INDIANA DEPARTMENT OF ENVIRONMENTAL MANAGEMENT
We Protect Hoosiers and Our Environment.
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Eric J. Holcomb
Governor

Bruno L. Pigott
Commissioner

Part 70 Operating Permit Renewal
OFFICE OF AIR QUALITY

Indiana University
820 North Walnut Grove Ave.
Bloomington, Indiana 47405

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

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

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

Operation Permit No.: T105-41051-00005 Master Agency Interest ID: 11548	
Issued by: Josiah K. Balogun, Section Chief Permits Branch Office of Air Quality	Issuance Date: Expiration Date:

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

Attachment D: 40 CFR Part 63, Subpart DDDDD- National Emission Standards for Hazardous Air Pollutants for Major Sources: Industrial, Commercial, and Institutional Boilers and Process Heaters

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 power plant that supplies campus.

Source Address:	820 North Walnut Grove Ave., Bloomington, Indiana 47405
General Source Phone Number:	(812) 855-3231
SIC Code:	8221(Colleges, Universities, and Professional Schools)
County Location:	Monroe
Source Location Status:	Attainment for all criteria pollutants
Source Status:	Part 70 Operating Permit Program Minor Source, under PSD Rules Major Source, Section 112 of the Clean Air Act 1 of 28 Source Categories

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

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

(a) One (1) natural gas-fired boiler, (using low-sulfur No. 1 or No. 2 fuel oil as a back-up), identified as EU-07, approved for construction in 2007, including a mud drum heat exchanger, with a maximum design capacity of 217 MMBtu per hour heat input when combusting natural gas and 208 MMBtu per hour heat input when combusting fuel oil, and equipped with low NOx burners and induced flue gas recirculation for NOx control, with continuous emissions monitors (CEM) for monitoring CO and NOx, exhausting to stack 002. The boiler burner pilot light can ignite using propane.

Under [40 CFR 60, Subpart Db] and [40 CFR 63, Subpart DDDDD], this is an affected source.

(b) Two (2) coal, natural gas, No. 1 or No. 2 fuel oil fired boilers, identified as EU-03 and EU-04, both constructed in 1959, with economizers replaced in 2010, with a maximum design capacity of 125 MMBtu per hour heat input each (operating at a maximum capacity of 100 MMBtu per hour heat input each when combusting coal or a combination of fuels), and with a maximum design capacity of 80 MMBtu per hour heat input each when combusting natural gas and/or fuel oil, each equipped with low NOx burners for natural gas and/or fuel oil, and each with a multiclone and a jet pulse baghouse, identified as Boiler 3 Bag and Boiler 4 Bag, for particulate control, permitted in 2008, when combusting coal and/or fuel oil, both exhausting at stack 002. In addition, the stack exhaust from boilers EU-03 and EU-04 can be treated by an activated carbon injection system for mercury control and a lime injection system for hydrogen chloride control.

[Under 40 CFR 63, Subpart DDDDD, this is an affected source]

(c) One (1) natural gas-fired boiler, (using low-sulfur No. 1 or No. 2 fuel oil as a back-up), identified as EU-05, constructed in 1964, and modified in 1989, with a maximum design capacity of 190 MMBtu per hour heat input, equipped with a mud drum heat exchanger installed in 2013 and low NOx burners (two natural gas fired burners at 75 MMBtu per hour heat input each) for natural gas and/or fuel oil, and a multiclone for particulate control when combusting fuel oil, exhausting to stack 002 or 003. The boiler burner pilot light can ignite using propane.

[Under 40 CFR 63, Subpart DDDDD, this is an affected source]

(d) One (1) coal, natural gas, No. 1 or No. 2 fuel oil fired boiler, identified as EU-06, constructed in 1970, with economizers replaced in 2010, with a maximum design capacity of 190 MMBtu per hour heat input when combusting coal and/or fuel oil, and 150 MMBtu per hour heat input (two natural gas fired burners rated at 75 MMBtu per hour heat input each) when combusting natural gas, equipped with a mud drum heat exchanger installed in 2014, equipped with low NOx burners for natural gas and/or fuel oil, a multiclone and a jet pulse baghouse, identified as Boiler 6 Bag, for particulate control when combusting coal and/or fuel oil, permitted in 2008, and a continuous opacity monitor for monitoring opacity, exhausting to stack 003. In addition, the stack exhaust from boiler EU-06 can be treated by an activated carbon injection system for mercury control and a lime injection system for hydrogen chloride control.

[Under 40 CFR 63, Subpart DDDDD, this is an affected source]

(e) One (1) coal storage and handling system, with a maximum design throughput of 200 tons of coal per hour, consisting of the following:

(1) One (1) coal truck receiving system, consisting of an interior wet suppression system to control coal dust emissions during coal receiving, and two (2) truck hoppers. [326 IAC 6-3-2]

(2) Four (4) enclosed belt conveyors, and one (1) enclosed bucket conveyor, with particulate emissions controlled by a fabric filter system, with four (4) dust collectors, identified as DC1 through 4, located internally at various points along the enclosed conveyor system, with all dust collectors exhausting internally. [326 IAC 6-3-2]

(3) One (1) coal storage silo with a storage capacity of 1,000 tons of coal, with particulate emissions controlled by one (1) dust collector, identified as DC6, exhausting externally at vent 6. [326 IAC 6-3-2]

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) Natural gas-fired combustion sources with heat input equal to or less than ten (10) million Btu per hour heat input:

(1) Twenty-two (22) boilers constructed before 1972, with a combined total heat input of 29.130 MMBtu per hour. [326 IAC 6-2] [40 CFR 63, Subpart DDDDD]

(2) One (1) boiler constructed in 1977, with a heat input of 0.60 MMBtu per hour. [326 IAC 6-2] [40 CFR 63, Subpart DDDDD]

(3) One (1) boiler constructed in 1981, with a heat input of 0.110 MMBtu per hour. [326 IAC 6-2] [40 CFR 63, Subpart DDDDD]

(4) Sixty-six (66) boilers constructed after 1983, with a combined heat input of 145.25 MMBtu per hour. [326 IAC 6-2-4(a) and (b)] [40 CFR 63, Subpart DDDDD]

(5) Informatics East Building Boiler, constructed in 2008, with a heat input capacity of 1.44 MMBtu/hr. [326 IAC 6-2-4] [40 CFR 63, Subpart DDDDD]

(6) Hutton Honors College Furnace, constructed in 2008, with a heat input capacity of 0.432 MMBtu/hr. [326 IAC 6-2-4] [40 CFR 63, Subpart DDDDD]

(7) Three (3) natural gas-fired boilers, each constructed in 2009 and located at the Innovation Center, each with a heat input capacity of 1.1 MMBtu/hr. [326 IAC 6-2-4] [40 CFR 63, Subpart DDDDD]

(b) Degreasing operations that do not exceed 145 gallons per 12 months, except if subject to [326 IAC 20-6] [326 IAC 8-3-2] [326 IAC 8-3-8].

(c) Oil-fired emergency generators not exceeding 1,600 horsepower:

(1) One (1) emergency generator, identified as MSB-1, permitted in 2007, rated at 1,200 horsepower, located inside of utility structure. [40 CFR Part 60, Subpart IIII][40 CFR 63, Subpart ZZZZ]

(d) Two (2) pneumatic ash handling legs, identified as Ash Leg #1 and Ash Leg #2, permitted in 2008, with a maximum throughput capacity of 0.71 tons of fly ash per hour, emissions are controlled by water spray. [326 IAC 6-3-2]

(e) One (1) activated carbon injection system, constructed in 2008, consisting of one (1) activated carbon storage silo, with a maximum storage capacity of 52 tons and throughput of 1,200 lbs/hr, identified as Carbon Silo, controlled by a bin vent baghouse, identified as CS Bag, exhausting indoors to stack CS Vent. [326 IAC 6-3-2]

(f) One (1) lime injection system, constructed in 2008, consisting of one (1) lime storage silo, with a maximum storage capacity of 25 tons and throughput of 30 lbs/hr, identified as Lime Silo, controlled by a bin vent baghouse, identified as LS Bag, exhausting indoors to stack LS Vent. [326 IAC 6-3-2]

(g) Twenty Three (23) Diesel Emergency Generators:

(1) One (1) diesel emergency generators, identified as FQHSB-1, manufactured in 2006, with a maximum capacity of 282 hp, located outside the Foster Quad/Harper Buildings.
[Under 40 CFR 60, Subpart IIII, this is an affected source]
[Under 40 CFR 63, Subpart ZZZZ, this is an affected source]

(2) One (1) diesel emergency generators, identified as TTASB-1, manufactured in 2006, with a maximum capacity of 300 hp, located outside the Tulip Tree Apartments.
[Under 40 CFR 60, Subpart IIII, this is an affected source]
[Under 40 CFR 63, Subpart ZZZZ, this is an affected source]

(3) One (1) diesel emergency generator, identified as HAPSB-1, manufactured in 2007, with a maximum capacity of 60 hp, located outside the Henderson/Atwater Parking Area.
[Under 40 CFR 60, Subpart IIII, this is an affected source]
[Under 40 CFR 63, Subpart ZZZZ, this is an affected source]

(4) One (1) diesel emergency generator, identified as IUPD-1, manufactured in 2007, with a maximum capacity of 545 hp, located outside of the IU Police Department Building.
[Under 40 CFR 60, Subpart IIII, this is an affected source]
[Under 40 CFR 63, Subpart ZZZZ, this is an affected source]

(5) One (1) diesel emergency generator, identified as JHSB-1, manufactured in 2007, with a maximum capacity of 225 hp, located outside of Johnston Hall.
[Under 40 CFR 60, Subpart IIII, this is an affected source]
[Under 40 CFR 63, Subpart ZZZZ, this is an affected source]

(6) One (1) diesel emergency generator, identified as TQSB-1, manufactured in 2007, with a maximum capacity of 320 hp, located outside of Teter Quad Building.
[Under 40 CFR 60, Subpart IIII, this is an affected source]
[Under 40 CFR 63, Subpart ZZZZ, this is an affected source]

(7) One (1) diesel emergency generator, identified as MSB-1, manufactured in 2007, with a maximum capacity of 1,200 hp, located inside of the MSB-1 Building.
[Under 40 CFR 60, Subpart IIII, this is an affected source]
[Under 40 CFR 63, Subpart ZZZZ, this is an affected source]

(8) One (1) diesel emergency generator, identified as JDHSB-1, manufactured in 2007, with a maximum capacity of 80 hp, located at Jordan Hall.
[Under 40 CFR 60, Subpart IIII, this is an affected source]
[Under 40 CFR 63, Subpart ZZZZ, this is an affected source]

(9) One (1) diesel emergency generator, identified as WQSB-1, manufactured in 2007, with a maximum capacity of 225.6 hp, located at Wright Quad.
[Under 40 CFR 60, Subpart IIII, this is an affected source]
[Under 40 CFR 63, Subpart ZZZZ, this is an affected source]

(10) One (1) diesel emergency generator, identified as HCSB-1, manufactured in 2007, with a maximum capacity of 1,150 hp, located outside of the Health Center.
[Under 40 CFR 60, Subpart IIII, this is an affected source]
[Under 40 CFR 63, Subpart ZZZZ, this is an affected source]

(11) One (1) diesel emergency generator, identified as MSB-2, manufactured in 2008, with a maximum capacity of 1,490 hp, located at Simon Hall.
[Under 40 CFR 60, Subpart IIII, this is an affected source]
[Under 40 CFR 63, Subpart ZZZZ, this is an affected source]

(12) One (1) diesel emergency generator, identified as MSNSB-1, manufactured in 2008, with a maximum capacity of 258 hp, located at Memorial Stadium North.
[Under 40 CFR 60, Subpart IIII, this is an affected source]
[Under 40 CFR 63, Subpart ZZZZ, this is an affected source]

(13) One (1) diesel emergency generator, identified as BCSB-1, manufactured in 2008, with a maximum capacity of 360 hp, located at Basketball Center Cook Hall.
[Under 40 CFR 60, Subpart IIII, this is an affected source]
[Under 40 CFR 63, Subpart ZZZZ, this is an affected source]

(14) One (1) diesel emergency generator, identified as CHSB-1, manufactured in 2009, with a maximum capacity of 300 hp, located at Cedar Hall.
[Under 40 CFR 60, Subpart IIII, this is an affected source]
[Under 40 CFR 63, Subpart ZZZZ, this is an affected source]

(15) One (1) diesel emergency generator, identified as HPSB-1, manufactured in 2009, with a maximum capacity of 606 hp, located at HPER.
[Under 40 CFR 60, Subpart IIII, this is an affected source]
[Under 40 CFR 63, Subpart ZZZZ, this is an affected source]

(16) One (1) diesel emergency generator, identified as ICSB-1, manufactured in 2009, with a maximum capacity of 186 hp, located at IU Innovation Center.
[Under 40 CFR 60, Subpart IIII, this is an affected source]
[Under 40 CFR 63, Subpart ZZZZ, this is an affected source]

(17) One (1) diesel emergency generator, identified as MHSB-1, manufactured in 2009, with a maximum capacity of 56 hp, located outside of Mason Hall.
[Under 40 CFR 60, Subpart IIII, this is an affected source]
[Under 40 CFR 63, Subpart ZZZZ, this is an affected source]

(18) One (1) diesel emergency generator, identified as DCSB-1, manufactured in 2008, with a maximum capacity of 2,200 hp, located inside of Data Center #1.
[Under 40 CFR 60, Subpart IIII, this is an affected source]
[Under 40 CFR 63, Subpart ZZZZ, this is an affected source]

(19) One (1) diesel emergency generator, identified as DCSB-2, manufactured in 2008, with a maximum capacity of 2,200 hp, located inside of Data Center #2.
[Under 40 CFR 60, Subpart IIII, this is an affected source]
[Under 40 CFR 63, Subpart ZZZZ, this is an affected source]

(20) One (1) diesel emergency generator, identified as BBSB-1, manufactured in 2011, with a maximum capacity of 720 hp, located at Briscoe Building.
[Under 40 CFR 60, Subpart IIII, this is an affected source]
[Under 40 CFR 63, Subpart ZZZZ, this is an affected source]

(21) One (1) diesel emergency generator, identified as MACSB-1, manufactured in 2011, with a maximum capacity of 120 hp, located at the Musical Arts Center.
[Under 40 CFR 60, Subpart IIII, this is an affected source]
[Under 40 CFR 63, Subpart ZZZZ, this is an affected source]

(22) One (1) diesel emergency generator, identified as FQSB-1, manufactured in 2012, with a maximum capacity of 460 hp, located at Forest Quad.
[Under 40 CFR 60, Subpart IIII, this is an affected source]
[Under 40 CFR 63, Subpart ZZZZ, this is an affected source]

(23) One (1) diesel emergency generator, identified as JSMSB-1, manufactured in 2012, with a maximum capacity of 475 hp, located at the Jacobs School of Music.
[Under 40 CFR 60, Subpart IIII, this is an affected source]
[Under 40 CFR 63, Subpart ZZZZ, this is an affected source]

(h) The following existing unpermitted Forty Two (42) Diesel Emergency Generators are being incorporated in the permit as part of this permitting action.

(24) One (1) diesel emergency generator, identified as FHSB-1, constructed in 1957 with a maximum capacity of 67.5 hp, located at Field House / 604.
[Under 40 CFR 63, Subpart ZZZZ, this is an affected source]

(25) One (1) diesel emergency generator, identified as HASB-1, constructed in 1970 with a maximum capacity of 26.2 hp, located at Hall Admin. / 463.
[Under 40 CFR 63, Subpart ZZZZ, this is an affected source]

(26) One (1) diesel emergency generator, identified as FHSB-2, constructed in 1972 with a maximum capacity of 22.5 hp, located at Franklin Hall / 007.
[Under 40 CFR 63, Subpart ZZZZ, this is an affected source]

(27) One (1) diesel emergency generator, identified as LBSB-1, constructed in 1981 with a maximum capacity of 150 hp, located at Law Building / 001.
[Under 40 CFR 63, Subpart ZZZZ, this is an affected source]

(28) One (1) diesel emergency generator, identified as POPSB-1, constructed in 1985 with a maximum capacity of 255 hp, located at Poplars Bldg. / 008.
[Under 40 CFR 63, Subpart ZZZZ, this is an affected source]

(29) One (1) diesel emergency generator, identified as SBSB-4, constructed in 1986 with a maximum capacity of 765 hp, located at Service Bldg / 630.
[Under 40 CFR 63, Subpart ZZZZ, this is an affected source]

(30) One (1) diesel emergency generator, identified as MASB-1, constructed in 1989 with a maximum capacity of 91.5 hp, located at Music Addition / 148.
[Under 40 CFR 63, Subpart ZZZZ, this is an affected source]

(31) One (1) diesel emergency generator, identified as CASB-1, constructed in 1990 with a maximum capacity of 900 hp, located at Chemistry Addition / 072.
[Under 40 CFR 63, Subpart ZZZZ, this is an affected source]

(32) One (1) diesel emergency generator, identified as JHSB-2, constructed in 1990 with a maximum capacity of 600 hp, located at Jordan Hall / 107.
[Under 40 CFR 63, Subpart ZZZZ, this is an affected source]

(33) One (1) diesel emergency generator, identified as SBSB-3, constructed in 1991 with a maximum capacity of 30 hp, located at Student Building / 017.
[Under 40 CFR 63, Subpart ZZZZ, this is an affected source]

(34) One (1) diesel emergency generator, identified as CEESB-1, constructed in 1991 with a maximum capacity of 600 hp, located at W.W. Wright (CEE) / 245.
[Under 40 CFR 63, Subpart ZZZZ, this is an affected source]

(35) One (1) diesel emergency generator, identified as IMUSB-1, constructed in 1993 with a maximum capacity of 750 hp, located at Memorial Union / 053.
[Under 40 CFR 63, Subpart ZZZZ, this is an affected source]

(36) One (1) diesel emergency generator, identified as GSSB-1, constructed in 1994 with a maximum capacity of 30 hp, located at Geological Sciences /417.
[Under 40 CFR 63, Subpart ZZZZ, this is an affected source]

(37) One (1) diesel emergency generator, identified as RSSB-1, constructed in 1994 with a maximum capacity of 187.5 hp, located at Recreational Sports / 475.
[Under 40 CFR 63, Subpart ZZZZ, this is an affected source]

(38) One (1) diesel emergency generator, identified as RTVSB-1, constructed in 1996 with a maximum capacity of 300 hp, located at Radio/TV / 158.
[Under 40 CFR 63, Subpart ZZZZ, this is an affected source]

(39) One (1) diesel emergency generator, identified as AUSB-1, constructed in 1999 with a maximum capacity of 600 hp, located at Auditorium / 171.
[Under 40 CFR 63, Subpart ZZZZ, this is an affected source]

(40) One (1) diesel emergency generator, identified as CHPSB-1, constructed in 1999 with a maximum capacity of 1109 hp, located at Cen. Heat Plant / 445.
[Under 40 CFR 63, Subpart ZZZZ, this is an affected source]

(41) One (1) diesel emergency generator, identified as WQSB-2, constructed in 1999 with a maximum capacity of 600 hp, located at Willkie Quad / 299.
[Under 40 CFR 63, Subpart ZZZZ, this is an affected source]

(42) One (1) diesel emergency generator, identified as ALFSB-1, constructed in 2000 with a maximum capacity of 335 hp, located at ALF.
[Under 40 CFR 63, Subpart ZZZZ, this is an affected source]

(43) One (1) diesel emergency generator, identified as RHSB-1, constructed in 2000 with a maximum capacity of 525 hp, located at Read Hall / 227.
[Under 40 CFR 63, Subpart ZZZZ, this is an affected source]

(44) One (1) diesel emergency generator, identified as CVSB-1, constructed in 2001 with a maximum capacity of 300 hp, located at Campus View / 529.
[Under 40 CFR 63, Subpart ZZZZ, this is an affected source]

(45) One (1) diesel emergency generator, identified as EGSB-1, constructed in 2001 with a maximum capacity of 450 hp, located at Eigenmann / 313.
[Under 40 CFR 63, Subpart ZZZZ, this is an affected source]

(46) One (1) diesel emergency generator, identified as SHSB-1, constructed in 2001 with a maximum capacity of 375 hp, located at Spruce Hall / 298.
[Under 40 CFR 63, Subpart ZZZZ, this is an affected source]

(47) One (1) diesel emergency generator, identified as TDSB-1, constructed in 2001 with a maximum capacity of 412.5 hp, located at Lee Norvelle Theatre Drama /172.
[Under 40 CFR 63, Subpart ZZZZ, this is an affected source]

(48) One (1) diesel emergency generator, identified as MHSB-2, constructed in 2001 with a maximum capacity of 600 hp, located at McNutt / 439.
[Under 40 CFR 63, Subpart ZZZZ, this is an affected source]

(49) One (1) diesel emergency generator, identified as MHSB-3, constructed in 2001 with a maximum capacity of 750 hp, located at Myers Hall / 101.
[Under 40 CFR 63, Subpart ZZZZ, this is an affected source]

(50) One (1) diesel emergency generator, identified as ALSB-1, constructed in 2002 with a maximum capacity of 90 hp, located at Animal Lab / 411.
[Under 40 CFR 63, Subpart ZZZZ, this is an affected source]

(51) One (1) diesel emergency generator, identified as USASB-1, constructed in 2005 with a maximum capacity of 450 hp, located at Union St Apts / 296.
[Under 40 CFR 63, Subpart ZZZZ, this is an affected source]

(52) One (1) diesel emergency generator, identified as CIBSB-1, constructed in 2007 with a maximum capacity of 469 hp, located at CIB / 578.
[Under 40 CFR 60, Subpart IIII, this is an affected source]
[Under 40 CFR 63, Subpart ZZZZ, this is an affected source]

(53) One (1) diesel emergency generator, identified as BASB-1, constructed in 2012 with a maximum capacity of 147 hp, located at Baseball/ 593.
[Under 40 CFR 60, Subpart IIII, this is an affected source]

[Under 40 CFR 63, Subpart ZZZZ, this is an affected source]

(54) One (1) diesel emergency generator, identified as SBSB-2, constructed in 2012 with a maximum capacity of 99 hp, located at Softball/ 594.
[Under 40 CFR 60, Subpart IIII, this is an affected source]
[Under 40 CFR 63, Subpart ZZZZ, this is an affected source]

(55) One (1) diesel emergency generator, identified as OPSB-1, constructed in 2014 with a maximum capacity of 375 hp, located at Optometry / 065
[Under 40 CFR 60, Subpart IIII, this is an affected source]
[Under 40 CFR 63, Subpart ZZZZ, this is an affected source]

(56) One (1) diesel emergency generator, identified as WLSB-1, constructed in 2014 with a maximum capacity of 1206 hp, located at Wells Library /GISB 209.
[Under 40 CFR 60, Subpart IIII, this is an affected source]
[Under 40 CFR 63, Subpart ZZZZ, this is an affected source]

(57) One (1) diesel emergency generator, identified as AHSB-2, constructed in 2015 with a maximum capacity of 668 hp, located at Assembly Hall / 603.
[Under 40 CFR 60, Subpart IIII, this is an affected source]
[Under 40 CFR 63, Subpart ZZZZ, this is an affected source]

(58) One (1) diesel emergency generator, identified as FWSB-1, constructed in 2016 with a maximum capacity of 536 hp, located at Food Warehouse / 615.
[Under 40 CFR 60, Subpart IIII, this is an affected source]
[Under 40 CFR 63, Subpart ZZZZ, this is an affected source]

(59) One (1) diesel emergency generator, identified as MESH-1, constructed in 2018 with a maximum capacity of 683.91 hp, located at MESH.
[Under 40 CFR 60, Subpart IIII, this is an affected source]
[Under 40 CFR 63, Subpart ZZZZ, this is an affected source]

(60) One (1) diesel emergency generator, identified as 2NDSB-1, constructed in 2018 with a maximum capacity of 131 hp, located at 2427 E 2ND ST.
[Under 40 CFR 60, Subpart IIII, this is an affected source]
[Under 40 CFR 63, Subpart ZZZZ, this is an affected source]

(61) One (1) diesel emergency generator, identified as ALFSB-2, constructed in 2018 with a maximum capacity of 201 hp, located at ALF.
[Under 40 CFR 60, Subpart IIII, this is an affected source]
[Under 40 CFR 63, Subpart ZZZZ, this is an affected source]

(62) One (1) diesel emergency generator, identified as LHSB-1, constructed in 2018 with a maximum capacity of 324 hp, located at Luddy Hall.
[Under 40 CFR 60, Subpart IIII, this is an affected source]
[Under 40 CFR 63, Subpart ZZZZ, this is an affected source]

(63) One (1) diesel emergency generator, identified as MSEZSB-1, constructed in 2018 with a maximum capacity of 450 hp, located at Memorial Stadium South End Zone.
[Under 40 CFR 60, Subpart IIII, this is an affected source]
[Under 40 CFR 63, Subpart ZZZZ, this is an affected source]

(64) One (1) diesel emergency generator, identified as SPEASB-1, constructed in 2018 with a maximum capacity of 670 hp, located at SPEA / 452.
[Under 40 CFR 60, Subpart IIII, this is an affected source]
[Under 40 CFR 63, Subpart ZZZZ, this is an affected source]

(65) One (1) diesel emergency generator, identified as SWSB-1, constructed in 2018 with a maximum capacity of 754 hp, located at Swain West.
[Under 40 CFR 60, Subpart IIII, this is an affected source]
[Under 40 CFR 63, Subpart ZZZZ, this is an affected source]

(i) The source also has following four (4) existing Off Campus Diesel Emergency Generators.

(66) One (1) diesel emergency generator, identified as Off Campus, constructed in 1996 with a maximum capacity of 52.5 hp, located at Morgan-Monroe Observatory / 690.

(67) One (1) diesel emergency generator, identified as Off Campus, constructed in 1999 with a maximum capacity of 30 hp, located at Kent Farm / 700A.

(68) One (1) diesel emergency generator, identified as Off Campus, constructed in 2007 with a maximum capacity of 145 hp, located at Sare Rd Transmitter.

(69) One (1) diesel emergency generator, identified as Off Campus, constructed in 2012 with a maximum capacity of 315 hp, located at Sare Rd Transmitter /800A.

(j) Fifteen (15) portable non-road Diesel Emergency Generators.

(70) One (1) diesel emergency generator, identified as PORT-1, constructed in 2002 with a maximum capacity of 80.46 hp, located at Service Building.
[Under 40 CFR 63, Subpart ZZZZ, this is an affected source]

(71) One (1) diesel emergency generator, identified as PORT-2, constructed in 1999 with a maximum capacity of 22.80 hp, located at Service Building/630.
[Under 40 CFR 63, Subpart ZZZZ, this is an affected source]

(72) Two (2) diesel emergency generators, identified as PORT-3 and PORT-4, each, constructed in 1999 with a maximum capacity of 80.46 hp, located at Union St. Chiller Plant – RPS.
[Under 40 CFR 63, Subpart ZZZZ, this is an affected source]

(73) Four (4) diesel emergency generator, identified as PORT-5, PORT-6, PORT-7 and PORT-8, each, constructed in 1999 with a maximum capacity of 13 hp, located at Service Building.
[Under 40 CFR 63, Subpart ZZZZ, this is an affected source]

(74) One (1) diesel emergency generator, identified as PORT-9, constructed in 2007 with a maximum capacity of 8.05 hp, located at service Building-Carpenter.
[Under 40 CFR 60, Subpart IIII, this is an affected source]
[Under 40 CFR 63, Subpart ZZZZ, this is an affected source]

(75) Three (3) diesel emergency generator, identified as PORT-10, PORT-11 and PORT-12, each, constructed in 2006 with a maximum capacity of 156 hp, 2.68 hp and 2.68 hp respectively, located at service Building.
[Under 40 CFR 60, Subpart IIII, this is an affected source]
[Under 40 CFR 63, Subpart ZZZZ, this is an affected source]

(76) Three (3) diesel emergency generator, identified as PORT-13, PORT-14 and PORT-15, constructed in 2015, 2017 and 2008 with a maximum capacity of 23.5 hp, 23.5 hp and 24.5 hp respectively, located at Utilities Building.
[Under 40 CFR 60, Subpart IIII, this is an affected source]

[Under 40 CFR 63, Subpart ZZZZ, this is an affected source]

A.4 Other Insignificant Activities

(h) Woodworking area for maintenance, installed in 2007, equipped with a baghouse with an exhaust flow rate of 11,700 CFM.

(i) One (1) natural gas-fired make-up air unit (direct heat source), constructed in 2009, located at the Innovation Center, with a heat input capacity of 0.7 MMBtu/hr.

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, T105-41051-00005, is issued for a fixed term of five (5) years from the issuance date of this permit, as determined in accordance with IC 4-21.5-3-5(f) and IC 13-15-5-3. Subsequent revisions, modifications, or amendments of this permit do not affect the expiration date of this permit.

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

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

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 July 1 of each year to:

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

and

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

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

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

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

(2) The compliance status;

(3) Whether compliance was continuous or intermittent;

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

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

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

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

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

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

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

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

The Permittee shall implement the PMPs.

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

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

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

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

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

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

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

The Permittee shall implement the PMPs.

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

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

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

(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 Southeast 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
Southeast Regional Office phone: (812) 358-2027; fax: (812) 358-2058.

(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 T105-41051-00005 and issued pursuant to permitting programs approved into the state implementation plan have been either:

(1) incorporated as originally stated,

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

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

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

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

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

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

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

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

(1) That this permit contains a material mistake.

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

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

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

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

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

(a) The application for renewal shall be submitted using the application form or forms prescribed by IDEM, OAQ and shall include the information specified in 326 IAC 2-7-4. Such information shall be included in the application for each emission unit at this source, except those emission units included on the trivial or insignificant activities list contained in 326 IAC 2-7-1(21) and 326 IAC 2-7-1(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 317-233-4230 (ask for OAQ, Billing, Licensing, and Training Section), to determine the appropriate permit fee.

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

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

SECTION C SOURCE OPERATION CONDITIONS

Entire Source

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

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

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

C.2 Opacity [326 IAC 5-1]

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

(A) Asbestos removal or demolition start date;

(B) Removal or demolition contractor; or

(C) Waste disposal site.

(c) The Permittee shall ensure that the notice is postmarked or delivered according to the guidelines set forth in 326 IAC 14-10-3(2).

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

All required notifications shall be submitted to:

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

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

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

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

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

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

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

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

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

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

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

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

Compliance Requirements [326 IAC 2-1.1-11]

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

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

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

C.10 Compliance Monitoring [326 IAC 2-7-5(3)][326 IAC 2-7-6(1)][40 CFR 64][326 IAC 3-8]

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

(d) For monitoring required by CAM, except for, as applicable, monitoring malfunctions, associated repairs, and required quality assurance or control activities (including, as applicable, calibration checks and required zero and span adjustments), the Permittee shall conduct all monitoring in continuous operation (or shall collect data at all required intervals) at all times that the pollutant-specific emissions unit is operating. Data recorded during monitoring malfunctions, associated repairs, and required quality assurance or control activities shall not be used for purposes of this part, including data averages and calculations, or fulfilling a minimum data availability requirement, if applicable. The owner or operator shall use all the data collected during all other periods in assessing the operation of the control device and associated control system. A monitoring malfunction is any sudden, infrequent, not reasonably preventable failure of the monitoring to provide valid data. Monitoring failures that are caused in part by poor maintenance or careless operation are not malfunctions.

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

(a) When required by any condition of this permit, an analog instrument used to measure a parameter related to the operation of an air pollution control device shall have a scale such that the expected maximum reading for the normal range shall be no less than twenty percent (20%) of full scale. The analog instrument shall be capable of measuring values outside of the normal range.

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

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

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

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

(a) The Permittee shall maintain the most recently submitted written emergency reduction plans (ERPs) consistent with safe operating procedures.

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

C.13 Risk Management Plan [326 IAC 2-7-5(11)][40 CFR 68]

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

C.14 Response to Excursions or Exceedances [40 CFR 64][326 IAC 3-8][326 IAC 2-7-5][326 IAC 2-7-6]

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

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

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

(1) initial inspection and evaluation;

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

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

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

(1) monitoring results;

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

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

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

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

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

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

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

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

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

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

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

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

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

(2) Indicate estimated actual emissions of regulated pollutants as defined by 326 IAC 2-7-1(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.17 General Record Keeping Requirements [326 IAC 2-7-5(3)][326 IAC 2-7-6] [326 IAC 2-2][326 IAC 2-3]

(a) Records of all required monitoring data, reports and support information required by this permit shall be retained for a period of at least five (5) years from the date of monitoring sample, measurement, report, or application. Support information includes the following, 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.18 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 project at an existing emissions unit shall be submitted no later than sixty (60) days after the end of the year and contain the following:

(1) The name, address, and telephone number of the major stationary source.

(2) The annual emissions calculated in accordance with (d)(1) and (2) in Section C - General Record Keeping Requirements.

(3) The emissions calculated under the actual-to-projected actual test stated in 326 IAC 2-2-2(d)(3) and/or 326 IAC 2-3-2(c)(3).

(4) Any other information that the Permittee wishes to include in this report such as an explanation as to why the emissions differ from the preconstruction projection.

Reports required in this part shall be submitted to:

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

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

Stratospheric Ozone Protection

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

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

SECTION D.1 EMISSIONS UNIT OPERATION CONDITIONS

Emissions Unit Description [326 IAC 2-7-5(14)]:

(a) One (1) natural gas-fired boiler, (using low-sulfur No. 1 or No. 2 fuel oil as a back-up), identified as EU-07, approved for construction in 2007, including a mud drum heat exchanger, with a maximum design capacity of 217 MMBtu per hour heat input when combusting natural gas and 208 MMBtu per hour heat input when combusting fuel oil, and equipped with low NOx burners and induced flue gas recirculation for NOx control, with continuous emissions monitors (CEM) for monitoring CO and NOx, exhausting to stack 002. The boiler burner pilot light can ignite using propane.
[Under 40 CFR 60, Subpart Db, this is an affected source]

(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 Prevention of Significant Deterioration (PSD) Minor Limits [326 IAC 2-2]

In order to render the requirements of 326 IAC 2-2 (Prevention of Significant Deterioration (PSD)) not applicable, the Permittee shall comply with the following:

(a) Fuel Oil Usage Limit
The input of No.1 and No.2 fuel to the EU-7 boiler shall be limited to less than 329,000 gallons per twelve (12) consecutive month period, with compliance determined at the end of each month.

(b) SO_2
The sulfur content in the No.1 or No.2 fuel oil used in Boiler EU-07 shall not exceed 0.1 percent.

(c) The emissions of PM_{10} while burning No.1 or No.2 fuel oil shall not exceed 3.3 pounds per 1,000 gallons of No.1 or No.2 fuel oil burned.

(d) NOx
The emissions of NOx while burning natural gas shall not exeed 36.72 lb/MMCF (this value equals 0.036 lb/MMBtu using natural gas heating value of 1020 MMBtu/MMCF), with a 30 day averaging period for compliance determination. The emissions of NOx while burning No. 1 or No. 2 fuel oil shall not exceed 12.51 lb/Kgal.

Compliance with these limits, combined with the potential to emit PM10, NOx and SO2 from all the other emission units in this modification, shall limit the total potential to emit of PM_{10} emissions to less than fifteen (15) tons per year, SO_2 emission to less than 40 tons/yr and NOx to less than forty (40) tons/year, and shall render the requirements of 326 IAC 2 2 (PSD) not applicable to the 2007 modification.

D.1.2 Particulate Emission Limitations for Sources of Indirect Heating [326 IAC 6-2-4]

Pursuant to 326 IAC 6-2-4(a), the PM emissions from EU-07, shall not exceed 0.18 pounds of particulate matter per million British thermal units heat input.

D.1.3 Sulfur Dioxide (SO_2) Emission Limitations [326 IAC 7-1.1]

Pursuant to 326 IAC 7-1.1-2, sulfur dioxide emissions shall not exceed 0.5 pounds per million British thermal units (lb/MMBtu) of heat input from boiler EU-07 when combusting No. 1 or No. 2 fuel oil.

D.1.4 Preventive Maintenance Plan [326 IAC 2-7-5(12)]

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

Compliance Determination Requirements

D.1.5 Sulfur Dioxide Emissions and Sulfur Content [326 IAC 3-7] [326 IAC 7-2] [326 IAC 7-1.1-2]

To determine the compliance status with the sulfur content limit of the fuel oil in D,1,1(b) and the sulfur dioxide emissions limit in D.1.3, the Permittee shall perform sampling of the sulfur-bearing fuels 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 million Btu heat input for distillate oil combustion or does not exceed a sulfur content of 0.1 percent by:

(1) Providing vendor analysis of fuel delivered, if accompanied by a vendor certification; or

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

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

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

(b) Compliance may also be determined by conducting a stack test for sulfur dioxide emissions from boiler EU-07, using 40 CFR 60, Appendix A, Method 6 in accordance with the procedures in 326 IAC 3-6.

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

D.1.6 Continuous Emissions Monitoring System (CEMS) [326 IAC 3-5] [40 CFR Part 60]

(a) Pursuant to 326 IAC 3-5-1 and 40 CFR Part 60, the Permittee must calibrate, certify, operate and maintain a continuous emission monitoring system (CEMS) for measuring CO and NO_X emissions from Boiler EU-07. Each CEMS must meet all applicable performance specifications of 326 IAC 3-5-2 and 40 CFR Part 60. The data from the respective CEMS shall be used to determine compliance with Condition D.1.1.

(b) 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 breakdowns, repairs, calibration checks, and zero and span adjustments.

(c) All CEMS are subject to monitor system certification requirements pursuant to 326 IAC 3-5-3.

(d) Nothing in this permit shall excuse the Permittee from complying with the requirements to operate a CEMS pursuant to 326 IAC 3-5 and/or 40 CFR Part 60.

(e) Upon successful completion of the certification of the NOx and CO CEMS, the Permittee shall submit all required certification testing information 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

D.1.7 Maintenance of Continuous Emission Monitoring System [326 IAC 2-7-5(3)(A)(iii)]

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

(b) The Permittee shall implement its CO and NOx CEMS operation and maintenance plan (O&M Plan) any time the CO and NOx CEMs are down for four (4) or more hours. The backup system for the CO and NOx CEMS will include a calibrated online process control CO and NOx analyzer on a representative portion of the stack gas flow. The primary CEMS shall be returned to operation as soon as practicable.

(c) 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 or 40 CFR 60.

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

D.1.8 Visible Emissions Notations

(a) Visible emission (VE) notations of stack exhaust 002 shall be performed once per day during normal daylight operations while boiler EU-07 combusts fuel oil. A trained employee shall record whether emissions are normal or abnormal.

(b) If abnormal emissions are observed at exhaust 002 while boiler EU-07 combusts fuel oil, the Permittee shall take a reasonable response. Section C - Response to Excursions or Exceedances contains the Permittee's obligation with regard to the reasonable response steps required by this condition. Observation of abnormal emissions that do not violate an applicable opacity limit is not a deviation from this permit. Failure to take response steps in accordance shall be considered a deviation from this permit.

