiler B-6, have been corrected in Section E.1.2. There is no limit for PM in the rule but there is 0.3% sulfur limit for fuel oil. Therefore, Condition E.1.2 was modified to reflect the correct provisions of 40 CFR Part 60, Subpart Db that are applicable to the source.

(4) Reporting form for NOx emissions from Boiler B-6 has been included to report PSD minor limit in Condition D.6.8. The reporting form was inadvertently not included in the permit.

(5) Reporting form for average sulfur content of 0.5% for No 2-fuel oil has been removed for G8, G9, and G10 as there is no requirement to include reporting form for sulfur content. The source is required to keep records of fuel oil sulfur content.

(6) The emission reporting has changed from annually to triennially due to lower emissions from the Boilers B-2, B-3, and B-4.

(7) The PM emission limits in Condition D.9 for the two duct burners associated with two turbines GT-1 and GT-2 were corrected, since incorrect rule 326 IAC 6-2-4, was applied in the permit. The correct rule is 326 IAC 6.5.

(8) With the removal of coal combusting equipment, the source has become an area source for HAPs.

(9) The diesel fired non-emergency generators and all new emergency generators were reviewed for area source requirements of the National Emission Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines,40 CFR Part 63, Subpart ZZZZ and 326 IAC 20.

(10) The requirements of the National Emission Standards for Hazardous Air Pollutants for Major Sources: Industrial, Commercial, and Institutional Boilers and Process Heaters, 40 CFR Part 63, Subpart DDDDD were removed from the permit for boiler B-1, boiler B-4, boiler B-5, and boiler B-6 because the boilers are now subject to the National Emission Standards for Hazardous Air Pollutants for Industrial, Commercial, and Institutional Boilers Area Sources, 40 CFR Part 63, Subpart JJJJJJ and 326 IAC 20.

(11) The requirements of the National Emission Standards for Hazardous Air Pollutants for Major Sources: Industrial, Commercial, and Institutional Boilers and Process Heaters, 40 CFR Part 63, Subpart DDDDD were removed from the permit for natural gas fired boiler B-2, and boiler B-3 because the source is now an area source for HAPs and pursuant to 40 CFR 63.11195 (e), the natural gas fired boilers are exempt from the National Emission Standards for Hazardous Air Pollutants for Industrial, Commercial, and Institutional Boilers Area Sources, 40 CFR Part 63, Subpart JJJJJJ and 326 IAC 20.

(12) The requirements of the National Emission Standards for Hazardous Air Pollutants for Stationary Combustion Turbines, 40 CFR Part 63, Subpart YYYY, and 326 IAC 20 were removed from the permit for the two natural gas-fired combustion turbines, GT-1 and GT-2 because the source is

now an area source for HAPs and there are no other NESHAP applicable for the combustion turbines.

(13) The gasoline fuel transfer dispensing operation is now subject to National Emission Standards for Hazardous Air Pollutants for Gasoline Dispensing Facilities 40 CFR Part 63, Subpart CCCCCC because the source is now an area source for HAPs.

(14) All existing emergency engines are now exempt from the requirements of the National Emission Standards for Hazardous Air Pollutants of National Emissions Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines,40 CFR Part 63, Subpart ZZZZ and 326 IAC 20, because these existing diesel-fired and natural gas fired emergency generators commenced construction before June 12, 2006 at an area source for HAPs and meet the definition of institutional emergency stationary RICE as defined in 40 CFR 63.6675, operate according to the provisions specified in 40 CFR 63.6640(f) and that do not operate for the purpose specified in § 63.6640(f)(4)(ii), which are exempted by 40 CFR 63.6585(f)(3).

Conclusion and Recommendation

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 March 19, 2019. Additional information was received on September 25, 2019, February 24, 2020, May 21, 2020, June 29, 2021, and September 11, 2020.

The operation of the University shall be subject to the conditions of the attached proposed Part 70 Operating Permit Renewal No. 141-41227-00013.

The staff recommends to the Commissioner that the Part 70 Operating Permit Renewal be approved.

IDEM Contact

(a) If you have any questions regarding this permit, please contact Tripurari Sinha, Ph. D., Indiana Department Environmental Management, Office of Air Quality, Permits Branch, 100 North Senate Avenue, MC 61-53 IGCN 1003, Indianapolis, Indiana 46204-2251, or by telephone at (317) 234-4907 or (800) 451-6027, and ask for Tripurari Sinha, Ph. D., or (317) 234-4907.

(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 Air Permits page on the Internet at: http://www.in.gov/idem/airquality/2356.htm; and the Citizens' Guide to IDEM on the Internet at: http://www.in.gov/idem/6900.htm.

Appendix A: Emissions Calculations
Summary

Company Name: University of Notre Dame du Lac
Address City IN Zip: 100 Facilities Building, Notre Dame, Indiana 46556
TV Renewl No.: 141-41227-00013
Reviewer: Tripurari Sinha, Ph. D.

Unrestricted Potential Emissions (tons/year)							
Emission Units	**PM**	**PM_{10}**	**$PM_{2.5}$**	**SO_2**	**NOx**	**VOC**	**CO**
Boiler B-1	8.57	9.86	6.86	304.32	82.36	3.24	49.42
Boiler B-2	0.78	3.13	3.13	0.25	20.61	2.27	34.63
Boiler B-3	0.78	3.13	3.13	0.25	20.61	2.27	34.63
Boiler B-4	14.64	16.84	11.71	519.78	281.35	5.53	84.41
Boiler B-5	15.30	17.59	12.24	543.10	183.58	5.77	88.19
Boiler B-6	15.58	17.92	12.46	331.86	106.92	5.88	321.73
Nested Source Total	55.66	68.47	49.54	1,699.56	695.44	24.95	613.00
GT-1 & GT-2	6.61	6.61	6.61	3.70	50.46	5.83	51.02
HRSG1 & HRSG 2	5.75	5.75	5.75	0.45	61.32	6.88	61.32
Generator G-3 and G-4	0.69	0.39	0.38	3.46	21.92	0.56	5.82
Generator G-8, G-9 and G-10	11.43	11.43	11.43	137.82	491.96	15.24	40.08
Diesel Gen<600	3.51	3.51	3.51	3.27	49.48	4.01	10.66
Diesel Gen>600	0.61	0.61	0.61	0.00	39.43	1.38	3.60
Emergency Natural Gas Generators	0.06	0.08	0.08	0.00	5.00	0.19	5.87
Above-Ground Diesel Fuel Storage Tanks, AST-1 and AST-2	0.00	0.00	0.00	0.00	0.00	0.28	0.00
Replacement Cooling Towers 6 and 7	2.81	2.81	2.81	0.00	0.00	0.00	0.00
Cooling Towers 8 and 9 for Remote Chiller Plant	3.51	3.51	3.51	0.00	0.00	0.00	0.00
Irish Athletic heaters	0.04	0.16	0.16	0.01	2.06	0.11	1.73
300 Heaters	0.10	0.39	0.39	0.03	5.15	0.28	4.33
Primary Source	**90.76**	**103.71**	**84.77**	**1,848.30**	**1,422.24**	**59.72**	**797.44**

Source Potential to Emit after Issuance (tons/year)							
Emission Units	**PM**	**PM_{10}**	**$PM_{2.5}$**	**SO_2**	**NOx**	**VOC**	**CO**
Boiler B-1	8.57	9.86	6.86	304.32	82.36	3.24	49.42
Boiler B-2	0.78	3.13	3.13	0.25	20.61	2.27	34.63
Boiler B-3	0.78	3.13	3.13	0.25	20.61	2.27	34.63
Boiler B-4	14.64	16.84	11.71	519.78	281.35	5.53	84.41
Boiler B-5	15.30	17.59	12.24	543.10	183.58	5.77	88.19
Boiler B-6	15.58	15.58	12.46	331.86	39.99	5.88	321.73
Nested Source Total	55.66	66.14	49.54	1,699.56	628.51	24.95	613.00
GT-1 & GT-2	6.61	6.61	6.61	3.70	50.46	5.83	51.02
HRSG1 and HRSG2	5.75	5.75	5.75	0.45	61.32	6.88	61.32
Generators G-3 and G-4	0.69	0.39	0.38	3.46	21.92	0.56	5.82
Generator G-8, G-9 and G-10	11.43	11.43	11.43	88.04	491.96	15.24	40.08
Diesel Gen < 600 HP	3.51	3.51	3.51	3.27	49.48	4.01	10.66
Diesel Gen > 600 HP	0.61	0.61	0.61	0.00	39.43	1.38	3.60
Emergency Natural Gas Generators	0.06	0.08	0.08	0.00	5.00	0.19	5.87
Above-Ground Diesel Fuel Storage Tanks, AST-1 and AST-2	0.00	0.00	0.00	0.00	0.00	0.28	0.00
Replacement Cooling Towers 6 and 7	2.81	2.81	2.81	0.00	0.00	0.00	0.00
Cooling Towers 8 and 9 for Remote Chiller Plant	3.51	3.51	3.51	0.00	0.00	0.00	0.00
Irish Athletic heaters	0.04	0.16	0.16	0.01	2.06	0.11	1.73
300 Heaters	0.10	0.39	0.39	0.03	5.15	0.28	4.33
Primary Source	**90.76**	**101.37**	**84.77**	**1,798.52**	**1,355.31**	**59.72**	**797.44**

Boiler 6 has an emission Offset limit of Nox less than 40 tons per year,
Boiler 6 has an PSD limit of PM10 of 15.58 tons per year,
Boiler 6 has an PSD limit of CO of 321.73 tons per year,
Generators G8, G9, and G10 has SO2 limit of 88.04 tons per year.
Generators G8, G9, and G10 has PSD PM10 limit of 14.92 tons per year.

Appendix A: Emissions Calculations

HAP Summary of Emissions

Company Name: University of Notre Dame du Lac
Source Address 100 Facilities Building, Notre Dame, Indiana 46556
Permt Number 141-41227-00013
Reviewer: Tripurari Sinha, Ph. D.

Uncontrolled HAPs Emissions

Activity ID	Benzene	Formal-dehyde	Hexane	Lead	Total HAPs
Boiler B-1	0.001	0.044	1.06	0.00	1.11
Boiler B-2	0.001	0.031	0.74	0.00	0.78
Boiler B-3	0.001	0.031	0.74	0.00	0.78
Boiler B-4	0.002	0.075	1.81	0.00	1.90
Boiler B-5	0.002	0.079	1.89	0.00	1.98
Boiler B-6	0.002	0.080	1.92	0.00	2.02
GT-1 & GT-2 NG Turbines	0.000	1.902	0.00	-	2.11
HRSG1 &HRSG 2	-	-	1.35	0.00	1.42
Nested Source Total	0.010	2.243	9.52	0.00	12.09
Generator G-3 and G-4	0.005	0.001	-	-	0.01
Generator G-8, G-9 and G-10	0.185	0.019	-	-	0.38
Emergency Gen <600 HP	**0.010**	0.013			0.04
Emergency Generator > 600 HP	**0.019**	0.002			0.04
Emergency Natural Gas Generators	0.003	0.087	0.00	-	0.13
Irish Athletic heaters	0.000	0.002	0.04	0.00	0.04
300 Heaters	0.000	0.004	0.09	0.00	0.10
Degreaser	-	-	-	-	-
Totals	0.23	2.37	**9.65**	0.00	**12.83**

Appendix A: Emissions Calculations
Fuel Combustion > 100 MMBtu/hr
Boiler B-1

Company Name: University of Notre Dame du Lac
Source Address 100 Facilities Building, Notre Dame, Indiana 46556
Permt Number 141-41227-00013
Reviewer: Tripurari Sinha, Ph. D.

Heat Input Capacity	137	MMBtu/hr	Natural gas =	1020	Btu/scf
Potential Throughput	1,177	MMCF/yr			
Potential Throughput	8,572	Kgal/yr		0.5	% Sulfur
Heating Value of Fuel Oil =		140,000	Btu/gal		

Unlimited/Uncontrolled Emissions

	Emission Factor (units)		Unlimited/Uncontrolled Potential to Emit		
Criteria Pollutant	Natural Gas (lb/MMCF)	No. 2 Fuel Oil (lb/kgal)	Natural Gas (tons/yr)	No. 2 Fuel Oil (tons/yr)	**Worse Case Fuel (tons/yr)**
PM	1.9	2.0	1.12	8.57	**8.57**
PM10	7.6	2.3	4.47	9.86	**9.86**
PM2.5	7.6	1.6	4.47	6.86	**6.86**
SO2	0.6	71.0	2.57	304.32	**304.32**
Nox (Low Nox Burner)	140	10.0	82.36	42.86	**82.36**
VOC	5.5	0.20	3.24	0.86	**3.24**
CO	84	5.0	49.42	21.43	**49.42**
Hazardous Air Pollutant					
Arsenic		4.0E-06		1.7E-05	**1.71E-05**
Beryllium		3.0E-06		1.3E-05	**1.29E-05**
Mercury		3.0E-06		1.3E-05	**1.29E-05**
Selenium		1.5E-05		6.4E-05	**6.43E-05**
Manganese	3.8E-04	6.0E-06	2.2E-04	2.6E-05	**2.24E-04**
Lead	5.0E-04	9.0E-06	2.9E-04	3.9E-05	**2.94E-04**
Cadmium	1.1E-03	4.2E-04	6.5E-04	1.8E-03	**1.80E-03**
Chromium	1.4E-03	4.2E-04	8.2E-04	1.8E-03	**1.80E-03**
Nickel	2.1E-03	4.2E-04	1.2E-03	1.8E-03	**1.80E-03**
Benzene	2.1E-03		1.2E-03		**1.24E-03**
Dichlorobenzene	1.2E-03		7.1E-04		**7.06E-04**
Formaldehyde	7.5E-02		4.4E-02		**4.41E-02**
Hexane	1.8E+00		1.1E+00		**1.06E+00**
Toluene	3.4E-03		2.0E-03		**2.00E-03**
		Total HAPs			**1.11**

*PM emission factor is filterable PM only. PM10 emission factor is condensable and filterable PM10 combined.
PM2.5 emission factor is condensable and filterable PM2.5 combined.

Methodology
Natural Gas Usage (MMCF/yr) = [Maximum Fuel Input Rate (MMBtu/hr)] * [8,760 hrs/yr] * [1 MMCF/1,000 MMBtu]
Oil Usage (gal/yr) = [Maximum Fuel Input Rate (MMBtu/hr)] * [8,760 hrs/yr] * [1 gal/0.140 MMBtu]
Potential to Emit (tons/yr) =
Potential to Emit (tons/yr) =
Sources of AP-42 Emission Factors for fuel combustion:
Natural Gas : AP-42 Chapter 1.4 (dated 7/98), Tables 1.4-1, 1.4-2, 1.4-3, and 1.4-4
No. 2 Fuel Oil: AP-42 Chapter 1.3 (dated 5/10), Tables 1.3-1, 1.3-2, 1.3-3, 1.3-8, 1.3-9, 1.3-10, and 1.3-11
Low Nox Burner, Nox = 140 lb/MMBtu

Abbreviations

PM = Particulate Matter	VOC - Volatile Organic Compounds
PM10 = Particulate Matter (<10 um)	CO = Carbon Monoxide
PM2.5 = Particulate Matter (< 2.5 um)	HAP = Hazardous Air Pollutant
SO2 = Sulfur Dioxide	HCl = Hydrogen Chloride
NOx = Nitrous Oxides	PAH = Polyaromatic Hydrocarbon

Hazardous Air Pollutants (HAPs)
Methodology is the same above.
The five highest organic and metal HAPs emission factors are provided above.
Additional HAPs emission factors are available in AP-42, Chapter 1.4 and Chapter 1.3

Appendix A: Emissions Calculations
Natural Gas Combustion Only
MM BTU/HR <100

Boiler B2

Company Name: **University of Notre Dame du Lac**
Source Address: **100 Facilities Building, Notre Dame, Indiana 46556**
Permit Number: **141-41227-00013**
Reviewer: **Tripurari Sinha, Ph. D.**

Heat Input Capacity	96	MMBtu/hr
Potential Throughput	824	MMCF/yr
	1020	Btu/scf

Criteria Pollutant	Emission Factor (units) Natural Gas (lb/MMCF)	ncontrolled Potential to Emit (tons/yr) Natural Gas (tons/yr)
PM	1.9	0.78
PM10	7.6	3.13
PM2.5	7.6	3.13
SO2	0.6	0.25
NOx	50	20.61
VOC	5.5	2.27
CO	84	34.63
Hazardous Air Pollutant		
Chromium	1.4E-03	5.8E-04
Lead	5.0E-04	2.1E-04
Manganese	3.8E-04	1.6E-04
Benzene	2.1E-03	8.7E-04
Dichlorobenzene	1.2E-03	4.9E-04
Formaldehyde	7.5E-02	3.1E-02
Hexane	1.8E+00	7.4E-01
Toluene	3.4E-03	1.4E-03
Cadmium	1.1E-03	4.5E-04
Nickel	2.1E-03	8.7E-04
Total HAPs		**0.78**

*PM emission factor is filterable PM only. PM10 emission factor is filterable and condensable PM10 combined.
PM2.5 emission factor is filterable and condensable PM2.5 combined.
**Emission Factors for NOx: Uncontrolled = 100, Low NOx Burner = 50, Low NOx Burners/Flue gas recirculation = 32

Methodology:
All emission factors are based on normal firing.
MMBtu = 1,000,000 Btu
MMCF = 1,000,000 Cubic Feet of Gas
Emission Factors are from AP 42, Chapter 1.4, Tables 1.4-1, 1.4-2, 1.4-3, SCC #1-02-006-02, 1-01-006-02, 1-03-006-02, and 1-03-006-03
Potential Throughput (MMCF) = Heat Input Capacity (MMBtu/hr) x 8,760 hrs/yr x 1 MMCF/1,020 MMBtu
Emission (tons/yr) = Throughput (MMCF/yr) x Emission Factor (lb/MMCF)/2,000 lb/ton
Low Nox Burner
The boilers B-2 and B-3 share the same stack, S1

Abbreviations
PM = Particulate Matter
PM10 = Particulate Matter (<10 um)
PM2.5 = Particulate Matter (< 2.5 um)
SO2 = Sulfur Dioxide
NOx = Nitrous Oxides

Hazardous Air Pollutants (HAPs)
Methodology is the same above.
The five highest organic and metal HAPs emission factors are provided above.
Additional HAPs emission factors are available in AP-42, Chapter 1.4.

Appendix A: Emissions Calculations
Combustion with Capacity < 100 MMBtu/hr
Boiler B-3

Company Name: University of Notre Dame du Lac
Source Address 100 Facilities Building, Notre Dame, Indiana 46556
Permt Number 141-41227-00013
Reviewer: Tripurari Sinha, Ph. D.

Heat Input Capacity	96	MMBtu/hr
Potential Throughput	824	MMCF/yr
	1020	Btu/scf

Criteria Pollutant	Emission Factor (units) Natural Gas (lb/MMCF)	Unlimited/Uncontrolled Potential to Emit (tons/yr) Natural Gas (tons/yr)
PM	1.9	0.78
PM10	7.6	3.13
PM2.5	7.6	3.13
SO2	0.6	0.25
NOx	50	20.61
VOC	5.5	2.27
CO	84	34.63
Hazardous Air Pollutant		
Chromium	1.4E-03	5.8E-04
Lead	5.0E-04	2.1E-04
Manganese	3.8E-04	1.6E-04
Benzene	2.1E-03	8.7E-04
Dichlorobenzene	1.2E-03	4.9E-04
Formaldehyde	7.5E-02	3.1E-02
Hexane	1.8E+00	7.4E-01
Toluene	3.4E-03	1.4E-03
Cadmium	1.1E-03	4.5E-04
Nickel	2.1E-03	8.7E-04
Total HAPs		**0.78**

Methodology:
*PM emission factor is filterable PM only. PM10 emission factor is filterable and condensable PM10 combined.
PM2.5 emission factor is filterable and condensable PM2.5 combined.
**Emission Factors for NOx: Uncontrolled = 100, Low NOx Burner = 50, Low NOx Burners/Flue gas recirculation = 32
Low Nox Burner
Methodology
All emission factors are based on normal firing.
MMBtu = 1,000,000 Btu
MMCF = 1,000,000 Cubic Feet of Gas
Emission Factors are from AP 42, Chapter 1.4, Tables 1.4-1, 1.4-2, 1.4-3, SCC #1-02-006-02, 1-01-006-02, 1-03-006-02, and 1-03-006-03
Potential Throughput (MMCF) = Heat Input Capacity (MMBtu/hr) x 8,760 hrs/yr x 1 MMCF/1,020 MMBtu
Emission (tons/yr) = Throughput (MMCF/yr) x Emission Factor (lb/MMCF)/2,000 lb/ton

Hazardous Air Pollutants (HAPs)
Methodology is the same above.
The five highest organic and metal HAPs emission factors are provided above.
Additional HAPs emission factors are available in AP-42, Chapter 1.4 and Chapter 1.1,and Table 1.1 -19 (dated 9/98).