(c) “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.

(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 boilers.

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

D.1.9 Record Keeping Requirements

(a) To document the compliance status with Condition D.1.1, the Permittee shall maintain records of monthly fuel usage for natural gas, No. 1 and No. 2 fuel oil combusted in the boiler.

(b) To document the compliance status with Conditions D.1.1, D.1.2, and D.1.4, the Permittee shall maintain records in accordance with (1) through (7) below.

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

(2) No. 1 and No. 2 fuel oil usage and natural gas usage since last compliance determination period and NOx and SO_2 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, the natural gas fired boiler certification does require the certification by a "Responsible Official" as defined by 326 IAC 2-7-1(35); and

(4) All fuel sampling and analysis data, pursuant to 326 IAC 7-2, and data collected in accordance with Condition D.1.4.

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

(5) Fuel supplier certifications.

(6) The name of the fuel supplier; and

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

The Permittee shall retain records of all recording/monitoring data and support information for a period of five (5) years, or longer if specified elsewhere in this permit, from the date of the monitoring sample, measurement, or report. Support information includes all calibration and maintenance records and all original strip-chart recordings for continuous monitoring instrumentation, and copies of all reports required by this permit.

(c) To document the compliance status with Condition D.1.1(d), the Permittee shall maintain records of the emission rates of NOx in pounds per MMCF and pounds per Kgal based on CEMS data.

(d) To document the compliance status with Condition D.1.5, the Permittee shall maintain records of daily visible emission notations of the stack 002 exhaust, during times when fuels other than natural gas are combusted. The Permittee shall include in its daily record when a visible emission notation is not taken and the reason for the lack of a visible emission notation (e.g. the process did not operate that day).

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

D.1.10 Reporting Requirements

A quarterly summary of the information to document the compliance status with Condition D.1.1 (a) shall be submitted using the reporting forms located at the end of this permit or their equivalent, not later than thirty (30) days after the end of the quarter being reported. Section C - General Reporting 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.2 EMISSIONS UNIT OPERATION CONDITIONS

Emissions Unit Description [326 IAC 2-7-5(14)]:

(b) Two (2) coal, natural gas, No. 1 or No. 2 fuel oil fired boilers, identified as EU-03 and EU-04, both constructed in 1959, with economizers replaced in 2010, with a maximum design capacity of 125 MMBtu per hour heat input each (operating at a maximum capacity of 100 MMBtu per hour heat input each when combusting coal or a combination of fuels), and with a maximum design capacity of 80 MMBtu per hour heat input each when combusting natural gas and/or fuel oil, each equipped with low NOx burners for natural gas and/or fuel oil, and each with a multiclone and a jet pulse baghouse, identified as Boiler 3 Bag and Boiler 4 Bag including a bag leak detection system, for particulate control, permitted in 2008, when combusting coal and/or fuel oil, both exhausting at stack 002. In addition, the stack exhaust from boilers EU-03 and EU-04 can be treated by an activated carbon injection system for mercury control and a lime injection system for hydrogen chloride control.

[Under 40 CFR 63, Subpart DDDDD, this is an affected source]

(c) One (1) natural gas, No. 1 or No. 2 fuel oil fired boiler, identified as EU-05, constructed in 1964, and modified in 1989, with a maximum design capacity of 190 MMBtu per hour heat input, equipped with a mud drum heat exchanger installed in 2013 and low NOx burners (two natural gas fired burners at 75 MMBtu per hour heat input each) for natural gas and/or fuel oil, and a multiclone for particulate control when combusting fuel oil, exhausting to stack 002 or 003. The boiler burner pilot light can ignite using propane.

[Under 40 CFR 63, Subpart DDDDD, this is an affected source]

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

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

D.2.1 Particulate Emission Limitations for Sources of Indirect Heating [326 IAC 6-2-3]

(a) Pursuant to 326 IAC 6-2-3(d), the PM emissions from EU-03 and EU-04, shall not exceed 0.8 pounds of particulate matter per million British thermal unit heat input each.

(b) Pursuant to 326 IAC 6-2-3(b)(Particulate emission limitations for sources of indirect heating: emission limitations for facilities specified in 326 IAC 6-2-1(c)), the PM emissions from EU-05, shall not exceed 0.62 pounds of particulate matter per million British thermal unit heat input.

D.2.2 Sulfur Dioxide (SO_2) Emission Limitations [326 IAC 7-1.1]

(a) Pursuant to 326 IAC 7-1.1-2 (Sulfur Dioxide Emission Limitations), sulfur dioxide emissions from each boiler, EU-03 and EU-04, shall not exceed 6.0 pounds per million British thermal units (lb/MMBtu) of heat input when combusting coal, and when combusting coal and oil simultaneously, and 0.5 pounds per million British thermal unit (lb/MMBtu) of heat input when combusting No.1 or No.2 fuel oil.

(b) Pursuant to 326 IAC 7-1.1-2 (Sulfur Dioxide Emission Limitations), sulfur dioxide emissions shall not exceed 0.5 pounds per million British thermal unit (lb/MMBtu) of heat input from boiler EU-05 when combusting No.1 or No.2 fuel oil.

D.2.3 Heat Input Capacity Limitations

Pursuant to 1265 Exemption Qualification 105-8180, issued February 24, 1997, the total heat input to boilers EU-03 and EU-04 when burning coal, natural gas, No. 1 fuel oil or No. 2 fuel oil, or any combination of these three fuels shall not exceed 100 million British thermal units per hour for each boiler.

D.2.4 Prevention of Significant Deterioration (PSD) Minor Limit [326 IAC 2-2]

In order to render the requirements of 326 IAC 2-2 (Prevention of Significant Deterioration (PSD)) not applicable, the Permittee shall comply with the following:

(a) The total input of natural gas to boiler EU-05 shall not exceed 870 MMCF per twelve (12) consecutive month period, with compliance determined at the end of each month.

For purposes of determining compliance, every 3.84 kilo-gallons of No. 1 or No. 2 fuel oil combusted shall be equivalent to 1 MMCF of natural gas based on NOx emissions and 0.08% sulfur content of No. 1 fuel oil and 0.49% sulfur content of No. 2 fuel oil.

(b) The total input of No. 2 fuel oil to boiler EU-05 shall not exceed 1,120 kgals per (12) twelve consecutive month period, with compliance determined at the end of each month.

For purposes of determining compliance, every kilo-gallon of No. 1 fuel oil combusted shall be equivalent to 5.89 kgal of No. 2 fuel oil based on SO_2 emissions and 0.08% sulfur content of No. 1 fuel oil and 0.49% sulfur content of No. 2 fuel oil, and every MMCF of natural gas burned shall be equivalent to 0.009 kgal of No. 2 fuel oil based on SO_2 emissions and 0.49% sulfur content of No. 2 fuel oil.

Compliance with these limits, combined with the potential to emit PM10, NOx and SO2 from all the other emission units in this modification, shall limit the total potential to emit of PM_{10} emissions to less than fifteen (15) tons per year, SO_2 emission to less than 40 tons/yr and NOx to less than forty (40) tons/year, and shall render the requirements of 326 IAC 2 2 (PSD) not applicable to the 1989 modification.

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

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

Compliance Determination Requirements

D.2.6 Testing Requirements [326 IAC 2-7-6(1),(6)] [326 IAC 2-1.1-11]

In order to demonstrate compliance with condition D.2.1, the Permittee shall perform PM testing for the coal-fired boilers, identified as EU-03 and EU-04, utilizing methods as approved by the Commissioner at least once every five (5) calendar years from the date of the most recent valid compliance demonstration .

Testing shall be conducted in accordance with the provisions of 326 IAC -3-6 (Source Sampling Procedures). Section C – Performance Testing contains the Permittee’s obligation with regard to the performance testing required by this condition. PM10 and PM2.5 includes filterable and condensable PM.

D.2.7 Natural Gas Equivalents - Calculations for NOx Emissions

The amount of natural gas and natural gas equivalents used shall be determined as follows:

Amount of natural gas and natural gas equivalents used = ((EU-05 No. 1 fuel oil usage in kgal/yr)/(3.84 kgal/MMCF)) + ((EU-05 No. 2 fuel oil usage in kgal/yr)/(3.84 kgal/MMCF)) + (EU-05 natural gas usage in MMCF/yr)

D.2.8 Fuel Oil Equivalents - Calculations for SO_2 Emissions

The amount of No. 2 fuel oil and No. 2 fuel oil equivalents used shall be determined as follows:

Amount of No. 2 fuel oil and No. 2 fuel oil equivalents used = (EU-05 No. 1 fuel oil usage in kgal/yr * 5.89 kgal of No. 2 fuel oil/kgal of No. 1 fuel oil) + (EU-05 No. 2 fuel oil usage in kgal/yr) + (EU-05 natural gas usage in MMCF/yr * 0.009 kgal No. 2 fuel oil/MMCF natural gas)

D.2.9 Particulate Control [326 IAC 2-7-6(6)]

(a) The multiclones for particulate control shall be in operation at all times when boilers EU-03 and EU-04 are combusting coal.

(b) The baghouses for particulate control shall be in operation at all times (except periods of boiler startup) boilers EU-03 and/or EU-04 are in operation and combusting coal.

(c) In the event that bag failure is observed in a multi-compartment baghouse, if operations will continue for ten (10) days or more after the failure is observed before the failed units will be repaired or replaced, the Permittee shall promptly notify the IDEM, OAQ of the expected date the failed units will be repaired or replaced. The notification shall also include the status of the applicable compliance monitoring parameters with respect to normal, and the results of any response actions taken up to the time of notification.

D.2.10 Sulfur Dioxide Emissions and Sulfur Content [326 IAC 3-7] [326 IAC 7-2] [326 IAC 7-1.1-2]

To determine the compliance status with the sulfur dioxide emissions limit in D.2.2(a), the Permittee shall perform sampling of the sulfur-bearing fuels utilizing one of the following options:

(a) Pursuant to 326 IAC 7-2-1(c), the Permittee shall demonstrate that the sulfur dioxide emissions do not exceed six (6.0) pounds per MMBtu using a calendar month average when EU-03 and EU-04 are combusting coal, or coal in combination with another fuel.

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

  (1) Coal sampling shall be performed using the methods specified in 326 IAC 3-7-2(a), and sample preparation and analysis shall be performed as specified in 326 IAC 3-7-2(c), (d), and (e); or

  (2) Pursuant to 326 IAC 3-7-2(b)(2) and 326 IAC 3-7-3, manual or other non-ASTM automatic sampling and analysis procedures may be used upon a demonstration, submitted to the department for approval, that such procedures provide sulfur dioxide emission estimates representative either of estimates based on coal sampling and analysis procedures specified in 326 IAC 3-7-2 or of continuous emissions monitoring; or

  (3) The Permittee shall meet the minimum sampling requirements specified in 326 IAC 3-7-2(b)(3), and sample preparation and analysis shall be performed as specified in 326 IAC 3-7-2(c), (d), and (e).

(c) Upon written notification to IDEM by a facility owner or operator, continuous emission monitoring data collected and reported pursuant to 326 IAC 3-5 may be used as the means for determining compliance with the emission limitations in 326 IAC 7. Upon such notification, the other requirements of 326 IAC 7-2 shall not apply. [326 IAC 7-2-1(g)]

D.2.11 Sulfur Dioxide Emissions and Sulfur Content [326 IAC 3-7] [326 IAC 7-2] [326 IAC 7-1.1-2]

To determine the compliance status with the sulfur dioxide emissions limit in D.2.2(b), the Permittee shall perform sampling of the sulfur-bearing fuels utilizing one of the following options, when EU-03, EU-04, and EU-05 are combusting fuel oil, or fuel oil in combination with natural gas:

(a) Pursuant to 326 IAC 3-7-4, 326 IAC 7-2, and 326 IAC 7-1.1-2, the Permittee shall demonstrate that the sulfur dioxide 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 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.

(c) Upon written notification to IDEM by a facility owner or operator, continuous emission monitoring data collected and reported pursuant to 326 IAC 3-5 may be used as the means for determining compliance with the emission limitations in 326 IAC 7. Upon such notification, the other requirements of 326 IAC 7-2 shall not apply. [326 IAC 7-2-1(g)]

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

D.2.12 Visible Emissions Notations [326 IAC 2-7-6(1)] [326 IAC 2-7-5(1)]

(a) Visible emission (VE) notations of stack exhaust 002 shall be performed once per day during normal daylight operations while boilers EU-03 and EU-04 combust coal and/or fuel oil and the Bag Leak Detection System (BLDS) is not in operation. A trained employee shall record whether emissions are normal or abnormal.

(b) Visible emission (VE) notations of stack exhaust of EU-05 shall be performed once per day during normal daylight operations while boiler EU-05 combusts fuel oil. A trained employee shall record whether emissions are normal or abnormal.

(c) If abnormal emissions are observed at exhaust 002 while boilers EU-03 and EU-04 combust coal and/or fuel oil, or while EU-05 combusts fuel oil, or if abnormal emissions are observed at exhaust 003 while EU-05 combusts fuel oil after EU-05 begins exhausting to exhaust 003, the Permittee shall take a reasonable response. Section C - Response to Excursions or Exceedances contains the Permittee's obligation with regard to the reasonable response steps required by this condition. Observation of abnormal emissions that do not violate an applicable opacity limit is not a deviation from this permit. Failure to take response steps shall be considered a deviation from this permit.

(d) "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.

(e) 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 boilers.

D.2.13 Bag Leak Detection System (BLDS)

(a) The Permittee shall operate a continuous bag leak detection system (BLDS) for both pulse jet fabric filter baghouses, identified as Boiler 3 Bag and Boiler 4 Bag. The bag leak detection system shall meet the following requirements:

(i) The Permittee must operate a bag leak detection system for each exhaust stack of the fabric filter.

(ii) The bag leak detection system must be installed, operated, calibrated, and maintained in a manner consistent with the manufacturer's written specifications and recommendations and in accordance with the guidance provided in EPA–454/R–98–015, September 1997.

(iii) The bag leak detection system shall be capable of detecting particulate matter emissions at concentrations of 10 milligrams per actual cubic meter or less.

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

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

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

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

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

(b) If operations continue after bag failure is observed and it will be 10 days or more after the failure is observed before the failed units will be repaired or replaced, the Permittee shall promptly notify the IDEM, OAQ of the expected date the failed units will be repaired or replaced. The notification shall also include the status of the applicable compliance monitoring parameters with respect to normal, and the results of any response actions taken up to the time of notification.

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

D.2.14 Record Keeping Requirements

(a) To document the compliance status with Conditions D.2.2, and D.2.10, the Permittee shall maintain records in accordance with (1) through (4) below. Records maintained for (1) through (4) shall be taken monthly and shall be complete and sufficient to establish compliance with the SO_2 emission limits established in Condition D.2.2. Records necessary to demonstrate compliance shall be available within 30 days of the end of each compliance period.

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

(2) Actual coal and fuel oil usage since last compliance determination period;

(3) Sulfur content and heat content;

(4) Sulfur dioxide emission rates.

(b) To document the compliance status with Section C - Opacity and Conditions D.2.1, , the Permittee shall maintain records in accordance with (1) through (3) below. Records shall be complete and sufficient to establish compliance with the limits established in Section C - Opacity, and in Condition D.2.1. Records necessary to demonstrate compliance shall be available within 30 days of the end of each compliance period.

(1) Data and results from the most recent stack tests;

(2) All parametric monitoring readings;

(3) Records of the dates and times of all bag leak detection system alarms, the cause of each alarm, and an explanation of all corrective actions taken.

(c) To document the compliance status with Conditions D.2.3, the Permittee shall maintain records of monthly average heat input (MMBtu per hour) for EU-03 and EU-04.

(d) To document the compliance status with Condition D.2.4, the Permittee shall maintain records of fuel usage for boiler EU-05.

(e) To document the compliance status with ConditionD.2.12, the Permittee shall maintain records of daily visible emission notations of the boiler stack exhausts when operating. The Permittee shall include in its daily record when a visible emission notation is not taken and the reason for the lack of a visible emission notation (e.g. the process did not operate that day).

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

D.2.15 Reporting Requirements

(a) A quarterly summary of the information to document the compliance status with Condition D.2.2 shall be submitted using the reporting forms located at the end of this permit or their equivalent, not later than thirty (30) days after the end of the quarter being reported. Section C - General Reporting contains the Permittee’s obligation with regard to the reporting required by this condition.

(b) A quarterly summary of the information to document the compliance status with Condition D.2.4 shall be submitted using the reporting forms located at the end of this permit or their equivalent, not later than thirty (30) days after the end of the quarter being reported. Section C - General Reporting contains the Permittee’s obligation with regard to the reporting required by this condition.

(c) 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.3 EMISSIONS UNIT OPERATION CONDITIONS

Emissions Unit Description [326 IAC 2-7-5(14)]:

(d) One (1) coal, natural gas, No. 1 or No. 2 fuel oil fired boiler, identified as EU-06, constructed in 1970, with economizers replaced in 2010, with a maximum design capacity of 190 MMBtu per hour heat input when combusting coal and/or fuel oil, and 150 MMBtu per hour heat input (two natural gas fired burners rated at 75 MMBtu per hour heat input each) when combusting natural gas, equipped with a mud drum heat exchanger installed in 2014, equipped with low NOx burners for natural gas and/or fuel oil, a multiclone and a jet pulse baghouse, identified as Boiler 6 Bag including a bag leak detection system, for particulate control when combusting coal and/or fuel oil, permitted in 2008, and a continuous opacity monitor (COM) for monitoring opacity, exhausting to stack 003. In addition, the stack exhaust from boiler EU-06 can be treated by an activated carbon injection system for mercury control and a lime injection system for hydrogen chloride control.

[Under 40 CFR 63, Subpart DDDDD, this is an affected source]

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

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

D.3.1 Particulate Emission Limitations for Sources of Indirect Heating [326 IAC 6-2-3]

Pursuant to 326 IAC 6-2-3(b) (Particulate Emission Limitations for Sources of Indirect Heating) the PM emissions from EU-06 shall not exceed 0.46 pounds of particulate matter per million British thermal units heat input.

D.3.2 Sulfur Dioxide (SO_2) Emission Limitations [326 IAC 7-1.1]

(a) Pursuant to 326 IAC 7-1.1-2 (Sulfur Dioxide Emission Limitations), sulfur dioxide emissions from boiler EU-06 shall not exceed 6.0 pounds per million British thermal units (lb/MMBtu) of heat input when combusting coal.

(b) Pursuant to 326 IAC 7-1.1-2 (Sulfur Dioxide Emission Limitations), for facilities (EU-06) combusting coal and oil simultaneously, sulfur dioxide emissions shall not exceed six and zero-tenths (6.0) pounds per million British thermal units (lb/MMBtu) of heat input, and when EU-06 is combusting No. 1 or No. 2 fuel oil, solely, sulfur dioxide emissions shall not exceed 0.5 pounds per million British thermal units (lb/MMBtu) of heat input.

D.3.3 Preventive Maintenance Plan [326 IAC 2-7-5(12)]

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

Compliance Determination Requirements

D.3.4 Testing Requirements [326 IAC 2-7-6(1),(6)] [326 IAC 2-1.1-11]

In order to demonstrate compliance with the PM limitation, the Permittee shall perform PM testing for the coal-fired boiler, identified as EU-06, utilizing methods as approved by the Commissioner at least once every five (5) calendar years from the date of the most recent valid compliance demonstration. Testing shall be conducted in accordance with the provisions of 326 IAC -3-6 (Source Sampling Procedures). Section C – Performance Testing contains the Permittee’s obligation with regard to the performance testing required by this condition. PM10 and PM2.5 includes filterable and condensable PM.

D.3.5 Particulate and Opacity Control [326 IAC 2-7-6(6)] [326 IAC 3-5-1(b)(2)(A)]

Except as otherwise provided by statute or rule, or in this permit;

(a) The multiclones for particulate control shall be in operation at all times when boiler EU-06 is in operation and EU-06 is combusting coal.

(b) The baghouses for particulate control shall be in operation at all times (except periods of boiler startup) boiler EU-06 is in operation and combusting coal.

(c) In the event that bag failure is observed in a multi-compartment baghouse, if operations will continue for ten (10) days or more after the failure is observed before the failed units will be repaired or replaced, the Permittee shall promptly notify the IDEM, OAQ of the expected date the failed units will be repaired or replaced. The notification shall also include the status of the applicable compliance monitoring parameters with respect to normal, and the results of any response actions taken up to the time of notification.

(d) The ability of EU-06 Bag to control particulate emissions shall be monitored continuously, when boiler EU-06 is in operation and combusting coal, by measuring and recording the opacity of emissions with a certified continuous opacity monitor.

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

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

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

(f) 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.

(g) 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 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 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.

(h) 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 60 and/or 40 CFR 63.

D.3.6 Sulfur Dioxide Emissions and Sulfur Content [326 IAC 3-7] [326 IAC 7-2] [326 IAC 7-1.1-2]

To determine the compliance status with the sulfur dioxide emissions limit in D.3.2(a), the Permittee shall perform sampling of the sulfur-bearing fuels utilizing one of the following options:

(a) Pursuant to 326 IAC 7-2-1(c), the Permittee shall demonstrate that the sulfur dioxide emissions do not exceed six (6.0) pounds per MMBtu using a calendar month average when EU-06 is combusting coal, or coal in combination with another fuel.

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

(1) Coal sampling shall be performed using the methods specified in 326 IAC 3-7-2(a), and sample preparation and analysis shall be performed as specified in 326 IAC 3-7-2(c), (d), and (e); or

(2) Pursuant to 326 IAC 3-7-2(b)(2) and 326 IAC 3-7-3, manual or other non-ASTM automatic sampling and analysis procedures may be used upon a demonstration, submitted to the department for approval, that such procedures provide sulfur dioxide emission estimates representative either of estimates based on coal sampling and analysis procedures specified in 326 IAC 3-7-2 or of continuous emissions monitoring; or

(3) The Permittee shall meet the minimum sampling requirements specified in 326 IAC 3-7-2(b)(3), and sample preparation and analysis shall be performed as specified in 326 IAC 3-7-2(c), (d), and (e).

(c) Upon written notification to IDEM by a facility owner or operator, continuous emission monitoring data collected and reported pursuant to 326 IAC 3-5 may be used as the means for determining compliance with the emission limitations in 326 IAC 7. Upon such notification, the other requirements of 326 IAC 7-2 shall not apply. [326 IAC 7-2-1(g)]

D.3.7 Sulfur Dioxide Emissions and Sulfur Content [326 IAC 3-7] [326 IAC 7-2] [326 IAC 7-1.1-2]

To determine the compliance status with the sulfur dioxide emissions limit in D.3.2(b), the Permittee shall perform sampling of the sulfur-bearing fuels utilizing one of the following options when EU-06 is combusting fuel oil, or fuel oil in combination with natural gas:

(a) Pursuant to 326 IAC 3-7-4, 326 IAC 7-2, and 326 IAC 7-1.1-2, the Permittee shall demonstrate that the sulfur dioxide do not exceed the equivalent of 0.5 pounds per MMBtu, demonstrated on 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 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.

(c) Upon written notification to IDEM by a facility owner or operator, continuous emission monitoring data collected and reported pursuant to 326 IAC 3-5 may be used as the means for determining compliance with the emission limitations in 326 IAC 7. Upon such notification, the other requirements of 326 IAC 7-2 shall not apply. [326 IAC 7-2-1(g)]

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

D.3.8 Bag Leak Detection System (BLDS)

(a) After installation of the baghouse controlling emissions from boiler EU-06 is complete, the Permittee shall install and operate a continuous bag leak detection system (BLDS) for pulse jet fabric filter baghouse EU-06 Bag. The bag leak detection system shall meet the following requirements:

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

(ii) The bag leak detection system must be installed, operated, calibrated, and maintained in a manner consistent with the manufacturer's written specifications and recommendations and in accordance with the guidance provided in EPA–454/R–98–015, September 1997.

(iii) The bag leak detection system shall be capable of detecting particulate matter emissions at concentrations of 10 milligrams per actual cubic meter or less.

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

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

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

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

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

(b) If operations continue after bag failure is observed and it will be 10 days or more after the failure is observed before the failed units will be repaired or replaced, the Permittee shall promptly notify the IDEM, OAQ of the expected date the failed units will be repaired or replaced. The notification shall also include the status of the applicable compliance monitoring parameters with respect to normal, and the results of any response actions taken up to the time of notification.

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

D.3.9 Record Keeping Requirements

(a) To document the compliance status with Condition D.3.2, the Permittee shall maintain records in accordance with (1) through (6) below. Records necessary to demonstrate compliance shall be available within 30 days of the end of each compliance period.

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

(2) Actual fuel oil usage since last compliance determination period and equivalent sulfur dioxide and particulate matter emission rates;

(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.

The Permittee shall retain records of all recording/monitoring data and support information for a period of five (5) years or longer if specified elsewhere in this permit, from the date of the monitoring sample, measurement, or report. Support information Includes all calibration and maintenance records and all original strip-chart recordings for continuous monitoring instrumentation, and copies of all reports required by this permit.

(b) To document the compliance status with Condition D.3.2, the Permittee shall maintain records in accordance with (1) through (4) below. Records maintained for (1) through (4) shall be taken monthly and shall be complete and sufficient to establish compliance with the SO_2 emission limits established in D.3.2. Records necessary to demonstrate compliance shall be available within 30 days of the end of each compliance period.

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

(2) Actual coal usage since last compliance determination period;

(3) Sulfur content, heat content;

(4) Sulfur dioxide emission rates.

(c) To document the compliance status with Section C - Opacity and Conditions D.3.1, D.3.4, D.3.5 and D.3.8, the Permittee shall maintain records in accordance with (1) through (3) below. Records shall be complete and sufficient to establish compliance with the limits established in Section C - Opacity, and in Condition D.3.1. Records necessary to demonstrate compliance shall be available within 30 days of the end of each compliance period.

(1) Data and results from the most recent stack test(s).

(2) All continuous monitoring data, pursuant to 326 IAC 3-5.

(3) Records of the dates and times of all bag leak detection system alarms, the cause of each alarm, and an explanation of all corrective actions taken.

(d) Pursuant to 326 IAC 3-7-5(a), the Permittee shall develop a standard operating procedure (SOP) to be followed for sampling, handling, analysis, quality control, quality assurance, and data reporting of the information collected pursuant to 326 IAC 3-7-2 through 326 IAC 3-7-4. In addition, any revision to the SOP shall be submitted to IDEM, OAQ.

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

D.3.10 Reporting Requirements

(a) A quarterly summary of the information to document the compliance status with Conditions D.3.2, D.3.6 and D.3.7 shall be submitted using the reporting forms located at the end of this permit or their equivalent, not later than thirty (30) days after the end of the quarter being reported. Section C - General Reporting contains the Permittee's obligation with regard to the reporting required by this condition.

(b) Quarterly report of opacity exceedances shall be submitted using the reporting forms located at the end of this permit or their equivalent, not later than thirty (30) days after the end of the quarter being reported. Section C - General Reporting contains the Permittee's obligation with regard to the reporting required by this condition.

(c) 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.4 EMISSIONS UNIT OPERATION CONDITIONS

Emissions Unit Description [326 IAC 2-7-5(14)]:

(e) One (1) coal storage and handling system, with a maximum design throughput of 200 tons of coal per hour, consisting of the following:

(1) One (1) coal truck receiving system, consisting of an interior wet suppression system to control coal dust emissions during coal receiving, and two (2) truck hoppers.

(2) Four (4) enclosed belt conveyors, and one (1) enclosed bucket conveyor, with particulate emissions controlled by a fabric filter system, with four (4) dust collectors, identified as DC1 through 4, located internally at various points along the enclosed conveyor system, with all dust collectors exhausting internally.

(3) One (1) coal storage silo with a storage capacity of 1,000 tons of coal, with particulate emissions controlled by one (1) dust collector, identified as DC6, exhausting externally at vent 6.

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

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

D.4.1 Particulate Emission Limitations for Manufacturing Processes [326 IAC 6-3-2]

Pursuant to 326 IAC 6-3-2, the PM emission from the coal storage and handling system shall not exceed 58.5 pounds per hour when operating at a maximum process weight rate of 200 tons per hour.

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

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

Pursuant to 326 IAC 6-3-2(e)(3) (Particulate Emission Limitations for Manufacturing Processes), for any process weight rate greater than 200 tons per hour, the concentration of particulate in the discharge gases to the atmosphere shall be less than 0.10 pounds per one thousand (1,000) pounds of gases.

D.4.2 Preventive Maintenance Plan [326 IAC 2-7-5(12)]

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

Compliance Determination Requirements

D.4.3 Particulate Matter (PM)

(a) The coal truck receiving interior wet suppression system shall be in operation and control the PM emissions from the associated equipment at all times that the coal receiving system is in operation.

(b) The dust collectors (DC1 through DC4), all for PM control, shall be in operation and ontrol the PM emissions from their associated equipment at all times that the coal storage and handling system is in operation.

(c) All equipment exhausting internally (DC1 through DC4) for the coal storage and handling system shall not exhaust to the atmosphere at any time the system is in operation.

(d) Dust collector DC6, for PM control, shall be in operation and control the PM emissions from the silo when it is receiving coal.

(e) In the event that bag failure is observed in a multi-compartment baghouse, if operations will continue for ten (10) days or more after the failure is observed before the failed units will be repaired or replaced, the Permittee shall promptly notify the IDEM, OAQ of the expected date the failed units will be repaired or replaced. The notification shall also include the status of the applicable compliance monitoring parameters with respect to normal, and the results of any response actions taken up to the time of notification.

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

D.4.4 Baghouse Parametric Monitoring

(a) The Permittee shall record the pressure drop across dust collectors DC-1, DC-2, DC-3, DC-4 and DC-6 used in conjunction with the coal transfer drop points at least once per week when coal is being transferred. When for any one reading, the pressure drop across the dust collectors is outside the normal range of 1.0 and 8.0 inches of water or a range established during the latest stack test, the Permittee shall take a reasonable response. Section C- Response to Excursions or Exceedances, contains the Permittee's obligation with regard to the reasonable response steps required by this condition. A pressure reading that is outside the above mentioned range is not a deviation from this permit. Failure to take response steps shall be considered a deviation from this permit.

(b) The instrument used for determining the pressure shall comply with Section C - Instrument Specifications, of this permit, shall be subject to approval by IDEM, OAQ and shall be calibrated or replaced at least once every six (6) months.

D.4.5 Visible Emissions Notations

(a) Once per week visible emission notations of the dust collector DC6 vent exhaust shall be performed during normal daylight operations when the silo is receiving coal. A trained employee shall record whether emissions are normal or abnormal.

(b) Once per week visible emission notations of the coal truck receiving system shall be performed during normal daylight operations when either of the two (2) truck hoppers are receiving coal. A trained employee shall record whether emissions are normal or abnormal.

(c) 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.

(d) 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.

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

(f) If any visible emissions of dust are observed from the coal storage and handling system, the Permittee shall take a reasonable response. Section C - Response to Excursions or Exceedances contains the Permittee's obligation with regard to the reasonable response steps required by this condition. Observation of abnormal emissions that do not violate an applicable opacity limit is not a deviation from this permit. Failure to take response steps shall be considered a deviation from this permit.

(g) If abnormal emissions are observed from the coal storage and handling system, the Permittee shall take a reasonable response. Section C - Response to Excursions or Exceedances contains the Permittee's obligation with regard to the reasonable response steps required by this condition. Observation of abnormal emissions that do not violate an applicable opacity limit is not a deviation from this permit. Failure to take response steps shall be considered a deviation from this permit.

(h) If abnormal emissions are observed, the Permittee shall take a reasonable response. Section C - Response to Excursions or Exceedances contains the Permittee's obligation with regard to the reasonable response steps required by this condition. Observation of abnormal emissions that do not violate an applicable opacity limit is not a deviation from this permit. Failure to take response steps shall be considered a deviation from this permit.

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

D.4.6 Record Keeping Requirements

(a) To document the compliance status with Condition D.4.4 the Permittee shall maintain weekly records of the pressure drop across each dust collector. The Permittee shall include in its weekly record when a pressure drop reading is not taken and the reason for the lack of a pressure drop reading, (i.e., the process did not operate that week).

(b) To document the compliance status with Conditions D.4.5 (a) and (b), the Permittee shall maintain records of visible emission notations of the dust collector vent for DC-6 once per week. Also, once per week, the Permittee shall maintain records of visible emission notations of the coal truck receiving system when coal is being received by the silo and either of the truck hoppers. The Permittee shall include in its weekly 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 obligation with regard to the records required by this condition.

SECTION D.5 EMISSIONS UNIT OPERATION CONDITIONS

Emissions Unit Description [326 IAC 2-7-1(21)][326 IAC 2-7-4(c)][326 IAC 2-7-5(14)]:

A.3 Specifically Regulated Insignificant Activities

(a) Natural gas-fired combustion sources with heat input equal to or less than ten (10) million Btu per hour [326 IAC 6-2]:

(1) Twenty-two (22) boilers constructed before 1972, with a combined total heat input of 29.130 MMBtu per hour.

(2) One (1) boiler constructed in 1977, with a heat input of 0.60 MMBtu per hour.

(3) One (1) boiler constructed in 1981, with a heat input of 0.110 MMBtu per hour.

(4) Sixty-six (66) boilers constructed after 1983, with a combined heat input of 145.25 MMBtu per hour. [326 IAC 6-2-4(a) and (b)]

(5) Informatics East Building Boiler, constructed in 2008, with a heat input capacity of 1.44 MMBtu/hr [326 IAC 6-2-4]

(6) Hutton Honors College Furnace, constructed in 2008, with a heat input capacity of 0.432 MMBtu/hr [326 IAC 6-2-4]

(7) Three (3) natural gas-fired boilers, each constructed in 2009 and located at the Innovation Center, each with a heat input capacity of 1.1 MMBtu/hr. [326 IAC 6-2-4] [40 CFR 63, Subpart DDDDD]

[Under 40 CFR 63, Subpart DDDDD, these all boilers (SNo. 1 to 7) are affected source]

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

(c) Oil fired emergency generators not exceeding 1,600 horsepower:

(1) One (1) emergency generator, identified as MSB-1, permitted in 2007, rated at 1,200 horsepower, located inside of utility structure.
Under 40 CFR 60, Subpart IIII, this is an affected source.
Under 40 CFR 63, Subpart ZZZZ, this is an affected source.

(d) Two (2) pneumatic ash handling legs, identified as Ash Leg #1 and Ash Leg #2, permitted in 2008, with a maximum throughput capacity of 0.71 tons of fly ash per hour, emissions are controlled by water spray [326 IAC 6-3-2].

(e) One (1) activated carbon injection system, constructed in 2008, consisting of one (1) activated carbon storage silo, with a maximum storage capacity of 52 tons and throughput of 1,200 lbs/hr, identified as Carbon Silo, controlled by a bin vent baghouse, identified as CS Bag, exhausting indoors to stack CS Vent [326 IAC 6-3-2].

(f) One (1) lime injection system, constructed in 2008, consisting of one (1) lime storage silo, with a maximum storage capacity of 25 tons and throughput of 30 lbs/hr, identified as Lime Silo, controlled by a bin vent baghouse, identified as LS Bag, exhausting indoors to stack LS Vent [326 IAC 6-3-2].

(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 Prevention of Significant Deterioration (PSD) Minor Limits [326 IAC 2-2]

In order to render the requirements of 326 IAC 2-2 (Prevention of Significant Deteriration) not applicable, the Permittee shall comply with the following;

(a) The operating hours for the emergency generator MSB-1 shall not exceed 250 hours per twelve (12) consecutive month period with compliance determined at the end of each month.

(b) The emission of NOx shall not exceed 0.024 lb/hp-hr.

Compliance with these limits, combined with the potential to emit PM10, NOx and SO2 from all the other emission units in this modification, shall limit the total potential to emit of PM_{10} emissions to less than fifteen (15) tons per year, SO_2 emission to less than 40 tons/yr and NOx to less than forty (40) tons/year, and shall render the requirements of 326 IAC 2 2 (PSD) not applicable to the 2007 modification.

D.5.2 Particulate Emission Limitations for Sources of Indirect Heating [326 IAC 6-2]

(a) Pursuant to 326 IAC 6-2-3(b) (Particulate Emission Limitations for Sources of Indirect Heating: Emission limitations for facilities specified in 326 IAC 6-2-1(c)), the emission limitations for those indirect heating facilities which were existing and in operation on or before June 8, 1972, from the twenty-two (22) boilers constructed prior to 1972 shall not exceed 0.44 pounds of particulate matter per million British thermal units heat input.

(b) Pursuant to 326 IAC 6-2-3(c), the emission limitations for those indirect heating facilities which began operation after June 8, 1972, and before September 21, 1983, from the boiler constructed in 1977, and the boiler constructed in 1981, shall not exceed 0.15 pounds of particulate matter per million British thermal units heat input.

(c) Pursuant to 326 IAC 6-2-4 (Particulate Emission Limitations for Sources of Indirect Heating: Emission limitations for facilities specified in 326 IAC 6-2-1(d)), the PM emissions from indirect heating facilities constructed after September 21, 1983, from the Boiler EU-7, and the 66 boilers constructed after 1983, the Informatics East Building Boiler, the Hutton Honors College Furnace (indirect forced air unit), and the three (3) natural gas-fired boilers located at the Innovation Center, shall be limited to the pounds per million British thermal units heat input as indicated below:

Construction Year	Type of Unit	Maximum Heat Input Capacity (MMBtu/hr)	Total Q (MMBtu/hr)	Pt (lb/MMBtu) PM
-	-	-	609.84	0.15
After 1983	66 Boilers	145.25 (Total)	755.09	0.19
2007	Boiler EU-07	217	972.09	0.18
2008	Informatics E. Bldg. Boiler	1.44	973.96	0.18
	Hutton Honors College Furnace	0.432		
2009	3 Boilers at Innovation Center	1.1 (each)	977.26	0.18

D.5.3 Particulate Emission Limitations for Manufacturing Processes (PM) [326 IAC 6-3]

Pursuant to 326 IAC 6-3-2, the particulate matter (PM) emissions from Ash Leg #1 and Ash Leg #2 shall not exceed 3.26 pound per hour each when operating at a process weight rate of 0.71 ton/hr.

The pound per hour limitation was calculated with the following equation:

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

D.5.4 Volatile Organic Compounds (VOC) [326 IAC 8-3-2]

(a) Pursuant to 326 IAC 8-3-2 (Cold Cleaner Degreaser Control Equipment and Operating Requirements), for cold cleaning degreasers without remote solvent reservoirs constructed after July 1, 1990:

(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 (a)(3), (a)(4), (a)(6), and (a)(7) of this condition.