Appendix A: Emissions Calculations
Fuel Combustion > 100 MMBtu/hr
Boiler B-4

Company Name: University of Notre Dame du Lac
Source Address 100 Facilities Building, Notre Dame, Indiana 46556
Permt Number 141-41227-00013
Reviewer: Tripurari Sinha, Ph. D.

Heat Input Capacity	MMBtu/hr	**234**			
Potential Throughput	MMCF/yr	2010	Natural gas =	1020	Btu/scf
Potential Throughput	kgal/yr	14642		140000	Btu/gal
				0.50	% sulfur (Fuel oil)

	Emission Factor (units)		Unlimited/Uncontrolled Potential to Emit		
Criteria Pollutant	Natural Gas (lb/MMCF)	No. 2 Fuel Oil (lb/kgal)	Natural Gas (tons/yr)	No. 2 Fuel Oil (tons/yr)	**Worse Case Fuel (tons/yr)**
PM	1.9	2.0	1.91	14.64	**14.64**
PM10	7.6	2.3	7.64	16.84	**16.84**
PM2.5	7.6	1.6	7.64	11.71	**11.71**
SO2	0.6	71.0	0.60	519.78	**519.78**
NOx	280	24.0	281.35	175.70	**281.35**
VOC	5.5	0.20	5.53	1.46	**5.53**
CO	84	5.0	84.41	36.60	**84.41**
Hazardous Air Pollutant					
Arsenic		4.0E-06		2.9E-05	**2.9E-05**
Beryllium		3.0E-06		2.2E-05	**2.2E-05**
Mercury		3.0E-06		2.2E-05	**2.2E-05**
Selenium		1.5E-05		1.1E-04	**1.1E-04**
Manganese	3.8E-04	6.0E-06	3.8E-04	4.4E-05	**3.8E-04**
Lead	5.0E-04	9.0E-06	5.0E-04	6.6E-05	**5.0E-04**
Cadmium	1.1E-03	3.0E-06	1.1E-03	2.2E-05	**1.1E-03**
Chromium	1.4E-03	3.0E-06	1.4E-03	2.2E-05	**1.4E-03**
Nickel	2.1E-03	3.0E-06	2.1E-03	2.2E-05	**2.1E-03**
Benzene	2.1E-03		2.1E-03		**2.1E-03**
Dichlorobenzene	1.2E-03		1.2E-03		**1.2E-03**
Formaldehyde	7.5E-02		7.5E-02		**7.5E-02**
Hexane	1.8E+00		1.8E+00		**1.8E+00**
Toluene	3.4E-03		3.4E-03		**3.4E-03**
		Total HAPs			**1.9E+00**

*PM emission factor is filterable PM only. PM10 emission factor is condensable and filterable PM10 combined.
PM2.5 emission factor is condensable and filterable PM2.5 combined.
**Emission Factors for NOx: Uncontrolled = 280 (pre-NSPS) or 190 (post-NSPS), Low NOx Burner = 140, Flue gas recirculation = 100 (See Table 1.4-1)

*PM emission factor is filterable PM only. PM10 emission factor is condensable and filterable PM10 combined.
PM2.5 emission factor is condensable and filterable PM2.5 combined.

Methodology
Natural Gas Usage (MMCF/yr) = [Maximum Fuel Input Rate (MMBtu/hr)] * [8,760 hrs/yr] * [1 MMCF/1,000 MMBtu]
Oil Usage (gal/yr) = [Maximum Fuel Input Rate (MMBtu/hr)] * [8,760 hrs/yr] * [1 gal/0.140 MMBtu]
Natural Gas: Unlimited Potential to Emit (tons/yr) = [Maximum Natural Gas Usage (MMCF/yr)] * [Emission
No. 2 Fuel Oil : Uncontrolled Potential to Emit (tons/yr) = [Maximum Fuel Usage (gals/yr)] * [Emission
Sources of AP-42 Emission Factors for fuel combustion:
Natural Gas : AP-42 Chapter 1.4 (dated 7/98), Tables 1.4-1, 1.4-2, 1.4-3, and 1.4-4
No. 2 Fuel Oil: AP-42 Chapter 1.3 (dated 5/10), Tables 1.3-1, 1.3-2, 1.3-3, 1.3-8, 1.3-9, 1.3-10, and 1.3-11

Abbreviations
PM = Particulate Matter
PM10 = Particulate Matter (<10 um)
PM2.5 = Particulate Matter (< 2.5 um)
SO2 = Sulfur Dioxide
NOx = Nitrous Oxides
VOC - Volatile Organic Compounds
CO = Carbon Monoxide
HAP = Hazardous Air Pollutant
HCl = Hydrogen Chloride
PAH = Polyaromatic Hydrocarbon

Hazardous Air Pollutants (HAPs)
Methodology is the same above.
The five highest organic and metal HAPs emission factors are provided above.
Additional HAPs emission factors are available in AP-42, Chapter 1.4 and Chapter 1.3

Appendix A: Emissions Calculations
Fuel Combustion > 100 MMBtu/hr
Boiler B-5

Company Name: University of Notre Dame du Lac
Source Address: 100 Facilities Building, Notre Dame, Indiana 46556
Permt Number: 141-41227-00013
Reviewer: Tripurari Sinha, Ph. D.

Maximum Capacity

Maximum Fuel Input Rate =	244.5	MMBtu/hr	**Natural Gas =**	1020 lb/scf
Natural Gas Usage =	2,100	MMCF/yr		
No. 2 Fuel Oil Usage =	15,299	Kgal/yr	0.50	% sulfur
		Fuel Oil No. 2 =	140,000	Btu/gal

Unlimited/Uncontrolled Emissions

	Emission Factor (units)		Unlimited/Uncontrolled Potential to Emit			
Criteria Pollutant	Natural Gas (lb/MMCF)	No. 2 Fuel Oil (lb/kgal)	Natural Gas (tons/yr)	No. 2 Fuel Oil (tons/yr)	**Worse Case Fuel (tons/yr)**	SO2 Limited for No. 2 Fuel Oil (ton/yr)
PM	1.9	2.0	1.99	15.30	**15.30**	
PM10	7.6	2.3	7.98	17.59	**17.59**	
PM2.5	7.6	1.6	7.98	12.24	**12.24**	
SO2	0.6	71.0	0.63	543.10	**543.10**	535.455
NOx	140	24.0	146.99	183.58	**183.58**	
VOC	5.5	0.34	5.77	2.60	**5.77**	
CO	84	5.0	88.19	38.25	**88.19**	
Hazardous Air Pollutant						
Arsenic		0.0E+00		0.0E+00	**0.00E+00**	
Beryllium		3.0E-06		2.3E-05	**2.29E-05**	
Mercury		3.0E-06		2.3E-05	**2.29E-05**	
Selenium		1.5E-05		1.1E-04	**1.15E-04**	
Manganese	3.8E-04	6.0E-06	4.0E-04	4.6E-05	**3.99E-04**	
Lead	5.0E-04	9.0E-06	5.2E-04	6.9E-05	**5.25E-04**	
Cadmium	1.1E-03	3.0E-06	1.2E-03	2.3E-05	**1.15E-03**	
Chromium	1.4E-03	3.0E-06	1.5E-03	2.3E-05	**1.47E-03**	
Nickel	2.1E-03	3.0E-06	2.2E-03	2.3E-05	**2.20E-03**	
Benzene	2.1E-03		2.2E-03		**2.20E-03**	
Dichlorobenzene	1.2E-03		1.3E-03		**1.26E-03**	
Formaldehyde	7.5E-02		7.9E-02		**7.87E-02**	
Hexane	1.8E+00		1.9E+00		**1.89E+00**	
Toluene	3.4E-03		3.6E-03		**3.57E-03**	
			Total HAPs		**1.98**	

*PM emission factor is filterable PM only. PM10 emission factor is condensable and filterable PM10 combined.
PM2.5 emission factor is condensable and filterable PM2.5 combined.

Methodology

Natural Gas Usage (MMCF/yr) = [Maximum Fuel Input Rate (MMBtu/hr)] * [8,760 hrs/yr] * [1 MMCF/1,000 MMBtu]
Oil Usage (gal/yr) = [Maximum Fuel Input Rate (MMBtu/hr)] * [8,760 hrs/yr] * [1 gal/0.140 MMBtu]
Natural Gas: Unlimited Potential to Emit (tons/yr) = [Maximum Natural Gas Usage (MMCF/yr)] * [Emission Factor (lb/MMCF)] *
No. 2 Fuel Oil : Uncontrolled Potential to Emit (tons/yr) = [Maximum Fuel Usage (gals/yr)] * [Emission Factor (lb/kgal)] *
Sources of AP-42 Emission Factors for fuel combustion:
Natural Gas : AP-42 Chapter 1.4 (dated 7/98), Tables 1.4-1, 1.4-2, 1.4-3, and 1.4-4
No. 2 Fuel Oil: AP-42 Chapter 1.3 (dated 5/10), Tables 1.3-1, 1.3-2, 1.3-3, 1.3-8, 1.3-9, 1.3-10, and 1.3-11
Low Nox Burner for natural gas and fuel oil no. 2
1 gallon of No. 2 Fuel Oil has a heating value of 140,000 Btu
Potential Throughput (kgals/year) = Heat Input Capacity (MMBtu/hr) x 8,760 hrs/yr x 1kgal per 1000 gallon x 1 gal per 0.140 MMBtu
Emission Factors are from AP 42, Tables 1.3-1, 1.3-2, 1.3-3, and 1.3-6 (SCC 1-02-005-01/02/03) Supplement E 9/98
*PM emission factor is filterable PM only. Condensable PM emission factor is 1.3 lb/kgal.