(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) The Permittee shall 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 (b)(1)(A) through (D) of this condition 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.5.5 Volatile Organic Compounds (VOC) [326 IAC 8-3-8]

Pursuant to 326 IAC 8-3-8 (Material Requirements for Cold Cleaner Degreasers), on and after January 1, 2015, the Permittee shall not operate a cold cleaner degreaser with a solvent that has a VOC composite partial vapor pressure than 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.5.6 Preventive Maintenance Plan [326 IAC 2-7-5(12)]

A Preventive Maintenance Plan is required for this facility and its control device. 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 Requirements [326 IAC 2-7-5(3)] [326 IAC 2-7-19]

D.5.7 Record Keeping Requirements

To document the compliance status with Condition D.5.1, the Permittee shall maintain monthly records of the operating hours for the emergency generator MSB-1.

(a) Pursuant to 326 IAC 8-3-8(c)(2), on and after January 1, 2015, the following records shall be maintained for each purchase of cold cleaner degreaser solvent:

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

(2) The date of purchase (or invoice/bill dates of contract servicer indicating service date).

(3) The type of solvent purchased.

(4) The total volume of the solvent purchased.

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

(b) Section C - General Record Keeping Requirements of this permit contains the Permittee’s obligations with regard to the records required by this condition.

D.5.8 Reporting Requirements

A quarterly summary of the information to document the compliance status with Condition D.5.1 shall be submitted using the reporting forms located at the end of this permit or their equivalent, not later than thirty (30) days after the end of the quarter being reported. Section C - General Reporting 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 E.1 NSPS

Emissions Unit Description:

(a) One (1) natural gas-fired boiler, (using low-sulfur No. 1 or No. 2 fuel oil as a back-up), identified as EU-07, approved for construction in 2007, including a mud drum heat exchanger, with a maximum design capacity of 217 MMBtu per hour heat input when combusting natural gas and 208 MMBtu per hour heat input when combusting fuel oil, and equipped with low NOx burners and induced flue gas recirculation for NOx control, with continuous emissions monitors (CEM) for monitoring CO and NOx, exhausting to stack 002. The boiler burner pilot light can ignite using propane.

[Under 40 CFR 60 Subpart Db, this is an affected source]

(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 (NSPS) [326 IAC 12-1] [40 CFR 60, Subpart A] [326 IAC 12]

(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 units 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 [326 IAC 12] [40 CFR 60, Subpart Db]

The Permittee shall comply with the provisions of 40 CFR 60 Subpart Db (included as Attachment A to the operating permit), which are incorporated as 326 IAC 12-1 for Boiler EU-07.

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

SECTION E.2 **NSPS**

Emissions Unit Description:

A.3 Specifically Regulated Insignificant Activities

(c) Oil-fired emergency generators not exceeding 1,600 horsepower:

(1) One (1) emergency generator, identified as MSB-1, permitted in 2007, rated at 1200 horsepower, located inside of utility structure.

(g) Twenty three (23) Diesel Emergency Generators:

(1) One (1) diesel emergency generators, identified as FQHSB-1, manufactured in 2006, with a maximum capacity of 282 hp, located outside the Foster Quad/Harper Buildings.
[Under 40 CFR 60, Subpart IIII, this is an affected source]
[Under 40 CFR 63, Subpart ZZZZ, this is an affected source]

(2) One (1) diesel emergency generators, identified as TTASB-1, manufactured in 2006, with a maximum capacity of 300 hp, located outside the Tulip Tree Apartments.
[Under 40 CFR 60, Subpart IIII, this is an affected source]
[Under 40 CFR 63, Subpart ZZZZ, this is an affected source]

(3) One (1) diesel emergency generator, identified as HAPSB-1, manufactured in 2007, with a maximum capacity of 60 hp, located outside the Henderson/Atwater Parking Area.
[Under 40 CFR 60, Subpart IIII, this is an affected source]
[Under 40 CFR 63, Subpart ZZZZ, this is an affected source]

(4) One (1) diesel emergency generator, identified as IUPD-1, manufactured in 2007, with a maximum capacity of 545 hp, located outside of the IU Police Department Building.
[Under 40 CFR 60, Subpart IIII, this is an affected source]
[Under 40 CFR 63, Subpart ZZZZ, this is an affected source]

(5) One (1) diesel emergency generator, identified as JHSB-1, manufactured in 2007, with a maximum capacity of 225 hp, located outside of Johnston Hall.
[Under 40 CFR 60, Subpart IIII, this is an affected source]
[Under 40 CFR 63, Subpart ZZZZ, this is an affected source]

(6) One (1) diesel emergency generator, identified as TQSB-1, manufactured in 2007, with a maximum capacity of 320 hp, located outside of Teter Quad Building.
[Under 40 CFR 60, Subpart IIII, this is an affected source]
[Under 40 CFR 63, Subpart ZZZZ, this is an affected source]

(7) One (1) diesel emergency generator, identified as MSB-1, manufactured in 2007, with a maximum capacity of 1,200 hp, located inside of the MSB-1 Building.
[Under 40 CFR 60, Subpart IIII, this is an affected source]
[Under 40 CFR 63, Subpart ZZZZ, this is an affected source]

(8) One (1) diesel emergency generator, identified as JDHSB-1, manufactured in 2007, with a maximum capacity of 80 hp, located at Jordan Hall.

[Under 40 CFR 60, Subpart IIII, this is an affected source]
[Under 40 CFR 63, Subpart ZZZZ, this is an affected source]

(9) One (1) diesel emergency generator, identified as WQSB-1, manufactured in 2007, with a maximum capacity of 225.6 hp, located at Wright Quad.
[Under 40 CFR 60, Subpart IIII, this is an affected source]
[Under 40 CFR 63, Subpart ZZZZ, this is an affected source]

(10) One (1) diesel emergency generator, identified as HCSB-1, manufactured in 2007, with a maximum capacity of 1,150 hp, located outside of the Health Center.
[Under 40 CFR 60, Subpart IIII, this is an affected source]
[Under 40 CFR 63, Subpart ZZZZ, this is an affected source]

(11) One (1) diesel emergency generator, identified as MSB-2, manufactured in 2008, with a maximum capacity of 1,490 hp, located at Simon Hall.
[Under 40 CFR 60, Subpart IIII, this is an affected source]
[Under 40 CFR 63, Subpart ZZZZ, this is an affected source]

(12) One (1) diesel emergency generator, identified as MSNSB-1, manufactured in 2008, with a maximum capacity of 258 hp, located at Memorial Stadium North.
[Under 40 CFR 60, Subpart IIII, this is an affected source]
[Under 40 CFR 63, Subpart ZZZZ, this is an affected source]

(13) One (1) diesel emergency generator, identified as BCSB-1, manufactured in 2008, with a maximum capacity of 360 hp, located at Basketball Center Cook Hall.
[Under 40 CFR 60, Subpart IIII, this is an affected source]
[Under 40 CFR 63, Subpart ZZZZ, this is an affected source]

(14) One (1) diesel emergency generator, identified as CHSB-1, manufactured in 2009, with a maximum capacity of 300 hp, located at Cedar Hall.
[Under 40 CFR 60, Subpart IIII, this is an affected source]
[Under 40 CFR 63, Subpart ZZZZ, this is an affected source]

(15) One (1) diesel emergency generator, identified as HPSB-1, manufactured in 2009, with a maximum capacity of 606 hp, located at HPER.
[Under 40 CFR 60, Subpart IIII, this is an affected source]
[Under 40 CFR 63, Subpart ZZZZ, this is an affected source]

(16) One (1) diesel emergency generator, identified as ICSB-1, manufactured in 2009, with a maximum capacity of 186 hp,located at IU Innovation Center.
[Under 40 CFR 60, Subpart IIII, this is an affected source]
[Under 40 CFR 63, Subpart ZZZZ, this is an affected source]

(17) One (1) diesel emergency generator, identified as MHSB-1, manufactured in 2009, with a maximum capacity of 56 hp, located outside of Mason Hall.
[Under 40 CFR 60, Subpart IIII, this is an affected source]
[Under 40 CFR 63, Subpart ZZZZ, this is an affected source]

(18) One (1) diesel emergency generator, identified as DCSB-1, manufactured in 2008, with a maximum capacity of 2,200 hp, located inside of Data Center #1.
[Under 40 CFR 60, Subpart IIII, this is an affected source]
[Under 40 CFR 63, Subpart ZZZZ, this is an affected source]

(19) One (1) diesel emergency generator, identified as DCSB-2, manufactured in 2008, with a maximum capacity of 2,200 hp, located inside of Data Center #2.

[Under 40 CFR 60, Subpart IIII, this is an affected source]
[Under 40 CFR 63, Subpart ZZZZ, this is an affected source]

(20) One (1) diesel emergency generator, identified as BBSB-1, manufactured in 2011, with a maximum capacity of 720 hp, located at Briscoe Building.
[Under 40 CFR 60, Subpart IIII, this is an affected source]
[Under 40 CFR 63, Subpart ZZZZ, this is an affected source]

(21) One (1) diesel emergency generator, identified as MACSB-1, manufactured in 2011, with a maximum capacity of 120 hp, located at the Musical Arts Center.
[Under 40 CFR 60, Subpart IIII, this is an affected source]
[Under 40 CFR 63, Subpart ZZZZ, this is an affected source]

(22) One (1) diesel emergency generator, identified as FQSB-1, manufactured in 2012, with a maximum capacity of 460 hp, located at Forest Quad.
[Under 40 CFR 60, Subpart IIII, this is an affected source]
[Under 40 CFR 63, Subpart ZZZZ, this is an affected source]

(23) One (1) diesel emergency generator, identified as JSMSB-1, manufactured in 2012, with a maximum capacity of 475 hp, located at the Jacobs School of Music.
[Under 40 CFR 60, Subpart IIII, this is an affected source]
[Under 40 CFR 63, Subpart ZZZZ, this is an affected source]

(h) Fourteen (14) Diesel Emergency Generators:

(52) One (1) diesel emergency generator, identified as CIBSB-1, constructed in 2007 with a maximum capacity of 469 hp, located at CIB / 578.
[Under 40 CFR 60, Subpart IIII, this is an affected source]
[Under 40 CFR 63, Subpart ZZZZ, this is an affected source]

(53) One (1) diesel emergency generator, identified as BASB-1, constructed in 2012 with a maximum capacity of 147 hp, located at Baseball/ 593.
[Under 40 CFR 60, Subpart IIII, this is an affected source]
[Under 40 CFR 63, Subpart ZZZZ, this is an affected source]

(54) One (1) diesel emergency generator, identified as SBSB-2, constructed in 2012 with a maximum capacity of 99 hp, located at Softball/ 594.
[Under 40 CFR 60, Subpart IIII, this is an affected source]
[Under 40 CFR 63, Subpart ZZZZ, this is an affected source]

(55) One (1) diesel emergency generator, identified as OPSB-1, constructed in 2014 with a maximum capacity of 375 hp, located at Optometry / 065
[Under 40 CFR 60, Subpart IIII, this is an affected source]
[Under 40 CFR 63, Subpart ZZZZ, this is an affected source]

(56) One (1) diesel emergency generator, identified as WLSB-1, constructed in 2014 with a maximum capacity of 1206 hp, located at Wells Library /GISB 209.
[Under 40 CFR 60, Subpart IIII, this is an affected source]
[Under 40 CFR 63, Subpart ZZZZ, this is an affected source]

(57) One (1) diesel emergency generator, identified as AHSB-2, constructed in 2015 with a maximum capacity of 668 hp, located at Assembly Hall / 603.
[Under 40 CFR 60, Subpart IIII, this is an affected source]
[Under 40 CFR 63, Subpart ZZZZ, this is an affected source]

(58) One (1) diesel emergency generator, identified as FWSB-1, constructed in 2016 with a maximum capacity of 536 hp, located at Food Warehouse / 615.
[Under 40 CFR 60, Subpart IIII, this is an affected source]
[Under 40 CFR 63, Subpart ZZZZ, this is an affected source]

(59) One (1) diesel emergency generator, identified as MESH-1, constructed in 2018 with a maximum capacity of 683.91 hp, located at MESH.
[Under 40 CFR 60, Subpart IIII, this is an affected source]
[Under 40 CFR 63, Subpart ZZZZ, this is an affected source]

(60) One (1) diesel emergency generator, identified as 2NDSB-1, constructed in 2018 with a maximum capacity of 131 hp, located at 2427 E 2ND ST.
[Under 40 CFR 60, Subpart IIII, this is an affected source]
[Under 40 CFR 63, Subpart ZZZZ, this is an affected source]

(61) One (1) diesel emergency generator, identified as ALFSB-2, constructed in 2018 with a maximum capacity of 201 hp, located at ALF.
[Under 40 CFR 60, Subpart IIII, this is an affected source]
[Under 40 CFR 63, Subpart ZZZZ, this is an affected source]

(62) One (1) diesel emergency generator, identified as LHSB-1, constructed in 2018 with a maximum capacity of 324 hp, located at Luddy Hall.
[Under 40 CFR 60, Subpart IIII, this is an affected source]
[Under 40 CFR 63, Subpart ZZZZ, this is an affected source]

(63) One (1) diesel emergency generator, identified as MSEZSB-1, constructed in 2018 with a maximum capacity of 450 hp, located at Memorial Stadium South End Zone.
[Under 40 CFR 60, Subpart IIII, this is an affected source]
[Under 40 CFR 63, Subpart ZZZZ, this is an affected source]

(64) One (1) diesel emergency generator, identified as SPEASB-1, constructed in 2018 with a maximum capacity of 670 hp, located at SPEA / 452.
[Under 40 CFR 60, Subpart IIII, this is an affected source]
[Under 40 CFR 63, Subpart ZZZZ, this is an affected source]

(65) One (1) diesel emergency generator, identified as SWSB-1, constructed in 2018 with a maximum capacity of 754 hp, located at Swain West.
[Under 40 CFR 60, Subpart IIII, this is an affected source]
[Under 40 CFR 63, Subpart ZZZZ, this is an affected source]

(j) Seven (7) portable non-road Diesel Emergency Generators.

(74) One (1) diesel emergency generator, identified as PORT-9, constructed in 2007 with a maximum capacity of 8.05 hp, located at service Building-Carpenter.
[Under 40 CFR 60, Subpart IIII, this is an affected source]
[Under 40 CFR 63, Subpart ZZZZ, this is an affected source]

(75) Three (3) diesel emergency generator, identified as PORT-10, PORT-11 and PORT-12, each, constructed in 2006 with a maximum capacity of 156 hp, 2.68 hp and 2.68 hp respectively, located at service Building.
[Under 40 CFR 60, Subpart IIII, this is an affected source]
[Under 40 CFR 63, Subpart ZZZZ, this is an affected source]

(76) Three (3) diesel emergency generator, identified as PORT-13, PORT-14 and PORT-15, constructed in 2015, 2017 and 2008 with a maximum capacity of 23.5 hp, 23.5 hp and 24.5 hp respectively, located at Utilities Building. [Under 40 CFR 60, Subpart IIII, this is an affected source] [Under 40 CFR 63, Subpart ZZZZ, this is an affected source] (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 (NSPS) [326 IAC 12-1] [40 CFR 60, Subpart A] [326 IAC 12]

(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 units 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 [326 IAC 12] [40 CFR 60, Subpart IIII]

The Permittee shall comply with the provisions of 40 CFR 60 Subpart IIII (included as Attachment B to the operating permit), which are incorporated as 326 IAC 12-1.

(a) Emergency Generators identified as:
HAPSB-1, IUPD-1, JHSB-1, TQSB-1, MSB-1, JDHSB-1, WQSB-1, HCSB-1, MSB-2, MSNSB-1, BCSB-1, MHSB-1, DCSB-1, DCSB-2, CHSB-1, HPSB-1, ICSB-1, BBSB-1, MACSB-1,FQSB-1, and JSMSB-1.

(1) 40 CFR 60.4202(a)(2)
(2) 40 CFR 60.4205(b)
(3) 40 CFR 60.4206
(4) 40 CFR 60.4207(a), (b)
(5) 40 CFR 60.4208(a), (b), (h), (i)
(6) 40 CFR 60.4209(a)
(7) 40 CFR 60.4211(a), (c),(f)(2)(i), (g)
(8) 40 CFR 60.4212
(9) 40 CFR 60.4214(b)
(10) 40 CFR 60.4218
(11) 40 CFR 60.4219
(12) Table 8, Subpart IIII of 60

(b) Emergency Generators identified as:
FQHSB-1 and TTASB-1.

(1) 40 CFR 60.4200(a)(2)(i)
(2) 40 CFR 60.4205(a)

(3) 40 CFR 60.4206
(4) 40 CFR 60.4207(b)
(5) 40 CFR 60.4209(a)
(6) 40 CFR 60.4211(f)(2)(i)
(7) 40 CFR 60.4214(b)
(8) 40 CFR 60.4218
(9) 40 CFR 60.4219
(10) Table 8, Subpart IIII of 60

(c) Emergency Generators identified as:
CIBSB-1, BASB-1, SBSB-2, OPSB-1, WLSB-1, AHSB-2, FWSB-1, MESH-1, 2NDSB-1, ALFSB-2, LHSB-1, MSEZSB-1, SPEASB-1, SWSB-1 and PORT-9 through PORT-15.

(1) 40 CFR 60.4200(a)(2)(i)
(2) 40 CFR 60.4202(a)
(3) 40 CFR 60.4205(a)(b)
(4) 40 CFR 60.4206
(5) 40 CFR 60.4207(a)(b)
(6) 40 CFR 60.4208
(7) 40 CFR 60.4209(a)
(8) 40 CFR 60.4211(a)(f)(2)(i), (g)
(9) 40 CFR 60.4214(b)
(10) 40 CFR 60.4218
(11) 40 CFR 60.4219
(12) Table 8, Subpart IIII of 60

SECTION E.3 NESHAP

Emissions Unit Description:

A.3 Specifically Regulated Insignificant Activities

(c) Oil-fired emergency generators not exceeding 1,600 horsepower:

(1) One (1) emergency generator, identified as MSB-1, permitted in 2007, rated at 1,200 horsepower, located inside of utility structure.

(g) Twenty three (23) Diesel Emergency Generators:

(1) One (1) diesel emergency generators, identified as FQHSB-1, manufactured in 2006, with a maximum capacity of 282 hp, located outside the Foster Quad/Harper Buildings.
[Under 40 CFR 60, Subpart IIII, this is an affected source]
[Under 40 CFR 63, Subpart ZZZZ, this is an affected source]

(2) One (1) diesel emergency generators, identified as TTASB-1, manufactured in 2006, with a maximum capacity of 300 hp, located outside the Tulip Tree Apartments.
[Under 40 CFR 60, Subpart IIII, this is an affected source]
[Under 40 CFR 63, Subpart ZZZZ, this is an affected source]

(3) One (1) diesel emergency generator, identified as HAPSB-1, manufactured in 2007, with a maximum capacity of 60 hp, located outside the Henderson/Atwater Parking Area.
[Under 40 CFR 60, Subpart IIII, this is an affected source]
[Under 40 CFR 63, Subpart ZZZZ, this is an affected source]

(4) One (1) diesel emergency generator, identified as IUPD-1, manufactured in 2007, with a maximum capacity of 545 hp, located outside of the IU Police Department Building.
[Under 40 CFR 60, Subpart IIII, this is an affected source]
[Under 40 CFR 63, Subpart ZZZZ, this is an affected source]

(5) One (1) diesel emergency generator, identified as JHSB-1, manufactured in 2007, with a maximum capacity of 225 hp, located outside of Johnston Hall.
[Under 40 CFR 60, Subpart IIII, this is an affected source]
[Under 40 CFR 63, Subpart ZZZZ, this is an affected source]

(6) One (1) diesel emergency generator, identified as TQSB-1, manufactured in 2007, with a maximum capacity of 320 hp, located outside of Teter Quad Building.
[Under 40 CFR 60, Subpart IIII, this is an affected source]
[Under 40 CFR 63, Subpart ZZZZ, this is an affected source]

(7) One (1) diesel emergency generator, identified as MSB-1, manufactured in 2007, with a maximum capacity of 1,200 hp, located inside of the MSB-1 Building.
[Under 40 CFR 60, Subpart IIII, this is an affected source]
[Under 40 CFR 63, Subpart ZZZZ, this is an affected source]

(8) One (1) diesel emergency generator, identified as JDHSB-1, manufactured in 2007, with a maximum capacity of 80 hp, located at Jordan Hall.
[Under 40 CFR 60, Subpart IIII, this is an affected source]
[Under 40 CFR 63, Subpart ZZZZ, this is an affected source]

(9) One (1) diesel emergency generator, identified as WQSB-1, manufactured in 2007, with a maximum capacity of 225.6 hp, located at Wright Quad.
[Under 40 CFR 60, Subpart IIII, this is an affected source]
[Under 40 CFR 63, Subpart ZZZZ, this is an affected source]

(10) One (1) diesel emergency generator, identified as HCSB-1, manufactured in 2007, with a maximum capacity of 1,150 hp, located outside of the Health Center.
[Under 40 CFR 60, Subpart IIII, this is an affected source]
[Under 40 CFR 63, Subpart ZZZZ, this is an affected source]

(11) One (1) diesel emergency generator, identified as MSB-2, manufactured in 2008, with a maximum capacity of 1,490 hp, located at Simon Hall.
[Under 40 CFR 60, Subpart IIII, this is an affected source]
[Under 40 CFR 63, Subpart ZZZZ, this is an affected source]

(12) One (1) diesel emergency generator, identified as MSNSB-1, manufactured in 2008, with a maximum capacity of 258 hp, located at Memorial Stadium North.
[Under 40 CFR 60, Subpart IIII, this is an affected source]
[Under 40 CFR 63, Subpart ZZZZ, this is an affected source]

(13) One (1) diesel emergency generator, identified as BCSB-1, manufactured in 2008, with a maximum capacity of 360 hp, located at Basketball Center Cook Hall.
[Under 40 CFR 60, Subpart IIII, this is an affected source]
[Under 40 CFR 63, Subpart ZZZZ, this is an affected source]

(14) One (1) diesel emergency generator, identified as CHSB-1, manufactured in 2009, with a maximum capacity of 300 hp, located at Cedar Hall.
[Under 40 CFR 60, Subpart IIII, this is an affected source]
[Under 40 CFR 63, Subpart ZZZZ, this is an affected source]

(15) One (1) diesel emergency generator, identified as HPSB-1, manufactured in 2009, with a maximum capacity of 606 hp, located at HPER.
[Under 40 CFR 60, Subpart IIII, this is an affected source]
[Under 40 CFR 63, Subpart ZZZZ, this is an affected source]

(16) One (1) diesel emergency generator, identified as ICSB-1, manufactured in 2009, with a maximum capacity of 186 hp, located at IU Innovation Center.
[Under 40 CFR 60, Subpart IIII, this is an affected source]
[Under 40 CFR 63, Subpart ZZZZ, this is an affected source]

(17) One (1) diesel emergency generator, identified as MHSB-1, manufactured in 2009, with a maximum capacity of 56 hp, located outside of Mason Hall.
[Under 40 CFR 60, Subpart IIII, this is an affected source]
[Under 40 CFR 63, Subpart ZZZZ, this is an affected source]

(18) One (1) diesel emergency generator, identified as DCSB-1, manufactured in 2008, with a maximum capacity of 2,200 hp, located inside of Data Center #1.
[Under 40 CFR 60, Subpart IIII, this is an affected source]
[Under 40 CFR 63, Subpart ZZZZ, this is an affected source]

(19) One (1) diesel emergency generator, identified as DCSB-2, manufactured in 2008, with a maximum capacity of 2,200 hp, located inside of Data Center #2.
[Under 40 CFR 60, Subpart IIII, this is an affected source]
[Under 40 CFR 63, Subpart ZZZZ, this is an affected source]

(20) One (1) diesel emergency generator, identified as BBSB-1, manufactured in 2011, with a maximum capacity of 720 hp, located at Briscoe Building.
[Under 40 CFR 60, Subpart IIII, this is an affected source]
[Under 40 CFR 63, Subpart ZZZZ, this is an affected source]

(21) One (1) diesel emergency generator, identified as MACSB-1, manufactured in 2011, with a maximum capacity of 120 hp, located at the Musical Arts Center.
[Under 40 CFR 60, Subpart IIII, this is an affected source]
[Under 40 CFR 63, Subpart ZZZZ, this is an affected source]

(22) One (1) diesel emergency generator, identified as FQSB-1, manufactured in 2012, with a maximum capacity of 460 hp, located at Forest Quad.
[Under 40 CFR 60, Subpart IIII, this is an affected source]
[Under 40 CFR 63, Subpart ZZZZ, this is an affected source]

(23) One (1) diesel emergency generator, identified as JSMSB-1, manufactured in 2012, with a maximum capacity of 475 hp, located at the Jacobs School of Music.
[Under 40 CFR 60, Subpart IIII, this is an affected source]
[Under 40 CFR 63, Subpart ZZZZ, this is an affected source]

(h) Forty Two (42) Diesel Emergency Generators:

(24) One (1) diesel emergency generator, identified as FHSB-1, constructed in 1957 with a maximum capacity of 67.5 hp, located at Field House / 604.
[Under 40 CFR 63, Subpart ZZZZ, this is an affected source]

(25) One (1) diesel emergency generator, identified as HASB-1, constructed in 1970 with a maximum capacity of 26.2 hp, located at Hall Admin. / 463.
[Under 40 CFR 63, Subpart ZZZZ, this is an affected source]

(26) One (1) diesel emergency generator, identified as FHSB-2, constructed in 1972 with a maximum capacity of 22.5 hp, located at Franklin Hall / 007.
[Under 40 CFR 63, Subpart ZZZZ, this is an affected source]

(27) One (1) diesel emergency generator, identified as LBSB-1, constructed in 1981 with a maximum capacity of 150 hp, located at Law Building / 001.
[Under 40 CFR 63, Subpart ZZZZ, this is an affected source]

(28) One (1) diesel emergency generator, identified as POPSB-1, constructed in 1985 with a maximum capacity of 255 hp, located at Poplars Bldg. / 008.
[Under 40 CFR 63, Subpart ZZZZ, this is an affected source]

(29) One (1) diesel emergency generator, identified as SBSB-4, constructed in 1986 with a maximum capacity of 765 hp, located at Service Bldg / 630.
[Under 40 CFR 63, Subpart ZZZZ, this is an affected source]

(30) One (1) diesel emergency generator, identified as MASB-1, constructed in 1989 with a maximum capacity of 91.5 hp, located at Music Addition / 148.
[Under 40 CFR 63, Subpart ZZZZ, this is an affected source]

(31) One (1) diesel emergency generator, identified as CASB-1, constructed in 1990 with a maximum capacity of 900 hp, located at Chemistry Addition / 072.
[Under 40 CFR 63, Subpart ZZZZ, this is an affected source]

(32) One (1) diesel emergency generator, identified as JHSB-2, constructed in 1990 with a maximum capacity of 600 hp, located at Jordan Hall / 107.
[Under 40 CFR 63, Subpart ZZZZ, this is an affected source]

(33) One (1) diesel emergency generator, identified as SBSB-3, constructed in 1991 with a maximum capacity of 30 hp, located at Student Building / 017.
[Under 40 CFR 63, Subpart ZZZZ, this is an affected source]

(34) One (1) diesel emergency generator, identified as CEESB-1, constructed in 1991 with a maximum capacity of 600 hp, located at W.W. Wright (CEE) / 245.
[Under 40 CFR 63, Subpart ZZZZ, this is an affected source]

(35) One (1) diesel emergency generator, identified as IMUSB-1, constructed in 1993 with a maximum capacity of 750 hp, located at Memorial Union / 053.
[Under 40 CFR 63, Subpart ZZZZ, this is an affected source]

(36) One (1) diesel emergency generator, identified as GSSB-1, constructed in 1994 with a maximum capacity of 30 hp, located at Geological Sciences /417.
[Under 40 CFR 63, Subpart ZZZZ, this is an affected source]

(37) One (1) diesel emergency generator, identified as RSSB-1, constructed in 1994 with a maximum capacity of 187.5 hp, located at Recreational Sports / 475.
[Under 40 CFR 63, Subpart ZZZZ, this is an affected source]

(38) One (1) diesel emergency generator, identified as RTVSB-1, constructed in 1996 with a maximum capacity of 300 hp, located at Radio/TV / 158.
[Under 40 CFR 63, Subpart ZZZZ, this is an affected source]

(39) One (1) diesel emergency generator, identified as AUSB-1, constructed in 1999 with a maximum capacity of 600 hp, located at Auditorium / 171.
[Under 40 CFR 63, Subpart ZZZZ, this is an affected source]

(40) One (1) diesel emergency generator, identified as CHPSB-1, constructed in 1999 with a maximum capacity of 1109 hp, located at Cen. Heat Plant / 445.
[Under 40 CFR 63, Subpart ZZZZ, this is an affected source]

(41) One (1) diesel emergency generator, identified as WQSB-2, constructed in 1999 with a maximum capacity of 600 hp, located at Willkie Quad / 299.
[Under 40 CFR 63, Subpart ZZZZ, this is an affected source]

(42) One (1) diesel emergency generator, identified as ALFSB-1, constructed in 2000 with a maximum capacity of 335 hp, located at ALF.
[Under 40 CFR 63, Subpart ZZZZ, this is an affected source]

(43) One (1) diesel emergency generator, identified as RHSB-1, constructed in 2000 with a maximum capacity of 525 hp, located at Read Hall / 227.
[Under 40 CFR 63, Subpart ZZZZ, this is an affected source]

(44) One (1) diesel emergency generator, identified as CVSB-1, constructed in 2001 with a maximum capacity of 300 hp, located at Campus View / 529.
[Under 40 CFR 63, Subpart ZZZZ, this is an affected source]

(45) One (1) diesel emergency generator, identified as EGSB-1, constructed in 2001 with a maximum capacity of 450 hp, located at Eigenmann / 313.
[Under 40 CFR 63, Subpart ZZZZ, this is an affected source]

(46) One (1) diesel emergency generator, identified as SHSB-1, constructed in 2001 with a maximum capacity of 375 hp, located at Spruce Hall / 298.
[Under 40 CFR 63, Subpart ZZZZ, this is an affected source]

(47) One (1) diesel emergency generator, identified as TDSB-1, constructed in 2001 with a maximum capacity of 412.5 hp, located at Lee Norvelle Theatre Drama /172.
[Under 40 CFR 63, Subpart ZZZZ, this is an affected source]

(48) One (1) diesel emergency generator, identified as MHSB-2, constructed in 2001 with a maximum capacity of 600 hp, located at McNutt / 439.
[Under 40 CFR 63, Subpart ZZZZ, this is an affected source]

(49) One (1) diesel emergency generator, identified as MHSB-3, constructed in 2001 with a maximum capacity of 750 hp, located at Myers Hall / 101.
[Under 40 CFR 63, Subpart ZZZZ, this is an affected source]

(50) One (1) diesel emergency generator, identified as ALSB-1, constructed in 2002 with a maximum capacity of 90 hp, located at Animal Lab / 411.
[Under 40 CFR 63, Subpart ZZZZ, this is an affected source]

(51) One (1) diesel emergency generator, identified as USASB-1, constructed in 2005 with a maximum capacity of 450 hp, located at Union St Apts / 296.
[Under 40 CFR 63, Subpart ZZZZ, this is an affected source]

(52) One (1) diesel emergency generator, identified as CIBSB-1, constructed in 2007 with a maximum capacity of 469 hp, located at CIB / 578.
[Under 40 CFR 60, Subpart IIII, this is an affected source]
[Under 40 CFR 63, Subpart ZZZZ, this is an affected source]

(53) One (1) diesel emergency generator, identified as BASB-1, constructed in 2012 with a maximum capacity of 147 hp, located at Baseball/ 593.
[Under 40 CFR 60, Subpart IIII, this is an affected source]
[Under 40 CFR 63, Subpart ZZZZ, this is an affected source]

(54) One (1) diesel emergency generator, identified as SBSB-2, constructed in 2012 with a maximum capacity of 99 hp, located at Softball/ 594.
[Under 40 CFR 60, Subpart IIII, this is an affected source]
[Under 40 CFR 63, Subpart ZZZZ, this is an affected source]

(55) One (1) diesel emergency generator, identified as OPSB-1, constructed in 2014 with a maximum capacity of 375 hp, located at Optometry / 065
[Under 40 CFR 60, Subpart IIII, this is an affected source]
[Under 40 CFR 63, Subpart ZZZZ, this is an affected source]

(56) One (1) diesel emergency generator, identified as WLSB-1, constructed in 2014 with a maximum capacity of 1206 hp, located at Wells Library /GISB 209.
[Under 40 CFR 60, Subpart IIII, this is an affected source]
[Under 40 CFR 63, Subpart ZZZZ, this is an affected source]

(57) One (1) diesel emergency generator, identified as AHSB-2, constructed in 2015 with a maximum capacity of 668 hp, located at Assembly Hall / 603.
[Under 40 CFR 60, Subpart IIII, this is an affected source]
[Under 40 CFR 63, Subpart ZZZZ, this is an affected source]

(58) One (1) diesel emergency generator, identified as FWSB-1, constructed in 2016 with a maximum capacity of 536 hp, located at Food Warehouse / 615.
[Under 40 CFR 60, Subpart IIII, this is an affected source]
[Under 40 CFR 63, Subpart ZZZZ, this is an affected source]

(59) One (1) diesel emergency generator, identified as MESH-1, constructed in 2018 with a maximum capacity of 683.91 hp, located at MESH.
[Under 40 CFR 60, Subpart IIII, this is an affected source]
[Under 40 CFR 63, Subpart ZZZZ, this is an affected source]

(60) One (1) diesel emergency generator, identified as 2NDSB-1, constructed in 2018 with a maximum capacity of 131 hp, located at 2427 E 2ND ST.
[Under 40 CFR 60, Subpart IIII, this is an affected source]
[Under 40 CFR 63, Subpart ZZZZ, this is an affected source]

(61) One (1) diesel emergency generator, identified as ALFSB-2, constructed in 2018 with a maximum capacity of 201 hp, located at ALF.
[Under 40 CFR 60, Subpart IIII, this is an affected source]
[Under 40 CFR 63, Subpart ZZZZ, this is an affected source]

(62) One (1) diesel emergency generator, identified as LHSB-1, constructed in 2018 with a maximum capacity of 324 hp, located at Luddy Hall.
[Under 40 CFR 60, Subpart IIII, this is an affected source]
[Under 40 CFR 63, Subpart ZZZZ, this is an affected source]

(63) One (1) diesel emergency generator, identified as MSEZSB-1, constructed in 2018 with a maximum capacity of 450 hp, located at Memorial Stadium South End Zone.
[Under 40 CFR 60, Subpart IIII, this is an affected source]
[Under 40 CFR 63, Subpart ZZZZ, this is an affected source]

(64) One (1) diesel emergency generator, identified as SPEASB-1, constructed in 2018 with a maximum capacity of 670 hp, located at SPEA / 452.
[Under 40 CFR 60, Subpart IIII, this is an affected source]
[Under 40 CFR 63, Subpart ZZZZ, this is an affected source]

(65) One (1) diesel emergency generator, identified as SWSB-1, constructed in 2018 with a maximum capacity of 754 hp, located at Swain West.
[Under 40 CFR 60, Subpart IIII, this is an affected source]
[Under 40 CFR 63, Subpart ZZZZ, this is an affected source]

(j) Fifteen (15) portable non-road Diesel Emergency Generators.

(70) One (1) diesel emergency generator, identified as PORT-1, constructed in 2002 with a maximum capacity of 80.46 hp, located at Service Building.
[Under 40 CFR 63, Subpart ZZZZ, this is an affected source]

(71) One (1) diesel emergency generator, identified as PORT-2, constructed in 1999 with a maximum capacity of 22.80 hp, located at Service Building/630.
[Under 40 CFR 63, Subpart ZZZZ, this is an affected source]

(72) Two (2) diesel emergency generators, identified as PORT-3 and PORT-4, each, constructed in 1999 with a maximum capacity of 80.46 hp, located at Union St. Chiller Plant – RPS.

[Under 40 CFR 63, Subpart ZZZZ, this is an affected source]

(73) Four (4) diesel emergency generator, identified as PORT-5, PORT-6, PORT-7 and PORT-8, each, constructed in 1999 with a maximum capacity of 13 hp, located at Service Building.
[Under 40 CFR 63, Subpart ZZZZ, this is an affected source]

(74) One (1) diesel emergency generator, identified as PORT-9, constructed in 2007 with a maximum capacity of 8.05 hp, located at service Building-Carpenter.
[Under 40 CFR 60, Subpart IIII, this is an affected source]
[Under 40 CFR 63, Subpart ZZZZ, this is an affected source]

(75) Three (3) diesel emergency generator, identified as PORT-10, PORT-11 and PORT-12, each, constructed in 2006 with a maximum capacity of 156 hp, 2.68 hp and 2.68 hp respectively, located at service Building.
[Under 40 CFR 60, Subpart IIII, this is an affected source]
[Under 40 CFR 63, Subpart ZZZZ, this is an affected source]

(76) Three (3) diesel emergency generator, identified as PORT-13, PORT-14 and PORT-15, constructed in 2015, 2017 and 2008 with a maximum capacity of 23.5 hp, 23.5 hp and 24.5 hp respectively, located at Utilities Building.
[Under 40 CFR 60, Subpart IIII, this is an affected source]
[Under 40 CFR 63, Subpart ZZZZ, this is an affected source]

(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 (NESHAP) [326 IAC 20-82] [40 CFR 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 20-82, for the emission units 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 [326 IAC 20-82] [40 CFR 63, Subpart ZZZZ]

The Permittee shall comply with the provisions of 40 CFR 63 Subpart ZZZZ (included as Attachment C to the operating permit), which are incorporated as 326 IAC 20-82.

(a) Emergency Generators identified as:
BBSB-1, HPSB-1, and MSB-2.

(1) 40 CFR 63.6590(b)(1)(i), (c)
(2) 40 CFR 63.6645(f)

(b) Emergency Generators identified as:
BCSB-1, CHSB-1, FQSB-1, JSMSB-1, JDHSB-1, MACSB-1, ICSB-1, WQSB-1, and MSNSB-1.

(1) 40 CFR 63.6590(b)(1)(i) and (c)(6)
(2) 40 CFR 63.6645(f)

(c) Emergency Generators identified as:
FQHSB-1, HAPSB-1, IUPD-1, JHSB-1, MHSB-1, TQSB-1, and TTASB-1.

(1) 40 CFR 63.6580
(2) 40 CFR 63.6585
(3) 40 CFR 63.6585(b)
(4) 40 CFR 63.6590(a)
(5) 40 CFR 63.6590(a)(2)(ii)
(6) 40 CFR 63.6590(c)
(7) 40 CFR 63.6605
(8) 40 CFR 63.6675

(d) Emergency Generators identified as:
HCSB-1, DCSB-1, DCSB-2, and MSB-1.