Hazardous Air Pollutants (HAPs)

Methodology is the same above.
The five highest organic and metal HAPs emission factors are provided above.
Additional HAPs emission factors are available in AP-42, Chapter 1.4 and Chapter 1.3

Appendix A: Emissions Calculations
Fuel Combustion > 100 MMBtu/hr
Boiler B-6

Company Name: University of Notre Dame du Lac
Source Address: 100 Facilities Building, Notre Dame, Indiana 46556
Permt Number: 141-41227-00013
Reviewer: Tripurari Sinha, Ph. D.

Maximum Fuel Input Rate =	249	MMBtu/hr	**Natural Gas =**	1020	Btu/scf
Natural Gas Usage =	2,138	MMCF/yr	Fuel Oil No. 2 =	140000	Btu/gal.
No. 2 Fuel Oil Usage =	15,580	Kgal/yr	0.30	% sulfur	

Unlimited/Uncontrolled Emissions

	Emission Factor (units)		Unlimited/Uncontrolled Potential to Emit		
Criteria Pollutant	Natural Gas (lb/MMCF)	No. 2 Fuel Oil (lb/kgal)	Natural Gas (tons/yr)	No. 2 Fuel Oil (tons/yr)	**Worse Case Fuel (tons/yr)**
PM	1.9	2.0	2.03	15.58	**15.58**
PM10	7.6	2.3	8.13	17.92	**17.92**
PM2.5	7.6	1.6	8.13	12.46	**12.46**
SO2	0.6	42.6	0.64	331.86	**331.86**
NOx	100	10.0	106.92	77.90	**106.92**
VOC	5.5	0.34	5.88	2.65	**5.88**
CO	84	41.3	89.82	321.73	**321.73**
Hazardous Air Pollutant					
Manganese	3.800E-04	6.000E-06	4.063E-04	4.674E-05	**4.06E-04**
Lead	5.000E-04	9.000E-06	5.346E-04	7.011E-05	**5.35E-04**
Cadmium	1.100E-03	3.000E-06	1.176E-03	2.337E-05	**1.18E-03**
Chromium	1.400E-03	3.000E-06	1.497E-03	2.337E-05	**1.50E-03**
Nickel	2.100E-03	3.000E-06	2.245E-03	2.337E-05	**2.25E-03**
Benzene	2.100E-03		2.245E-03		**2.25E-03**
Dichlorobenzene	1.200E-03		1.283E-03		**1.28E-03**
Formaldehyde	7.500E-02		8.019E-02		**8.02E-02**
Hexane	1.800E+00		1.925E+00		**1.92E+00**
Toluene	3.400E-03		3.635E-03		**3.64E-03**
		Total HAPs			**2.018**

*PM emission factor is filterable PM only. PM10 emission factor is condensable and filterable PM10 combined.
PM2.5 emission factor is condensable and filterable PM2.5 combined.

Methodology
Natural Gas Usage (MMCF/yr) = [Maximum Fuel Input Rate (MMBtu/hr)] * [8,760 hrs/yr] * [1 MMCF/1,000 MMBtu]
Oil Usage (gal/yr) = [Maximum Fuel Input Rate (MMBtu/hr)] * [8,760 hrs/yr] * [1 gal/0.140 MMBtu]
Natural Gas: Unlimited Potential to Emit (tons/yr) = [Maximum Natural Gas Usage (MMCF/yr)] * [Emission Factor
Natural Gas AP-42, Chapter 1.4 (dated 7/98), Tables 1.4-1, 1.4-2, 1.4 -3, and 1.4-4.
For fuel oil, the limit from 40 CFR 60.42b (k) (20), the limit is 0.32 lb per MMBtu, which is appox. 0.3%S content.
No. 2 Fuel Oil emission factor for this boiler is established from 40 CFR 60.42b (k) (2) as it is federally enforceable.
1 gallon of No. 2 Fuel Oil has a heating value of 140,000 Btu
Potential Throughput (kgals/year) = Heat Input Capacity (MMBtu/hr) x 8,760 hrs/yr x 1kgal per 1000 gallon x 1 gal per 0.140 MMBtu
Emission Factors are from AP 42, Tables 1.3-1, 1.3-2, 1.3-3, and 1.3-6 (SCC 1-02-005-01/02/03) Supplement E 9/98
*PM emission factor is filterable PM only. Condensable PM emission factor is 1.3 lb/kgal.
Boiler is equiped with Low Nox burner and flue gas recirculation control. (LNB/FGR) For Natural Gas Nox = 100 lb/MMBtu, and for No. 2 fuel oil, Nox = 10 lb/Kgal

Hazardous Air Pollutants (HAPs)
Methodology is the same above.
The five highest organic and metal HAPs emission factors are provided above.
Additional HAPs emission factors are available in AP-42, Chapter 1.4 and Chapter 1.3

Appendix A: Emission Calculations
Emergency Large Reciprocating Internal Combustion Engines - Diesel Fuel
Output Rating (>600 HP)
Maximum Input Rate (>4.2 MMBtu/hr)

Company Name: **University of Notre Dame du Lac**
Source Address: **100 Facilities Building, Notre Dame, Indiana 46556**
Permt Number: **141-41227-00013**
Reviewer: **Tripurari Sinha, Ph. D.**

Emission Unit	MMBtu/hr
G-3	13.7
G-4	13.7
Total	27.4

Heat Input Capacity (MMBtu/hr)	27.4
Maximum Hours Operated per Year	500
Potential Throughput (MMBtu/yr)	13,700
Sulfur Content (S) of Fuel (% by weight)	0.500

	Pollutant						
	PM*	PM10*	direct PM2.5*	SO2	NOx	VOC†	CO
Emission Factor in lb/MMBtu	0.10	0.0573	0.0556	0.505 *(1.01S)*	3.2 **see below	0.08	0.85
Potential Emission in tons/yr	0.69	0.39	0.38	3.46	21.92	0.56	5.82

*PM emission factor is from AP-42 Section 3.4, Table 3.4-1. The emission factors for PM10 and PM2.5 are from AP-42 Section 3.4, Table 3.4-2. The PM10 emission factor is the sum of filterable PM10 and condensable particulate. The PM2.5 emission factor is the sum of filterable particulate less than 3 um and condensable particulate.

**NOx emissions: uncontrolled = 3.2 lb/MMBtu, controlled with ignition timing retard = 1.9 lb/MMBtu

†Per AP 42 Section 3.4, Table 3.4-1, The source has requested that the VOC emission factor be adjusted downward 9% to reflect only the non-methane components.

Hazardous Air Pollutants (HAPs)

	Pollutant						
	Benzene	Toluene	Xylene	Formaldehyde	Acetaldehyde	Acrolein	Total PAH HAPs***
Emission Factor in lb/MMBtu	7.76E-04	2.81E-04	1.93E-04	7.89E-05	2.52E-05	7.88E-06	2.12E-04
Potential Emission in tons/yr	5.32E-03	1.92E-03	1.32E-03	5.40E-04	1.73E-04	5.40E-05	1.45E-03

***PAH = Polyaromatic Hydrocarbon (PAHs are considered HAPs, since they are considered Polycyclic Organic Matter)

Total HAPs (tons/yr)	**0.01**

Methodology

Emission Factors are from AP 42 (Supplement B 10/96) Tables 3.4-1 , 3.4-2, 3.4-3, and 3.4-4.

Potential Throughput (MMBtu/yr) = [Heat Input Capacity (MMBtu/hr)] * [Maximum Hours Operated per Year]

Potential Emission (tons/yr) = [Potential Throughput (MMBtu/yr)] * [Emission Factor (lb/MMBtu)] / [2,000 lb/ton]

Appendix A: Emission Calculations
Large Reciprocating Internal Combustion Engines - Diesel Fuel
Output Rating (>600 HP)
Maximum Input Rate (>4.2 MMBtu/hr)

Company Name: **University of Notre Dame du Lac**
Source Address: **100 Facilities Building, Notre Dame, Indiana 46556**
Permt Number: **141-41227-00013**
Reviewer: **Tripurari Sinha, Ph. D.**

Emission Unit	HP
G-8	2,593
G-9	2,593
G-10	2,593
Total	7,779

Emissions calculated based on output rating (hp)

		PSD Minor Limit - Diesel oil Limit	3,076,600	Gallons/yr
Output Horsepower Rating (hp)	7779.0	PSD Minor Limit PM10 limit	0.0097	for G8, G9, and G10
Maximum Hours Operated per Year	8760			
Potential Throughput (hp-hr/yr)	68,144,040	PSD Limit SO2 =	6.7	lbs/hr each, for G8, G9, and G10
Sulfur Content (S) of Fuel (% by weight)	0.500	PSD Limit NOx =	37.44	lbs/hr each, for G8, G9, and G10

	Pollutant (tons/yr)						
	PM**	PM10**	direct PM2.5**	SO2*	Nox***	VOC†	CO**
Emission Factor in lb/hp-hr*				4.05E-03 *(.00809S)*			
Emission Factor in lb/hr**	0.87	0.87	0.87	-	37.44	1.16	3.05
Potential Emission in tons/yr*	11.43	11.43	11.43	137.82	491.96	15.24	40.08
Limited PTE	11.43	11.43	11.43	88.04	491.96	15.24	40.08
SO2 emissions at 0.3%S				82.69			

Source needs to use less than 0.3%S content in No.2 fuel oil to comply with 6.7 lbs/hr PSD limit. .
*Emission Factors are from AP 42 (Supplement B 10/96) Tables 3.4-1 , 3.4-2, 3.4-3, and 3.4-4.
**Emission factor based on vendor specification at 100% load as a worse case.

Hazardous Air Pollutants (HAPs)

	Pollutant						
	Benzene	Toluene	Xylene	Formaldehyde	Acetaldehyde	Acrolein	Total PAH HAPs***
Emission Factor in lb/hp-hr****	5.43E-06	1.97E-06	1.35E-06	5.52E-07	1.76E-07	5.52E-08	1.48E-06
Potential Emission in tons/yr	1.85E-01	6.70E-02	4.60E-02	1.88E-02	6.01E-03	1.88E-03	5.06E-02

***PAH = Polyaromatic Hydrocarbon (PAHs are considered HAPs, since they are considered Polycyclic Organic Matter)
****Emission factors in lb/hp-hr were calculated using emission factors in lb/MMBtu and a brake specific fuel consumption of 7,000 Btu / hp-hr (AP-42 Tables 3.3-1 and 3.4-1).