(1) 40 CFR 63.6590(b)(1)(i)
(2) 40 CFR 63.6645(f)

(e) Emergency Generators identified as:
FHSB-1, HASB-1, FHSB-2, LBSB-1, POPSB-1, SBSB-4, MASB-1, CASB-1, JHSB-2, SBSB-3, CEESB-1, IMUSB-1, GSSB-1, RSSB-1, RTVSB-1, AUSB-1, CHPSB-1, WQSB-2, ALFSB-1, RHSB-1, CVSB-1, EGSB-1, SHSB-1, TDSB-1, MHSB-2, MHSB-3, ALSB-1, USASB-1, CIBSB-1, BASB-1, SBSB-2, OPSB-1, WLSB-1, AHSB-2, FWSB-1, MESH-1, 2NDSB-1, ALFSB-2, LHSB-1, MSEZSB-1, SPEASB-1, SWSB-1 and PORT-1 through PORT-15.

(1) 40 CFR 63.6580
(2) 40 CFR 63.6585(b)
(3) 40 CFR 63.6590
(4) 40 CFR 63.6595
(5) 40 CFR 63.6605
(6) 40 CFR 63.6645
(7) 40 CFR 63.6655(d),(e),(f)
(8) 40 CFR 63.6670
(9) 40 CFR 63.6675
(10) Table 2c, Subpart ZZZZ of 63
(11) Table 2d, item 1, Subpart ZZZZ of 63
(12) Table 6, item 9, Subpart ZZZZ of 63
(13) Table 8, Subpart ZZZZ of 63

SECTION E.4 NESHAP

Emissions Unit Description:

(a) One (1) natural gas-fired boiler, (using low-sulfur No.1 or No. 2 fuel oil as a back-up), identified as EU-07, approved for construction in 2007, including a mud drum heat exchanger, with a maximum design capacity of 217 MMBtu per hour heat input when combusting natural gas and 208 MMBtu per hour heat input when combusting fuel oil, and equipped with low NOx burners and induced flue gas recirculation for NOx control, with continuous emissions monitors (CEM) for monitoring CO and NOx, exhausting to stack 002. The boiler burner pilot light can ignite using propane. Under 40 CFR 60 Subpart Db, this is an affected source.

(b) Two (2) coal, natural gas, No. 1 or No. 2 fuel oil fired boilers, identified as EU-03 and EU-04, both constructed in 1959, with economizers replaced in 2010, with a maximum design capacity of 125 MMBtu per hour heat input each (operating at a maximum capacity of 100 MMBtu per hour heat input each when combusting coal or a combination of fuels), and with a maximum design capacity of 80 MMBtu per hour heat input each when combusting natural gas and/or fuel oil, each equipped with low NOx burners for natural gas and/or fuel oil, and each with a multiclone and a jet pulse baghouse, identified as Boiler 3 Bag and Boiler 4 Bag, for particulate control, permitted in 2008, when combusting coal and/or fuel oil, both exhausting at stack 002. In addition, the stack exhaust from boilers EU-03 and EU-04 can be treated by an activated carbon injection system for mercury control and a lime injection system for hydrogen chloride control.

(c) One (1) natural gas-fired boiler, (using low-sulfur No. 1 or No. 2 fuel oil as a back-up), identified as EU-05, constructed in 1964, and modified in 1989, with a maximum design capacity of 190 MMBtu per hour heat input, equipped with a mud drum heat exchanger installed in 2013 and low NOx burners (two natural gas fired burners at 75 MMBtu per hour heat input each) for natural gas and/or fuel oil, and a multiclone for particulate control when combusting fuel oil, exhausting to stack 002 or 003. The boiler burner pilot light can ignite using propane.

(d) One (1) coal, natural gas, No. 1 or No. 2 fuel oil fired boiler, identified as EU-06, constructed in 1970, with economizers replaced in 2010, with a maximum design capacity of 190 MMBtu per hour heat input when combusting coal and/or fuel oil, and 150 MMBtu per hour heat input (two natural gas fired burners rated at 75 MMBtu per hour heat input each) when combusting natural gas, equipped with a mud drum heat exchanger installed in 2014, equipped with low NOx burners for natural gas and/or fuel oil, a multiclone and a jet pulse baghouse, identified as Boiler 6 Bag, for particulate control when combusting coal and/or fuel oil, permitted in 2008, and a continuous opacity monitor (COM) for monitoring opacity, exhausting to stack 003. In addition, the stack exhaust from boiler EU-06 can be treated by an activated carbon injection system for mercury control and a lime injection system for hydrogen chloride control.

A.3 Specifically Regulated Insignificant Activities

(a) Natural gas-fired combustion sources with heat input equal to or less than ten (10) million Btu per hour heat input [326 IAC 6-2]:

(1) Twenty-two (22) boilers constructed before 1972, with a combined total heat input of 29.130 MMBtu per hour.

(2) One (1) boiler constructed in 1977, with a heat input of 0.60 MMBtu per hour.

(3) One (1) boiler constructed in 1981, with a heat input of 0.110 MMBtu per hour.

(4) Sixty-six (66) boilers constructed after 1983, with a combined heat input of 145.25 MMBtu per hour. [326 IAC 6-2-4(a) and (b)]

(5) Informatics East Building Boiler, constructed in 2008, with a heat input capacity of 1.44 MMBtu/hr [326 IAC 6-2-4]

(6) Hutton Honors College Furnace, constructed in 2008, with a heat input capacity of 0.432 MMBtu/hr [326 IAC 6-2-4]

(7) Three (3) natural gas-fired boilers, each constructed in 2009 and located at the Innovation Center, each with a heat input capacity of 1.1 MMBtu/hr. [326 IAC 6-2-4] [40 CFR 63, Subpart DDDDD]

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

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 [326 IAC 20-1-1] [40 CFR 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 20-1-1, for the emission units listed above, except as otherwise specified in 40 CFR Part 63, Subpart DDDDD.

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

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

E.4.2 National Emissions Standards for Hazardous Air Pollutants for Major Source: Industrial, Commercial, and Institutional Boilers and Process Heaters [326 IAC 20-1-1] [40 CFR 63, Subpart DDDDD]

The Permittee shall comply with the provisions of 40 CFR 63 Subpart DDDDD (included as Attachment D to the operating permit), which are incorporated as 326 IAC 20-1-1.

(a) Boilers identified as:
EU-03, EU-04, and EU-06.

(1) 40 CFR 63.7500(a), (f)
(2) 40 CFR 63.7505
(3) 40 CFR 63.7510(a)-(e)
(4) 40 CFR 63.7515
(5) 40 CFR 63.7520
(6) 40 CFR 63.7521(a)-(e)
(7) 40 CFR 63.7525
(8) 40 CFR 63.7530
(9) 40 CFR 63.7535
(10) 40 CFR 63.7540(a)
(11) 40 CFR 63.7545
(12) 40 CFR 63.7550
(13) 40 CFR 63.7555

(14) 40 CFR 63.7560
(15) 40 CFR 63.740(a)(10)

(b) Boilers identified as:
EU-05, EU-07, Various Insignificant Boilers, the three boilers located at the Innovation Center, and the indirect-heat furnace located at Hutton Honors College.

(1) 40 CFR 63.7540(a)(10)
(2) 40 CFR 63.7500(a), (e), (f)
(3) 40 CFR 63.7505(a)
(4) 40 CFR 63.7510(e)
(5) 40 CFR 63.7515(d)
(6) 40 CFR 63.7530(a)
(7) 40 CFR 63.7540(a)(2), (10), and (11)
(8) 40 CFR 63.7545(a), (b), (f)
(9) 40 CFR 63.7550(a), (b), (c)(1) and (5), (d)
(10) 40 CFR 63.7559(a), (d), & (h)
(11) 40 CFR 63.7560

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

Source Name:	Indiana University
Source Address:	820 North Walnut Grove, Bloomington, Indiana 47405
Part 70 Permit No.:	T105-41051-00005

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

Please check what document is being certified:

☐ Annual Compliance Certification Letter

☐ Test Result (specify)

☐ Report (specify)

☐ Notification (specify)

☐ Affidavit (specify)

☐ Other (specify)

I certify that, based on information and belief formed after reasonable inquiry, the statements and information in the document are true, accurate, and complete.
Signature:
Printed Name:
Title/Position:
Phone:
Date:

INDIANA DEPARTMENT OF ENVIRONMENTAL MANAGEMENT

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

PART 70 OPERATING PERMIT
EMERGENCY OCCURRENCE REPORT

Source Name: Indiana University
Source Address: 820 North Walnut Grove, Bloomington, Indiana 47405
Part 70 Permit No.: T105-41051-00005

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 for Boilers EU-03 and EU-04

Source Name: Indiana University
Source Address: 820 North Walnut Grove, Bloomington, Indiana 47405-2206
Permit No.: T105-41051-00005
Facility: Boilers EU-03 and EU-04
Parameter: Heat input from all fuels used (NG, FO No1 or No2, Coal or any combination)
Limit: 100 MMBtu per hour heat input to each boiler

QUARTER/YEAR: _________________ MONTH: ________________

Fuel Type	Amount of fuel burned this month	High heat value of fuel burned this month	Total heat input from fuel this month (MMBtu/mo)	Hours of boiler operation this month (hrs/mo)	Average monthly heat input from fuel this month (MMBtu/hr)
Boiler EU-03					
coal	_______ tons/mo	_______ MMBtu/ton			
natural gas	_____ MMCF/mo	1050 MMBtu/MMCF			
fuel oil	_______ gals/mo	0.139 MMBtu/gal			
Average monthly heat input from all fuels this month (MMBtu/hr)					
Boiler EU-04					
coal	_______ tons/mo	_______ MMBtu/ton			
natural gas	_____ MMCF/mo	1050 MMBtu/MMCF			
fuel oil	_______ gals/mo	0.139 MMBtu/gal			
Average monthly heat input from all fuels this month (MMBtu/hr)					

☐ 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 for Boiler EU-05 (NG usage)

Source Name: Indiana University
Source Address: 820 North Walnut Grove, Bloomington, Indiana 47405-2206
Part 70 Permit No.: T105-41051-00005
Facility: Boiler EU-05
Parameters: Natural gas usage
Limits: Less than 870 MMCF per twelve consecutive month period

For purposes of determining compliance, every 3.84 kilo-gallons of No.1 or No.2 fuel oil combusted shall be equivalent to 1 MMCF of natural gas based on NOx emissions and 0.08% sulfur content of No.1 fuel oil and 0.49% sulfur content of No.2 fuel oil.

QUARTER: _______________ YEAR: ________________

This Month					Previous 11 Months				12 Months Total			
Month	**A** No.1 Oil Usage (kgals)	**B** No.2 Oil Usage (kgals)	**C** Nat. Gas Usage (MMCF)	**NOx This Month** (A/3.84)+(B/3.84)+C	**A** No.1 Oil Usage (kgals)	**B** No.2 Oil Usage (kgals)	**C** Nat. Gas Usage (MMCF)	NOx Previous 11 Months	**A** No.1 Oil Usage (kgals)	**B** No.2 Oil Usage (kgals)	**C** Nat. Gas Usage (MMCF)	NOx 12 Months Total

☐ 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 for Boiler EU-05 (FO No. 2 usage)

Source Name: Indiana University
Source Address: 820 North Walnut Grove, Bloomington, Indiana 47405-2206
Part 70 Permit No.: T105-41051-00005
Facility: Boiler EU-05
Parameters: No. 2 fuel oil usage
Limits: Less than 1,120 kgals per twelve consecutive month period

For purposes of determining compliance, every kilo-gallon of No.1 fuel oil combusted shall be equivalent to 5.89 kgal of No. 2 fuel oil based on SO2 emissions and 0.08% sulfur content of No. 1 fuel oil and 0.49% sulfur content of No. 2 fuel oil, and every MMCF of natural gas burned shall be equivalent to 0.009 kgal of No. 2 fuel oil based on SO2 emissions and 0.49% sulfur content of No. 2 fuel oil.

QUARTER: _______________ **YEAR:** ________________

This Month					Previous 11 Months				12 Months Total			
Month	**A** No.1 Oil Usage (kgals)	**B** No.2 Oil Usage (kgals)	**C** Nat. Gas Usage (MMCF)	This Month Total	**A** No.1 Oil Usage (kgals)	**B** No.2 Oil Usage (kgals)	**C** Nat. Gas Usage (MMCF)	Previous 11 Months Total	**A** No.1 Oil Usage (kgals)	**B** No.2 Oil Usage (kgals)	**C** Nat. Gas Usage (MMCF)	12 Months Total

☐ 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 for Boiler EU-06

Source Name: Indiana University
Source Address: 820 North Walnut Grove, Bloomington, Indiana 47405-2206
Part 70 Permit No.: T105-41051-00005
Facility: Boiler EU-06
Parameters: SO_2 emissions, coal usage & analysis
Limits: SO_2 emissions shall not exceed 6.0 pounds per million Btu when combusting coal, and when coal and fuel oil are used simultaneously; and
SO_2 emissions shall not exceed 0.5 pounds per million Btu when combusting fuel oil

QUARTER: _______________ YEAR: ______________

Month	Coal Usage (tons)	Monthly Average Heat Content (MMBtu/lb)		Monthly Average Sulfur Content (%)		SO_2 Emission Rate (lbs/MMBtu)	
		coal	oil	coal	oil	coal	oil
# of Deviations							

☐ 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 for Boiler EU-07

Source Name: Indiana University
Source Address: 820 North Walnut Grove, Bloomington, Indiana 47405-2206
Part 70 Permit No.: T105-41051-00005
Facility: Boiler EU-07
Parameter: No. 1 and No. 2 fuel oil
Limit: 329,000 gallons per twelve (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 hr/yr	Previous 11 Months hr/yr	12 Month Total hr/yr

☐ 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 for MSB-1

Source Name: Indiana University
Source Address: 820 North Walnut Grove, Bloomington, Indiana 47405-2206
Part 70 Permit No.: T105-41051-00005
Facility: Emergency Generator MSB-1
Parameter: Operating Hours
Limit: Less than 250 hours per twelve (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	Previous 11 Months	12 Month Total

☐ 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: Indiana University
Source Address: 820 North Walnut Grove, Bloomington, Indiana 47405-2206
Part 70 Permit No.: T105-41051-00005

Months: _ to ___________ Year: _____________

Page 1 of 2

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

Page 2 of 2

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

Form Completed by:______________________________

Title / Position: ______________________________

Date:______________________________

Phone: ______________________________

Attachment A

Part 70 Operating Permit No: T105-41051-00005

[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:

Fuel/steam generating unit type	**Nitrogen oxide emission limits (expressed as NO_2) heat input**	
	ng/J	**lb/MMBTu**
(1) Natural gas and distillate oil, except (4):		
(i) Low heat release rate	43	0.10
(ii) High heat release rate	86	0.20
(2) Residual oil:		
(i) Low heat release rate	130	0.30
(ii) High heat release rate	170	0.40
(3) Coal:		
(i) Mass-feed stoker	210	0.50

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 ($E_{ho}{}^o$) is used in Equation 19-19 of Method 19 of appendix A of this part to compute an adjusted 30-day average emission rate ($E_{ao}{}^o$). The Eho° is computed using the following formula:

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

Where:

E_{ho}^{o} = Adjusted hourly SO_2 emission rate, ng/J (lb/MMBtu);

E_{ho} = Hourly SO_2 emission rate, ng/J (lb/MMBtu);

E_w = SO_2 concentration in fuels other than coal and oil combusted in the affected facility, as determined by the fuel sampling and analysis procedures in Method 19 of appendix A of this part, ng/J (lb/MMBtu). The value E_w for each fuel lot is used for each hourly average during the time that the lot is being combusted; and

X_k = Fraction of total heat input from fuel combustion derived from coal, oil, or coal and oil, as determined by applicable procedures in Method 19 of appendix A of this part.

(ii) To compute the percent of potential SO_2 emission rate ($\%P_s$), an adjusted $\%R_g$ ($\%R_g^{o}$) is computed from the adjusted E_{ao}^{o} from paragraph (b)(3)(i) of this section and an adjusted average SO_2 inlet rate (E_{ai}^{o}) using the following formula:

$$\%R_g^{o} = 100\left(1.0 - \frac{E_{ao}^{o}}{E_{ai}^{o}}\right)$$

To compute E_{ai}^{o}, an adjusted hourly SO_2 inlet rate (E_{hi}^{o}) is used. The E_{hi}^{o} is computed using the following formula:

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

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:

$$E = E_{sg} + \left(\frac{H_g}{H_b}\right)(E_{sg} - E_g) \qquad \text{(Eq.1)}$$

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.

[72 FR 32742, June 13, 2007, as amended at 74 FR 5086, Jan. 28, 2009; 76 FR 3523, Jan. 20, 2011; 77 FR 9460, Feb. 16, 2012; 79 FR 11249, Feb. 27, 2014]

§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: T105-41051-00005

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.

$1.912x10^{-3}$ = Conversion constant for ppm NO_X to grams per standard cubic meter at 25 degrees Celsius.

Q = Stack gas volumetric flow rate, in standard cubic meter per hour.

T = Time of test run, in hours.

KW-hour = Brake work of the engine, in KW-hour.

(f) To determine compliance with the PM mass per unit output emission limitation, convert the concentration of PM in the engine exhaust using Equation 8 of this section:

$$ER = \frac{C_{adj} \times Q \times T}{\text{KW-hour}} \qquad \text{(Eq. 8)}$$

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: T105-41051-00005

[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: T105-41051-00005

[Downloaded from the eCFR on November 25, 2015]

Title 40: Protection of Environment

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

Subpart DDDDD—National Emission Standards for Hazardous Air Pollutants for Major Sources: Industrial, Commercial, and Institutional Boilers and Process Heaters

Source: 76 FR 15664, Mar. 21, 2011, unless otherwise noted.

What This Subpart Covers

§63.7480 What is the purpose of this subpart?

This subpart establishes national emission limitations and work practice standards for hazardous air pollutants (HAP) emitted from industrial, commercial, and institutional boilers and process heaters located at major sources of HAP. This subpart also establishes requirements to demonstrate initial and continuous compliance with the emission limitations and work practice standards.

§63.7485 Am I subject to this subpart?

You are subject to this subpart if you own or operate an industrial, commercial, or institutional boiler or process heater as defined in §63.7575 that is located at, or is part of, a major source of HAP, except as specified in §63.7491. For purposes of this subpart, a major source of HAP is as defined in §63.2, except that for oil and natural gas production facilities, a major source of HAP is as defined in §63.7575.

[78 FR 7162, Jan. 31, 2013]

§63.7490 What is the affected source of this subpart?

(a) This subpart applies to new, reconstructed, and existing affected sources as described in paragraphs (a)(1) and (2) of this section.

(1) The affected source of this subpart is the collection at a major source of all existing industrial, commercial, and institutional boilers and process heaters within a subcategory as defined in §63.7575.

(2) The affected source of this subpart is each new or reconstructed industrial, commercial, or institutional boiler or process heater, as defined in §63.7575, located at a major source.

(b) A boiler or process heater is new if you commence construction of the boiler or process heater after June 4, 2010, and you meet the applicability criteria at the time you commence construction.

(c) A boiler or process heater is reconstructed if you meet the reconstruction criteria as defined in §63.2, you commence reconstruction after June 4, 2010, and you meet the applicability criteria at the time you commence reconstruction.

(d) A boiler or process heater is existing if it is not new or reconstructed.

(e) An existing electric utility steam generating unit (EGU) that meets the applicability requirements of this subpart after the effective date of this final rule due to a change (e.g., fuel switch) is considered to be an existing source under this subpart.

[76 FR 15664, Mar. 21, 2011, as amended at 78 FR 7162, Jan. 31, 2013]

§63.7491 Are any boilers or process heaters not subject to this subpart?

The types of boilers and process heaters listed in paragraphs (a) through (n) of this section are not subject to this subpart.

(a) An electric utility steam generating unit (EGU) covered by subpart UUUUU of this part or a natural gas-fired EGU as defined in subpart UUUUU of this part firing at least 85 percent natural gas on an annual heat input basis.

(b) A recovery boiler or furnace covered by subpart MM of this part.

(c) A boiler or process heater that is used specifically for research and development, including test steam boilers used to provide steam for testing the propulsion systems on military vessels. This does not include units that provide heat or steam to a process at a research and development facility.

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

(e) A refining kettle covered by subpart X of this part.

(f) An ethylene cracking furnace covered by subpart YY of this part.

(g) Blast furnace stoves as described in EPA-453/R-01-005 (incorporated by reference, see §63.14).

(h) Any boiler or process heater that is part of the affected source subject to another subpart of this part, such as boilers and process heaters used as control devices to comply with subparts JJJ, OOO, PPP, and U of this part.

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

(j) Temporary boilers and process heaters as defined in this subpart.

(k) Blast furnace gas fuel-fired boilers and process heaters as defined in this subpart.

(l) Any boiler or process heater specifically listed as an affected source in any standard(s) established under section 129 of the Clean Air Act.

(m) A unit that burns hazardous waste covered by Subpart EEE of this part. A unit that is exempt from Subpart EEE as specified in §63.1200(b) is not covered by Subpart EEE.

(n) Residential boilers as defined in this subpart.

[76 FR 15664, Mar. 21, 2011, as amended at 78 FR 7162, Jan. 31, 2013; 80 FR 72806, Nov. 20, 2015]

§63.7495 When do I have to comply with this subpart?

(a) If you have a new or reconstructed boiler or process heater, you must comply with this subpart by April 1, 2013, or upon startup of your boiler or process heater, whichever is later.

(b) If you have an existing boiler or process heater, you must comply with this subpart no later than January 31, 2016, except as provided in §63.6(i).

(c) If you have an area source that increases its emissions or its potential to emit such that it becomes a major source of HAP, paragraphs (c)(1) and (2) of this section apply to you.

(1) Any new or reconstructed boiler or process heater at the existing source must be in compliance with this subpart upon startup.

(2) Any existing boiler or process heater at the existing source must be in compliance with this subpart within 3 years after the source becomes a major source.

(d) You must meet the notification requirements in §63.7545 according to the schedule in §63.7545 and in subpart A of this part. Some of the notifications must be submitted before you are required to comply with the emission limits and work practice standards in this subpart.

(e) If you own or operate an industrial, commercial, or institutional boiler or process heater and would be subject to this subpart except for the exemption in §63.7491(l) for commercial and industrial solid waste incineration units covered by part 60, subpart CCCC or subpart DDDD, and you cease combusting solid waste, you must be in compliance with this subpart and are no longer subject to part 60, subparts CCCC or DDDD beginning on the effective date of the switch as identified under the provisions of §60.2145(a)(2) and (3) or §60.2710(a)(2) and (3).

(f) If you own or operate an existing EGU that becomes subject to this subpart after January 31, 2016, you must be in compliance with the applicable existing source provisions of this subpart on the effective date such unit becomes subject to this subpart.

(g) If you own or operate an existing industrial, commercial, or institutional boiler or process heater and would be subject to this subpart except for a exemption in §63.7491(i) that becomes subject to this subpart after January 31, 2013, you must be in compliance with the applicable existing source provisions of this subpart within 3 years after such unit becomes subject to this subpart.

(h) If you own or operate an existing industrial, commercial, or institutional boiler or process heater and have switched fuels or made a physical change to the boiler or process heater that resulted in the applicability of a different subcategory after the compliance date of this subpart, you must be in compliance with the applicable existing source provisions of this subpart on the effective date of the fuel switch or physical change.

(i) If you own or operate a new industrial, commercial, or institutional boiler or process heater and have switched fuels or made a physical change to the boiler or process heater that resulted in the applicability of a different subcategory, you must be in compliance with the applicable new source provisions of this subpart on the effective date of the fuel switch or physical change.

[76 FR 15664, Mar. 21, 2011, as amended at 78 FR 7162, Jan. 31, 2013; 80 FR 72807, Nov. 20, 2015]

Emission Limitations and Work Practice Standards

§63.7499 What are the subcategories of boilers and process heaters?

The subcategories of boilers and process heaters, as defined in §63.7575 are:

(a) Pulverized coal/solid fossil fuel units.

(b) Stokers designed to burn coal/solid fossil fuel.

(c) Fluidized bed units designed to burn coal/solid fossil fuel.

(d) Stokers/sloped grate/other units designed to burn kiln dried biomass/bio-based solid.

(e) Fluidized bed units designed to burn biomass/bio-based solid.

(f) Suspension burners designed to burn biomass/bio-based solid.

(g) Fuel cells designed to burn biomass/bio-based solid.

(h) Hybrid suspension/grate burners designed to burn wet biomass/bio-based solid.

(i) Stokers/sloped grate/other units designed to burn wet biomass/bio-based solid.

(j) Dutch ovens/pile burners designed to burn biomass/bio-based solid.

(k) Units designed to burn liquid fuel that are non-continental units.

(l) Units designed to burn gas 1 fuels.

(m) Units designed to burn gas 2 (other) gases.

(n) Metal process furnaces.

(o) Limited-use boilers and process heaters.

(p) Units designed to burn solid fuel.

(q) Units designed to burn liquid fuel.

(r) Units designed to burn coal/solid fossil fuel.

(s) Fluidized bed units with an integrated fluidized bed heat exchanger designed to burn coal/solid fossil fuel.

(t) Units designed to burn heavy liquid fuel.

(u) Units designed to burn light liquid fuel.

[76 FR 15664, Mar. 21, 2011, as amended at 78 FR 7163, Jan. 31, 2013]

§63.7500 What emission limitations, work practice standards, and operating limits must I meet?

(a) You must meet the requirements in paragraphs (a)(1) through (3) of this section, except as provided in paragraphs (b), through (e) of this section. You must meet these requirements at all times the affected unit is operating, except as provided in paragraph (f) of this section.

(1) You must meet each emission limit and work practice standard in Tables 1 through 3, and 11 through 13 to this subpart that applies to your boiler or process heater, for each boiler or process heater at your source, except as provided under §63.7522. The output-based emission limits, in units of pounds per million Btu of steam output, in Tables 1 or 2 to this subpart are an alternative applicable only to boilers and process heaters that generate either steam, cogenerate steam with electricity, or both. The output-based emission limits, in units of pounds per megawatt-hour, in Tables 1 or 2 to this subpart are an alternative applicable only to boilers that generate only electricity. Boilers that perform multiple functions (cogeneration and electricity generation) or supply steam to common headers would calculate a total steam energy output using equation 21 of §63.7575 to demonstrate compliance with the output-based emission limits, in units of pounds per million Btu of steam output, in Tables 1 or 2 to this subpart. If you operate a new boiler or process heater, you can choose to comply with alternative limits as discussed in paragraphs (a)(1)(i) through (iii) of this section, but on or after January 31, 2016, you must comply with the emission limits in Table 1 to this subpart.

(i) If your boiler or process heater commenced construction or reconstruction after June 4, 2010 and before May 20, 2011, you may comply with the emission limits in Table 1 or 11 to this subpart until January 31, 2016.

(ii) If your boiler or process heater commenced construction or reconstruction on or after May 20, 2011 and before December 23, 2011, you may comply with the emission limits in Table 1 or 12 to this subpart until January 31, 2016.

(iii) If your boiler or process heater commenced construction or reconstruction on or after December 23, 2011 and before April 1, 2013, you may comply with the emission limits in Table 1 or 13 to this subpart until January 31, 2016.

(2) You must meet each operating limit in Table 4 to this subpart that applies to your boiler or process heater. If you use a control device or combination of control devices not covered in Table 4 to this subpart, or you wish to establish and monitor an alternative operating limit or an alternative monitoring parameter, you must apply to the EPA Administrator for approval of alternative monitoring under §63.8(f).

(3) At all times, you must operate and maintain any affected source (as defined in §63.7490), including associated air pollution control equipment and monitoring equipment, in a manner consistent with safety and good air pollution control practices for minimizing emissions. Determination of whether such operation and maintenance procedures are being used will be based on information available to the Administrator that may include, but is not limited to, monitoring results, review of operation and maintenance procedures, review of operation and maintenance records, and inspection of the source.

(b) As provided in §63.6(g), EPA may approve use of an alternative to the work practice standards in this section.

(c) Limited-use boilers and process heaters must complete a tune-up every 5 years as specified in §63.7540. They are not subject to the emission limits in Tables 1 and 2 or 11 through 13 to this subpart, the annual tune-up, or the energy assessment requirements in Table 3 to this subpart, or the operating limits in Table 4 to this subpart.

(d) Boilers and process heaters with a heat input capacity of less than or equal to 5 million Btu per hour in the units designed to burn gas 2 (other) fuels subcategory or units designed to burn light liquid fuels subcategory must complete a tune-up every 5 years as specified in §63.7540.

(e) Boilers and process heaters in the units designed to burn gas 1 fuels subcategory with a heat input capacity of less than or equal to 5 million Btu per hour must complete a tune-up every 5 years as specified in §63.7540. Boilers and process heaters in the units designed to burn gas 1 fuels subcategory with a heat input capacity greater than 5 million Btu per hour and less than 10 million Btu per hour must complete a tune-up every 2 years as specified in §63.7540. Boilers and process heaters in the units designed to burn gas 1 fuels subcategory are not subject to the emission limits in Tables 1 and 2 or 11 through 13 to this subpart, or the operating limits in Table 4 to this subpart.

(f) These standards apply at all times the affected unit is operating, except during periods of startup and shutdown during which time you must comply only with items 5 and 6 of Table 3 to this subpart.

[76 FR 15664, Mar. 21, 2011, as amended at 78 FR 7163, Jan. 31, 2013; 80 FR 72807, Nov. 20, 2015]

§63.7501 [Reserved]

General Compliance Requirements

§63.7505 What are my general requirements for complying with this subpart?

(a) You must be in compliance with the emission limits, work practice standards, and operating limits in this subpart. These emission and operating limits apply to you at all times the affected unit is operating except for the periods noted in §63.7500(f).

(b) [Reserved]

(c) You must demonstrate compliance with all applicable emission limits using performance stack testing, fuel analysis, or continuous monitoring systems (CMS), including a continuous emission monitoring system (CEMS), or particulate matter continuous parameter monitoring system (PM CPMS), where applicable. You may demonstrate compliance with the applicable emission limit for hydrogen chloride (HCl), mercury, or total selected metals (TSM) using fuel analysis if the emission rate calculated according to §63.7530(c) is less than the applicable emission limit. (For gaseous fuels, you may not use fuel analyses to comply with the TSM alternative standard or the HCl standard.) Otherwise, you must demonstrate compliance for HCl, mercury, or TSM using performance stack testing, if subject to an applicable emission limit listed in Tables 1, 2, or 11 through 13 to this subpart.

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

(1) For each CMS required in this section (including CEMS, COMS, or CPMS), you must develop, and submit to the Administrator for approval upon request, a site-specific monitoring plan that addresses design, data collection, and the quality assurance and quality control elements outlined in §63.8(d) and the elements described in paragraphs (d)(1)(i) through (iii) of this section. You must submit this site-specific monitoring plan, if requested, at least 60 days before your initial performance evaluation of your CMS. This requirement to develop and submit a site specific monitoring plan does not apply to affected sources with existing CEMS or COMS operated according to the performance specifications under appendix B to part 60 of this chapter and that meet the requirements of §63.7525. Using the process described in §63.8(f)(4), you may request approval of alternative monitoring system quality assurance and quality control procedures in place of those specified in this paragraph and, if approved, include the alternatives in your site-specific monitoring plan.

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

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

(iii) Performance evaluation procedures and acceptance criteria (e.g., calibrations, accuracy audits, analytical drift).

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

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

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

(iii) Ongoing recordkeeping and reporting procedures in accordance with the general requirements of §63.10(c) (as applicable in Table 10 to this subpart), (e)(1), and (e)(2)(i).

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

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

(e) If you have an applicable emission limit, and you choose to comply using definition (2) of “startup” in §63.7575, you must develop and implement a written startup and shutdown plan (SSP) according to the requirements in Table 3 to this subpart. The SSP must be maintained onsite and available upon request for public inspection.

[76 FR 15664, Mar. 21, 2011, as amended at 78 FR 7164, Jan. 31, 2013; 80 FR 72807, Nov. 20, 2015]

Testing, Fuel Analyses, and Initial Compliance Requirements

§63.7510 What are my initial compliance requirements and by what date must I conduct them?

(a) For each boiler or process heater that is required or that you elect to demonstrate compliance with any of the applicable emission limits in Tables 1 or 2 or 11 through 13 of this subpart through performance (stack) testing, your initial compliance requirements include all the following:

(1) Conduct performance tests according to §63.7520 and Table 5 to this subpart.

(2) Conduct a fuel analysis for each type of fuel burned in your boiler or process heater according to §63.7521 and Table 6 to this subpart, except as specified in paragraphs (a)(2)(i) through (iii) of this section.

(i) For each boiler or process heater that burns a single type of fuel, you are not required to conduct a fuel analysis for each type of fuel burned in your boiler or process heater according to §63.7521 and Table 6 to this subpart. For purposes of this subpart, units that use a supplemental fuel only for startup, unit shutdown, and transient flame stability purposes still qualify as units that burn a single type of fuel, and the supplemental fuel is not subject to the fuel analysis requirements under §63.7521 and Table 6 to this subpart.

(ii) When natural gas, refinery gas, or other gas 1 fuels are co-fired with other fuels, you are not required to conduct a fuel analysis of those Gas 1 fuels according to §63.7521 and Table 6 to this subpart. If gaseous fuels other than natural gas, refinery gas, or other gas 1 fuels are co-fired with other fuels and those non-Gas 1 gaseous fuels are subject to another subpart of this part, part 60, part 61, or part 65, you are not required to conduct a fuel analysis of those non-Gas 1 fuels according to §63.7521 and Table 6 to this subpart.

(iii) You are not required to conduct a chlorine fuel analysis for any gaseous fuels. You must conduct a fuel analysis for mercury on gaseous fuels unless the fuel is exempted in paragraphs (a)(2)(i) and (ii) of this section.

(3) Establish operating limits according to §63.7530 and Table 7 to this subpart.

(4) Conduct CMS performance evaluations according to §63.7525.

(b) For each boiler or process heater that you elect to demonstrate compliance with the applicable emission limits in Tables 1 or 2 or 11 through 13 to this subpart for HCl, mercury, or TSM through fuel analysis, your initial compliance requirement is to conduct a fuel analysis for each type of fuel burned in your boiler or process heater according to §63.7521 and Table 6 to this subpart and establish operating limits according to §63.7530 and Table 8 to this subpart. The fuels described in paragraph (a)(2)(i) and (ii) of this section are exempt from these fuel analysis and operating limit requirements. The fuels described in paragraph (a)(2)(ii) of this section are exempt from the chloride fuel analysis and operating limit requirements. Boilers and process heaters that use a CEMS for mercury or HCl are exempt from the performance testing and operating limit requirements specified in paragraph (a) of this section for the HAP for which CEMS are used.

(c) If your boiler or process heater is subject to a carbon monoxide (CO) limit, your initial compliance demonstration for CO is to conduct a performance test for CO according to Table 5 to this subpart or conduct a performance evaluation of your continuous CO monitor, if applicable, according to §63.7525(a). Boilers and process heaters that use a CO CEMS to comply with the applicable alternative CO CEMS emission standard listed in Tables 1, 2, or 11 through 13 to this subpart, as specified in §63.7525(a), are exempt from the initial CO performance testing and oxygen concentration operating limit requirements specified in paragraph (a) of this section.

(d) If your boiler or process heater is subject to a PM limit, your initial compliance demonstration for PM is to conduct a performance test in accordance with §63.7520 and Table 5 to this subpart.

(e) For existing affected sources (as defined in §63.7490), you must complete the initial compliance demonstrations, as specified in paragraphs (a) through (d) of this section, no later than 180 days after the compliance date that is specified for your source in §63.7495 and according to the applicable provisions in §63.7(a)(2) as cited in Table 10 to this subpart, except as specified in paragraph (j) of this section. You must complete an initial tune-up by following the procedures described in §63.7540(a)(10)(i) through (vi) no later than the compliance date specified in §63.7495, except as specified in paragraph (j) of this section. You must complete the one-time energy assessment specified in Table 3 to this subpart no later than the compliance date specified in §63.7495.

(f) For new or reconstructed affected sources (as defined in §63.7490), you must complete the initial compliance demonstration with the emission limits no later than July 30, 2013 or within 180 days after startup of the source, whichever is later. If you are demonstrating compliance with an emission limit in Tables 11 through 13 to this subpart that is less stringent (that is, higher) than the applicable emission limit in Table 1 to this subpart, you must demonstrate compliance with the applicable emission limit in Table 1 no later than July 29, 2016.

(g) For new or reconstructed affected sources (as defined in §63.7490), you must demonstrate initial compliance with the applicable work practice standards in Table 3 to this subpart within the applicable annual, biennial, or 5-year schedule as specified in §63.7515(d) following the initial compliance date specified in §63.7495(a). Thereafter, you are required to complete the applicable annual, biennial, or 5-year tune-up as specified in §63.7515(d).

(h) For affected sources (as defined in §63.7490) that ceased burning solid waste consistent with §63.7495(e) and for which the initial compliance date has passed, you must demonstrate compliance within 60 days of the effective date of the waste-to-fuel switch. If you have not conducted your compliance demonstration for this subpart within the previous 12 months, you must complete all compliance demonstrations for this subpart before you commence or recommence combustion of solid waste.

(i) For an existing EGU that becomes subject after January 31, 2016, you must demonstrate compliance within 180 days after becoming an affected source.

(j) For existing affected sources (as defined in §63.7490) that have not operated between the effective date of the rule and the compliance date that is specified for your source in §63.7495, you must complete the initial compliance demonstration, if subject to the emission limits in Table 2 to this subpart, as specified in paragraphs (a) through (d) of this section, no later than 180 days after the re-start of the affected source and according to the applicable provisions in §63.7(a)(2) as cited in Table 10 to this subpart. You must complete an initial tune-up by following the procedures described in §63.7540(a)(10)(i) through (vi) no later than 30 days after the re-start of the affected source and, if applicable, complete the one-time energy assessment specified in Table 3 to this subpart, no later than the compliance date specified in §63.7495.

(k) For affected sources, as defined in §63.7490, that switch subcategories consistent with §63.7545(h) after the initial compliance date, you must demonstrate compliance within 60 days of the effective date of the switch, unless you had previously conducted your compliance demonstration for this subcategory within the previous 12 months.

[78 FR 7164, Jan. 31, 2013, as amended at 80 FR 72808, Nov. 20, 2015]

§63.7515 When must I conduct subsequent performance tests, fuel analyses, or tune-ups?

(a) You must conduct all applicable performance tests according to §63.7520 on an annual basis, except as specified in paragraphs (b) through (e), (g), and (h) of this section. Annual performance tests must be completed no more than 13 months after the previous performance test, except as specified in paragraphs (b) through (e), (g), and (h) of this section.