Potential Emission of Total HAPs (tons/yr)	**0.38**

Methodology
Potential Throughput (hp-hr/yr) = [Output Horsepower Rating (hp)] * [Maximum Hours Operated per Year]
Potential Emission (tons/yr) = [Potential Throughput (hp-hr/yr)] * [Emission Factor (lb/hp-hr)] / [2,000 lb/ton]

Appendix A: Emissions Calculations
Natural Gas Combustion Only
Turbines

Company Name: University of Notre Dame du Lac
Source Address 100 Facilities Building, Notre Dame, Indiana 46556
Permt Number 141-41227-00013
Reviewer: Tripurari Sinha, Ph. D.

Emission Unit	MW	MMBtu/hr
GT-1	6.4	75.4
GT-2	6.4	75.4
Total	**12.8**	**150.8**

Heat Input Capacity MW	Heat Input Capacity MMBtu/hr	HHV mmBtu/mmscf	Potential Throughput MMCF/yr	Sulfur Content gr/100scf
12.8	150.8	1020	1295.1	2

	Pollutant						
	PM*[2]	PM10*[2]	direct PM2.5*[2]	SO2[1]	NOx[3]	VOC[3]	CO[3]
Emission Factor in lb/MMBtu	1.00E-02	1.00E-02	1.00E-02	5.60E-03	--	--	--
Emission Factor in lb/MW-hr	--	--	--	--	9.00E-01	1.04E-01	9.10E-01
Potential Emission in tons/yr (source data)	6.61	6.61	6.61	3.70	50.46	5.83	51.02

*Emission factors are provided by the source and have been approved by IDEM.
[1] Sulfur Content from USEPA's *Resolution of "Natural Gas" and "Pipeline Natural Gas" Definition Issues*, dated June 12, 2000. Assumes pipeline quality fuel is burned.
[2] Emission factor provided by Solar Turbines through an email to the source.
[3] Vendor specific data from Solar Turbines, Engine Model Taurus 60-7901S GSC Standard

Methodology
All emission factors are based on normal firing.
MMBtu = 1,000,000 Btu
MMCF = 1,000,000 Cubic Feet of Gas
Potential Throughput (MMCF) = Heat Input Capacity (MMBtu/hr) x 8,760 hrs/yr x 1 MMCF/1,020 MMBtu
Emission (tons/yr) = Throughput (MMCF/yr) x Emission Factor (lb/MMCF)/2,000 lb/ton

Hazardous Air Pollutants (HAPs)

	HAPs						
	Benzene	1, 3 Butadiene	Formaldehyde	Acetaldehyde	Toluene	Xylenes	**Total**
Emission Factor in lb/MMBtu	1.2E-05	4.3E-07	2.9E-03	4.0E-05	1.3E-04	6.40E-05	
Potential Emission in tons/yr	7.9E-03	2.8E-04	1.9E+00	2.6E-02	8.6E-02	4.2E-02	**2.07**

	HAPs					
	Acrolein	Ethylbenzene	Naphthalene	PAH	Propylene Oxide	**Total**
Emission Factor in lb/MMBtu	6.4E-06	3.2E-05	1.3E-06	2.2E-06	2.9E-05	
Potential Emission in tons/yr	4.2E-03	2.1E-02	8.6E-04	1.5E-03	1.9E-02	**4.7E-02**
					Total HAPs	**2.11**
					Worst HAP	**1.90**

Formaldehyde

Methodology is the same as above.
The five highest organic and metal HAPs emission factors are provided above.
Additional HAPs emission factors are available in AP-42, Chapter 3.1.

Appendix A: Emissions Calculations
Natural Gas Combustion Only
MM BTU/HR <100

Company Name: University of Notre Dame du Lac
Source Address 100 Facilities Building, Notre Dame, Indiana 46556
Permt Number 141-41227-00013
Reviewer: Tripurari Sinha, Ph. D.

Emission Unit	MMBtu/hr
HRSG1	87.5
HRSG2	87.5
Total	**175**

Heat Input Capacity MMBtu/hr	HHV mmBtu / mmscf	Potential Throughput MMCF/yr
175.0	1020	1502.9

	Pollutant						
	PM*	PM10*	direct PM2.5*	SO2	NOx	VOC	CO
Emission Factor in lb/MMBtu	0.0075	0.0075	0.0075	--	0.08	0.00898	0.08
Emission Factor in lb/MMCF				0.6			
Potential Emission in tons/yr	5.75	5.75	5.75	0.45	61.32	6.88	61.32

*Emission factors are provided by the source and have been approved by IDEM.

Methodology
All emission factors are based on normal firing.
MMBtu = 1,000,000 Btu
MMCF = 1,000,000 Cubic Feet of Gas
Emission Factors are from AP 42, Chapter 1.4, Tables 1.4-1, 1.4-2, 1.4-3, SCC #1-02-006-02, 1-01-006-02, 1-03-006-02, and 1-03-006-03
Potential Throughput (MMCF) = Heat Input Capacity (MMBtu/hr) x 8,760 hrs/yr x 1 MMCF/1,020 MMBtu
Emission (tons/yr) = Throughput (MMCF/yr) x Emission Factor (lb/MMCF)/2,000 lb/ton

Hazardous Air Pollutants (HAPs)

	HAPs - Organics					
	Benzene	Dichlorobenzene	Formaldehyde	Hexane	Toluene	**Total - Organics**
Emission Factor in lb/MMcf	2.1E-03	1.2E-03	7.5E-02	1.8E+00	3.4E-03	
Potential Emission in tons/yr	1.6E-03	9.0E-04	5.6E-02	1.35	2.6E-03	**1.41**

	HAPs - Metals					
	Lead	Cadmium	Chromium	Manganese	Nickel	**Total - Metals**
Emission Factor in lb/MMcf	5.0E-04	1.1E-03	1.4E-03	3.8E-04	2.1E-03	
Potential Emission in tons/yr	3.8E-04	8.3E-04	1.1E-03	2.9E-04	1.6E-03	**4.1E-03**
					Total HAPs	**1.42**
					Worst Single HAP (Hexane	**1.35**

Methodology is the same as above.
The five highest organic and metal HAPs emission factors are provided above.
Additional HAPs emission factors are available in AP-42, Chapter 1.4.

Appendix A: Emission Calculations
Large Reciprocating Internal Combustion Engines - Diesel Fuel
Output Rating (>600 HP)
Maximum Input Rate (>4.2 MMBtu/hr)

Sixteen Diesel-fired Emergency Engines

Company Name: University of Notre Dame du Lac
Source Address: 100 Facilities Building, Notre Dame, Indiana 46556
Permt Number: 141-41227-00013
Reviewer: Tripurari Sinha, Ph. D.

Location	Gen. Rating	Year of Mfr.
Galvin No. 3	805	2005
Joyce Center	671	2013
Hesburgh Library #1	671	2013
Hesburgh Library #2	671	2013
Galvin Life Sciences	755	2015
Nieuwland	755	2015
Stinson-Remick	1,073	2010
McCourtney Hall	1,220	2016
Stadium 1	1,474	2016
Stadium 2	1,474	2016
Stepan Chemistry	755	2019
Fitzpatrick	755	2019
Flanner/Grace/Wells 1 & 2	671	1996
ITC	671	2002
Administration Bldg.	671	1997
Jordan Hall of Science	805	2004
Total	13897	

Output Horsepower Rating (hp)	13893
Maximum Hours Operated per Year	500
Potential Throughput (hp-hr/yr)	6,946,500
Sulfur Content (S) of Fuel (% by weight)*	0.0015%

	Pollutant						
	PM*	PM10*	direct PM2.5*	SO2	NOx	VOC	CO
AP-42 Emission Factor Table 3.4-1 in lb/hp-hr				1.21E-07 *(.00809S)*		7.05E-04	5.50E-03
Engine Data Sheet Emission Factor in grams/hp-hr	0.08	0.08	0.08		5.15	0.18	0.47
Emission Factor conversion in lb/hp-hr	0.0002	0.0002	0.0002		0.01	0.0004	0.001
Potential Emission in tons/yr	0.61	0.61	0.61	4.21E-04	39.43	1.38	3.60

* Sulfur content required by 40 CFR 60.4207(b) and 40 CFR 80.510(b).
Conversion factor grams/hp-hr to lb/hp-hr = 1 gram = 0.0022046 lbs

Hazardous Air Pollutants (HAPs)

	Pollutant						
	Benzene	Toluene	Xylene	Formaldehyde	Acetaldehyde	Acrolein	Total PAH HAPs***
Emission Factor in lb/hp-hr****	5.43E-06	1.97E-06	1.35E-06	5.52E-07	1.76E-07	5.52E-08	1.48E-06
Potential Emission in tons/yr	1.89E-02	6.83E-03	4.69E-03	1.92E-03	6.13E-04	1.92E-04	5.15E-03

***PAH = Polyaromatic Hydrocarbon (PAHs are considered HAPs, since they are considered Polycyclic Organic Matter)
****Emission factors in lb/hp-hr were calculated using emission factors in lb/MMBtu and a brake specific fuel consumption of 7,000 Btu / hp-hr (AP-42 Table 3.3-1).