(b) If your performance tests for a given pollutant for at least 2 consecutive years show that your emissions are at or below 75 percent of the emission limit (or, in limited instances as specified in Tables 1 and 2 or 11 through 13 to this subpart, at or below the emission limit) for the pollutant, and if there are no changes in the operation of the individual boiler or process heater or air pollution control equipment that could increase emissions, you may choose to conduct performance tests for the pollutant every third year. Each such performance test must be conducted no more than 37 months after the previous performance test. If you elect to demonstrate compliance using emission averaging under §63.7522, you must continue to conduct performance tests annually. The requirement to test at maximum chloride input level is waived unless the stack test is conducted for HCl. The requirement to test at maximum mercury input level is waived unless the stack test is conducted for mercury. The requirement to test at maximum TSM input level is waived unless the stack test is conducted for TSM.

(c) If a performance test shows emissions exceeded the emission limit or 75 percent of the emission limit (as specified in Tables 1 and 2 or 11 through 13 to this subpart) for a pollutant, you must conduct annual performance tests for that pollutant until all performance tests over a consecutive 2-year period meet the required level (at or below 75 percent of the emission limit, as specified in Tables 1 and 2 or 11 through 13 to this subpart).

(d) If you are required to meet an applicable tune-up work practice standard, you must conduct an annual, biennial, or 5-year performance tune-up according to §63.7540(a)(10), (11), or (12), respectively. Each annual tune-up specified in §63.7540(a)(10) must be no more than 13 months after the previous tune-up. Each biennial tune-up specified in §63.7540(a)(11) must be conducted no more than 25 months after the previous tune-up. Each 5-year tune-up specified in §63.7540(a)(12) must be conducted no more than 61 months after the previous tune-up. For a new or reconstructed affected source (as defined in §63.7490), the first annual, biennial, or 5-year tune-up must be no later than 13 months, 25 months, or 61 months, respectively, after April 1, 2013 or the initial startup of the new or reconstructed affected source, whichever is later.

(e) If you demonstrate compliance with the mercury, HCl, or TSM based on fuel analysis, you must conduct a monthly fuel analysis according to §63.7521 for each type of fuel burned that is subject to an emission limit in Tables 1, 2, or 11 through 13 to this subpart. You may comply with this monthly requirement by completing the fuel analysis any time within the calendar month as long as the analysis is separated from the previous analysis by at least 14 calendar days. If you burn a new type of fuel, you must conduct a fuel analysis before burning the new type of fuel in your boiler or process heater. You must still meet all applicable continuous compliance requirements in §63.7540. If each of 12 consecutive monthly fuel analyses demonstrates 75 percent or less of the compliance level, you may decrease the fuel analysis frequency to quarterly for that fuel. If any quarterly sample exceeds 75 percent of the compliance level or you begin burning a new type of fuel, you must return to monthly monitoring for that fuel, until 12 months of fuel analyses are again less than 75 percent of the compliance level. If sampling is conducted on one day per month, samples should be no less than 14 days apart, but if multiple samples are taken per month, the 14-day restriction does not apply.

(f) You must report the results of performance tests and the associated fuel analyses within 60 days after the completion of the performance tests. This report must also verify that the operating limits for each boiler or process heater have not changed or provide documentation of revised operating limits established according to §63.7530 and Table 7 to this subpart, as applicable. The reports for all subsequent performance tests must include all applicable information required in §63.7550.

(g) For affected sources (as defined in §63.7490) that have not operated since the previous compliance demonstration and more than one year has passed since the previous compliance demonstration, you must complete the subsequent compliance demonstration, if subject to the emission limits in Tables 1, 2, or 11 through 13 to this subpart, no later than 180 days after the re-start of the affected source and according to the applicable provisions in §63.7(a)(2) as cited in Table 10 to this subpart. You must complete a subsequent tune-up by following the procedures described in §63.7540(a)(10)(i) through (vi) and the schedule described in §63.7540(a)(13) for units that are not operating at the time of their scheduled tune-up.

(h) If your affected boiler or process heater is in the unit designed to burn light liquid subcategory and you combust ultra-low sulfur liquid fuel, you do not need to conduct further performance tests (stack tests or fuel analyses) if the pollutants measured during the initial compliance performance tests meet the emission limits in Tables 1 or 2 of this subpart providing you demonstrate ongoing compliance with the emissions limits by monitoring and recording the type of fuel combusted on a monthly basis. If you intend to use a fuel other than ultra-low sulfur liquid fuel, natural gas, refinery gas, or other gas 1 fuel, you must conduct new performance tests within 60 days of burning the new fuel type.

(i) If you operate a CO CEMS that meets the Performance Specifications outlined in §63.7525(a)(3) of this subpart to demonstrate compliance with the applicable alternative CO CEMS emission standard listed in Tables 1, 2, or 11 through 13 to this subpart, you are not required to conduct CO performance tests and are not subject to the oxygen concentration operating limit requirement specified in §63.7510(a).

[78 FR 7165, Jan. 31, 2013, as amended at 80 FR 72808, Nov. 20, 2015]

§63.7520 What stack tests and procedures must I use?

(a) You must conduct all performance tests according to §63.7(c), (d), (f), and (h). You must also develop a site-specific stack test plan according to the requirements in §63.7(c). You shall conduct all performance tests under such conditions as the Administrator specifies to you based on the representative performance of each boiler or process heater for the period being tested. Upon request, you shall make available to the Administrator such records as may be necessary to determine the conditions of the performance tests.

(b) You must conduct each performance test according to the requirements in Table 5 to this subpart.

(c) You must conduct each performance test under the specific conditions listed in Tables 5 and 7 to this subpart. You must conduct performance tests at representative operating load conditions while burning the type of fuel or mixture of fuels that has the highest content of chlorine and mercury, and TSM if you are opting to comply with the TSM alternative standard and you must demonstrate initial compliance and establish your operating limits based on these performance tests. These requirements could result in the need to conduct more than one performance test. Following each performance test and until the next performance test, you must comply with the operating limit for operating load conditions specified in Table 4 to this subpart.

(d) You must conduct a minimum of three separate test runs for each performance test required in this section, as specified in §63.7(e)(3). Each test run must comply with the minimum applicable sampling times or volumes specified in Tables 1 and 2 or 11 through 13 to this subpart.

(e) To determine compliance with the emission limits, you must use the F-Factor methodology and equations in sections 12.2 and 12.3 of EPA Method 19 at 40 CFR part 60, appendix A-7 of this chapter to convert the measured particulate matter (PM) concentrations, the measured HCl concentrations, the measured mercury concentrations, and the measured TSM concentrations that result from the performance test to pounds per million Btu heat input emission rates.

(f) Except for a 30-day rolling average based on CEMS (or sorbent trap monitoring system) data, if measurement results for any pollutant are reported as below the method detection level (e.g., laboratory analytical results for one or more sample components are below the method defined analytical detection level), you must use the method detection level as the measured emissions level for that pollutant in calculating compliance. The measured result for a multiple component analysis (e.g., analytical values for multiple Method 29 fractions both for individual HAP metals and for total HAP metals) may include a combination of method detection level data and analytical data reported above the method detection level.

[76 FR 15664, Mar. 21, 2011, as amended at 78 FR 7166, Jan. 31, 2013]

§63.7521 What fuel analyses, fuel specification, and procedures must I use?

(a) For solid and liquid fuels, you must conduct fuel analyses for chloride and mercury according to the procedures in paragraphs (b) through (e) of this section and Table 6 to this subpart, as applicable. For solid fuels and liquid fuels, you must also conduct fuel analyses for TSM if you are opting to comply with the TSM alternative standard. For gas 2 (other) fuels, you must conduct fuel analyses for mercury according to the procedures in paragraphs (b) through (e) of this section and Table 6 to this subpart, as applicable. (For gaseous fuels, you may not use fuel analyses to comply with the TSM alternative standard or the HCl standard.) For purposes of complying with this section, a fuel gas system that consists of multiple gaseous fuels collected and mixed with each other is considered a single fuel type and sampling and analysis is only required on the combined fuel gas system that will feed the boiler or process heater. Sampling and analysis of the individual gaseous streams prior to combining is not required. You are not required to conduct fuel analyses for fuels used for only startup, unit shutdown, and transient flame stability purposes. You are required to conduct fuel analyses only for fuels and units that are subject to emission limits for mercury, HCl, or TSM in Tables 1 and 2 or 11 through 13 to this subpart. Gaseous and liquid fuels are exempt from the sampling requirements in paragraphs (c) and (d) of this section.

(b) You must develop a site-specific fuel monitoring plan according to the following procedures and requirements in paragraphs (b)(1) and (2) of this section, if you are required to conduct fuel analyses as specified in §63.7510.

(1) If you intend to use an alternative analytical method other than those required by Table 6 to this subpart, you must submit the fuel analysis plan to the Administrator for review and approval no later than 60 days before the date that you intend to conduct the initial compliance demonstration described in §63.7510.

(2) You must include the information contained in paragraphs (b)(2)(i) through (vi) of this section in your fuel analysis plan.

(i) The identification of all fuel types anticipated to be burned in each boiler or process heater.

(ii) For each anticipated fuel type, the notification of whether you or a fuel supplier will be conducting the fuel analysis.

(iii) For each anticipated fuel type, a detailed description of the sample location and specific procedures to be used for collecting and preparing the composite samples if your procedures are different from paragraph (c) or (d) of this section. Samples should be collected at a location that most accurately represents the fuel type, where possible, at a point prior to mixing with other dissimilar fuel types.

(iv) For each anticipated fuel type, the analytical methods from Table 6, with the expected minimum detection levels, to be used for the measurement of chlorine or mercury.

(v) If you request to use an alternative analytical method other than those required by Table 6 to this subpart, you must also include a detailed description of the methods and procedures that you are proposing to use. Methods in Table 6 shall be used until the requested alternative is approved.

(vi) If you will be using fuel analysis from a fuel supplier in lieu of site-specific sampling and analysis, the fuel supplier must use the analytical methods required by Table 6 to this subpart.

(c) You must obtain composite fuel samples for each fuel type according to the procedures in paragraph (c)(1) or (2) of this section, or the methods listed in Table 6 to this subpart, or use an automated sampling mechanism that provides representative composite fuel samples for each fuel type that includes both coarse and fine material. At a minimum, for demonstrating initial compliance by fuel analysis, you must obtain three composite samples. For monthly fuel analyses, at a minimum, you must obtain a single composite sample. For fuel analyses as part of a performance stack test, as specified in §63.7510(a), you must obtain a composite fuel sample during each performance test run.

(1) If sampling from a belt (or screw) feeder, collect fuel samples according to paragraphs (c)(1)(i) and (ii) of this section.

(i) Stop the belt and withdraw a 6-inch wide sample from the full cross-section of the stopped belt to obtain a minimum two pounds of sample. You must collect all the material (fines and coarse) in the full cross-section. You must transfer the sample to a clean plastic bag.

(ii) Each composite sample will consist of a minimum of three samples collected at approximately equal one-hour intervals during the testing period for sampling during performance stack testing.

(2) If sampling from a fuel pile or truck, you must collect fuel samples according to paragraphs (c)(2)(i) through (iii) of this section.

(i) For each composite sample, you must select a minimum of five sampling locations uniformly spaced over the surface of the pile.

(ii) At each sampling site, you must dig into the pile to a uniform depth of approximately 18 inches. You must insert a clean shovel into the hole and withdraw a sample, making sure that large pieces do not fall off during sampling; use the same shovel to collect all samples.

(iii) You must transfer all samples to a clean plastic bag for further processing.

(d) You must prepare each composite sample according to the procedures in paragraphs (d)(1) through (7) of this section.

(1) You must thoroughly mix and pour the entire composite sample over a clean plastic sheet.

(2) You must break large sample pieces (e.g., larger than 3 inches) into smaller sizes.

(3) You must make a pie shape with the entire composite sample and subdivide it into four equal parts.

(4) You must separate one of the quarter samples as the first subset.

(5) If this subset is too large for grinding, you must repeat the procedure in paragraph (d)(3) of this section with the quarter sample and obtain a one-quarter subset from this sample.

(6) You must grind the sample in a mill.

(7) You must use the procedure in paragraph (d)(3) of this section to obtain a one-quarter subsample for analysis. If the quarter sample is too large, subdivide it further using the same procedure.

(e) You must determine the concentration of pollutants in the fuel (mercury and/or chlorine and/or TSM) in units of pounds per million Btu of each composite sample for each fuel type according to the procedures in Table 6 to this subpart, for use in Equations 7, 8, and 9 of this subpart.

(f) To demonstrate that a gaseous fuel other than natural gas or refinery gas qualifies as an other gas 1 fuel, as defined in §63.7575, you must conduct a fuel specification analyses for mercury according to the procedures in paragraphs (g) through (i) of this section and Table 6 to this subpart, as applicable, except as specified in paragraph (f)(1) through (4) of this section, or as an alternative where fuel specification analysis is not practical, you must measure mercury concentration in the exhaust gas when firing only the gaseous fuel to be demonstrated as an other gas 1 fuel in the boiler or process heater according to the procedures in Table 6 to this subpart.

(1) You are not required to conduct the fuel specification analyses in paragraphs (g) through (i) of this section for natural gas or refinery gas.

(2) You are not required to conduct the fuel specification analyses in paragraphs (g) through (i) of this section for gaseous fuels that are subject to another subpart of this part, part 60, part 61, or part 65.

(3) You are not required to conduct the fuel specification analyses in paragraphs (g) through (i) of this section on gaseous fuels for units that are complying with the limits for units designed to burn gas 2 (other) fuels.

(4) You are not required to conduct the fuel specification analyses in paragraphs (g) through (i) of this section for gas streams directly derived from natural gas at natural gas production sites or natural gas plants.

(g) You must develop a site-specific fuel analysis plan for other gas 1 fuels according to the following procedures and requirements in paragraphs (g)(1) and (2) of this section.

(1) If you intend to use an alternative analytical method other than those required by Table 6 to this subpart, you must submit the fuel analysis plan to the Administrator for review and approval no later than 60 days before the date that you intend to conduct the initial compliance demonstration described in §63.7510.

(2) You must include the information contained in paragraphs (g)(2)(i) through (vi) of this section in your fuel analysis plan.

(i) The identification of all gaseous fuel types other than those exempted from fuel specification analysis under (f)(1) through (3) of this section anticipated to be burned in each boiler or process heater.

(ii) For each anticipated fuel type, the identification of whether you or a fuel supplier will be conducting the fuel specification analysis.

(iii) For each anticipated fuel type, a detailed description of the sample location and specific procedures to be used for collecting and preparing the samples if your procedures are different from the sampling methods contained in Table 6 to this subpart. Samples should be collected at a location that most accurately represents the fuel type, where possible, at a point prior to mixing with other dissimilar fuel types. If multiple boilers or process heaters are fueled by a common fuel stream it is permissible to conduct a single gas specification at the common point of gas distribution.

(iv) For each anticipated fuel type, the analytical methods from Table 6 to this subpart, with the expected minimum detection levels, to be used for the measurement of mercury.

(v) If you request to use an alternative analytical method other than those required by Table 6 to this subpart, you must also include a detailed description of the methods and procedures that you are proposing to use. Methods in Table 6 to this subpart shall be used until the requested alternative is approved.

(vi) If you will be using fuel analysis from a fuel supplier in lieu of site-specific sampling and analysis, the fuel supplier must use the analytical methods required by Table 6 to this subpart. When using a fuel supplier's fuel analysis, the owner or operator is not required to submit the information in §63.7521(g)(2)(iii).

(h) You must obtain a single fuel sample for each fuel type for fuel specification of gaseous fuels.

(i) You must determine the concentration in the fuel of mercury, in units of microgram per cubic meter, dry basis, of each sample for each other gas 1 fuel type according to the procedures in Table 6 to this subpart.

[78 FR 7167, Jan. 31, 2013, as amended at 80 FR 72808, Nov. 20, 2015]

§63.7522 Can I use emissions averaging to comply with this subpart?

(a) As an alternative to meeting the requirements of §63.7500 for PM (or TSM), HCl, or mercury on a boiler or process heater-specific basis, if you have more than one existing boiler or process heater in any subcategories located at your facility, you may demonstrate compliance by emissions averaging, if your averaged emissions are not more than 90 percent of the applicable emission limit, according to the procedures in this section. You may not include new boilers or process heaters in an emissions average.

(b) For a group of two or more existing boilers or process heaters in the same subcategory that each vent to a separate stack, you may average PM (or TSM), HCl, or mercury emissions among existing units to demonstrate compliance with the limits in Table 2 to this subpart as specified in paragraph (b)(1) through (3) of this section, if you satisfy the requirements in paragraphs (c) through (g) of this section.

(1) You may average units using a CEMS or PM CPMS for demonstrating compliance.

(2) For mercury and HCl, averaging is allowed as follows:

(i) You may average among units in any of the solid fuel subcategories.

(ii) You may average among units in any of the liquid fuel subcategories.

(iii) You may average among units in a subcategory of units designed to burn gas 2 (other) fuels.

(iv) You may not average across the units designed to burn liquid, units designed to burn solid fuel, and units designed to burn gas 2 (other) subcategories.

(3) For PM (or TSM), averaging is only allowed between units within each of the following subcategories and you may not average across subcategories:

(i) Units designed to burn coal/solid fossil fuel.

(ii) Stokers/sloped grate/other units designed to burn kiln dried biomass/bio-based solids.

(iii) Stokers/sloped grate/other units designed to burn wet biomass/bio-based solids.

(iv) Fluidized bed units designed to burn biomass/bio-based solid.

(v) Suspension burners designed to burn biomass/bio-based solid.

(vi) Dutch ovens/pile burners designed to burn biomass/bio-based solid.

(vii) Fuel Cells designed to burn biomass/bio-based solid.

(viii) Hybrid suspension/grate burners designed to burn wet biomass/bio-based solid.

(ix) Units designed to burn heavy liquid fuel.

(x) Units designed to burn light liquid fuel.

(xi) Units designed to burn liquid fuel that are non-continental units.

(xii) Units designed to burn gas 2 (other) gases.

(c) For each existing boiler or process heater in the averaging group, the emission rate achieved during the initial compliance test for the HAP being averaged must not exceed the emission level that was being achieved on April 1, 2013 or the control technology employed during the initial compliance test must not be less effective for the HAP being averaged than the control technology employed on April 1, 2013.

(d) The averaged emissions rate from the existing boilers and process heaters participating in the emissions averaging option must not exceed 90 percent of the limits in Table 2 to this subpart at all times the affected units are subject to numeric emission limits following the compliance date specified in §63.7495.

(e) You must demonstrate initial compliance according to paragraph (e)(1) or (2) of this section using the maximum rated heat input capacity or maximum steam generation capacity of each unit and the results of the initial performance tests or fuel analysis.

(1) You must use Equation 1a or 1b or 1c of this section to demonstrate that the PM (or TSM), HCl, or mercury emissions from all existing units participating in the emissions averaging option for that pollutant do not exceed the emission limits in Table 2 to this subpart. Use Equation 1a if you are complying with the emission limits on a heat input basis, use Equation 1b if you are complying with the emission limits on a steam generation (output) basis, and use Equation 1c if you are complying with the emission limits on a electric generation (output) basis.

$$AveWeightedEmissions = 1.1 \times \sum_{i=1}^{n} \left(Er \times Hm\right) \div \sum_{i=1}^{n} Hm \qquad \text{(Eq.1a)}$$

Where:

AveWeightedEmissions = Average weighted emissions for PM (or TSM), HCl, or mercury, in units of pounds per million Btu of heat input.

Er = Emission rate (as determined during the initial compliance demonstration) of PM (or TSM), HCl, or mercury from unit, i, in units of pounds per million Btu of heat input. Determine the emission rate for PM (or TSM), HCl, or mercury by performance testing according to Table 5 to this subpart, or by fuel analysis for HCl or mercury or TSM using the applicable equation in §63.7530(c).

Hm = Maximum rated heat input capacity of unit, i, in units of million Btu per hour.

n = Number of units participating in the emissions averaging option.

1.1 = Required discount factor.

$$AveWeightedEmissions = 1.1 \times \sum_{i=1}^{n}(Er \times So) \div \sum_{i=1}^{n} So \qquad \text{(Eq.1b)}$$

Where:

AveWeightedEmissions = Average weighted emissions for PM (or TSM), HCl, or mercury, in units of pounds per million Btu of steam output.

Er = Emission rate (as determined during the initial compliance demonstration) of PM (or TSM), HCl, or mercury from unit, i, in units of pounds per million Btu of steam output. Determine the emission rate for PM (or TSM), HCl, or mercury by performance testing according to Table 5 to this subpart, or by fuel analysis for HCl or mercury or TSM using the applicable equation in §63.7530(c). If you are taking credit for energy conservation measures from a unit according to §63.7533, use the adjusted emission level for that unit, Eadj, determined according to §63.7533 for that unit.

So = Maximum steam output capacity of unit, i, in units of million Btu per hour, as defined in §63.7575.

n = Number of units participating in the emissions averaging option.

1.1 = Required discount factor.

$$AveWeightedEmissions = 1.1 \times \sum_{i=1}^{n}(Er \times Eo) \div \sum_{i=1}^{n} Eo \qquad \text{(Eq.1c)}$$

Where:

AveWeightedEmissions = Average weighted emissions for PM (or TSM), HCl, or mercury, in units of pounds per megawatt hour.

Er = Emission rate (as determined during the initial compliance demonstration) of PM (or TSM), HCl, or mercury from unit, i, in units of pounds per megawatt hour. Determine the emission rate for PM (or TSM), HCl, or mercury by performance testing according to Table 5 to this subpart, or by fuel analysis for HCl or mercury or TSM using the applicable equation in §63.7530(c). If you are taking credit for energy conservation measures from a unit according to §63.7533, use the adjusted emission level for that unit, Eadj, determined according to §63.7533 for that unit.

Eo = Maximum electric generating output capacity of unit, i, in units of megawatt hour, as defined in §63.7575.

n = Number of units participating in the emissions averaging option.

1.1 = Required discount factor.

(2) If you are not capable of determining the maximum rated heat input capacity of one or more boilers that generate steam, you may use Equation 2 of this section as an alternative to using Equation 1a of this section to demonstrate that the PM (or TSM), HCl, or mercury emissions from all existing units participating in the emissions averaging option do not exceed the emission limits for that pollutant in Table 2 to this subpart that are in pounds per million Btu of heat input.

$$AveWeightedEmissions = 1.1 \times \sum_{i=1}^{n}(Er \times Sm \times Cfi) \div \sum_{i=1}^{n}(Sm \times Cfi) \qquad \text{(Eq. 2)}$$

Where:

AveWeightedEmissions = Average weighted emission level for PM (or TSM), HCl, or mercury, in units of pounds per million Btu of heat input.

Er = Emission rate (as determined during the most recent compliance demonstration) of PM (or TSM), HCl, or mercury from unit, i, in units of pounds per million Btu of heat input. Determine the emission rate for PM (or TSM), HCl, or mercury by performance testing according to Table 5 to this subpart, or by fuel analysis for HCl or mercury or TSM using the applicable equation in §63.7530(c).

Sm = Maximum steam generation capacity by unit, i, in units of pounds per hour.

Cfi = Conversion factor, calculated from the most recent compliance test, in units of million Btu of heat input per pounds of steam generated for unit, i.

1.1 = Required discount factor.

(f) After the initial compliance demonstration described in paragraph (e) of this section, you must demonstrate compliance on a monthly basis determined at the end of every month (12 times per year) according to paragraphs (f)(1) through (3) of this section. The first monthly period begins on the compliance date specified in §63.7495. If the affected source elects to collect monthly data for up the 11 months preceding the first monthly period, these additional data points can be used to compute the 12-month rolling average in paragraph (f)(3) of this section.

(1) For each calendar month, you must use Equation 3a or 3b or 3c of this section to calculate the average weighted emission rate for that month. Use Equation 3a and the actual heat input for the month for each existing unit participating in the emissions averaging option if you are complying with emission limits on a heat input basis. Use Equation 3b and the actual steam generation for the month if you are complying with the emission limits on a steam generation (output) basis. Use Equation 3c and the actual electrical generation for the month if you are complying with the emission limits on an electrical generation (output) basis.

$$AveWeightedEmissions = 1.1 \times \sum_{i=1}^{n}(Er \times Hb) \div \sum_{i=1}^{n} Hb \qquad \text{(Eq. 3a)}$$

Where:

AveWeightedEmissions = Average weighted emission level for PM (or TSM), HCl, or mercury, in units of pounds per million Btu of heat input, for that calendar month.

Er = Emission rate (as determined during the most recent compliance demonstration) of PM (or TSM), HCl, or mercury from unit, i, in units of pounds per million Btu of heat input. Determine the emission rate for PM (or TSM), HCl, or mercury by performance testing according to Table 5 to this subpart, or by fuel analysis for HCl or mercury or TSM according to Table 6 to this subpart.

Hb = The heat input for that calendar month to unit, i, in units of million Btu.

n = Number of units participating in the emissions averaging option.

1.1 = Required discount factor.

$$AveWeightedEmissions = 1.1 \times \sum_{i=1}^{n}(Er \times So) \div \sum_{i=1}^{n} So \qquad \text{(Eq. 3b)}$$

Where:

AveWeightedEmissions = Average weighted emission level for PM (or TSM), HCl, or mercury, in units of pounds per million Btu of steam output, for that calendar month.

Er = Emission rate (as determined during the most recent compliance demonstration) of PM (or TSM), HCl, or mercury from unit, i, in units of pounds per million Btu of steam output. Determine the emission rate for PM (or TSM), HCl, or mercury by performance testing according to Table 5 to this subpart, or by fuel analysis for HCl or mercury or TSM according to Table 6 to this subpart. If you are taking credit for energy conservation measures from a unit according to §63.7533, use the adjusted emission level for that unit, E_{adj}, determined according to §63.7533 for that unit.

So = The steam output for that calendar month from unit, i, in units of million Btu, as defined in §63.7575.

n = Number of units participating in the emissions averaging option.

1.1 = Required discount factor.

$$AveWeightedEmissions = 1.1 \times \sum_{i=1}^{n} (Er \times Eo) \div \sum_{i=1}^{n} Eo \quad \text{(Eq. 3c)}$$

Where:

AveWeightedEmissions = Average weighted emission level for PM (or TSM), HCl, or mercury, in units of pounds per megawatt hour, for that calendar month.

Er = Emission rate (as determined during the most recent compliance demonstration) of PM (or TSM), HCl, or mercury from unit, i, in units of pounds per megawatt hour. Determine the emission rate for PM (or TSM), HCl, or mercury by performance testing according to Table 5 to this subpart, or by fuel analysis for HCl or mercury or TSM according to Table 6 to this subpart. If you are taking credit for energy conservation measures from a unit according to §63.7533, use the adjusted emission level for that unit, E_{adj}, determined according to §63.7533 for that unit.

Eo = The electric generating output for that calendar month from unit, i, in units of megawatt hour, as defined in §63.7575.

n = Number of units participating in the emissions averaging option.

1.1 = Required discount factor.

(2) If you are not capable of monitoring heat input, you may use Equation 4 of this section as an alternative to using Equation 3a of this section to calculate the average weighted emission rate using the actual steam generation from the boilers participating in the emissions averaging option.

$$AveWeightedEmissions = 1.1 \times \sum_{i=1}^{n} (Er \times Sa \times Cfi) \div \sum_{i=1}^{n} (Sa \times Cfi) \quad \text{(Eq. 4)}$$

Where:

AveWeightedEmissions = average weighted emission level for PM (or TSM), HCl, or mercury, in units of pounds per million Btu of heat input for that calendar month.

Er = Emission rate (as determined during the most recent compliance demonstration of PM (or TSM), HCl, or mercury from unit, i, in units of pounds per million Btu of heat input. Determine the emission rate for PM (or TSM), HCl, or mercury by performance testing according to Table 5 to this subpart, or by fuel analysis for HCl or mercury or TSM according to Table 6 to this subpart.

Sa = Actual steam generation for that calendar month by boiler, i, in units of pounds.

Cfi = Conversion factor, as calculated during the most recent compliance test, in units of million Btu of heat input per pounds of steam generated for boiler, i.

1.1 = Required discount factor.

(3) Until 12 monthly weighted average emission rates have been accumulated, calculate and report only the average weighted emission rate determined under paragraph (f)(1) or (2) of this section for each calendar month. After 12 monthly weighted average emission rates have been accumulated, for each subsequent calendar month, use Equation 5 of this section to calculate the 12-month rolling average of the monthly weighted average emission rates for the current calendar month and the previous 11 calendar months.

$$Eavg = \sum_{i=1}^{n} ERi \div 12 \quad \text{(Eq. 5)}$$

Where:

Eavg = 12-month rolling average emission rate, (pounds per million Btu heat input)

ERi = Monthly weighted average, for calendar month “i” (pounds per million Btu heat input), as calculated by paragraph (f)(1) or (2) of this section.

(g) You must develop, and submit upon request to the applicable Administrator for review and approval, an implementation plan for emission averaging according to the following procedures and requirements in paragraphs (g)(1) through (4) of this section.

(1) If requested, you must submit the implementation plan no later than 180 days before the date that the facility intends to demonstrate compliance using the emission averaging option.

(2) You must include the information contained in paragraphs (g)(2)(i) through (vii) of this section in your implementation plan for all emission sources included in an emissions average:

(i) The identification of all existing boilers and process heaters in the averaging group, including for each either the applicable HAP emission level or the control technology installed as of January 31, 2013 and the date on which you are requesting emission averaging to commence;

(ii) The process parameter (heat input or steam generated) that will be monitored for each averaging group;

(iii) The specific control technology or pollution prevention measure to be used for each emission boiler or process heater in the averaging group and the date of its installation or application. If the pollution prevention measure reduces or eliminates emissions from multiple boilers or process heaters, the owner or operator must identify each boiler or process heater;

(iv) The test plan for the measurement of PM (or TSM), HCl, or mercury emissions in accordance with the requirements in §63.7520;

(v) The operating parameters to be monitored for each control system or device consistent with §63.7500 and Table 4, and a description of how the operating limits will be determined;

(vi) If you request to monitor an alternative operating parameter pursuant to §63.7525, you must also include:

(A) A description of the parameter(s) to be monitored and an explanation of the criteria used to select the parameter(s); and

(B) A description of the methods and procedures that will be used to demonstrate that the parameter indicates proper operation of the control device; the frequency and content of monitoring, reporting, and recordkeeping requirements; and a demonstration, to the satisfaction of the Administrator, that the proposed monitoring frequency is sufficient to represent control device operating conditions; and

(vii) A demonstration that compliance with each of the applicable emission limit(s) will be achieved under representative operating load conditions. Following each compliance demonstration and until the next compliance demonstration, you must comply with the operating limit for operating load conditions specified in Table 4 to this subpart.

(3) If submitted upon request, the Administrator shall review and approve or disapprove the plan according to the following criteria:

(i) Whether the content of the plan includes all of the information specified in paragraph (g)(2) of this section; and

(ii) Whether the plan presents sufficient information to determine that compliance will be achieved and maintained.

(4) The applicable Administrator shall not approve an emission averaging implementation plan containing any of the following provisions:

(i) Any averaging between emissions of differing pollutants or between differing sources; or

(ii) The inclusion of any emission source other than an existing unit in the same subcategories.

(h) For a group of two or more existing affected units, each of which vents through a single common stack, you may average PM (or TSM), HCl, or mercury emissions to demonstrate compliance with the limits for that pollutant in Table 2 to this subpart if you satisfy the requirements in paragraph (i) or (j) of this section.

(i) For a group of two or more existing units in the same subcategory, each of which vents through a common emissions control system to a common stack, that does not receive emissions from units in other subcategories or categories, you may treat such averaging group as a single existing unit for purposes of this subpart and comply with the requirements of this subpart as if the group were a single unit.

(j) For all other groups of units subject to the common stack requirements of paragraph (h) of this section, including situations where the exhaust of affected units are each individually controlled and then sent to a common stack, the owner or operator may elect to:

(1) Conduct performance tests according to procedures specified in §63.7520 in the common stack if affected units from other subcategories vent to the common stack. The emission limits that the group must comply with are determined by the use of Equation 6 of this section.

$$En = \sum_{i=1}^{n}(ELi \times Hi) \div \sum_{i=1}^{n} Hi \qquad \text{(Eq. 6)}$$

Where:

En = HAP emission limit, pounds per million British thermal units (lb/MMBtu) or parts per million (ppm).

Eli = Appropriate emission limit from Table 2 to this subpart for unit i, in units of lb/MMBtu or ppm.

Hi = Heat input from unit i, MMBtu.

(2) Conduct performance tests according to procedures specified in §63.7520 in the common stack. If affected units and non-affected units vent to the common stack, the non-affected units must be shut down or vented to a different stack during the performance test unless the facility determines to demonstrate compliance with the non-affected units venting to the stack; and

(3) Meet the applicable operating limit specified in §63.7540 and Table 8 to this subpart for each emissions control system (except that, if each unit venting to the common stack has an applicable opacity operating limit, then a single continuous opacity monitoring system may be located in the common stack instead of in each duct to the common stack).

(k) The common stack of a group of two or more existing boilers or process heaters in the same subcategories subject to paragraph (h) of this section may be treated as a separate stack for purposes of paragraph (b) of this section and included in an emissions averaging group subject to paragraph (b) of this section.

[76 FR 15664, Mar. 21, 2011, as amended at 78 FR 7168, Jan. 31, 2013; 80 FR 72809, Nov. 20, 2015]

§63.7525 What are my monitoring, installation, operation, and maintenance requirements?

(a) If your boiler or process heater is subject to a CO emission limit in Tables 1, 2, or 11 through 13 to this subpart, you must install, operate, and maintain an oxygen analyzer system, as defined in §63.7575, or install, certify, operate and maintain continuous emission monitoring systems for CO and oxygen (or carbon dioxide (CO_2)) according to the procedures in paragraphs (a)(1) through (6) of this section.

(1) Install the CO CEMS and oxygen (or CO_2) analyzer by the compliance date specified in §63.7495. The CO and oxygen (or CO_2) levels shall be monitored at the same location at the outlet of the boiler or process heater. An owner or operator may request an alternative test method under §63.7 of this chapter, in order that compliance with the CO emissions limit be determined using CO_2 as a diluent correction in place of oxygen at 3 percent. EPA Method 19 F-factors and EPA Method 19 equations must be used to generate the appropriate CO_2 correction percentage for the fuel type burned in the unit, and must also take into account that the 3 percent oxygen correction is to be done on a dry basis. The alternative test method request must account for any CO_2 being added to, or removed from, the emissions gas stream as a result of limestone injection, scrubber media, etc.

(2) To demonstrate compliance with the applicable alternative CO CEMS emission standard listed in Tables 1, 2, or 11 through 13 to this subpart, you must install, certify, operate, and maintain a CO CEMS and an oxygen analyzer according to the applicable procedures under Performance Specification 4, 4A, or 4B at 40 CFR part 60, appendix B; part 75 of this chapter (if an CO_2 analyzer is used); the site-specific monitoring plan developed according to §63.7505(d); and the requirements in §63.7540(a)(8) and paragraph (a) of this section. Any boiler or process heater that has a CO CEMS that is compliant with Performance Specification 4, 4A, or 4B at 40 CFR part 60, appendix B, a site-specific monitoring plan developed according to §63.7505(d), and the requirements in §63.7540(a)(8) and paragraph (a) of this section must use the CO CEMS to comply with the applicable alternative CO CEMS emission standard listed in Tables 1, 2, or 11 through 13 to this subpart.

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

(ii) During each relative accuracy test run of the CO CEMS, you must be collect emission data for CO concurrently (or within a 30- to 60-minute period) by both the CO CEMS and by Method 10, 10A, or 10B at 40 CFR part 60, appendix A-4. The relative accuracy testing must be at representative operating conditions.

(iii) You must follow the quality assurance procedures (e.g., quarterly accuracy determinations and daily calibration drift tests) of Procedure 1 of appendix F to part 60. The measurement span value of the CO CEMS must be two times the applicable CO emission limit, expressed as a concentration.

(iv) Any CO CEMS that does not comply with §63.7525(a) cannot be used to meet any requirement in this subpart to demonstrate compliance with a CO emission limit listed in Tables 1, 2, or 11 through 13 to this subpart.

(v) For a new unit, complete the initial performance evaluation no later than July 30, 2013, or 180 days after the date of initial startup, whichever is later. For an existing unit, complete the initial performance evaluation no later than July 29, 2016.

(vi) When CO_2 is used to correct CO emissions and CO_2 is measured on a wet basis, correct for moisture as follows: Install, operate, maintain, and quality assure a continuous moisture monitoring system for measuring and recording the moisture content of the flue gases, in order to correct the measured hourly volumetric flow rates for moisture when calculating CO concentrations. The following continuous moisture monitoring systems are acceptable: A continuous moisture sensor; an oxygen analyzer (or analyzers) capable of measuring O_2 both on a wet basis and on a dry basis; or a stack temperature sensor and a moisture look-up table, *i.e.,* a psychrometric chart (for saturated gas streams following wet scrubbers or other demonstrably saturated gas streams, only). The moisture monitoring system shall include as a component the automated data acquisition and handling system (DAHS) for recording and reporting both the raw data (*e.g.,* hourly average wet-and dry basis O_2 values) and the hourly average values of the stack gas moisture content derived from those data. When a moisture look-up table is used, the moisture monitoring system shall be represented as a single component, the certified DAHS, in the monitoring plan for the unit or common stack.

(3) Complete a minimum of one cycle of CO and oxygen (or CO_2) CEMS operation (sampling, analyzing, and data recording) for each successive 15-minute period. Collect CO and oxygen (or CO_2) data concurrently. Collect at least four CO and oxygen (or CO_2) CEMS data values representing the four 15-minute periods in an hour, or at least two 15-minute data values during an hour when CEMS calibration, quality assurance, or maintenance activities are being performed.

(4) Reduce the CO CEMS data as specified in §63.8(g)(2).

(5) Calculate one-hour arithmetic averages, corrected to 3 percent oxygen (or corrected to an CO_2 percentage determined to be equivalent to 3 percent oxygen) from each hour of CO CEMS data in parts per million CO concentration. The one-hour arithmetic averages required shall be used to calculate the 30-day or 10-day rolling average emissions. Use Equation 19-19 in section 12.4.1 of Method 19 of 40 CFR part 60, appendix A-7 for calculating the average CO concentration from the hourly values.

(6) For purposes of collecting CO data, operate the CO CEMS as specified in §63.7535(b). You must use all the data collected during all periods in calculating data averages and assessing compliance, except that you must exclude certain data as specified in §63.7535(c). Periods when CO data are unavailable may constitute monitoring deviations as specified in §63.7535(d).

(7) Operate an oxygen trim system with the oxygen level set no lower than the lowest hourly average oxygen concentration measured during the most recent CO performance test as the operating limit for oxygen according to Table 7 to this subpart.