Potential Emission of Total HAPs (tons/yr)	**3.83E-02**

Methodology
Emission Factors are from AP 42 (Supplement B 10/96) Tables 3.4-1 , 3.4-2, 3.4-3, and 3.4-4.
Potential Throughput (hp-hr/yr) = [Output Horsepower Rating (hp)] * [Maximum Hours Operated per Year]
Potential Emission (tons/yr) = [Potential Throughput (hp-hr/yr)] * [Emission Factor (lb/hp-hr)] / [2,000 lb/ton]

Appendix A: Emission Calculations
Reciprocating Internal Combustion Engines - Diesel Fuel
Output Rating (<=600 HP)
Maximum Input Rate (<=4.2 MMBtu/hr)

Company Name: **University of Notre Dame du Lac**
Source Address: **100 Facilities Building, Notre Dame, Indiana 46556**
Permt Number: **141-41227-00013**
Reviewer: **Tripurari Sinha, Ph. D.**

Emissions calculated based on output rating (hp)

Output Horsepower Rating (hp)	6385.0
ximum Hours Operated per Year	500
Potential Throughput (hp-hr/yr)	3,192,500

	Pollutant						
	PM*	PM10*	direct PM2.5*	SO2	NOx	VOC	CO
Emission Factor in	0.0022	0.0022	0.0022	0.00205	0.0310	0.0025	0.00668
Potential Emission in tons/yr	3.51	3.51	3.51	3.27	49.48	4.01	10.66

*PM and PM2.5 emission factors are assumed to be equivalent to PM10 emission factors. No information was given regarding which method was used to determine the factor or the fraction of PM10 which is

Hazardous Air Pollutants (HAPs)

	Pollutant							
	Benzene	Toluene	Xylene	,3-Butadien	ormaldehyd	cetaldehyd	Acrolein	Total PAH HAPs***
Emission Factor in lb/hp-hr****	6.53E-06	2.86E-06	2.00E-06	2.74E-07	8.26E-06	5.37E-06	6.48E-07	1.18E-06
Potential Emission in t	1.04E-02	4.57E-03	3.18E-03	4.37E-04	1.32E-02	8.57E-03	1.03E-03	1.88E-03
Potential Emission of Total HAPs (tons/yr)								**4.33E-02**

***PAH = Polyaromatic Hydrocarbon (PAHs are considered HAPs, since they are considered Polycyclic Organic Matter)
****Emission factors in lb/hp-hr were calculated using emission factors in lb/MMBtu
and a brake specific fuel consumption of 7,000 Btu / hp-hr (AP-42 Table 3.3-1).

Appendix A: Emission Calculations
Reciprocating Internal Combustion Engines - Diesel Fuel

Company Name: University of Notre Dame du Lac
Source Address: 100 Facilities Building, Notre Dame, Indiana 46556
Permt Number: 141-41227-00013
Reviewer: Tripurari Sinha, Ph. D.

Existing Engines < 600HP 32 Engines < 600 HP

Location	Engine Rating	Year of Manufacture
Old Security Building	27	1990
Haggar	20	1990
Loftus Center	20	1987
North Dining Hall	44	1988
Hesburgh Ctr. For Int. Studies	54	1991
Hammes Mowbray	74	2004
Material Storage	80	1990
Bond Hall/Morrissey	80	1997
South Dining Hall	80	1993
Eck Center/Ryan Hall	107	1999
DeBartolo	121	1992
Hanks Aquatics	134	1997
Guigliemino CVA	134	2004
Holy Cross House	134	1999
O'Neill/Keough/Welsh/McGlinn/Dur	201	1995
Coleman Morse	201	1999
Performing Arts Center	201	2002
Galvin No. 2	268	1983
Geddes Hall	268	2005
East Plant	201	2003
COBA	469	1995
MVAP Complex	168	2009
Nanotechnology Research Ctr.	201	2006
Stayer Center	201	2012
Innovation Park Building 1	335	2009
Compton Ice Arena	335	2011
Eck Law School	402	2007
Morris Inn	235	2013
Jenkins-Nanovic Hall	385	2016
Secondary Chilled Water pumping Station	535	1996
Well #9	536	2012
Sacred Heart Basillica	134	2019
	6385	

Engines > 600HP

Location	Engine Rating	Year
Galvin No. 3	805	2005
Joyce Center	671	2013
Hesburgh Library	671	2013
Hesburgh Library	671	2013
Galvin Life Scienc	755	2015
Nieuwland	755	2015
Stinson-Remick	1,073	2010
McCourtney Hall	1,220	2016
Stadium 1	1,474	2016
Stadium 2	1,474	2016
Stepan Chemistry	755	2019
Fitzpatrick	755	2019
Total	**10274**	

Appendix A: Emission Calculations
Emergency Reciprocating Internal Combustion Engines - Natural Gas

Company Name: **University of Notre Dame du Lac**
Source Address: **100 Facilities Building, Notre Dame, Indiana 46556**
Permt Number: **141-41227-00013**
Reviewer: **Tripurari Sinha, Ph. D.**

Ten (10) Natural Gas fired emergency generators with a combined maximum output horsepower rating (hp) of 802

Maximum Output Horsepower Rating (hp)	842
Brake Specific Fuel Consumption (BSFC) (Btu/hp-hr)	7,500
Maximum Hours Operated per Year (hr/yr)	500
Potential Fuel Usage (MMBtu/yr)	3,158
High Heat Value (MMBtu/MMscf)	1,020
Potential Fuel Usage (MMcf/yr)	3.10

	Pollutant						
Criteria Pollutants	PM*	PM10*	PM2.5*	SO2	NOx	VOC	CO
Emission Factor (lb/MMBtu)	3.84E-02	4.83E-02	4.83E-02	5.88E-04	3.17E+00	1.20E-01	3.72E+00
Potential Emissions (tons/yr)	0.06	0.08	0.08	0.001	5.00	0.19	5.87

*PM emission factor is for filterable PM-10. PM10 emission factor is filterable PM10 + condensable PM.
PM2.5 emission factor is filterable PM2.5 + condensable PM.

Hazardous Air Pollutants (HAPs)

Pollutant	Emission Factor (lb/MMBtu)	Potential Emissions (tons/yr)
Acetaldehyde	8.36E-03	0.013
Acrolein	7.78E-03	0.012
Benzene	1.94E-03	0.003
1,3-Butadiene	8.20E-04	0.001
Ethylbenzene	1.08E-04	0.000
Formaldehyde	5.52E-02	0.087
Methanol	3.06E-03	0.005
Methylene Chloride	1.47E-04	0.000
Hexane	1.10E-03	0.002
Toluene	9.63E-04	0.002
2,2,4-Trimethylpentane	8.46E-04	0.001
Xylene	2.68E-04	0.000
Biphenyl	2.12E-04	0.000
Total PAH**	1.41E-04	0.000
	Total	**0.13**

HAP pollutants consist of the twelve highest HAPs included in AP-42 Table 3.2-1.
**PAH = Polyaromatic Hydrocarbon (PAHs are considered HAPs, since they are considered Polycyclic Organic Matter)

Methodology
Emission Factors are from AP-42 (Supplement F, July 2000), Table 3.2-1
Potential Fuel Usage (MMBtu/yr) = [Maximum Output Horsepower Rating (hp)] * [Brake Specific Fuel Consumption (Btu/hp-hr)] * [Maximum Hours Operated per Year (hr/yr)] / [1000000 Btu/MMBtu]
Potential Emissions (tons/yr) = [Potential Fuel Usage (MMBtu/yr)] * [Emission Factor (lb/MMBtu)] / [2000 lb/ton]

Abbreviations
PM = Particulate Matter
PM10 = Particulate Matter (<10 um)
SO2 = Sulfur Dioxide
NOx = Nitrous Oxides
VOC - Volatile Organic Compounds
CO = Carbon Monoxide

Appendix A: Emission Calculations
Two Above-Ground Diesel Fuel Storage Tanks, AST-1 and AST-2

Company Name: University of Notre Dame du Lac
Source Address: 100 Facilities Building, Notre Dame, Indiana 46556
Permt Number: 141-41227-00013
Reviewer: Tripurari Sinha, Ph. D.

Tank ID	Tank Contents	Tank Capacity (gal)	Product Losses (lbs/year)	VOC Content	VOC Emissions (tons/year)
AST-1	Diesel	300,789	129.75	100%	0.06
AST-2	Diesel	300,789	129.75	100%	0.06

METHODOLOGY
Emissions (tons/yr) = Product Losses (lb/yr) x Content (%) / (2000 lbs/ton)
Note: HAP emissions are not included in the calculations because HAPs are neglible.

Emission Source	EF (lb/kgal of throughput)	PTE VOC (tons/yr)
Filling Storage Tanks (submerged filling)	0.022	0.15

These emissions are from loading the tanks from tanker trucks, not from fuel dispensing.

Diesel fuel unloaded from both storage tanks: 13,535,489 gallons/yr
Diesel Throughput = 37,083.5 gallons/day
Diesel Throughput = 13,535.5 kgallons/year

Total VOC PTE from AST-1 & AST-2 : 0.28 tons/yr

Filling Storage Tank (submerged filling) EF (lbs/kgal) = Loading Loss, L = 12.46 x (SPM/T), where S = Saturation Factor; P = True Vapor Pressure of Material Loaded; M = Molecular Weight of Material Loaded; and T = Temperature of Material Loaded (in ºRankine). Reference Eqn. 1, Chapter 5.2 Transportation and Marketing of Petroleum Liquids

Saturation Factor, S = 0.6, which is saturation factor from AP-42, Table 5.2-1 for Submerged Loading: dedicated normal service (assumed value since Above-Ground Saturation Factor not published).
P = True Vapor Pressure of Liquid Loaded, (lbs/sq. in.) = 0.012; AP-42, Table 7.1-2
M = Vapor Molecular Weight of Material Loaded, (lbs/lb-mole) = 130; AP-42, Table 7.1-2.
T = Temperature of Liquid Loaded, (º Rankine = ºFahrenheit + 460; assume temperature = 80 ºF).