(b) If your boiler or process heater is in the unit designed to burn coal/solid fossil fuel subcategory or the unit designed to burn heavy liquid subcategory and has an average annual heat input rate greater than 250 MMBtu per hour from solid fossil fuel and/or heavy liquid, and you demonstrate compliance with the PM limit instead of the alternative TSM limit, you must install, maintain, and operate a PM CPMS monitoring emissions discharged to the atmosphere and record the output of the system as specified in paragraphs (b)(1) through (4) of this section. As an alternative to use of a PM CPMS to demonstrate compliance with the PM limit, you may choose to use a PM CEMS. If you choose to use a PM CEMS to demonstrate compliance with the PM limit instead of the alternative TSM limit, you must install, certify, maintain, and operate a PM CEMS monitoring emissions discharged to the atmosphere and record the output of the system as specified in paragraph (b)(5) through (8) of this section. For other boilers or process heaters, you may elect to use a PM CPMS or PM CEMS operated in accordance with this section in lieu of using other CMS for monitoring PM compliance (*e.g.,* bag leak detectors, ESP secondary power, and PM scrubber pressure). Owners of boilers and process heaters who elect to comply with the alternative TSM limit are not required to install a PM CPMS.

(1) Install, operate, and maintain your PM CPMS according to the procedures in your approved site-specific monitoring plan developed in accordance with §63.7505(d), the requirements in §63.7540(a)(9), and paragraphs (b)(1)(i) through (iii) of this section.

(i) The operating principle of the PM CPMS must be based on in-stack or extractive light scatter, light scintillation, beta attenuation, or mass accumulation detection of PM in the exhaust gas or representative exhaust gas sample. The reportable measurement output from the PM CPMS must be expressed as milliamps.

(ii) The PM CPMS must have a cycle time (i.e., period required to complete sampling, measurement, and reporting for each measurement) no longer than 60 minutes.

(iii) The PM CPMS must have a documented detection limit of 0.5 milligram per actual cubic meter, or less.

(2) For a new unit, complete the initial performance evaluation no later than July 30, 2013, or 180 days after the date of initial startup, whichever is later. For an existing unit, complete the initial performance evaluation no later than July 29, 2016.

(3) Collect PM CPMS hourly average output data for all boiler or process heater operating hours except as indicated in §63.7535(a) through (d). Express the PM CPMS output as milliamps.

(4) Calculate the arithmetic 30-day rolling average of all of the hourly average PM CPMS output data collected during all boiler or process heater operating hours (milliamps).

(5) Install, certify, operate, and maintain your PM CEMS according to the procedures in your approved site-specific monitoring plan developed in accordance with §63.7505(d), the requirements in §63.7540(a)(9), and paragraphs (b)(5)(i) through (iv) of this section.

(i) You shall conduct a performance evaluation of the PM CEMS according to the applicable requirements of §60.8(e), and Performance Specification 11 at 40 CFR part 60, appendix B of this chapter.

(ii) During each PM correlation testing run of the CEMS required by Performance Specification 11 at 40 CFR part 60, appendix B of this chapter, you shall collect PM and oxygen (or carbon dioxide) data concurrently (or within a 30-to 60-minute period) by both the CEMS and conducting performance tests using Method 5 at 40 CFR part 60, appendix A-3 or Method 17 at 40 CFR part 60, appendix A-6 of this chapter.

(iii) You shall perform quarterly accuracy determinations and daily calibration drift tests in accordance with Procedure 2 at 40 CFR part 60, appendix F of this chapter. You must perform Relative Response Audits annually and perform Response Correlation Audits every 3 years.

(iv) Within 60 days after the date of completing each CEMS relative accuracy test audit or performance test conducted to demonstrate compliance with this subpart, you must submit the relative accuracy test audit data and performance test data to the EPA by successfully submitting the data electronically into the EPA's Central Data Exchange by using the Electronic Reporting Tool (see *http://www.epa.gov/ttn/chief/ert/erttool.html/*).

(6) For a new unit, complete the initial performance evaluation no later than July 30, 2013, or 180 days after the date of initial startup, whichever is later. For an existing unit, complete the initial performance evaluation no later than July 29, 2016.

(7) Collect PM CEMS hourly average output data for all boiler or process heater operating hours except as indicated in §63.7535(a) through (d).

(8) Calculate the arithmetic 30-day rolling average of all of the hourly average PM CEMS output data collected during all boiler or process heater operating hours.

(c) If you have an applicable opacity operating limit in this rule, and are not otherwise required or elect to install and operate a PM CPMS, PM CEMS, or a bag leak detection system, you must install, operate, certify and maintain each COMS according to the procedures in paragraphs (c)(1) through (7) of this section by the compliance date specified in §63.7495.

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

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

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

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

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

(6) You must operate and maintain each COMS according to the requirements in the monitoring plan and the requirements of §63.8(e). You must identify periods the COMS is out of control including any periods that the COMS fails to pass a daily calibration drift assessment, a quarterly performance audit, or an annual zero alignment audit. Any 6-minute period for which the monitoring system is out of control and data are not available for a required calculation constitutes a deviation from the monitoring requirements.

(7) You must determine and record all the 6-minute averages (and daily block averages as applicable) collected for periods during which the COMS is not out of control.

(d) If you have an operating limit that requires the use of a CMS other than a PM CPMS or COMS, you must install, operate, and maintain each CMS according to the procedures in paragraphs (d)(1) through (5) of this section by the compliance date specified in §63.7495.

(1) The CPMS must complete a minimum of one cycle of operation every 15-minutes. You must have a minimum of four successive cycles of operation, one representing each of the four 15-minute periods in an hour, to have a valid hour of data.

(2) You must operate the monitoring system as specified in §63.7535(b), and comply with the data calculation requirements specified in §63.7535(c).

(3) Any 15-minute period for which the monitoring system is out-of-control and data are not available for a required calculation constitutes a deviation from the monitoring requirements. Other situations that constitute a monitoring deviation are specified in §63.7535(d).

(4) You must determine the 30-day rolling average of all recorded readings, except as provided in §63.7535(c).

(5) You must record the results of each inspection, calibration, and validation check.

(e) If you have an operating limit that requires the use of a flow monitoring system, you must meet the requirements in paragraphs (d) and (e)(1) through (4) of this section.

(1) You must install the flow sensor and other necessary equipment in a position that provides a representative flow.

(2) You must use a flow sensor with a measurement sensitivity of no greater than 2 percent of the design flow rate.

(3) You must minimize, consistent with good engineering practices, the effects of swirling flow or abnormal velocity distributions due to upstream and downstream disturbances.

(4) You must conduct a flow monitoring system performance evaluation in accordance with your monitoring plan at the time of each performance test but no less frequently than annually.

(f) If you have an operating limit that requires the use of a pressure monitoring system, you must meet the requirements in paragraphs (d) and (f)(1) through (6) of this section.

(1) Install the pressure sensor(s) in a position that provides a representative measurement of the pressure (*e.g.*, PM scrubber pressure drop).

(2) Minimize or eliminate pulsating pressure, vibration, and internal and external corrosion consistent with good engineering practices.

(3) Use a pressure sensor with a minimum tolerance of 1.27 centimeters of water or a minimum tolerance of 1 percent of the pressure monitoring system operating range, whichever is less.

(4) Perform checks at least once each process operating day to ensure pressure measurements are not obstructed (*e.g.*, check for pressure tap pluggage daily).

(5) Conduct a performance evaluation of the pressure monitoring system in accordance with your monitoring plan at the time of each performance test but no less frequently than annually.

(6) If at any time the measured pressure exceeds the manufacturer's specified maximum operating pressure range, conduct a performance evaluation of the pressure monitoring system in accordance with your monitoring plan and confirm that the pressure monitoring system continues to meet the performance requirements in you monitoring plan. Alternatively, install and verify the operation of a new pressure sensor.

(g) If you have an operating limit that requires a pH monitoring system, you must meet the requirements in paragraphs (d) and (g)(1) through (4) of this section.

(1) Install the pH sensor in a position that provides a representative measurement of scrubber effluent pH.

(2) Ensure the sample is properly mixed and representative of the fluid to be measured.

(3) Calibrate the pH monitoring system in accordance with your monitoring plan and according to the manufacturer's instructions. Clean the pH probe at least once each process operating day. Maintain on-site documentation that your calibration frequency is sufficient to maintain the specified accuracy of your device.

(4) Conduct a performance evaluation (including a two-point calibration with one of the two buffer solutions having a pH within 1 of the pH of the operating limit) of the pH monitoring system in accordance with your monitoring plan at the time of each performance test but no less frequently than annually.

(h) If you have an operating limit that requires a secondary electric power monitoring system for an electrostatic precipitator (ESP) operated with a wet scrubber, you must meet the requirements in paragraphs (h)(1) and (2) of this section.

(1) Install sensors to measure (secondary) voltage and current to the precipitator collection plates.

(2) Conduct a performance evaluation of the electric power monitoring system in accordance with your monitoring plan at the time of each performance test but no less frequently than annually.

(i) If you have an operating limit that requires the use of a monitoring system to measure sorbent injection rate (e.g., weigh belt, weigh hopper, or hopper flow measurement device), you must meet the requirements in paragraphs (d) and (i)(1) through (2) of this section.

(1) Install the system in a position(s) that provides a representative measurement of the total sorbent injection rate.

(2) Conduct a performance evaluation of the sorbent injection rate monitoring system in accordance with your monitoring plan at the time of each performance test but no less frequently than annually.

(j) If you are not required to use a PM CPMS and elect to use a fabric filter bag leak detection system to comply with the requirements of this subpart, you must install, calibrate, maintain, and continuously operate the bag leak detection system as specified in paragraphs (j)(1) through (6) of this section.

(1) You must install a bag leak detection sensor(s) in a position(s) that will be representative of the relative or absolute PM loadings for each exhaust stack, roof vent, or compartment (e.g., for a positive pressure fabric filter) of the fabric filter.

(2) Conduct a performance evaluation of the bag leak detection system in accordance with your monitoring plan and consistent with the guidance provided in EPA-454/R-98-015 (incorporated by reference, see §63.14).

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

(4) Use a bag leak detection system equipped with a device to record continuously the output signal from the sensor.

(5) Use a bag leak detection system equipped with a system that will alert plant operating personnel when an increase in relative PM emissions over a preset level is detected. The alert must easily recognizable (e.g., heard or seen) by plant operating personnel.

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

(k) For each unit that meets the definition of limited-use boiler or process heater, you must keep fuel use records for the days the boiler or process heater was operating.

(l) For each unit for which you decide to demonstrate compliance with the mercury or HCl emissions limits in Tables 1 or 2 or 11 through 13 of this subpart by use of a CEMS for mercury or HCl, you must install, certify, maintain, and operate a CEMS measuring emissions discharged to the atmosphere and record the output of the system as specified in paragraphs (l)(1) through (8) of this section. For HCl, this option for an affected unit takes effect on the date a final performance specification for a HCl CEMS is published in the FEDERAL REGISTER or the date of approval of a site-specific monitoring plan.

(1) Notify the Administrator one month before starting use of the CEMS, and notify the Administrator one month before stopping use of the CEMS.

(2) Each CEMS shall be installed, certified, operated, and maintained according to the requirements in §63.7540(a)(14) for a mercury CEMS and §63.7540(a)(15) for a HCl CEMS.

(3) For a new unit, you must complete the initial performance evaluation of the CEMS by the latest of the dates specified in paragraph (l)(3)(i) through (iii) of this section.

(i) No later than July 30, 2013.

(ii) No later 180 days after the date of initial startup.

(iii) No later 180 days after notifying the Administrator before starting to use the CEMS in place of performance testing or fuel analysis to demonstrate compliance.

(4) For an existing unit, you must complete the initial performance evaluation by the latter of the two dates specified in paragraph (l)(4)(i) and (ii) of this section.

(i) No later than July 29, 2016.

(ii) No later 180 days after notifying the Administrator before starting to use the CEMS in place of performance testing or fuel analysis to demonstrate compliance.

(5) Compliance with the applicable emissions limit shall be determined based on the 30-day rolling average of the hourly arithmetic average emissions rates using the continuous monitoring system outlet data. The 30-day rolling arithmetic average emission rate (lb/MMBtu) shall be calculated using the equations in EPA Reference Method 19 at 40 CFR part 60, appendix A-7, but substituting the mercury or HCl concentration for the pollutant concentrations normally used in Method 19.

(6) Collect CEMS hourly averages for all operating hours on a 30-day rolling average basis. Collect at least four CMS data values representing the four 15-minute periods in an hour, or at least two 15-minute data values during an hour when CMS calibration, quality assurance, or maintenance activities are being performed.

(7) The one-hour arithmetic averages required shall be expressed in lb/MMBtu and shall be used to calculate the boiler 30-day and 10-day rolling average emissions.

(8) You are allowed to substitute the use of the PM, mercury or HCl CEMS for the applicable fuel analysis, annual performance test, and operating limits specified in Table 4 to this subpart to demonstrate compliance with the PM,

mercury or HCl emissions limit, and if you are using an acid gas wet scrubber or dry sorbent injection control technology to comply with the HCl emission limit, you are allowed to substitute the use of a sulfur dioxide (SO_2) CEMS for the applicable fuel analysis, annual performance test, and operating limits specified in Table 4 to this subpart to demonstrate compliance with HCl emissions limit.

(m) If your unit is subject to a HCl emission limit in Tables 1, 2, or 11 through 13 of this subpart and you have an acid gas wet scrubber or dry sorbent injection control technology and you elect to use an SO_2 CEMS to demonstrate continuous compliance with the HCl emission limit, you must install the monitor at the outlet of the boiler or process heater, downstream of all emission control devices, and you must install, certify, operate, and maintain the CEMS according to either part 60 or part 75 of this chapter.

(1) The SO_2 CEMS must be installed by the compliance date specified in §63.7495.

(2) For on-going quality assurance (QA), the SO_2 CEMS must meet either the applicable daily and quarterly requirements in Procedure 1 of appendix F of part 60 or the applicable daily, quarterly, and semiannual or annual requirements in sections 2.1 through 2.3 of appendix B to part 75 of this chapter, with the following addition: You must perform the linearity checks required in section 2.2 of appendix B to part 75 of this chapter if the SO_2 CEMS has a span value of 30 ppm or less.

(3) For a new unit, the initial performance evaluation shall be completed no later than July 30, 2013, or 180 days after the date of initial startup, whichever is later. For an existing unit, the initial performance evaluation shall be completed no later than July 29, 2016.

(4) For purposes of collecting SO_2 data, you must operate the SO_2 CEMS as specified in §63.7535(b). You must use all the data collected during all periods in calculating data averages and assessing compliance, except that you must exclude certain data as specified in §63.7535(c). Periods when SO_2 data are unavailable may constitute monitoring deviations as specified in §63.7535(d).

(5) Collect CEMS hourly averages for all operating hours on a 30-day rolling average basis.

(6) Use only unadjusted, quality-assured SO_2 concentration values in the emissions calculations; do not apply bias adjustment factors to the part 75 SO_2 data and do not use part 75 substitute data values.

[76 FR 15664, Mar. 21, 2011, as amended at 78 FR 7171, Jan. 31, 2013; 80 FR 72810, Nov. 20, 2015]

§63.7530 How do I demonstrate initial compliance with the emission limitations, fuel specifications and work practice standards?

(a) You must demonstrate initial compliance with each emission limit that applies to you by conducting initial performance tests and fuel analyses and establishing operating limits, as applicable, according to §63.7520, paragraphs (b) and (c) of this section, and Tables 5 and 7 to this subpart. The requirement to conduct a fuel analysis is not applicable for units that burn a single type of fuel, as specified by §63.7510(a)(2). If applicable, you must also install, operate, and maintain all applicable CMS (including CEMS, COMS, and CPMS) according to §63.7525.

(b) If you demonstrate compliance through performance stack testing, you must establish each site-specific operating limit in Table 4 to this subpart that applies to you according to the requirements in §63.7520, Table 7 to this subpart, and paragraph (b)(4) of this section, as applicable. You must also conduct fuel analyses according to §63.7521 and establish maximum fuel pollutant input levels according to paragraphs (b)(1) through (3) of this section, as applicable, and as specified in §63.7510(a)(2). (Note that §63.7510(a)(2) exempts certain fuels from the fuel analysis requirements.) However, if you switch fuel(s) and cannot show that the new fuel(s) does (do) not increase the chlorine, mercury, or TSM input into the unit through the results of fuel analysis, then you must repeat the performance test to demonstrate compliance while burning the new fuel(s).

(1) You must establish the maximum chlorine fuel input (Clinput) during the initial fuel analysis according to the procedures in paragraphs (b)(1)(i) through (iii) of this section.

(i) You must determine the fuel type or fuel mixture that you could burn in your boiler or process heater that has the highest content of chlorine.

(ii) During the fuel analysis for hydrogen chloride, you must determine the fraction of the total heat input for each fuel type burned (Qi) based on the fuel mixture that has the highest content of chlorine, and the average chlorine concentration of each fuel type burned (Ci).

(iii) You must establish a maximum chlorine input level using Equation 7 of this section.

$$Clinput = \sum_{i=1}^{n} (Ci \times Qi) \quad \text{(Eq. 7)}$$

Where:

Clinput = Maximum amount of chlorine entering the boiler or process heater through fuels burned in units of pounds per million Btu.

Ci = Arithmetic average concentration of chlorine in fuel type, i, analyzed according to §63.7521, in units of pounds per million Btu.

Qi = Fraction of total heat input from fuel type, i, based on the fuel mixture that has the highest content of chlorine during the initial compliance test. If you do not burn multiple fuel types during the performance testing, it is not necessary to determine the value of this term. Insert a value of “1” for Qi. For continuous compliance demonstration, the actual fraction of the fuel burned during the month should be used.

n = Number of different fuel types burned in your boiler or process heater for the mixture that has the highest content of chlorine.

(2) You must establish the maximum mercury fuel input level (Mercuryinput) during the initial fuel analysis using the procedures in paragraphs (b)(2)(i) through (iii) of this section.

(i) You must determine the fuel type or fuel mixture that you could burn in your boiler or process heater that has the highest content of mercury.

(ii) During the compliance demonstration for mercury, you must determine the fraction of total heat input for each fuel burned (Qi) based on the fuel mixture that has the highest content of mercury, and the average mercury concentration of each fuel type burned (HGi).

(iii) You must establish a maximum mercury input level using Equation 8 of this section.

$$Mercuryinput = \sum_{i=1}^{n} (HGi \times Qi) \quad \text{(Eq. 8)}$$

Where:

Mercuryinput = Maximum amount of mercury entering the boiler or process heater through fuels burned in units of pounds per million Btu.

HGi = Arithmetic average concentration of mercury in fuel type, i, analyzed according to §63.7521, in units of pounds per million Btu.

Qi = Fraction of total heat input from fuel type, i, based on the fuel mixture that has the highest mercury content during the initial compliance test. If you do not burn multiple fuel types during the performance test, it is not necessary to determine the value of this term. Insert a value of “1” for Qi. For continuous compliance demonstration, the actual fraction of the fuel burned during the month should be used.

n = Number of different fuel types burned in your boiler or process heater for the mixture that has the highest content of mercury.

(3) If you opt to comply with the alternative TSM limit, you must establish the maximum TSM fuel input (TSMinput) for solid or liquid fuels during the initial fuel analysis according to the procedures in paragraphs (b)(3)(i) through (iii) of this section.

(i) You must determine the fuel type or fuel mixture that you could burn in your boiler or process heater that has the highest content of TSM.

(ii) During the fuel analysis for TSM, you must determine the fraction of the total heat input for each fuel type burned (Qi) based on the fuel mixture that has the highest content of TSM, and the average TSM concentration of each fuel type burned (TSMi).

(iii) You must establish a maximum TSM input level using Equation 9 of this section.

$$TSMinput = \sum_{i=1}^{n} (TSMi \times Qi) \qquad \text{(Eq. 9)}$$

Where:

TSMinput = Maximum amount of TSM entering the boiler or process heater through fuels burned in units of pounds per million Btu.

TSMi = Arithmetic average concentration of TSM in fuel type, i, analyzed according to §63.7521, in units of pounds per million Btu.

Qi = Fraction of total heat input from fuel type, i, based on the fuel mixture that has the highest content of TSM during the initial compliance test. If you do not burn multiple fuel types during the performance testing, it is not necessary to determine the value of this term. Insert a value of “1” for Qi. For continuous compliance demonstration, the actual fraction of the fuel burned during the month should be used.

n = Number of different fuel types burned in your boiler or process heater for the mixture that has the highest content of TSM.

(4) You must establish parameter operating limits according to paragraphs (b)(4)(i) through (ix) of this section. As indicated in Table 4 to this subpart, you are not required to establish and comply with the operating parameter limits when you are using a CEMS to monitor and demonstrate compliance with the applicable emission limit for that control device parameter.

(i) For a wet acid gas scrubber, you must establish the minimum scrubber effluent pH and liquid flow rate as defined in §63.7575, as your operating limits during the performance test during which you demonstrate compliance with your applicable limit. If you use a wet scrubber and you conduct separate performance tests for HCl and mercury emissions, you must establish one set of minimum scrubber effluent pH, liquid flow rate, and pressure drop operating limits. The minimum scrubber effluent pH operating limit must be established during the HCl performance test. If you conduct multiple performance tests, you must set the minimum liquid flow rate operating limit at the higher of the minimum values established during the performance tests.

(ii) For any particulate control device (e.g., ESP, particulate wet scrubber, fabric filter) for which you use a PM CPMS, you must establish your PM CPMS operating limit and determine compliance with it according to paragraphs (b)(4)(ii)(A) through (F) of this section.

(A) Determine your operating limit as the average PM CPMS output value recorded during the most recent performance test run demonstrating compliance with the filterable PM emission limit or at the PM CPMS output value corresponding to 75 percent of the emission limit if your PM performance test demonstrates compliance below 75 percent of the emission limit. You must verify an existing or establish a new operating limit after each repeated performance test. You must repeat the performance test annually and reassess and adjust the site-specific operating limit in accordance with the results of the performance test.

(*1*) Your PM CPMS must provide a 4-20 milliamp output and the establishment of its relationship to manual reference method measurements must be determined in units of milliamps.

(*2*) Your PM CPMS operating range must be capable of reading PM concentrations from zero to a level equivalent to at least two times your allowable emission limit. If your PM CPMS is an auto-ranging instrument capable of multiple scales, the primary range of the instrument must be capable of reading PM concentration from zero to a level equivalent to two times your allowable emission limit.

(*3*) During the initial performance test or any such subsequent performance test that demonstrates compliance with the PM limit, record and average all milliamp output values from the PM CPMS for the periods corresponding to the compliance test runs (e.g., average all your PM CPMS output values for three corresponding 2-hour Method 5I test runs).

(B) If the average of your three PM performance test runs are below 75 percent of your PM emission limit, you must calculate an operating limit by establishing a relationship of PM CPMS signal to PM concentration using the PM CPMS instrument zero, the average PM CPMS values corresponding to the three compliance test runs, and the average PM concentration from the Method 5 or performance test with the procedures in paragraphs (b)(4)(ii)(B)(*1*) through (*4*) of this section.

(*1*) Determine your instrument zero output with one of the following procedures:

(*i*) Zero point data for *in-situ* instruments should be obtained by removing the instrument from the stack and monitoring ambient air on a test bench.

(*ii*) Zero point data for *extractive* instruments should be obtained by removing the extractive probe from the stack and drawing in clean ambient air.

(*iii*) The zero point may also be established by performing manual reference method measurements when the flue gas is free of PM emissions or contains very low PM concentrations (e.g., when your process is not operating, but the fans are operating or your source is combusting only natural gas) and plotting these with the compliance data to find the zero intercept.

(*iv*) If none of the steps in paragraphs (b)(4)(ii)(B)(*1*)(*i*) through (*iii*) of this section are possible, you must use a zero output value provided by the manufacturer.

(*2*) Determine your PM CPMS instrument average in milliamps, and the average of your corresponding three PM compliance test runs, using equation 10.

$$\bar{x} = \frac{1}{n}\sum_{i=1}^{n} X_1, \bar{y} = \frac{1}{n}\sum_{i=1}^{n} Y_1 \qquad \text{(Eq. 10)}$$

Where:

X_1 = the PM CPMS data points for the three runs constituting the performance test,

Y_1 = the PM concentration value for the three runs constituting the performance test, and

n = the number of data points.

(*3*) With your instrument zero expressed in milliamps, your three run average PM CPMS milliamp value, and your three run average PM concentration from your three compliance tests, determine a relationship of lb/MMBtu per milliamp with equation 11.

$$R = \frac{Y_1}{(X_1 - z)} \qquad \text{(Eq. 11)}$$

Where:

R = the relative lb/MMBtu per milliamp for your PM CPMS,

Y_1 = the three run average lb/MMBtu PM concentration,

X_1 = the three run average milliamp output from you PM CPMS, and

z = the milliamp equivalent of your instrument zero determined from (B)(i).

(*4*) Determine your source specific 30-day rolling average operating limit using the lb/MMBtu per milliamp value from Equation 11 in equation 12, below. This sets your operating limit at the PM CPMS output value corresponding to 75 percent of your emission limit.

$$O_l = z + \frac{0.75(L)}{R} \qquad \text{(Eq. 12)}$$

Where:

O_l = the operating limit for your PM CPMS on a 30-day rolling average, in milliamps.

L = your source emission limit expressed in lb/MMBtu,

z = your instrument zero in milliamps, determined from (B)(i), and

R = the relative lb/MMBtu per milliamp for your PM CPMS, from Equation 11.

(C) If the average of your three PM compliance test runs is at or above 75 percent of your PM emission limit you must determine your 30-day rolling average operating limit by averaging the PM CPMS milliamp output corresponding to your three PM performance test runs that demonstrate compliance with the emission limit using equation 13 and you must submit all compliance test and PM CPMS data according to the reporting requirements in paragraph (b)(4)(ii)(F) of this section.

$$O_h = \frac{1}{n}\sum_{i=1}^{n} X_1 \qquad \text{(Eq. 13)}$$

Where:

X_1 = the PM CPMS data points for all runs i,

n = the number of data points, and

O_h = your site specific operating limit, in milliamps.

(D) To determine continuous compliance, you must record the PM CPMS output data for all periods when the process is operating and the PM CPMS is not out-of-control. You must demonstrate continuous compliance by using all quality-assured hourly average data collected by the PM CPMS for all operating hours to calculate the arithmetic average operating parameter in units of the operating limit (milliamps) on a 30-day rolling average basis, updated at the end of each new operating hour. Use Equation 14 to determine the 30-day rolling average.

$$30-\mathrm{day} = \frac{\sum_{i=1}^{n} Hpw}{n} \qquad \text{(Eq. 14)}$$

Where:

30-day = 30-day average.

Hpvi = is the hourly parameter value for hour i

n = is the number of valid hourly parameter values collected over the previous 30 operating days.

(E) Use EPA Method 5 of appendix A to part 60 of this chapter to determine PM emissions. For each performance test, conduct three separate runs under the conditions that exist when the affected source is operating at the highest load or capacity level reasonably expected to occur. Conduct each test run to collect a minimum sample volume specified in Tables 1, 2, or 11 through 13 to this subpart, as applicable, for determining compliance with a new source limit or an existing source limit. Calculate the average of the results from three runs to determine compliance. You need not determine the PM collected in the impingers ("back half") of the Method 5 particulate sampling train to demonstrate compliance with the PM standards of this subpart. This shall not preclude the permitting authority from requiring a determination of the "back half" for other purposes.

(F) For PM performance test reports used to set a PM CPMS operating limit, the electronic submission of the test report must also include the make and model of the PM CPMS instrument, serial number of the instrument, analytical principle of the instrument (*e.g.* beta attenuation), span of the instruments primary analytical range, milliamp value equivalent to the instrument zero output, technique by which this zero value was determined, and the average milliamp signals corresponding to each PM compliance test run.

(iii) For a particulate wet scrubber, you must establish the minimum pressure drop and liquid flow rate as defined in §63.7575, as your operating limits during the three-run performance test during which you demonstrate compliance with your applicable limit. If you use a wet scrubber and you conduct separate performance tests for PM and TSM emissions, you must establish one set of minimum scrubber liquid flow rate and pressure drop operating limits. The minimum scrubber effluent pH operating limit must be established during the HCl performance test. If you conduct multiple performance tests, you must set the minimum liquid flow rate and pressure drop operating limits at the higher of the minimum values established during the performance tests.

(iv) For an electrostatic precipitator (ESP) operated with a wet scrubber, you must establish the minimum total secondary electric power input, as defined in §63.7575, as your operating limit during the three-run performance test during which you demonstrate compliance with your applicable limit. (These operating limits do not apply to ESP that are operated as dry controls without a wet scrubber.)

(v) For a dry scrubber, you must establish the minimum sorbent injection rate for each sorbent, as defined in §63.7575, as your operating limit during the three-run performance test during which you demonstrate compliance with your applicable limit.

(vi) For activated carbon injection, you must establish the minimum activated carbon injection rate, as defined in §63.7575, as your operating limit during the three-run performance test during which you demonstrate compliance with your applicable limit.

(vii) The operating limit for boilers or process heaters with fabric filters that demonstrate continuous compliance through bag leak detection systems is that a bag leak detection system be installed according to the requirements in §63.7525, and that each fabric filter must be operated such that the bag leak detection system alert is not activated more than 5 percent of the operating time during a 6-month period.

(viii) For a minimum oxygen level, if you conduct multiple performance tests, you must set the minimum oxygen level at the lower of the minimum values established during the performance tests.

(ix) The operating limit for boilers or process heaters that demonstrate continuous compliance with the HCl emission limit using a SO_2 CEMS is to install and operate the SO_2 according to the requirements in §63.7525(m) establish a maximum SO_2 emission rate equal to the highest hourly average SO_2 measurement during the most recent three-run performance test for HCl.

(c) If you elect to demonstrate compliance with an applicable emission limit through fuel analysis, you must conduct fuel analyses according to §63.7521 and follow the procedures in paragraphs (c)(1) through (5) of this section.

(1) If you burn more than one fuel type, you must determine the fuel mixture you could burn in your boiler or process heater that would result in the maximum emission rates of the pollutants that you elect to demonstrate compliance through fuel analysis.

(2) You must determine the 90th percentile confidence level fuel pollutant concentration of the composite samples analyzed for each fuel type using the one-sided t-statistic test described in Equation 15 of this section.

$$P90 = mean + (SD \times t) \quad \text{(Eq. 15)}$$

Where:

P90 = 90th percentile confidence level pollutant concentration, in pounds per million Btu.

Mean = Arithmetic average of the fuel pollutant concentration in the fuel samples analyzed according to §63.7521, in units of pounds per million Btu.

SD = Standard deviation of the mean of pollutant concentration in the fuel samples analyzed according to §63.7521, in units of pounds per million Btu. SD is calculated as the sample standard deviation divided by the square root of the number of samples.

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

(3) To demonstrate compliance with the applicable emission limit for HCl, the HCl emission rate that you calculate for your boiler or process heater using Equation 16 of this section must not exceed the applicable emission limit for HCl.

$$HCl = \sum_{i=1}^{n} (Ci90 \times Qi \times 1.028) \quad \text{(Eq. 16)}$$

Where:

HCl = HCl emission rate from the boiler or process heater in units of pounds per million Btu.

Ci90 = 90th percentile confidence level concentration of chlorine in fuel type, i, in units of pounds per million Btu as calculated according to Equation 15 of this section.

Qi = Fraction of total heat input from fuel type, i, based on the fuel mixture that has the highest content of chlorine. If you do not burn multiple fuel types, it is not necessary to determine the value of this term. Insert a value of “1” for Qi. For continuous compliance demonstration, the actual fraction of the fuel burned during the month should be used.

n = Number of different fuel types burned in your boiler or process heater for the mixture that has the highest content of chlorine.

1.028 = Molecular weight ratio of HCl to chlorine.

(4) To demonstrate compliance with the applicable emission limit for mercury, the mercury emission rate that you calculate for your boiler or process heater using Equation 17 of this section must not exceed the applicable emission limit for mercury.

$$Mercury = \sum_{i=1}^{n} (Hgi90 \times Qi) \quad \text{(Eq. 17)}$$

Where:

Mercury = Mercury emission rate from the boiler or process heater in units of pounds per million Btu.

Hgi90 = 90th percentile confidence level concentration of mercury in fuel, i, in units of pounds per million Btu as calculated according to Equation 15 of this section.

Qi = Fraction of total heat input from fuel type, i, based on the fuel mixture that has the highest mercury content. If you do not burn multiple fuel types, it is not necessary to determine the value of this term. Insert a value of “1” for Qi. For continuous compliance demonstration, the actual fraction of the fuel burned during the month should be used.

n = Number of different fuel types burned in your boiler or process heater for the mixture that has the highest mercury content.

(5) To demonstrate compliance with the applicable emission limit for TSM for solid or liquid fuels, the TSM emission rate that you calculate for your boiler or process heater from solid fuels using Equation 18 of this section must not exceed the applicable emission limit for TSM.

$$Metals = \sum_{i=1}^{n} (TSM90i \times Qi) \qquad \text{(Eq. 18)}$$

Where:

Metals = TSM emission rate from the boiler or process heater in units of pounds per million Btu.

TSMi90 = 90th percentile confidence level concentration of TSM in fuel, i, in units of pounds per million Btu as calculated according to Equation 15 of this section.

Qi = Fraction of total heat input from fuel type, i, based on the fuel mixture that has the highest TSM content. If you do not burn multiple fuel types, it is not necessary to determine the value of this term. Insert a value of “1” for Qi. For continuous compliance demonstration, the actual fraction of the fuel burned during the month should be used.

n = Number of different fuel types burned in your boiler or process heater for the mixture that has the highest TSM content.

(d)[Reserved]

(e) You must include with the Notification of Compliance Status a signed certification that either the energy assessment was completed according to Table 3 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.

(f) You must submit the Notification of Compliance Status containing the results of the initial compliance demonstration according to the requirements in §63.7545(e).

(g) If you elect to demonstrate that a gaseous fuel meets the specifications of another gas 1 fuel as defined in §63.7575, you must conduct an initial fuel specification analyses according to §63.7521(f) through (i) and according to the frequency listed in §63.7540(c) and maintain records of the results of the testing as outlined in §63.7555(g). For samples where the initial mercury specification has not been exceeded, you will include a signed certification with the Notification of Compliance Status that the initial fuel specification test meets the gas specification outlined in the definition of other gas 1 fuels.

(h) If you own or operate a unit subject to emission limits in Tables 1 or 2 or 11 through 13 to this subpart, you must meet the work practice standard according to Table 3 of this subpart. During startup and shutdown, you must only follow the work practice standards according to items 5 and 6 of Table 3 of this subpart.

(i) If you opt to comply with the alternative SO_2 CEMS operating limit in Tables 4 and 8 to this subpart, you may do so only if your affected boiler or process heater:

(1) Has a system using wet scrubber or dry sorbent injection and SO_2 CEMS installed on the unit; and

(2) At all times, you operate the wet scrubber or dry sorbent injection for acid gas control on the unit consistent with §63.7500(a)(3); and

(3) You establish a unit-specific maximum SO_2 operating limit by collecting the maximum hourly SO_2 emission rate on the SO_2 CEMS during the paired 3-run test for HCl. The maximum SO_2 operating limit is equal to the highest hourly average SO_2 concentration measured during the HCl performance test.

[76 FR 15664, Mar. 21, 2011, as amended at 78 FR 7174, Jan. 31, 2013; 80 FR 72811, Nov. 20, 2015]

§63.7533 Can I use efficiency credits earned from implementation of energy conservation measures to comply with this subpart?

(a) If you elect to comply with the alternative equivalent output-based emission limits, instead of the heat input-based limits listed in Table 2 to this subpart, and you want to take credit for implementing energy conservation measures identified in an energy assessment, you may demonstrate compliance using efficiency credits according to the procedures in this section. You may use this compliance approach for an existing affected boiler for demonstrating initial compliance according to §63.7522(e) and for demonstrating monthly compliance according to §63.7522(f). Owners or operators using this compliance approach must establish an emissions benchmark, calculate and document the efficiency credits, develop an Implementation Plan, comply with the general reporting requirements, and apply the efficiency credit according to the procedures in paragraphs (b) through (f) of this section. You cannot use this compliance approach for a new or reconstructed affected boiler. Additional guidance from the Department of Energy on efficiency credits is available at: *http://www.epa.gov/ttn/atw/boiler/boilerpg.html.*

(b) For each existing affected boiler for which you intend to apply emissions credits, establish a benchmark from which emission reduction credits may be generated by determining the actual annual fuel heat input to the affected boiler before initiation of an energy conservation activity to reduce energy demand (*i.e.,* fuel usage) according to paragraphs (b)(1) through (4) of this section. The benchmark shall be expressed in trillion Btu per year heat input.

(1) The benchmark from which efficiency credits may be generated shall be determined by using the most representative, accurate, and reliable process available for the source. The benchmark shall be established for a one-year period before the date that an energy demand reduction occurs, unless it can be demonstrated that a different time period is more representative of historical operations.

(2) Determine the starting point from which to measure progress. Inventory all fuel purchased and generated on-site (off-gases, residues) in physical units (MMBtu, million cubic feet, etc.).

(3) Document all uses of energy from the affected boiler. Use the most recent data available.

(4) Collect non-energy related facility and operational data to normalize, if necessary, the benchmark to current operations, such as building size, operating hours, etc. If possible, use actual data that are current and timely rather than estimated data.

(c) Efficiency credits can be generated if the energy conservation measures were implemented after January 1, 2008 and if sufficient information is available to determine the appropriate value of credits.

(1) The following emission points cannot be used to generate efficiency credits:

(i) Energy conservation measures implemented on or before January 1, 2008, unless the level of energy demand reduction is increased after January 1, 2008, in which case credit will be allowed only for change in demand reduction achieved after January 1, 2008.

(ii) Efficiency credits on shut-down boilers. Boilers that are shut down cannot be used to generate credits unless the facility provides documentation linking the permanent shutdown to energy conservation measures identified in the energy assessment. In this case, the bench established for the affected boiler to which the credits from the shutdown will be applied must be revised to include the benchmark established for the shutdown boiler.

(2) For all points included in calculating emissions credits, the owner or operator shall:

(i) Calculate annual credits for all energy demand points. Use Equation 19 to calculate credits. Energy conservation measures that meet the criteria of paragraph (c)(1) of this section shall not be included, except as specified in paragraph (c)(1)(i) of this section.

(3) Credits are generated by the difference between the benchmark that is established for each affected boiler, and the actual energy demand reductions from energy conservation measures implemented after January 1, 2008. Credits shall be calculated using Equation 19 of this section as follows:

(i) The overall equation for calculating credits is:

$$ECredits = \left(\sum_{i=1}^{n} EIS_{iactual}\right) \div EI_{baseline} \quad \text{(Eq. 19)}$$

Where:

ECredits = Energy Input Savings for all energy conservation measures implemented for an affected boiler, expressed as a decimal fraction of the baseline energy input.

$EIS_{iactual}$ = Energy Input Savings for each energy conservation measure, i, implemented for an affected boiler, million Btu per year.