The diesel throughput was provided by the source.
Diesel Throughput (kgal/yr) = [Diesel Throughput (gallons/day)] * [365 days/yr] * [kgal/1000 gal]
PTE of VOC (tons/yr) = [Diesel Throughput (kgal/yr)] * [Emission Factor (lb/kgal)] * [ton/2000 lb]

Appendix A: Emissions Calculations
Cooling Tower 6 and Cooling Tower 7

Company Name: **University of Notre Dame du Lac**
Source Address: **100 Facilities Building, Notre Dame, Indiana 46556**
Permt Number: **141-41227-00013**
Reviewer: **Tripurari Sinha, Ph. D.**

Parameter & Units	Value	Source
Total capacity of cooling tower, gallons/minute (each)	10,000	(Source Data)
Total dissolved solids (TDS) of the circulating water, ppm by wt. (each)	3,200	(Provided to Source by Water Treatment Vendor)
Drift loss (percentage of liquid water emitted to the air by each tower), %	0.002	(Provided to Source by Cooling Tower Vendor)
Density of water, lb/gallon	8.34	Constant
Maximum operation, min/hr (each)	60	Constant

Calculations:

PM10 Emissions = (capacity) x (TDS) x (drift loss) x (density of water) x (operating min/day)
= 10,000 x 0.0032 x 0.00002 x 8.34 x 60
= 0.32 lb/hr PM10 for one cooling tower
= 7.69 lb/day PM10 for one cooling tower
= 1.40 tpy PM10 for one cooling tower

PTE: = 1.40 tons/yr PM / PM10 / PM2.5 (for each cooling tower)
Total PTE: = **2.81** **tons/yr PM / PM10 / PM2.5 (for both cooling towers)**
Assume PM10 = PM = PM2.5

Appendix A: Emissions Calculations
Cooling Tower 8 and Cooling Tower 9 at Remote Chiller Plant

Company Name: **University of Notre Dame du Lac**
Source Address: **100 Facilities Building, Notre Dame, Indiana 46556**
Permt Number: **141-41227-00013**
Reviewer: **Tripurari Sinha, Ph. D.**

Parameter & Units	Value	Source
Total capacity of cooling tower, gallons/minute (each)	5,000	(Source Data)
Total dissolved solids (TDS) of the circulating water, ppm by wt. (each)	3,200	(Provided to Source by Water Treatment Vendor)
Drift loss (percentage of liquid water emitted to the by air each tower), %	0.005	(Provided to Source by Cooling Tower Vendor)
Density of water, lb/gallon	8.34	Constant
Maximum operation, min/hr (each)	60	Constant

Calculations:

PM10 Emissions = (capacity) x (TDS) x (drift loss) x (density of water) x (operating min/day)
= 5,000 x 0.0032 x 0.00005 x 8.34 x 60
= 0.40 lb/hr PM10 for one cooling tower
= 9.61 lb/day PM10 for one cooling tower
= 1.75 tpy PM10 for one cooling tower

PTE: = 1.75 tons/yr PM / PM10 / PM2.5 (for each cooling tower)
Total PTE: = 3.51 **tons/yr PM / PM10 / PM2.5 (for both cooling towers)**
Assume PM10 = PM = PM2.5

Appendix A: Emissions Calculations
Combustion with Capacity < 100 MMBtu/hr
Irish Atheletic Center heaters

Company Name: **University of Notre Dame du Lac**
Source Address: **100 Facilities Building, Notre Dame, Indiana 46556**
Permit Number: **141-41227-00013**
Reviewer: **Tripurari Sinha, Ph. D.**

Heat Input Capacity MMBtu/hr	HHV mmBtu / mmscf	Potential Throughput MMCF/yr
4.8	1020	41.2

	Pollutant						
	PM*	PM10*	direct PM2.5*	SO2	NOx	VOC	CO
Emission Factor in lb/MMCF	1.9	7.6	7.6	0.6	100 **see below	5.5	84
Potential Emission in tons/yr	0.04	0.16	0.16	0.01	2.06	0.11	1.73

*PM emission factor is filterable PM only. PM10 emission factor is filterable and condensable PM10 combined.
PM2.5 emission factor is filterable and condensable PM2.5 combined.
**Emission Factors for NOx: Uncontrolled = 100, Low NOx Burner = 50, Low NOx Burners/Flue gas recirculation = 32

Methodology
All emission factors are based on normal firing.
MMBtu = 1,000,000 Btu
MMCF = 1,000,000 Cubic Feet of Gas
Emission Factors are from AP 42, Chapter 1.4, Tables 1.4-1, 1.4-2, 1.4-3, SCC #1-02-006-02, 1-01-006-02, 1-03-006-02, and 1-03-006-03
Potential Throughput (MMCF) = Heat Input Capacity (MMBtu/hr) x 8,760 hrs/yr x 1 MMCF/1,020 MMBtu
Emission (tons/yr) = Throughput (MMCF/yr) x Emission Factor (lb/MMCF)/2,000 lb/ton

Hazardous Air Pollutants (HAPs)

	HAPs - Organics					
	Benzene	Dichlorobenzene	Formaldehyde	Hexane	Toluene	**Total - Organics**
Emission Factor in lb/MMcf	2.1E-03	1.2E-03	7.5E-02	1.8E+00	3.4E-03	
Potential Emission in tons/yr	4.3E-05	2.5E-05	1.5E-03	0.04	7.0E-05	**0.04**

	HAPs - Metals					
	Lead	Cadmium	Chromium	Manganese	Nickel	**Total - Metals**
Emission Factor in lb/MMcf	5.0E-04	1.1E-03	1.4E-03	3.8E-04	2.1E-03	
Potential Emission in tons/yr	1.0E-05	2.3E-05	2.9E-05	7.8E-06	4.3E-05	**1.1E-04**
					Total HAPs	**0.04**
					Worst HAP	**0.04** **Hexane**

Methodology is the same as above.
The five highest organic and metal HAPs emission factors are provided above.
Additional HAPs emission factors are available in AP-42, Chapter 1.4.

Appendix A: Emissions Calculations
Natural Gas Combustion Only
MM BTU/HR <100
300 Heaters

Company Name: **University of Notre Dame du Lac**
Source Address: **100 Facilities Building, Notre Dame, Indiana 46556**
Permit Number: **141-41227-00013**
Reviewer: **Tripurari Sinha, Ph. D.**

No. of Heaters	300	
Heat Input Capacity	40,000.00	Btu/hr

Heat Input Capacity MMBtu/hr	HHV mmBtu / mmscf	Potential Throughput MMCF/yr
12.0	1020	103.1

	Pollutant						
	PM*	PM10*	direct PM2.5*	SO2	NOx	VOC	CO
Emission Factor in lb/MMCF	1.9	7.6	7.6	0.6	100 **see below	5.5	84
Potential Emission in tons/yr	0.10	0.39	0.39	0.03	5.15	0.28	4.33

*PM emission factor is filterable PM only. PM10 emission factor is filterable and condensable PM10 combined.
PM2.5 emission factor is filterable and condensable PM2.5 combined.
**Emission Factors for NOx: Uncontrolled = 100, Low NOx Burner = 50, Low NOx Burners/Flue gas recirculation = 32

Methodology
All emission factors are based on normal firing.
MMBtu = 1,000,000 Btu
MMCF = 1,000,000 Cubic Feet of Gas
Emission Factors are from AP 42, Chapter 1.4, Tables 1.4-1, 1.4-2, 1.4-3, SCC #1-02-006-02, 1-01-006-02, 1-03-006-02, and 1-03-006-03
Potential Throughput (MMCF) = Heat Input Capacity (MMBtu/hr) x 8,760 hrs/yr x 1 MMCF/1,020 MMBtu
Emission (tons/yr) = Throughput (MMCF/yr) x Emission Factor (lb/MMCF)/2,000 lb/ton

Hazardous Air Pollutants (HAPs)

	HAPs - Organics					
	Benzene	Dichlorobenzene	Formaldehyde	Hexane	Toluene	**Total - Organics**
Emission Factor in lb/MMcf	2.1E-03	1.2E-03	7.5E-02	1.8E+00	3.4E-03	
Potential Emission in tons/yr	1.1E-04	6.2E-05	3.9E-03	0.09	1.8E-04	**0.10**

	HAPs - Metals					
	Lead	Cadmium	Chromium	Manganese	Nickel	**Total - Metals**
Emission Factor in lb/MMcf	5.0E-04	1.1E-03	1.4E-03	3.8E-04	2.1E-03	
Potential Emission in tons/yr	2.6E-05	5.7E-05	7.2E-05	2.0E-05	1.1E-04	**2.8E-04**
					Total HAPs	**0.10**
					Worst HAP	**0.09**

Methodology is the same as above.
The five highest organic and metal HAPs emission factors are provided above.
Additional HAPs emission factors are available in AP-42, Chapter 1.4.

Appendix A: Emission Calculations
Reciprocating Internal Combustion Engines - Diesel Fuel
Output Rating (<=600 HP)
Maximum Input Rate (<=4.2 MMBtu/hr)

Company Name: **University of Notre Dame du Lac**
Source Address: **100 Facilities Building, Notre Dame, Indiana 46556**
Permt Number: **141-41227-00013**
Reviewer: **Tripurari Sinha, Ph. D.**

Emissions calculated based on output rating (hp)

Output Horsepower Rating (hp)	335.0
ximum Hours Operated per Year	500
Potential Throughput (hp-hr/yr)	167,500

Location	Engine Rating HP	Year of Manufacture
East Plant	201	2003
Sacred Heart Basilica	134	2019
Total	335	

East Plant (hp-hr/yr) 100,500
Sacred Heart Basilica (hp-hr/yr) 67000

	Pollutant						
	PM*	PM10*	direct PM2.5*	SO2	NOx	VOC	CO
Emission Factor in	0.0022	0.0022	0.0022	0.00205	0.0310	0.0025	0.00668
	Potential Emission in tons/yr						
East Plant	0.11	0.11	0.11	0.10	1.56	0.13	0.34
Sacres Heart Basilica	0.07	0.07	0.07	0.07	1.04	0.08	0.22
Total Emissions	0.18	0.18	0.18	0.17	2.60	0.21	0.56

*PM and PM2.5 emission factors are assumed to be equivalent to PM10 emission factors. No information was given regarding which method was used to determine the factor or the fraction of PM10 which is

Hazardous Air Pollutants (HAPs)

	Pollutant							
	Benzene	Toluene	Xylene	,3-Butadien	ormaldehyd	cetaldehyd	Acrolein	Total PAH HAPs***
Emission Factor in lb/hp-hr****	6.53E-06	2.86E-06	2.00E-06	2.74E-07	8.26E-06	5.37E-06	6.48E-07	1.18E-06
Potential Emission in t	5.47E-04	2.40E-04	1.67E-04	2.29E-05	6.92E-04	4.50E-04	5.42E-05	9.85E-05
							Potential Emission of Total HAPs (tons/yr)	**2.27E-03**

***PAH = Polyaromatic Hydrocarbon (PAHs are considered HAPs, since they are considered Polycyclic Organic Matter)
****Emission factors in lb/hp-hr were calculated using emission factors in lb/MMBtu
and a brake specific fuel consumption of 7,000 Btu / hp-hr (AP-42 Table 3.3-1).

Appendix A: Emission Calculations
Large Reciprocating Internal Combustion Engines - Diesel Fuel
Output Rating (>600 HP)
Maximum Input Rate (>4.2 MMBtu/hr)

Sixteen Diesel-fired Emergency Engines

Company Name: **University of Notre Dame du Lac**
Source Address: **100 Facilities Building, Notre Dame, Indiana 46556**
Permt Number: **141-41227-00013**
Reviewer: **Tripurari Sinha, Ph. D.**

Output Horsepower Rating (hp)	1510
Maximum Hours Operated per Year	500
Potential Throughput (hp-hr/yr)	755,000
Sulfur Content (S) of Fuel (% by weight)*	0.0015%

Location	Gen. Rating	Year of Mfr.
Stepan	755	2019
Fitzpatrick	755	2019
Total	1,510	

	Pollutant						
	PM*	PM10*	direct PM2.5*	SO2	NOx	VOC	CO
AP-42 Emission Factor Table 3.4-1 in lb/hp-hr				1.21E-07 *(.00809S)*		7.05E-04	5.50E-03
Engine Data Sheet Emission Factor in grams/hp-hr	0.08	0.08	0.08		5.15	0.18	0.47
Emission Factor conversion in lb/hp-hr	0.0002	0.0002	0.0002		0.01	0.0004	0.001
Potential Emission in tons/yr	0.07	0.07	0.07	4.58E-05	4.29	0.15	0.39

* Sulfur content required by 40 CFR 60.4207(b) and 40 CFR 80.510(b).
Conversion factor grams/hp-hr to lb/hp-hr = 1 gram = 0.0022046 lbs

Hazardous Air Pollutants (HAPs)

	Pollutant						
	Benzene	Toluene	Xylene	Formaldehyde	Acetaldehyde	Acrolein	Total PAH HAPs***
Emission Factor in lb/hp-hr****	5.43E-06	1.97E-06	1.35E-06	5.52E-07	1.76E-07	5.52E-08	1.48E-06
Potential Emission in tons/yr	2.05E-03	7.43E-04	5.10E-04	2.08E-04	6.66E-05	2.08E-05	5.60E-04

***PAH = Polyaromatic Hydrocarbon (PAHs are considered HAPs, since they are considered Polycyclic Organic Matter)
****Emission factors in lb/hp-hr were calculated using emission factors in lb/MMBtu and a brake specific fuel consumption of 7,000 Btu / hp-hr (AP-42 Table 3.3-1).

Potential Emission of Total HAPs (tons/yr)	**4.16E-03**

Methodology
Emission Factors are from AP 42 (Supplement B 10/96) Tables 3.4-1 , 3.4-2, 3.4-3, and 3.4-4.
Potential Throughput (hp-hr/yr) = [Output Horsepower Rating (hp)] * [Maximum Hours Operated per Year]
Potential Emission (tons/yr) = [Potential Throughput (hp-hr/yr)] * [Emission Factor (lb/hp-hr)] / [2,000 lb/ton]

INDIANA DEPARTMENT OF ENVIRONMENTAL MANAGEMENT
We Protect Hoosiers and Our Environment.
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Eric J. Holcomb
Governor

Bruno L. Pigott
Commissioner

September 23, 2020

Paul Kempf
University of Notre Dame du Lac
100 Facilities Building
Notre Dame, IN 46556-5602

Re: Public Notice
University of Notre Dame du Lac
Permit Level: Title V Renewal
Permit Number: 141-41227-00013

Dear Mr. Kempf:

Enclosed is a copy of the preliminary findings for your draft air permit, including the draft permit, Technical Support Document, emission calculations, and the Notice of 30-Day Period for Public Comment.

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. The Notice of 30-Day Period for Public Comment (without supporting documents) has also been sent to the OAQ Permits Branch Interested Parties List and, if applicable, your Consultant/Agent and/or Responsible Official/Authorized Individual.

The Public Notice period will begin the date the Notice is published on the IDEM Official Public Notice website. Publication has been requested and is expected within 2-3 business days. You may check the exact Public Notice begins and ends date here: https://www.in.gov/idem/5474.htm

Please note that as of April 17, 2019, IDEM is no longer required to publish the notice in a newspaper.

OAQ has submitted the draft permit package to the Hesburgh Library - University of Notre Dame, 221 Hesburgh in Notre Dame, IN. As a reminder, you are obligated by 326 IAC 2-1.1-6(c) to place a copy of the complete permit application at this library no later than ten (10) days after submittal of the application or additional information to our department. We highly recommend that even if you have already placed these materials at the library, that you confirm with the library that these materials are available for review and request that the library keep the materials available for review during the entire permitting process.

Please review the enclosed documents carefully. This is your opportunity to comment on the draft permit and notify the OAQ of any corrections that are needed before the final decision. Questions or comments about the enclosed documents should be directed to Tripurari Sinha, Ph. D., Indiana Department of Environmental Management, Office of Air Quality, 100 N. Senate Avenue, Indianapolis, Indiana, 46204 or call (800) 451-6027, and ask for extension 4-4907 or dial (317) 234-4907.

Sincerely,

Theresa Weaver

Theresa Weaver
Permits Branch
Office of Air Quality

Enclosures
PN Applicant Cover Letter 8/10/2020

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Governor

Bruno L. Pigott
Commissioner

September 23, 2020

To: Hesburgh Library - University of Notre Dame

From: Jenny Acker, Branch Chief
Permits Branch
Office of Air Quality

Subject: **Important Information to Display Regarding a Public Notice for an Air Permit**

Applicant Name: University of Notre Dame du Lac
Permit Number: 141-41227-00013

Enclosed is a copy of important information to make available to the public. This proposed project is regarding a source that may have the potential to significantly impact air quality. Librarians are encouraged to educate the public to make them aware of the availability of this information. The following information is enclosed for public reference at your library:

- Notice of a 30-day Period for Public Comment
- Draft Permit and Technical Support Document

You will not be responsible for collecting any comments from the citizens. Please refer all questions and request for the copies of any pertinent information to the person named below.

Members of your community could be very concerned in how these projects might affect them and their families. **Please make this information readily available until you receive a copy of the final package.**

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. Questions pertaining to the permit itself should be directed to the contact listed on the notice.

Enclosures
PN Library updated 4/2019

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Eric J. Holcomb
Governor

Bruno L. Pigott
Commissioner

Notice of Public Comment

September 23, 2020
University of Notre Dame du Lac
141-41227-00013

Dear Concerned Citizen(s):

You have been identified as someone who could potentially be affected by this proposed air permit. The Indiana Department of Environmental Management, in our ongoing efforts to better communicate with concerned citizens, invites your comment on the draft permit.

Enclosed is a Notice of Public Comment, which has posted on IDEM's Public Notice website at https://www.in.gov/idem/5474.htm.

The application and supporting documentation for this proposed permit have been placed at the library indicated in the Notice. These documents more fully describe the project, the applicable air pollution control requirements and how the applicant will comply with these requirements.

If you would like to comment on this draft permit, please contact the person named in the enclosed Public Notice. Thank you for your interest in the Indiana's Air Permitting Program.

Please Note: *If you feel you have received this Notice in error, or would like to be removed from the Air Permits mailing list, please contact Joanne Smiddie-Brush with the Air Permits Administration Section at 1-800-451-6027, ext. 3-0185 or via e-mail at JBRUSH@IDEM.IN.GOV. If you have recently moved and this Notice has been forwarded to you, please notify us of your new address and if you wish to remain on the mailing list. Mail that is returned to IDEM by the Post Office with a forwarding address in a different county will be removed from our list unless otherwise requested.*

Enclosure
PN AAA Cover Letter 2/28/2020

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Commissioner

AFFECTED STATE NOTIFICATION OF PUBLIC COMMENT PERIOD
DRAFT INDIANA AIR PERMIT

September 23, 2020

A 30-day public comment period has been initiated for:

Permit Number: **141-41227-00013**
Applicant Name: **University of Notre Dame du Lac**
Location: **Notre Dame, St. Joseph County, Indiana**

The public notice, draft permit and technical support documents can be accessed via the **IDEM Air Permits Online** site at:
http://www.in.gov/ai/appfiles/idem-caats/

Questions or comments on this draft permit should be directed to the person identified in the public notice by telephone or in writing to:

Indiana Department of Environmental Management
Office of Air Quality, Permits Branch
100 North Senate Avenue
Indianapolis, IN 46204

Questions or comments regarding this email notification or access to this information from the EPA Internet site can be directed to Chris Hammack at chammack@idem.IN.gov or (317) 233-2414.

Affected States Notification 1/9/2017

Mail Code 61-53

IDEM Staff	TAWEAVER 9/23/2020 UNIVERSITY OF NOTRE DAME DU LAC 141-41227-00013 (draft)			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		Paul Kempf University of Notre Dame Du Lac 100 Facilities Bldg Notre Dame IN 465565602 (Source CAATS)									
2		Doug Marsh Vice President UNIVERSITY OF NOTRE DAME DU LAC 200 Facilities Bldg Notre Dame IN 46556 *(RO CAATS)*									
3		Mishawaka City Council and Mayors Office 600 E. 3rd Street Mishawaka City Hall Mishawaka IN 46546 *(Local Official)*									
4		Frank J. Cunningham Ave Maria Press PO Box 428 Notre Dame IN 46556 *(Affected Party)*									
5		Mr. Wayne Falda South Bend Tribune 255 W Colfax Ave South Bend IN 46626 *(Affected Party)*									
6		Hesburgh Library University of Notre Dame 221 Hesburgh Notre Dame IN 46556 *(Library)*									
7		South Bend City Council / Mayors Office 227 W. Jefferson Blvd. South Bend IN 46601 *(Local Official)*									
8		St. Joseph County Board of Commissioners 227 West Jefferson Blvd, South Bend IN 46601 *(Local Official)*									
9		Mark Espich St. Joseph County Health Department 227 W Jefferson Blvd South Bend IN 46601 *(Health Department)*									
10		Wiltel Communications 1025 Eldorado Broomfield CO 80021 *(Affected Party)*									
11		Hayes Charles S Inc. 814 Marietta Street South Bend IN 46601 *(Affected Party)*									
12		Julie Johnson AECOM 1600 Perimeter Park Drive, Suite 400 Morrisville NC 27560 *(Consultant)*									
13		Jeff Mayes News-Dispatch 422 Franklin St Michigan City IN 46360 (Affected Party)									
14		Mr. Roger Schneider The Goshen News 114 S. Main St Goshen IN 46526 *(Affected Party)*									
15											

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