$EI_{baseline}$ = Energy Input baseline for the affected boiler, million Btu per year.

n = Number of energy conservation measures included in the efficiency credit for the affected boiler.

(ii) [Reserved]

(d) The owner or operator shall develop, and submit for approval upon request by the Administrator, an Implementation Plan containing all of the information required in this paragraph for all boilers to be included in an efficiency credit approach. The Implementation Plan shall identify all existing affected boilers to be included in applying the efficiency credits. The Implementation Plan shall include a description of the energy conservation measures implemented and the energy savings generated from each measure and an explanation of the criteria used for determining that savings. If requested, you must submit the implementation plan for efficiency credits to the Administrator for review and approval no later than 180 days before the date on which the facility intends to demonstrate compliance using the efficiency credit approach.

(e) The emissions rate as calculated using Equation 20 of this section from each existing boiler participating in the efficiency credit option must be in compliance with the limits in Table 2 to this subpart at all times the affected unit is subject to numeric emission limits, following the compliance date specified in §63.7495.

(f) You must use Equation 20 of this section to demonstrate initial compliance by demonstrating that the emissions from the affected boiler participating in the efficiency credit compliance approach do not exceed the emission limits in Table 2 to this subpart.

$$E_{adj} = E_m \times (1 - ECredits) \quad \text{(Eq. 20)}$$

Where:

E_{adj} = Emission level adjusted by applying the efficiency credits earned, lb per million Btu steam output (or lb per MWh) for the affected boiler.

E_m = Emissions measured during the performance test, lb per million Btu steam output (or lb per MWh) for the affected boiler.

ECredits = Efficiency credits from Equation 19 for the affected boiler.

(g) As part of each compliance report submitted as required under §63.7550, you must include documentation that the energy conservation measures implemented continue to generate the credit for use in demonstrating compliance with the emission limits.

[76 FR 15664, Mar. 21, 2011, as amended at 78 FR 7178, Jan. 31, 2013; 80 FR 72812, Nov. 20, 2015]

Continuous Compliance Requirements

§63.7535 Is there a minimum amount of monitoring data I must obtain?

(a) You must monitor and collect data according to this section and the site-specific monitoring plan required by §63.7505(d).

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

(c) You may not use data recorded during 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 control activities in data averages and calculations used to report emissions or operating levels. You must record and make available upon request results of CMS performance audits and dates and duration of periods when the CMS is out of control to completion of the corrective actions necessary to return the CMS to operation consistent with your site-specific monitoring plan. You must use all the data collected during all other periods in assessing compliance and the operation of the control device and associated control system.

(d) Except for periods of monitoring system malfunctions, repairs associated with monitoring system malfunctions, and required monitoring system quality assurance or quality control activities (including, as applicable, system accuracy audits, calibration checks, and required zero and span adjustments), failure to collect required data is a deviation of the monitoring requirements. In calculating monitoring results, do not use any data collected during periods of startup and shutdown, when the monitoring system is out of control as specified in your site-specific monitoring plan, while conducting repairs associated with periods when the monitoring system is out of control, or while conducting required monitoring system quality assurance or quality control activities. You must calculate monitoring results using all other monitoring data collected while the process is operating. You must report all periods when the monitoring system is out of control in your semi-annual report.

[76 FR 15664, Mar. 21, 2011, as amended at 78 FR 7179, Jan. 31, 2013; 80 FR 72812, Nov. 20, 2015]

§63.7540 How do I demonstrate continuous compliance with the emission limitations, fuel specifications and work practice standards?

(a) You must demonstrate continuous compliance with each emission limit in Tables 1 and 2 or 11 through 13 to this subpart, the work practice standards in Table 3 to this subpart, and the operating limits in Table 4 to this subpart that applies to you according to the methods specified in Table 8 to this subpart and paragraphs (a)(1) through (19) of this section.

(1) Following the date on which the initial compliance demonstration is completed or is required to be completed under §§63.7 and 63.7510, whichever date comes first, operation above the established maximum or below the established minimum operating limits shall constitute a deviation of established operating limits listed in Table 4 of this subpart except during performance tests conducted to determine compliance with the emission limits or to establish new operating limits. Operating limits must be confirmed or reestablished during performance tests.

(2) As specified in §63.7555(d), you must keep records of the type and amount of all fuels burned in each boiler or process heater during the reporting period to demonstrate that all fuel types and mixtures of fuels burned would result in either of the following:

(i) Equal to or lower emissions of HCl, mercury, and TSM than the applicable emission limit for each pollutant, if you demonstrate compliance through fuel analysis.

(ii) Equal to or lower fuel input of chlorine, mercury, and TSM than the maximum values calculated during the last performance test, if you demonstrate compliance through performance testing.

(3) If you demonstrate compliance with an applicable HCl emission limit through fuel analysis for a solid or liquid fuel and you plan to burn a new type of solid or liquid fuel, you must recalculate the HCl emission rate using Equation 16 of §63.7530 according to paragraphs (a)(3)(i) through (iii) of this section. You are not required to conduct fuel analyses for the fuels described in §63.7510(a)(2)(i) through (iii). You may exclude the fuels described in §63.7510(a)(2)(i) through (iii) when recalculating the HCl emission rate.

(i) You must determine the chlorine concentration for any new fuel type in units of pounds per million Btu, based on supplier data or your own fuel analysis, according to the provisions in your site-specific fuel analysis plan developed according to §63.7521(b).

(ii) You must determine the new mixture of fuels that will have the highest content of chlorine.

(iii) Recalculate the HCl emission rate from your boiler or process heater under these new conditions using Equation 16 of §63.7530. The recalculated HCl emission rate must be less than the applicable emission limit.

(4) If you demonstrate compliance with an applicable HCl emission limit through performance testing and you plan to burn a new type of fuel or a new mixture of fuels, you must recalculate the maximum chlorine input using Equation 7 of §63.7530. If the results of recalculating the maximum chlorine input using Equation 7 of §63.7530 are greater than the maximum chlorine input level established during the previous performance test, then you must conduct a new performance test within 60 days of burning the new fuel type or fuel mixture according to the procedures in §63.7520 to demonstrate that the HCl emissions do not exceed the emission limit. You must also establish new operating limits based on this performance test according to the procedures in §63.7530(b). In recalculating the maximum chlorine input and establishing the new operating limits, you are not required to conduct fuel analyses for and include the fuels described in §63.7510(a)(2)(i) through (iii).

(5) If you demonstrate compliance with an applicable mercury emission limit through fuel analysis, and you plan to burn a new type of fuel, you must recalculate the mercury emission rate using Equation 17 of §63.7530 according to the procedures specified in paragraphs (a)(5)(i) through (iii) of this section. You are not required to conduct fuel analyses for the fuels described in §63.7510(a)(2)(i) through (iii). You may exclude the fuels described in §63.7510(a)(2)(i) through (iii) when recalculating the mercury emission rate.

(i) You must determine the mercury concentration for any new fuel type in units of pounds per million Btu, based on supplier data or your own fuel analysis, according to the provisions in your site-specific fuel analysis plan developed according to §63.7521(b).

(ii) You must determine the new mixture of fuels that will have the highest content of mercury.

(iii) Recalculate the mercury emission rate from your boiler or process heater under these new conditions using Equation 17 of §63.7530. The recalculated mercury emission rate must be less than the applicable emission limit.

(6) If you demonstrate compliance with an applicable mercury emission limit through performance testing, and you plan to burn a new type of fuel or a new mixture of fuels, you must recalculate the maximum mercury input using

Equation 8 of §63.7530. If the results of recalculating the maximum mercury input using Equation 8 of §63.7530 are higher than the maximum mercury input level established during the previous performance test, then you must conduct a new performance test within 60 days of burning the new fuel type or fuel mixture according to the procedures in §63.7520 to demonstrate that the mercury emissions do not exceed the emission limit. You must also establish new operating limits based on this performance test according to the procedures in §63.7530(b). You are not required to conduct fuel analyses for the fuels described in §63.7510(a)(2)(i) through (iii). You may exclude the fuels described in §63.7510(a)(2)(i) through (iii) when recalculating the mercury emission rate.

(7) If your unit is controlled with a fabric filter, and you demonstrate continuous compliance using a bag leak detection system, you must initiate corrective action within 1 hour of a bag leak detection system alert and complete corrective actions as soon as practical, and operate and maintain the fabric filter system such that the periods which would cause an alert are no more than 5 percent of the operating time during a 6-month period. You must also keep records of the date, time, and duration of each alert, the time corrective action was initiated and completed, and a brief description of the cause of the alert and the corrective action taken. You must also record the percent of the operating time during each 6-month period that the conditions exist for an alert. In calculating this operating time percentage, if inspection of the fabric filter demonstrates that no corrective action is required, no alert time is counted. If corrective action is required, each alert shall be counted as a minimum of 1 hour. If you take longer than 1 hour to initiate corrective action, the alert time shall be counted as the actual amount of time taken to initiate corrective action.

(8) To demonstrate compliance with the applicable alternative CO CEMS emission limit listed in Tables 1, 2, or 11 through 13 to this subpart, you must meet the requirements in paragraphs (a)(8)(i) through (iv) of this section.

(i) Continuously monitor CO according to §§63.7525(a) and 63.7535.

(ii) Maintain a CO emission level below or at your applicable alternative CO CEMS-based standard in Tables 1 or 2 or 11 through 13 to this subpart at all times the affected unit is subject to numeric emission limits.

(iii) Keep records of CO levels according to §63.7555(b).

(iv) You must record and make available upon request results of CO CEMS performance audits, dates and duration of periods when the CO CEMS is out of control to completion of the corrective actions necessary to return the CO CEMS to operation consistent with your site-specific monitoring plan.

(9) The owner or operator of a boiler or process heater using a PM CPMS or a PM CEMS to meet requirements of this subpart shall install, certify, operate, and maintain the PM CPMS or PM CEMS in accordance with your site-specific monitoring plan as required in §63.7505(d).

(10) If your boiler or process heater has a heat input capacity of 10 million Btu per hour or greater, you must conduct an annual tune-up of the boiler or process heater to demonstrate continuous compliance as specified in paragraphs (a)(10)(i) through (vi) of this section. You must conduct the tune-up while burning the type of fuel (or fuels in case of units that routinely burn a mixture) that provided the majority of the heat input to the boiler or process heater over the 12 months prior to the tune-up. This frequency does not apply to limited-use boilers and process heaters, as defined in §63.7575, or units with continuous oxygen trim systems that maintain an optimum air to fuel ratio.

(i) As applicable, inspect the burner, and clean or replace any components of the burner as necessary (you may perform the burner inspection any time prior to the tune-up or delay the burner inspection until the next scheduled unit shutdown). Units that produce electricity for sale may delay the burner inspection until the first outage, not to exceed 36 months from the previous inspection. At units where entry into a piece of process equipment or into a storage vessel is required to complete the tune-up inspections, inspections are required only during planned entries into the storage vessel or process equipment;

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

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

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

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

(vi) Maintain on-site and submit, if requested by the Administrator, a report containing the information in paragraphs (a)(10)(vi)(A) through (C) of this section,

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

(B) A description of any corrective actions taken as a part of the tune-up; and

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

(11) If your boiler or process heater has a heat input capacity of less than 10 million Btu per hour (except as specified in paragraph (a)(12) of this section), you must conduct a biennial tune-up of the boiler or process heater as specified in paragraphs (a)(10)(i) through (vi) of this section to demonstrate continuous compliance.

(12) If your boiler or process heater has a continuous oxygen trim system that maintains an optimum air to fuel ratio, or a heat input capacity of less than or equal to 5 million Btu per hour and the unit is in the units designed to burn gas 1; units designed to burn gas 2 (other); or units designed to burn light liquid subcategories, or meets the definition of limited-use boiler or process heater in §63.7575, you must conduct a tune-up of the boiler or process heater every 5 years as specified in paragraphs (a)(10)(i) through (vi) of this section to demonstrate continuous compliance. You may delay the burner inspection specified in paragraph (a)(10)(i) of this section until the next scheduled or unscheduled unit shutdown, but you must inspect each burner at least once every 72 months. 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.

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

(14) If you are using a CEMS measuring mercury emissions to meet requirements of this subpart you must install, certify, operate, and maintain the mercury CEMS as specified in paragraphs (a)(14)(i) and (ii) of this section.

(i) Operate the mercury CEMS in accordance with performance specification 12A of 40 CFR part 60, appendix B or operate a sorbent trap based integrated monitor in accordance with performance specification 12B of 40 CFR part 60, appendix B. The duration of the performance test must be 30 operating days if you specified a 30 operating day basis in §63.7545(e)(2)(iii) for mercury CEMS or it must be 720 hours if you specified a 720 hour basis in §63.7545(e)(2)(iii) for mercury CEMS. For each day in which the unit operates, you must obtain hourly mercury concentration data, and stack gas volumetric flow rate data.

(ii) If you are using a mercury CEMS, you must install, operate, calibrate, and maintain an instrument for continuously measuring and recording the mercury mass emissions rate to the atmosphere according to the requirements of performance specifications 6 and 12A of 40 CFR part 60, appendix B, and quality assurance procedure 6 of 40 CFR part 60, appendix F.

(15) If you are using a CEMS to measure HCl emissions to meet requirements of this subpart, you must install, certify, operate, and maintain the HCl CEMS as specified in paragraphs (a)(15)(i) and (ii) of this section. This option for an affected unit takes effect on the date a final performance specification for an HCl CEMS is published in the FEDERAL REGISTER or the date of approval of a site-specific monitoring plan.

(i) Operate the continuous emissions monitoring system in accordance with the applicable performance specification in 40 CFR part 60, appendix B. The duration of the performance test must be 30 operating days if you specified a 30 operating day basis in §63.7545(e)(2)(iii) for HCl CEMS or it must be 720 hours if you specified a 720 hour basis in §63.7545(e)(2)(iii) for HCl CEMS. For each day in which the unit operates, you must obtain hourly HCl concentration data, and stack gas volumetric flow rate data.

(ii) If you are using a HCl CEMS, you must install, operate, calibrate, and maintain an instrument for continuously measuring and recording the HCl mass emissions rate to the atmosphere according to the requirements of the applicable performance specification of 40 CFR part 60, appendix B, and the quality assurance procedures of 40 CFR part 60, appendix F.

(16) If you demonstrate compliance with an applicable TSM emission limit through performance testing, and you plan to burn a new type of fuel or a new mixture of fuels, you must recalculate the maximum TSM input using Equation 9 of §63.7530. If the results of recalculating the maximum TSM input using Equation 9 of §63.7530 are higher than the maximum total selected input level established during the previous performance test, then you must conduct a new performance test within 60 days of burning the new fuel type or fuel mixture according to the procedures in §63.7520 to demonstrate that the TSM emissions do not exceed the emission limit. You must also establish new operating limits based on this performance test according to the procedures in §63.7530(b). You are not required to conduct fuel analyses for the fuels described in §63.7510(a)(2)(i) through (iii). You may exclude the fuels described in §63.7510(a)(2)(i) through (iii) when recalculating the TSM emission rate.

(17) If you demonstrate compliance with an applicable TSM emission limit through fuel analysis for solid or liquid fuels, and you plan to burn a new type of fuel, you must recalculate the TSM emission rate using Equation 18 of §63.7530 according to the procedures specified in paragraphs (a)(5)(i) through (iii) of this section. You are not required to conduct fuel analyses for the fuels described in §63.7510(a)(2)(i) through (iii). You may exclude the fuels described in §63.7510(a)(2)(i) through (iii) when recalculating the TSM emission rate.

(i) You must determine the TSM concentration for any new fuel type in units of pounds per million Btu, based on supplier data or your own fuel analysis, according to the provisions in your site-specific fuel analysis plan developed according to §63.7521(b).

(ii) You must determine the new mixture of fuels that will have the highest content of TSM.

(iii) Recalculate the TSM emission rate from your boiler or process heater under these new conditions using Equation 18 of §63.7530. The recalculated TSM emission rate must be less than the applicable emission limit.

(18) If you demonstrate continuous PM emissions compliance with a PM CPMS you will use a PM CPMS to establish a site-specific operating limit corresponding to the results of the performance test demonstrating compliance with the PM limit. You will conduct your performance test using the test method criteria in Table 5 of this subpart. You will use the PM CPMS to demonstrate continuous compliance with this operating limit. You must repeat the performance test annually and reassess and adjust the site-specific operating limit in accordance with the results of the performance test.

(i) To determine continuous compliance, you must record the PM CPMS output data for all periods when the process is operating and the PM CPMS is not out-of-control. You must demonstrate continuous compliance by using all quality-assured hourly average data collected by the PM CPMS for all operating hours to calculate the arithmetic average operating parameter in units of the operating limit (milliamps) on a 30-day rolling average basis.

(ii) For any deviation of the 30-day rolling PM CPMS average value from the established operating parameter limit, you must:

(A) Within 48 hours of the deviation, visually inspect the air pollution control device (APCD);

(B) If inspection of the APCD identifies the cause of the deviation, take corrective action as soon as possible and return the PM CPMS measurement to within the established value; and

(C) Within 30 days of the deviation or at the time of the annual compliance test, whichever comes first, conduct a PM emissions compliance test to determine compliance with the PM emissions limit and to verify or re-establish the

CPMS operating limit. You are not required to conduct additional testing for any deviations that occur between the time of the original deviation and the PM emissions compliance test required under this paragraph.

(iii) PM CPMS deviations from the operating limit leading to more than four required performance tests in a 12-month operating period constitute a separate violation of this subpart.

(19) If you choose to comply with the PM filterable emissions limit by using PM CEMS you must install, certify, operate, and maintain a PM CEMS and record the output of the PM CEMS as specified in paragraphs (a)(19)(i) through (vii) of this section. The compliance limit will be expressed as a 30-day rolling average of the numerical emissions limit value applicable for your unit in Tables 1 or 2 or 11 through 13 of this subpart.

(i) Install and certify your PM CEMS according to the procedures and requirements in Performance Specification 11—Specifications and Test Procedures for Particulate Matter Continuous Emission Monitoring Systems at Stationary Sources in Appendix B to part 60 of this chapter, using test criteria outlined in Table V of this rule. The reportable measurement output from the PM CEMS must be expressed in units of the applicable emissions limit (e.g., lb/MMBtu, lb/MWh).

(ii) Operate and maintain your PM CEMS according to the procedures and requirements in Procedure 2— Quality Assurance Requirements for Particulate Matter Continuous Emission Monitoring Systems at Stationary Sources in Appendix F to part 60 of this chapter.

(A) You must conduct the relative response audit (RRA) for your PM CEMS at least once annually.

(B) You must conduct the relative correlation audit (RCA) for your PM CEMS at least once every 3 years.

(iii) Collect PM CEMS hourly average output data for all boiler operating hours except as indicated in paragraph (v) of this section.

(iv) Calculate the arithmetic 30-day rolling average of all of the hourly average PM CEMS output data collected during all nonexempt boiler or process heater operating hours.

(v) You must collect data using the PM CEMS at all times the unit is operating and at the intervals specified this paragraph (a), except for periods of monitoring system malfunctions, repairs associated with monitoring system malfunctions, and required monitoring system quality assurance or quality control activities.

(vi) You must use all the data collected during all boiler or process heater operating hours in assessing the compliance with your operating limit except:

(A) Any data collected during monitoring system malfunctions, repairs associated with monitoring system malfunctions, or required monitoring system quality assurance or control activities conducted during monitoring system malfunctions in calculations and report any such periods in your annual deviation report;

(B) Any data collected during periods when the monitoring system is out of control as specified in your site-specific monitoring plan, repairs associated with periods when the monitoring system is out of control, or required monitoring system quality assurance or control activities conducted during out of control periods in calculations used to report emissions or operating levels and report any such periods in your annual deviation report;

(C) Any data recorded during periods of startup or shutdown.

(vii) You must record and make available upon request results of PM CEMS system performance audits, dates and duration of periods when the PM CEMS is out of control to completion of the corrective actions necessary to return the PM CEMS to operation consistent with your site-specific monitoring plan.

(b) You must report each instance in which you did not meet each emission limit and operating limit in Tables 1 through 4 or 11 through 13 to this subpart that apply to you. These instances are deviations from the emission limits or operating limits, respectively, in this subpart. These deviations must be reported according to the requirements in §63.7550.

(c) If you elected to demonstrate that the unit meets the specification for mercury for the unit designed to burn gas 1 subcategory, you must follow the sampling frequency specified in paragraphs (c)(1) through (4) of this section and conduct this sampling according to the procedures in §63.7521(f) through (i).

(1) If the initial mercury constituents in the gaseous fuels are measured to be equal to or less than half of the mercury specification as defined in §63.7575, you do not need to conduct further sampling.

(2) If the initial mercury constituents are greater than half but equal to or less than 75 percent of the mercury specification as defined in §63.7575, you will conduct semi-annual sampling. If 6 consecutive semi-annual fuel analyses demonstrate 50 percent or less of the mercury specification, you do not need to conduct further sampling. If any semi-annual sample exceeds 75 percent of the mercury specification, you must return to monthly sampling for that fuel, until 12 months of fuel analyses again are less than 75 percent of the compliance level.

(3) If the initial mercury constituents are greater than 75 percent of the mercury specification as defined in §63.7575, you will conduct monthly sampling. If 12 consecutive monthly fuel analyses demonstrate 75 percent or less of the mercury specification, you may decrease the fuel analysis frequency to semi-annual for that fuel.

(4) If the initial sample exceeds the mercury specification as defined in §63.7575, each affected boiler or process heater combusting this fuel is not part of the unit designed to burn gas 1 subcategory and must be in compliance with the emission and operating limits for the appropriate subcategory. You may elect to conduct additional monthly sampling while complying with these emissions and operating limits to demonstrate that the fuel qualifies as another gas 1 fuel. If 12 consecutive monthly fuel analyses samples are at or below the mercury specification as defined in §63.7575, each affected boiler or process heater combusting the fuel can elect to switch back into the unit designed to burn gas 1 subcategory until the mercury specification is exceeded.

(d) For startup and shutdown, you must meet the work practice standards according to items 5 and 6 of Table 3 of this subpart.

[78 FR 7179, Jan. 31, 2013, as amended at 80 FR 72813, Nov. 20, 2015]

§63.7541 How do I demonstrate continuous compliance under the emissions averaging provision?

(a) Following the compliance date, the owner or operator must demonstrate compliance with this subpart on a continuous basis by meeting the requirements of paragraphs (a)(1) through (5) of this section.

(1) For each calendar month, demonstrate compliance with the average weighted emissions limit for the existing units participating in the emissions averaging option as determined in §63.7522(f) and (g).

(2) You must maintain the applicable opacity limit according to paragraphs (a)(2)(i) and (ii) of this section.

(i) For each existing unit participating in the emissions averaging option that is equipped with a dry control system and not vented to a common stack, maintain opacity at or below the applicable limit.

(ii) For each group of units participating in the emissions averaging option where each unit in the group is equipped with a dry control system and vented to a common stack that does not receive emissions from non-affected units, maintain opacity at or below the applicable limit at the common stack.

(3) For each existing unit participating in the emissions averaging option that is equipped with a wet scrubber, maintain the 30-day rolling average parameter values at or above the operating limits established during the most recent performance test.

(4) For each existing unit participating in the emissions averaging option that has an approved alternative operating parameter, maintain the 30-day rolling average parameter values consistent with the approved monitoring plan.

(5) For each existing unit participating in the emissions averaging option venting to a common stack configuration containing affected units from other subcategories, maintain the appropriate operating limit for each unit as specified in Table 4 to this subpart that applies.

(b) Any instance where the owner or operator fails to comply with the continuous monitoring requirements in paragraphs (a)(1) through (5) of this section is a deviation.

[76 FR 15664, Mar. 21, 2011, as amended at 78 FR 7182, Jan. 31, 2013]

Notification, Reports, and Records

§63.7545 What notifications must I submit and when?

(a) You must submit to the Administrator all of the notifications in §§63.7(b) and (c), 63.8(e), (f)(4) and (6), and 63.9(b) through (h) that apply to you by the dates specified.

(b) As specified in §63.9(b)(2), if you startup your affected source before January 31, 2013, you must submit an Initial Notification not later than 120 days after January 31, 2013.

(c) As specified in §63.9(b)(4) and (5), if you startup your new or reconstructed affected source on or after January 31, 2013, you must submit an Initial Notification not later than 15 days after the actual date of startup of the affected source.

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

(e) If you are required to conduct an initial compliance demonstration as specified in §63.7530, you must submit a Notification of Compliance Status according to §63.9(h)(2)(ii). For the initial compliance demonstration for each boiler or process heater, you must submit the Notification of Compliance Status, including all performance test results and fuel analyses, before the close of business on the 60th day following the completion of all performance test and/or other initial compliance demonstrations for all boiler or process heaters at the facility according to §63.10(d)(2). The Notification of Compliance Status report must contain all the information specified in paragraphs (e)(1) through (8) of this section, as applicable. If you are not required to conduct an initial compliance demonstration as specified in §63.7530(a), the Notification of Compliance Status must only contain the information specified in paragraphs (e)(1) and (8) of this section and must be submitted within 60 days of the compliance date specified at §63.7495(b).

(1) A description of the affected unit(s) including identification of which subcategories the unit is in, the design heat input capacity of the unit, a description of the add-on controls used on the unit to comply with this subpart, description of the fuel(s) burned, including whether the fuel(s) were a secondary material determined by you or the EPA through a petition process to be a non-waste under §241.3 of this chapter, whether the fuel(s) were a secondary material processed from discarded non-hazardous secondary materials within the meaning of §241.3 of this chapter, and justification for the selection of fuel(s) burned during the compliance demonstration.

(2) Summary of the results of all performance tests and fuel analyses, and calculations conducted to demonstrate initial compliance including all established operating limits, and including:

(i) Identification of whether you are complying with the PM emission limit or the alternative TSM emission limit.

(ii) Identification of whether you are complying with the output-based emission limits or the heat input-based (i.e., lb/MMBtu or ppm) emission limits,

(iii) Identification of whether you are complying the arithmetic mean of all valid hours of data from the previous 30 operating days or of the previous 720 hours. This identification shall be specified separately for each operating parameter.

(3) A summary of the maximum CO emission levels recorded during the performance test to show that you have met any applicable emission standard in Tables 1, 2, or 11 through 13 to this subpart, if you are not using a CO CEMS to demonstrate compliance.

(4) Identification of whether you plan to demonstrate compliance with each applicable emission limit through performance testing, a CEMS, or fuel analysis.

(5) Identification of whether you plan to demonstrate compliance by emissions averaging and identification of whether you plan to demonstrate compliance by using efficiency credits through energy conservation:

(i) If you plan to demonstrate compliance by emission averaging, report the emission level that was being achieved or the control technology employed on January 31, 2013.

(ii) [Reserved]

(6) A signed certification that you have met all applicable emission limits and work practice standards.

(7) If you had a deviation from any emission limit, work practice standard, or operating limit, you must also submit a description of the deviation, the duration of the deviation, and the corrective action taken in the Notification of Compliance Status report.

(8) In addition to the information required in §63.9(h)(2), your notification of compliance status must include the following certification(s) of compliance, as applicable, and signed by a responsible official:

(i) "This facility completed the required initial tune-up for all of the boilers and process heaters covered by 40 CFR part 63 subpart DDDDD at this site according to the procedures in §63.7540(a)(10)(i) through (vi)."

(ii) "This facility has had an energy assessment performed according to §63.7530(e)."

(iii) Except for units that burn only natural gas, refinery gas, or other gas 1 fuel, or units that qualify for a statutory exemption as provided in section 129(g)(1) of the Clean Air Act, include the following: "No secondary materials that are solid waste were combusted in any affected unit."

(f) If you operate a unit designed to burn natural gas, refinery gas, or other gas 1 fuels that is subject to this subpart, and you intend to use a fuel other than natural gas, refinery gas, gaseous fuel subject to another subpart of this part, part 60, 61, or 65, or other gas 1 fuel to fire the affected unit during a period of natural gas curtailment or supply interruption, as defined in §63.7575, you must submit a notification of alternative fuel use within 48 hours of the declaration of each period of natural gas curtailment or supply interruption, as defined in §63.7575. The notification must include the information specified in paragraphs (f)(1) through (5) of this section.

(1) Company name and address.

(2) Identification of the affected unit.

(3) Reason you are unable to use natural gas or equivalent fuel, including the date when the natural gas curtailment was declared or the natural gas supply interruption began.

(4) Type of alternative fuel that you intend to use.

(5) Dates when the alternative fuel use is expected to begin and end.

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

(1) The name of the owner or operator of the affected source, as defined in §63.7490, the location of the source, the boiler(s) or process heater(s) that will commence burning solid waste, and the date of the notice.

(2) The currently applicable subcategories under this subpart.

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

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

(h) If you have switched fuels or made a physical change to the boiler or process heater and the fuel switch or physical change resulted in the applicability of a different subcategory, you must provide notice of the date upon which you switched fuels or made the physical change within 30 days of the switch/change. The notification must identify:

(1) The name of the owner or operator of the affected source, as defined in §63.7490, the location of the source, the boiler(s) and process heater(s) that have switched fuels, were physically changed, and the date of the notice.

(2) The currently applicable subcategory under this subpart.

(3) The date upon which the fuel switch or physical change occurred.

[76 FR 15664, Mar. 21, 2011, as amended at 78 FR 7183, Jan. 31, 2013; 80 FR 72814, Nov. 20, 2015]

§63.7550 What reports must I submit and when?

(a) You must submit each report in Table 9 to this subpart that applies to you.

(b) Unless the EPA Administrator has approved a different schedule for submission of reports under §63.10(a), you must submit each report, according to paragraph (h) of this section, by the date in Table 9 to this subpart and according to the requirements in paragraphs (b)(1) through (4) of this section. For units that are subject only to a requirement to conduct subsequent annual, biennial, or 5-year tune-up according to §63.7540(a)(10), (11), or (12), respectively, and not subject to emission limits or Table 4 operating limits, you may submit only an annual, biennial, or 5-year compliance report, as applicable, as specified in paragraphs (b)(1) through (4) of this section, instead of a semi-annual compliance report.

(1) The first semi-annual compliance report must cover the period beginning on the compliance date that is specified for each boiler or process heater in §63.7495 and ending on June 30 or December 31, whichever date is the first date that occurs at least 180 days after the compliance date that is specified for your source in §63.7495. If submitting an annual, biennial, or 5-year compliance report, the first compliance report must cover the period beginning on the compliance date that is specified for each boiler or process heater in §63.7495 and ending on December 31 within 1, 2, or 5 years, as applicable, after the compliance date that is specified for your source in §63.7495.

(2) The first semi-annual compliance report must be postmarked or submitted no later than July 31 or January 31, whichever date is the first date following the end of the first calendar half after the compliance date that is specified for each boiler or process heater in §63.7495. The first annual, biennial, or 5-year compliance report must be postmarked or submitted no later than January 31.

(3) Each subsequent semi-annual compliance report must cover the semiannual reporting period from January 1 through June 30 or the semiannual reporting period from July 1 through December 31. Annual, biennial, and 5-year compliance reports must cover the applicable 1-, 2-, or 5-year periods from January 1 to December 31.

(4) Each subsequent semi-annual compliance report must be postmarked or submitted no later than July 31 or January 31, whichever date is the first date following the end of the semiannual reporting period. Annual, biennial, and 5-year compliance reports must be postmarked or submitted no later than January 31.

(5) For each affected source that is subject to permitting regulations pursuant to part 70 or part 71 of this chapter, and if the permitting authority has established dates for submitting semiannual reports pursuant to 70.6(a)(3)(iii)(A) or 71.6(a)(3)(iii)(A), you may submit the first and subsequent compliance reports according to the dates the permitting authority has established in the permit instead of according to the dates in paragraphs (b)(1) through (4) of this section.

(c) A compliance report must contain the following information depending on how the facility chooses to comply with the limits set in this rule.

(1) If the facility is subject to the requirements of a tune up you must submit a compliance report with the information in paragraphs (c)(5)(i) through (iii) of this section, (xiv) and (xvii) of this section, and paragraph (c)(5)(iv) of this section for limited-use boiler or process heater.

(2) If you are complying with the fuel analysis you must submit a compliance report with the information in paragraphs (c)(5)(i) through (iii), (vi), (x), (xi), (xiii), (xv), (xvii), (xviii) and paragraph (d) of this section.

(3) If you are complying with the applicable emissions limit with performance testing you must submit a compliance report with the information in (c)(5)(i) through (iii), (vi), (vii), (viii), (ix), (xi), (xiii), (xv), (xvii), (xviii) and paragraph (d) of this section.

(4) If you are complying with an emissions limit using a CMS the compliance report must contain the information required in paragraphs (c)(5)(i) through (iii), (v), (vi), (xi) through (xiii), (xv) through (xviii), and paragraph (e) of this section.

(5)(i) Company and Facility name and address.

(ii) Process unit information, emissions limitations, and operating parameter limitations.

(iii) Date of report and beginning and ending dates of the reporting period.

(iv) The total operating time during the reporting period.

(v) If you use a CMS, including CEMS, COMS, or CPMS, you must include the monitoring equipment manufacturer(s) and model numbers and the date of the last CMS certification or audit.

(vi) The total fuel use by each individual boiler or process heater subject to an emission limit within the reporting period, including, but not limited to, a description of the fuel, whether the fuel has received a non-waste determination by the EPA or your basis for concluding that the fuel is not a waste, and the total fuel usage amount with units of measure.

(vii) If you are conducting performance tests once every 3 years consistent with §63.7515(b) or (c), the date of the last 2 performance tests and a statement as to whether there have been any operational changes since the last performance test that could increase emissions.

(viii) A statement indicating that you burned no new types of fuel in an individual boiler or process heater subject to an emission limit. Or, if you did burn a new type of fuel and are subject to a HCl emission limit, you must submit the calculation of chlorine input, using Equation 7 of §63.7530, that demonstrates that your source is still within its maximum chlorine input level established during the previous performance testing (for sources that demonstrate compliance through performance testing) or you must submit the calculation of HCl emission rate using Equation 16 of §63.7530 that demonstrates that your source is still meeting the emission limit for HCl emissions (for boilers or process heaters that demonstrate compliance through fuel analysis). If you burned a new type of fuel and are subject to a mercury emission limit, you must submit the calculation of mercury input, using Equation 8 of §63.7530, that demonstrates that your source is still within its maximum mercury input level established during the previous performance testing (for sources that demonstrate compliance through performance testing), or you must submit the calculation of mercury emission rate using Equation 17 of §63.7530 that demonstrates that your source is still meeting the emission limit for mercury emissions (for boilers or process heaters that demonstrate compliance through fuel analysis). If you burned a new type of fuel and are subject to a TSM emission limit, you must submit the calculation of TSM input, using Equation 9 of §63.7530, that demonstrates that your source is still within its maximum TSM input level established during the previous performance testing (for sources that demonstrate compliance through performance testing), or you must submit the calculation of TSM emission rate, using Equation 18 of §63.7530, that demonstrates that your source is still meeting the emission limit for TSM emissions (for boilers or process heaters that demonstrate compliance through fuel analysis).

(ix) If you wish to burn a new type of fuel in an individual boiler or process heater subject to an emission limit and you cannot demonstrate compliance with the maximum chlorine input operating limit using Equation 7 of §63.7530 or the maximum mercury input operating limit using Equation 8 of §63.7530, or the maximum TSM input operating limit using Equation 9 of §63.7530 you must include in the compliance report a statement indicating the intent to conduct a new performance test within 60 days of starting to burn the new fuel.

(x) A summary of any monthly fuel analyses conducted to demonstrate compliance according to §§63.7521 and 63.7530 for individual boilers or process heaters subject to emission limits, and any fuel specification analyses conducted according to §§63.7521(f) and 63.7530(g).

(xi) If there are no deviations from any emission limits or operating limits in this subpart that apply to you, a statement that there were no deviations from the emission limits or operating limits during the reporting period.

(xii) If there were no deviations from the monitoring requirements including no periods during which the CMSs, including CEMS, COMS, and CPMS, were out of control as specified in §63.8(c)(7), a statement that there were no deviations and no periods during which the CMS were out of control during the reporting period.

(xiii) If a malfunction occurred during the reporting period, the report must include the number, duration, and a brief description for each type of malfunction which occurred during the reporting period and which caused or may have caused any applicable emission limitation to be exceeded. The report must also include a description of actions taken by you during a malfunction of a boiler, process heater, or associated air pollution control device or CMS to minimize emissions in accordance with §63.7500(a)(3), including actions taken to correct the malfunction.

(xiv) Include the date of the most recent tune-up for each unit subject to only the requirement to conduct an annual, biennial, or 5-year tune-up according to §63.7540(a)(10), (11), or (12) respectively. Include the date of the most recent burner inspection if it was not done annually, biennially, or on a 5-year period and was delayed until the next scheduled or unscheduled unit shutdown.

(xv) If you plan to demonstrate compliance by emission averaging, certify the emission level achieved or the control technology employed is no less stringent than the level or control technology contained in the notification of compliance status in §63.7545(e)(5)(i).

(xvi) For each reporting period, the compliance reports must include all of the calculated 30 day rolling average values for CEMS (CO, HCl, SO_2, and mercury), 10 day rolling average values for CO CEMS when the limit is expressed as a 10 day instead of 30 day rolling average, and the PM CPMS data.

(xvii) Statement by a responsible official with that official's name, title, and signature, certifying the truth, accuracy, and completeness of the content of the report.

(xviii) For each instance of startup or shutdown include the information required to be monitored, collected, or recorded according to the requirements of §63.7555(d).

(d) For each deviation from an emission limit or operating limit in this subpart that occurs at an individual boiler or process heater where you are not using a CMS to comply with that emission limit or operating limit, or from the work practice standards for periods if startup and shutdown, the compliance report must additionally contain the information required in paragraphs (d)(1) through (3) of this section.

(1) A description of the deviation and which emission limit, operating limit, or work practice standard from which you deviated.

(2) Information on the number, duration, and cause of deviations (including unknown cause), as applicable, and the corrective action taken.

(3) If the deviation occurred during an annual performance test, provide the date the annual performance test was completed.

(e) For each deviation from an emission limit, operating limit, and monitoring requirement in this subpart occurring at an individual boiler or process heater where you are using a CMS to comply with that emission limit or operating limit, the compliance report must additionally contain the information required in paragraphs (e)(1) through (9) of this section. This includes any deviations from your site-specific monitoring plan as required in §63.7505(d).

(1) The date and time that each deviation started and stopped and description of the nature of the deviation (i.e., what you deviated from).

(2) The date and time that each CMS was inoperative, except for zero (low-level) and high-level checks.

(3) The date, time, and duration that each CMS was out of control, including the information in §63.8(c)(8).

(4) The date and time that each deviation started and stopped.

(5) A summary of the total duration of the deviation during the reporting period and the total duration as a percent of the total source operating time during that reporting period.

(6) A characterization of the total duration of the deviations during the reporting period into those that are due to control equipment problems, process problems, other known causes, and other unknown causes.

(7) A summary of the total duration of CMS's downtime during the reporting period and the total duration of CMS downtime as a percent of the total source operating time during that reporting period.

(8) A brief description of the source for which there was a deviation.

(9) A description of any changes in CMSs, processes, or controls since the last reporting period for the source for which there was a deviation.

(f)-(g) [Reserved]

(h) You must submit the reports according to the procedures specified in paragraphs (h)(1) through (3) of this section.

(1) Within 60 days after the date of completing each performance test (as defined in §63.2) required by this subpart, you must submit the results of the performance tests, including any fuel analyses, following the procedure specified in either paragraph (h)(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 (*http://www.epa.gov/ttn/chief/ert/index.html*), 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 use of the EPA's ERT or an 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/OAPQS/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 (h)(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 transmitted 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 media must be clearly marked as CBI and mailed to U.S. EPA/OAPQS/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 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.

(3) You must submit all reports required by Table 9 of this subpart electronically to the EPA via the CEDRI. (CEDRI can be accessed through the EPA's CDX.) You must use the appropriate electronic report in CEDRI for this subpart. Instead of using the electronic report in CEDRI for this subpart, you may submit an alternate electronic file consistent with the XML schema listed on the CEDRI Web site (*http://www.epa.gov/ttn/chief/cedri/index.html*), once the XML schema is available. If the reporting form specific to this subpart is not available in CEDRI at the time that the report is due, you must submit the report to the Administrator at the appropriate address listed in §63.13. You must begin submitting reports via CEDRI no later than 90 days after the form becomes available in CEDRI.

[78 FR 7183, Jan. 31, 2013, as amended at 80 FR 72814, Nov. 20, 2015]

§63.7555 What records must I keep?

(a) You must keep records according to paragraphs (a)(1) and (2) of this section.

(1) A copy of each notification and report that you submitted to comply with this subpart, including all documentation supporting any Initial Notification or Notification of Compliance Status or semiannual compliance report that you submitted, according to the requirements in §63.10(b)(2)(xiv).

(2) Records of performance tests, fuel analyses, or other compliance demonstrations and performance evaluations as required in §63.10(b)(2)(viii).

(3) For units in the limited use subcategory, you must keep a copy of the federally enforceable permit that limits the annual capacity factor to less than or equal to 10 percent and fuel use records for the days the boiler or process heater was operating.

(b) For each CEMS, COMS, and continuous monitoring system you must keep records according to paragraphs (b)(1) through (5) of this section.

(1) Records described in §63.10(b)(2)(vii) through (xi).

(2) Monitoring data for continuous opacity monitoring system during a performance evaluation as required in §63.6(h)(7)(i) and (ii).

(3) Previous (*i.e.,* superseded) versions of the performance evaluation plan as required in §63.8(d)(3).

(4) Request for alternatives to relative accuracy test for CEMS as required in §63.8(f)(6)(i).

(5) Records of the date and time that each deviation started and stopped.

(c) You must keep the records required in Table 8 to this subpart including records of all monitoring data and calculated averages for applicable operating limits, such as opacity, pressure drop, pH, and operating load, to show continuous compliance with each emission limit and operating limit that applies to you.

(d) For each boiler or process heater subject to an emission limit in Tables 1, 2, or 11 through 13 to this subpart, you must also keep the applicable records in paragraphs (d)(1) through (11) of this section.

(1) You must keep records of monthly fuel use by each boiler or process heater, including the type(s) of fuel and amount(s) used.

(2) If you combust non-hazardous secondary materials that have been determined not to be solid waste pursuant to §241.3(b)(1) and (2) of this chapter, you must keep a record that documents how the secondary material meets each of the legitimacy criteria under §241.3(d)(1) of this chapter. If you combust a fuel that has been processed from a discarded non-hazardous secondary material pursuant to §241.3(b)(4) of this chapter, you must keep records as to how the operations that produced the fuel satisfy the definition of processing in §241.2 of this chapter. If the fuel received a non-waste determination pursuant to the petition process submitted under §241.3(c) of this chapter, you must keep a record that documents how the fuel satisfies the requirements of the petition process. For operating units that combust non-hazardous secondary materials as fuel per §241.4 of this chapter, you must keep records documenting that the material is listed as a non-waste under §241.4(a) of this chapter. Units exempt from the incinerator standards under section 129(g)(1) of the Clean Air Act because they are qualifying facilities burning a homogeneous waste stream do not need to maintain the records described in this paragraph (d)(2).

(3) A copy of all calculations and supporting documentation of maximum chlorine fuel input, using Equation 7 of §63.7530, that were done to demonstrate continuous compliance with the HCl emission limit, for sources that demonstrate compliance through performance testing. For sources that demonstrate compliance through fuel analysis, a copy of all calculations and supporting documentation of HCl emission rates, using Equation 16 of §63.7530, that were done to demonstrate compliance with the HCl emission limit. Supporting documentation should include results of any fuel analyses and basis for the estimates of maximum chlorine fuel input or HCl emission rates. You can use the results from one fuel analysis for multiple boilers and process heaters provided they are all burning the same fuel type. However, you must calculate chlorine fuel input, or HCl emission rate, for each boiler and process heater.

(4) A copy of all calculations and supporting documentation of maximum mercury fuel input, using Equation 8 of §63.7530, that were done to demonstrate continuous compliance with the mercury emission limit for sources that demonstrate compliance through performance testing. For sources that demonstrate compliance through fuel analysis, a copy of all calculations and supporting documentation of mercury emission rates, using Equation 17 of §63.7530, that were done to demonstrate compliance with the mercury emission limit. Supporting documentation should include results of any fuel analyses and basis for the estimates of maximum mercury fuel input or mercury emission rates. You can use the results from one fuel analysis for multiple boilers and process heaters provided they are all burning the same fuel type. However, you must calculate mercury fuel input, or mercury emission rates, for each boiler and process heater.

(5) If, consistent with §63.7515(b), you choose to stack test less frequently than annually, you must keep a record that documents that your emissions in the previous stack test(s) were less than 75 percent of the applicable emission limit (or, in specific instances noted in Tables 1 and 2 or 11 through 13 to this subpart, less than the applicable emission limit), and document that there was no change in source operations including fuel composition and operation of air pollution control equipment that would cause emissions of the relevant pollutant to increase within the past year.

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

(7) Records of actions taken during periods of malfunction to minimize emissions in accordance with the general duty to minimize emissions in §63.7500(a)(3), including corrective actions to restore the malfunctioning boiler or process heater, air pollution control, or monitoring equipment to its normal or usual manner of operation.

(8) A copy of all calculations and supporting documentation of maximum TSM fuel input, using Equation 9 of §63.7530, that were done to demonstrate continuous compliance with the TSM emission limit for sources that demonstrate compliance through performance testing. For sources that demonstrate compliance through fuel analysis, a copy of all calculations and supporting documentation of TSM emission rates, using Equation 18 of §63.7530, that were done to demonstrate compliance with the TSM emission limit. Supporting documentation should include results of any fuel analyses and basis for the estimates of maximum TSM fuel input or TSM emission rates. You can use the results from one fuel analysis for multiple boilers and process heaters provided they are all burning

the same fuel type. However, you must calculate TSM fuel input, or TSM emission rates, for each boiler and process heater.

(9) You must maintain records of the calendar date, time, occurrence and duration of each startup and shutdown.

(10) You must maintain records of the type(s) and amount(s) of fuels used during each startup and shutdown.

(11) For each startup period, for units selecting paragraph (2) of the definition of “startup” in §63.7575 you must maintain records of the time that clean fuel combustion begins; the time when you start feeding fuels that are not clean fuels; the time when useful thermal energy is first supplied; and the time when the PM controls are engaged.

(12) If you choose to rely on paragraph (2) of the definition of “startup” in §63.7575, for each startup period, you must maintain records of the hourly steam temperature, hourly steam pressure, hourly steam flow, hourly flue gas temperature, and all hourly average CMS data (*e.g.,* CEMS, PM CPMS, COMS, ESP total secondary electric power input, scrubber pressure drop, scrubber liquid flow rate) collected during each startup period to confirm that the control devices are engaged. In addition, if compliance with the PM emission limit is demonstrated using a PM control device, you must maintain records as specified in paragraphs (d)(12)(i) through (iii) of this section.

(i) For a boiler or process heater with an electrostatic precipitator, record the number of fields in service, as well as each field's secondary voltage and secondary current during each hour of startup.

(ii) For a boiler or process heater with a fabric filter, record the number of compartments in service, as well as the differential pressure across the baghouse during each hour of startup.

(iii) For a boiler or process heater with a wet scrubber needed for filterable PM control, record the scrubber's liquid flow rate and the pressure drop during each hour of startup.

(13) If you choose to use paragraph (2) of the definition of “startup” in §63.7575 and you find that you are unable to safely engage and operate your PM control(s) within 1 hour of first firing of non-clean fuels, you may choose to rely on paragraph (1) of definition of “startup” in §63.7575 or you may submit to the delegated permitting authority a request for a variance with the PM controls requirement, as described below.

(i) The request shall provide evidence of a documented manufacturer-identified safety issue.

(ii) The request shall provide information to document that the PM control device is adequately designed and sized to meet the applicable PM emission limit.

(iii) In addition, the request shall contain documentation that:

(A) The unit is using clean fuels to the maximum extent possible to bring the unit and PM control device up to the temperature necessary to alleviate or prevent the identified safety issues prior to the combustion of primary fuel;

(B) The unit has explicitly followed the manufacturer's procedures to alleviate or prevent the identified safety issue; and

(C) Identifies with specificity the details of the manufacturer's statement of concern.

(iv) You must comply with all other work practice requirements, including but not limited to data collection, recordkeeping, and reporting requirements.

(e) If you elect to average emissions consistent with §63.7522, you must additionally keep a copy of the emission averaging implementation plan required in §63.7522(g), all calculations required under §63.7522, including monthly records of heat input or steam generation, as applicable, and monitoring records consistent with §63.7541.

(f) If you elect to use efficiency credits from energy conservation measures to demonstrate compliance according to §63.7533, you must keep a copy of the Implementation Plan required in §63.7533(d) and copies of all data and calculations used to establish credits according to §63.7533(b), (c), and (f).

(g) If you elected to demonstrate that the unit meets the specification for mercury for the unit designed to burn gas 1 subcategory, you must maintain monthly records (or at the frequency required by §63.7540(c)) of the calculations and results of the fuel specification for mercury in Table 6.

(h) If you operate a unit in the unit designed to burn gas 1 subcategory that is subject to this subpart, and you use an alternative fuel other than natural gas, refinery gas, gaseous fuel subject to another subpart under this part, other gas 1 fuel, or gaseous fuel subject to another subpart of this part or part 60, 61, or 65, you must keep records of the total hours per calendar year that alternative fuel is burned and the total hours per calendar year that the unit operated during periods of gas curtailment or gas supply emergencies.

[76 FR 15664, Mar. 21, 2011, as amended at 78 FR 7185, Jan. 31, 2013; 80 FR 72816, Nov. 20, 2015]

§63.7560 In what form and how long must I keep my records?

(a) Your records must be in a form suitable and readily available for expeditious review, according to §63.10(b)(1).

(b) As specified in §63.10(b)(1), you must keep each record for 5 years following the date of each occurrence, measurement, maintenance, corrective action, report, or record.

(c) You must keep each record on site, or they must be accessible from on site (for example, through a computer network), for at least 2 years after the date of each occurrence, measurement, maintenance, corrective action, report, or record, according to §63.10(b)(1). You can keep the records off site for the remaining 3 years.

Other Requirements and Information

§63.7565 What parts of the General Provisions apply to me?

Table 10 to this subpart shows which parts of the General Provisions in §§63.1 through 63.15 apply to you.

§63.7570 Who implements and enforces this subpart?

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

(b) In delegating implementation and enforcement authority of this subpart to a state, local, or tribal agency under 40 CFR part 63, subpart E, the authorities listed in paragraphs (b)(1) through (4) of this section are retained by the EPA Administrator and are not transferred to the state, local, or tribal agency, however, the EPA retains oversight of this subpart and can take enforcement actions, as appropriate.

(1) Approval of alternatives to the emission limits and work practice standards in §63.7500(a) and (b) under §63.6(g), except as specified in §63.7555(d)(13).

(2) Approval of major change to test methods in Table 5 to this subpart under §63.7(e)(2)(ii) and (f) and as defined in §63.90, and alternative analytical methods requested under §63.7521(b)(2).

(3) Approval of major change to monitoring under §63.8(f) and as defined in §63.90, and approval of alternative operating parameters under §§63.7500(a)(2) and 63.7522(g)(2).

(4) Approval of major change to recordkeeping and reporting under §63.10(e) and as defined in §63.90.

[76 FR 15664, Mar. 21, 2011, as amended at 78 FR 7186, Jan. 31, 2013; 80 FR 72817, Nov. 20, 2015]

§63.7575 What definitions apply to this subpart?

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

10-day rolling average means the arithmetic mean of the previous 240 hours of valid operating data. Valid data excludes hours during startup and shutdown, data collected during periods when the monitoring system is out of control as specified in your site-specific monitoring plan, while conducting repairs associated with periods when the monitoring system is out of control, or while conducting required monitoring system quality assurance or quality control activities, and periods when this unit is not operating. The 240 hours should be consecutive, but not necessarily continuous if operations were intermittent.

30-day rolling average means the arithmetic mean of the previous 720 hours of valid CO CEMS data. The 720 hours should be consecutive, but not necessarily continuous if operations were intermittent. For parameters other than CO, 30-day rolling average means either the arithmetic mean of all valid hours of data from 30 successive operating days or the arithmetic mean of the previous 720 hours of valid operating data. Valid data excludes hours during startup and shutdown, data collected during periods when the monitoring system is out of control as specified in your site-specific monitoring plan, while conducting repairs associated with periods when the monitoring system is out of control, or while conducting required monitoring system quality assurance or quality control activities, and periods when this unit is not operating.

Annual capacity factor means the ratio between the actual heat input to a boiler or process heater from the fuels burned during a calendar year and the potential heat input to the boiler or process heater had it been operated for 8,760 hours during a year at the maximum steady state design heat input capacity.

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

Average annual heat input rate means total heat input divided by the hours of operation for the 12 months preceding the compliance demonstration.

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

Benchmark means the fuel heat input for a boiler or process heater for the one-year period before the date that an energy demand reduction occurs, unless it can be demonstrated that a different time period is more representative of historical operations.

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

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

Blast furnace gas fuel-fired boiler or process heater means an industrial/commercial/institutional boiler or process heater that receives 90 percent or more of its total annual gas volume from blast furnace gas.

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

Boiler system means the boiler and associated components, such as, the feed water system, the combustion air system, the fuel system (including burners), blowdown system, combustion control systems, steam systems, and condensate return systems.

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

Clean dry biomass means any biomass-based solid fuel that have not been painted, pigment-stained, or pressure treated, does not contain contaminants at concentrations not normally associated with virgin biomass materials and has a moisture content of less than 20 percent and is not a solid waste.

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

Coal refuse means any by-product of coal mining or coal cleaning operations with an ash content greater than 50 percent (by weight) and a heating value less than 13,900 kilojoules per kilogram (6,000 Btu per pound) on a dry basis.

Commercial/institutional boiler means a boiler used in commercial establishments or institutional establishments such as medical centers, nursing homes, research centers, institutions of higher education, elementary and secondary schools, libraries, religious establishments, governmental buildings, hotels, restaurants, and laundries to provide electricity, steam, and/or hot water.

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

Cost-effective energy conservation measure means a measure that is implemented to improve the energy efficiency of the boiler or facility that has a payback (return of investment) period of 2 years or less.

Daily block average means the arithmetic mean of all valid emission concentrations or parameter levels recorded when a unit is operating measured over the 24-hour period from 12 a.m. (midnight) to 12 a.m. (midnight), except for periods of startup and shutdown or downtime.

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

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

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

(2) A deviation is not always a violation.

Dioxins/furans means tetra- through octa-chlorinated dibenzo-p-dioxins and dibenzofurans.

Distillate oil means fuel oils that contain 0.05 weight percent nitrogen or less and comply with the specifications for fuel oil numbers 1 and 2, as defined by the American Society of Testing and Materials in ASTM D396 (incorporated by reference, see §63.14) or diesel fuel oil numbers 1 and 2, as defined by the American Society for Testing and Materials in ASTM D975 (incorporated by reference, see §63.14), kerosene, and biodiesel as defined by the American Society of Testing and Materials in ASTM D6751-11b (incorporated by reference, see §60.14).

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

Dutch oven means a unit having a refractory-walled cell connected to a conventional boiler setting. Fuel materials are introduced through an opening in the roof of the dutch oven and burn in a pile on its floor. Fluidized bed boilers are not part of the dutch oven design category.

Efficiency credit means emission reductions above those required by this subpart. Efficiency credits generated may be used to comply with the emissions limits. Credits may come from pollution prevention projects that result in reduced fuel use by affected units. Boilers that are shut down cannot be used to generate credits unless the facility provides documentation linking the permanent shutdown to implementation of the energy conservation measures identified in the energy assessment.

Electric utility steam generating unit (EGU) means a fossil fuel-fired combustion unit of more than 25 megawatts electric (MWe) that serves a generator that produces electricity for sale. A fossil fuel-fired unit that cogenerates steam and electricity and supplies more than one-third of its potential electric output capacity and more than 25 MWe output to any utility power distribution system for sale is considered an electric utility steam generating unit. To be “capable of combusting” fossil fuels, an EGU would need to have these fuels allowed in their operating permits and have the appropriate fuel handling facilities on-site or otherwise available (e.g., coal handling equipment, including coal storage area, belts and conveyers, pulverizers, etc.; oil storage facilities). In addition, fossil fuel-fired EGU means any EGU that fired fossil fuel for more than 10.0 percent of the average annual heat input in any 3 consecutive calendar years or for more than 15.0 percent of the annual heat input during any one calendar year after April 16, 2012.

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

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

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

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

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

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

Energy management practices means the set of practices and procedures designed to manage energy use that are demonstrated by the facility's energy policies, a facility energy manager and other staffing responsibilities, energy performance measurement and tracking methods, an energy saving goal, action plans, operating procedures, internal reporting requirements, and periodic review intervals used at the facility.

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

Energy use system includes the following systems located on-site that use energy (steam, hot water, or electricity) provided by the affected boiler or process heater: process heating; compressed air systems; machine drive (motors, pumps, fans); process cooling; facility heating, ventilation, and air-conditioning systems; hot water systems; building envelop; and lighting; or other systems that use steam, hot water, process heat, or electricity provided by the affected boiler or process heater. Energy use systems are only those systems using energy clearly produced by affected boilers and process heaters.

Equivalent means the following only as this term is used in Table 6 to this subpart:

(1) An equivalent sample collection procedure means a published voluntary consensus standard or practice (VCS) or EPA method that includes collection of a minimum of three composite fuel samples, with each composite consisting of a minimum of three increments collected at approximately equal intervals over the test period.

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

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

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

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

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

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

Federally enforceable means all limitations and conditions that are enforceable by the EPA Administrator, including, but not limited to, the requirements of 40 CFR parts 60, 61, 63, and 65, requirements within any applicable state implementation plan, and any permit requirements established under 40 CFR 52.21 or under 40 CFR 51.18 and 40 CFR 51.24.

Fluidized bed boiler means a boiler utilizing a fluidized bed combustion process that is not a pulverized coal boiler.

Fluidized bed boiler with an integrated fluidized bed heat exchanger means a boiler utilizing a fluidized bed combustion where the entire tube surface area is located outside of the furnace section at the exit of the cyclone section and exposed to the flue gas stream for conductive heat transfer. This design applies only to boilers in the unit designed to burn coal/solid fossil fuel subcategory that fire coal refuse.

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

Fossil fuel means natural gas, oil, coal, and any form of solid, liquid, or gaseous fuel derived from such material.

Fuel cell means a boiler type in which the fuel is dropped onto suspended fixed grates and is fired in a pile. The refractory-lined fuel cell uses combustion air preheating and positioning of secondary and tertiary air injection ports to improve boiler efficiency. Fluidized bed, dutch oven, pile burner, hybrid suspension grate, and suspension burners are not part of the fuel cell subcategory.

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

Gaseous fuel includes, but is not limited to, natural gas, process gas, landfill gas, coal derived gas, refinery gas, and biogas. Blast furnace gas and process gases that are regulated under another subpart of this part, or part 60, part 61, or part 65 of this chapter, are exempted from this definition.

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

Heavy liquid includes residual oil and any other liquid fuel not classified as a light liquid.

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

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

Hybrid suspension grate boiler means a boiler designed with air distributors to spread the fuel material over the entire width and depth of the boiler combustion zone. The biomass fuel combusted in these units exceeds a moisture content of 40 percent on an as-fired annual heat input basis as demonstrated by monthly fuel analysis. The drying and much of the combustion of the fuel takes place in suspension, and the combustion is completed on the grate or floor of the boiler. Fluidized bed, dutch oven, and pile burner designs are not part of the hybrid suspension grate boiler design category.

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

Light liquid includes distillate oil, biodiesel, or vegetable oil.

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

Liquid fuel includes, but is not limited to, light liquid, heavy liquid, any form of liquid fuel derived from petroleum, used oil, liquid biofuels, biodiesel, and vegetable oil.

Load fraction means the actual heat input of a boiler or process heater divided by heat input during the performance test that established the minimum sorbent injection rate or minimum activated carbon injection rate, expressed as a fraction (*e.g.,* for 50 percent load the load fraction is 0.5). For boilers and process heaters that co-fire natural gas or refinery 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).

Major source for oil and natural gas production facilities, as used in this subpart, shall have the same meaning as in §63.2, except that:

(1) Emissions from any oil or gas exploration or production well (with its associated equipment, as defined in this section), and emissions from any pipeline compressor station or pump station shall not be aggregated with emissions from other similar units to determine whether such emission points or stations are major sources, even when emission points are in a contiguous area or under common control;

(2) Emissions from processes, operations, or equipment that are not part of the same facility, as defined in this section, shall not be aggregated; and

(3) For facilities that are production field facilities, only HAP emissions from glycol dehydration units and storage vessels with the potential for flash emissions shall be aggregated for a major source determination. For facilities that are not production field facilities, HAP emissions from all HAP emission units shall be aggregated for a major source determination.

Metal process furnaces are a subcategory of process heaters, as defined in this subpart, which include natural gas-fired annealing furnaces, preheat furnaces, reheat furnaces, aging furnaces, heat treat furnaces, and homogenizing furnaces.

Million Btu (MMBtu) means one million British thermal units.

Minimum activated carbon injection rate means load fraction multiplied by the lowest hourly average activated carbon injection rate measured according to Table 7 to this subpart during the most recent performance test demonstrating compliance with the applicable emission limit.

Minimum oxygen level means the lowest hourly average oxygen level measured according to Table 7 to this subpart during the most recent performance test demonstrating compliance with the applicable emission limit.

Minimum pressure drop means the lowest hourly average pressure drop measured according to Table 7 to this subpart during the most recent performance test demonstrating compliance with the applicable emission limit.

Minimum scrubber effluent pH means the lowest hourly average sorbent liquid pH measured at the inlet to the wet scrubber according to Table 7 to this subpart during the most recent performance test demonstrating compliance with the applicable hydrogen chloride emission limit.

Minimum scrubber liquid flow rate means the lowest hourly average liquid flow rate (e.g., to the PM scrubber or to the acid gas scrubber) measured according to Table 7 to this subpart during the most recent performance stack test demonstrating compliance with the applicable emission limit.

Minimum scrubber pressure drop means the lowest hourly average scrubber pressure drop measured according to Table 7 to this subpart during the most recent performance test demonstrating compliance with the applicable emission limit.

Minimum sorbent injection rate means:

(1) The load fraction multiplied by the lowest hourly average sorbent injection rate for each sorbent measured according to Table 7 to this subpart during the most recent performance test demonstrating compliance with the applicable emission limits; or

(2) For fluidized bed combustion not using an acid gas wet scrubber or dry sorbent injection control technology to comply with the HCl emission limit, the lowest average ratio of sorbent to sulfur measured during the most recent performance test.

Minimum total secondary electric power means the lowest hourly average total secondary electric power determined from the values of secondary voltage and secondary current to the electrostatic precipitator measured according to Table 7 to this subpart during the most recent performance test demonstrating compliance with the applicable emission limits.

Natural gas means:

(1) A naturally occurring mixture of hydrocarbon and nonhydrocarbon gases found in geologic formations beneath the earth's surface, of which the principal constituent is methane; or

(2) Liquefied petroleum gas, as defined in ASTM D1835 (incorporated by reference, see §63.14); or

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

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

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

Operating day means a 24-hour period between 12 midnight and the following midnight during which any fuel is combusted at any time in the boiler or process heater unit. It is not necessary for fuel to be combusted for the entire 24-hour period. For calculating rolling average emissions, an operating day does not include the hours of operation during startup or shutdown.

Other combustor means a unit designed to burn solid fuel that is not classified as a dutch oven, fluidized bed, fuel cell, hybrid suspension grate boiler, pulverized coal boiler, stoker, sloped grate, or suspension boiler as defined in this subpart.

Other gas 1 fuel means a gaseous fuel that is not natural gas or refinery gas and does not exceed a maximum concentration of 40 micrograms/cubic meters of mercury.

Oxygen analyzer system means all equipment required to determine the oxygen content of a gas stream and used to monitor oxygen in the boiler or process heater flue gas, boiler or process heater, firebox, or other appropriate location. This definition includes oxygen trim systems. The source owner or operator must install, calibrate, maintain, and operate the oxygen analyzer system in accordance with the manufacturer's recommendations.

Oxygen trim system means a system of monitors that is used to maintain excess air at the desired level in a combustion device over its operating load range. A typical system consists of a flue gas oxygen and/or CO 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.

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

Pile burner means a boiler design incorporating a design where the anticipated biomass fuel has a high relative moisture content. Grates serve to support the fuel, and underfire air flowing up through the grates provides oxygen for combustion, cools the grates, promotes turbulence in the fuel bed, and fires the fuel. The most common form of pile burning is the dutch oven.

Process heater means an enclosed device using controlled flame, and the unit's primary purpose is to transfer heat indirectly to a process material (liquid, gas, or solid) or to a heat transfer material (e.g., glycol or a mixture of glycol and water) for use in a process unit, instead of generating steam. Process heaters are devices in which the combustion gases do not come into direct contact with process materials. A device combusting solid waste, as defined in §241.3 of this chapter, is not a process heater unless the device is exempt from the definition of a solid waste incineration unit as provided in section 129(g)(1) of the Clean Air Act. Process heaters do not include units used for comfort heat or space heat, food preparation for on-site consumption, or autoclaves. Waste heat process heaters are excluded from this definition.

Pulverized coal boiler means a boiler in which pulverized coal or other solid fossil fuel is introduced into an air stream that carries the coal to the combustion chamber of the boiler where it is fired in suspension.

Qualified energy assessor means:

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

(i) Boiler combustion management.

(ii) Boiler thermal energy recovery, including

(A) Conventional feed water economizer,

(B) Conventional combustion air preheater, and

(C) Condensing economizer.

(iii) Boiler blowdown thermal energy recovery.

(iv) Primary energy resource selection, including

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

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

(v) Insulation issues.

(vi) Steam trap and steam leak management.

(vi) Condensate recovery.

(viii) Steam end-use management.

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

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

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

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

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

(v) Boiler-steam turbine cogeneration systems.

(vi) Industry specific steam end-use systems.

Refinery gas means any gas that is generated at a petroleum refinery and is combusted. Refinery gas includes natural gas when the natural gas is combined and combusted in any proportion with a gas generated at a refinery. Refinery gas includes gases generated from other facilities when that gas is combined and combusted in any proportion with gas generated at a refinery.

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

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

(1) A dwelling containing four or fewer families; or

(2) A single unit residence dwelling that has since been converted or subdivided into condominiums or apartments.

Residual oil means crude oil, fuel oil that does not comply with the specifications under the definition of distillate oil, and all fuel oil numbers 4, 5, and 6, as defined by the American Society of Testing and Materials in ASTM D396-10 (incorporated by reference, *see* §63.14(b)).

Responsible official means responsible official as defined in §70.2.

Rolling average means the average of all data collected during the applicable averaging period. For demonstration of compliance with a CO CEMS-based emission limit based on CO concentration a 30-day (10-day) rolling average is comprised of the average of all the hourly average concentrations over the previous 720 (240) operating hours calculated each operating day. To demonstrate compliance on a 30-day rolling average basis for parameters other than CO, you must indicate the basis of the 30-day rolling average period you are using for compliance, as discussed in §63.7545(e)(2)(iii). If you indicate the 30 operating day basis, you must calculate a new average value each operating day and shall include the measured hourly values for the preceding 30 operating days. If you select the 720 operating hours basis, you must average of all the hourly average concentrations over the previous 720 operating hours calculated each operating day.

Secondary material means the material as defined in §241.2 of this chapter.

Shutdown means the period in which cessation of operation of a boiler or process heater is initiated for any purpose. Shutdown begins when the boiler or process heater no longer supplies useful thermal energy (such as heat or steam) for heating, cooling, or process purposes and/or generates electricity or when no fuel is being fed to the boiler or process heater, whichever is earlier. Shutdown ends when the boiler or process heater no longer supplies useful thermal energy (such as steam or heat) for heating, cooling, or process purposes and/or generates electricity, and no fuel is being combusted in the boiler or process heater.

Sloped grate means a unit where the solid fuel is fed to the top of the grate from where it slides downwards; while sliding the fuel first dries and then ignites and burns. The ash is deposited at the bottom of the grate. Fluidized bed, dutch oven, pile burner, hybrid suspension grate, suspension burners, and fuel cells are not considered to be a sloped grate design.

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

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

Startup means:

(1) Either the first-ever firing of fuel in a boiler or process heater for the purpose of supplying useful thermal energy 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 from the boiler or process heater is supplied for heating, and/or producing electricity, or for any other purpose, or

(2) The period in which operation of a boiler or process heater is initiated for any purpose. Startup begins with either the first-ever firing of fuel in a boiler or process heater for the purpose of supplying useful thermal energy (such as steam or heat) for heating, cooling or process purposes, or producing electricity, or the firing of fuel in a boiler or process heater for any purpose after a shutdown event. Startup ends four hours after when the boiler or process heater supplies useful thermal energy (such as heat or steam) for heating, cooling, or process purposes, or generates electricity, whichever is earlier.

Steam output means:

(1) For a boiler that produces steam for process or heating only (no power generation), the energy content in terms of MMBtu of the boiler steam output,

(2) For a boiler that cogenerates process steam and electricity (also known as combined heat and power), the total energy output, which is the sum of the energy content of the steam exiting the turbine and sent to process in MMBtu and the energy of the electricity generated converted to MMBtu at a rate of 10,000 Btu per kilowatt-hour generated (10 MMBtu per megawatt-hour), and

(3) For a boiler that generates only electricity, the alternate output-based emission limits would be the appropriate emission limit from Table 1 or 2 of this subpart in units of pounds per million Btu heat input (lb per MWh).

(4) For a boiler that performs multiple functions and produces steam to be used for any combination of paragraphs (1), (2), and (3) of this definition that includes electricity generation of paragraph (3) of this definition, the total energy output, in terms of MMBtu of steam output, is the sum of the energy content of steam sent directly to the process and/or used for heating (S_1), the energy content of turbine steam sent to process plus energy in electricity according to paragraph (2) of this definition (S_2), and the energy content of electricity generated by a electricity only turbine as paragraph (3) of this definition ($MW_{(3)}$) and would be calculated using Equation 21 of this section. In the case of boilers supplying steam to one or more common heaters, S_1, S_2, and $MW_{(3)}$ for each boiler would be calculated based on the its (steam energy) contribution (fraction of total steam energy) to the common heater.

$$SO_M = S_1 + S_2 + (MW_{(3)}\ x\ CFn) \qquad \text{(Eq. 21)}$$

Where:

SO_M = Total steam output for multi-function boiler, MMBtu

S_1 = Energy content of steam sent directly to the process and/or used for heating, MMBtu

S_2 = Energy content of turbine steam sent to the process plus energy in electricity according to (2) above, MMBtu

$MW_{(3)}$ = Electricity generated according to paragraph (3) of this definition, MWh

CFn = Conversion factor for the appropriate subcategory for converting electricity generated according to paragraph (3) of this definition to equivalent steam energy, MMBtu/MWh

CFn for emission limits for boilers in the unit designed to burn solid fuel subcategory = 10.8

CFn PM and CO emission limits for boilers in one of the subcategories of units designed to burn coal = 11.7

CFn PM and CO emission limits for boilers in one of the subcategories of units designed to burn biomass = 12.1

CFn for emission limits for boilers in one of the subcategories of units designed to burn liquid fuel = 11.2

CFn for emission limits for boilers in the unit designed to burn gas 2 (other) subcategory = 6.2

Stoker means a unit consisting of a mechanically operated fuel feeding mechanism, a stationary or moving grate to support the burning of fuel and admit under-grate air to the fuel, an overfire air system to complete combustion, and an ash discharge system. This definition of stoker includes air swept stokers. There are two general types of stokers: Underfeed and overfeed. Overfeed stokers include mass feed and spreader stokers. Fluidized bed, dutch oven, pile burner, hybrid suspension grate, suspension burners, and fuel cells are not considered to be a stoker design.

Stoker/sloped grate/other unit designed to burn kiln dried biomass means the unit is in the units designed to burn biomass/bio-based solid subcategory that is either a stoker, sloped grate, or other combustor design and is not in the stoker/sloped grate/other units designed to burn wet biomass subcategory.

Stoker/sloped grate/other unit designed to burn wet biomass means the unit is in the units designed to burn biomass/bio-based solid subcategory that is either a stoker, sloped grate, or other combustor design and any of the biomass/bio-based solid fuel combusted in the unit exceeds 20 percent moisture on an annual heat input basis.

Suspension burner means a unit designed to fire dry biomass/biobased solid particles in suspension that are conveyed in an airstream to the furnace like pulverized coal. The combustion of the fuel material is completed on a grate or floor below. The biomass/biobased fuel combusted in the unit shall not exceed 20 percent moisture on an annual heat input basis. Fluidized bed, dutch oven, pile burner, and hybrid suspension grate units are not part of the suspension burner subcategory.

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

(1) The equipment is attached to a foundation.

(2) The boiler or process heater 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 or process heater that replaces a temporary boiler or process heater at a location and performs the same or similar function will be included in calculating the consecutive time period.

(3) The equipment is located at a seasonal facility and operates during the full annual operating period of the seasonal facility, remains at the facility for at least 2 years, and operates at that facility for at least 3 months each year.

(4) The equipment is moved from one location to another within the facility but continues to perform the same or similar function and serve the same electricity, process heat, steam, and/or hot water system in an attempt to circumvent the residence time requirements of this definition.

Total selected metals (TSM) means the sum of the following metallic hazardous air pollutants: arsenic, beryllium, cadmium, chromium, lead, manganese, nickel and selenium.

Traditional fuel means the fuel as defined in §241.2 of this chapter.

Tune-up means adjustments made to a boiler or process heater in accordance with the procedures outlined in §63.7540(a)(10).

Ultra low sulfur liquid fuel means a distillate oil that has less than or equal to 15 ppm sulfur.

Unit designed to burn biomass/bio-based solid subcategory includes any boiler or process heater that burns at least 10 percent biomass or bio-based solids on an annual heat input basis in combination with solid fossil fuels, liquid fuels, or gaseous fuels.

Unit designed to burn coal/solid fossil fuel subcategory includes any boiler or process heater that burns any coal or other solid fossil fuel alone or at least 10 percent coal or other solid fossil fuel on an annual heat input basis in combination with liquid fuels, gaseous fuels, or less than 10 percent biomass and bio-based solids on an annual heat input basis.

Unit designed to burn gas 1 subcategory includes any boiler or process heater that burns only natural gas, refinery gas, and/or other gas 1 fuels. Gaseous fuel boilers and process heaters that burn liquid fuel for periodic testing of liquid fuel, maintenance, or operator training, not to exceed a combined total of 48 hours during any calendar year, are included in this definition. Gaseous fuel boilers and process heaters that burn liquid fuel during periods of gas curtailment or gas supply interruptions of any duration are also included in this definition.

Unit designed to burn gas 2 (other) subcategory includes any boiler or process heater that is not in the unit designed to burn gas 1 subcategory and burns any gaseous fuels either alone or in combination with less than 10 percent coal/solid fossil fuel, and less than 10 percent biomass/bio-based solid fuel on an annual heat input basis, and no liquid fuels. Gaseous fuel boilers and process heaters that are not in the unit designed to burn gas 1 subcategory and that burn liquid fuel for periodic testing of liquid fuel, maintenance, or operator training, not to exceed a combined total of 48 hours during any calendar year, are included in this definition. Gaseous fuel boilers and process heaters that are not in the unit designed to burn gas 1 subcategory and that burn liquid fuel during periods of gas curtailment or gas supply interruption of any duration are also included in this definition.

Unit designed to burn heavy liquid subcategory means a unit in the unit designed to burn liquid subcategory where at least 10 percent of the heat input from liquid fuels on an annual heat input basis comes from heavy liquids.

Unit designed to burn light liquid subcategory means a unit in the unit designed to burn liquid subcategory that is not part of the unit designed to burn heavy liquid subcategory.

Unit designed to burn liquid subcategory includes any boiler or process heater that burns any liquid fuel, but less than 10 percent coal/solid fossil fuel and less than 10 percent biomass/bio-based solid fuel on an annual heat input basis, either alone or in combination with gaseous fuels. Units in the unit design to burn gas 1 or unit designed to burn gas 2 (other) subcategories that burn liquid fuel for periodic testing of liquid fuel, maintenance, or operator training, not to exceed a combined total of 48 hours during any calendar year are not included in this definition. Units in the unit design to burn gas 1 or unit designed to burn gas 2 (other) subcategories during periods of gas curtailment or gas supply interruption of any duration are also not included in this definition.

Unit designed to burn liquid fuel that is a non-continental unit means an industrial, commercial, or institutional boiler or process heater meeting the definition of the unit designed to burn liquid subcategory located in the State of Hawaii, the Virgin Islands, Guam, American Samoa, the Commonwealth of Puerto Rico, or the Northern Mariana Islands.

Unit designed to burn solid fuel subcategory means any boiler or process heater that burns only solid fuels or at least 10 percent solid fuel on an annual heat input basis in combination with liquid fuels or gaseous fuels.

Useful thermal energy means energy (*i.e.,* steam, hot water, or process heat) that meets the minimum operating temperature, flow, and/or pressure required by any energy use system that uses energy provided by the affected boiler or process heater.

Vegetable oil means oils extracted from vegetation.

Voluntary Consensus Standards or VCS mean technical standards (*e.g.,* materials specifications, test methods, sampling procedures, business practices) developed or adopted by one or more voluntary consensus bodies. EPA/Office of Air Quality Planning and Standards, by precedent, has only used VCS that are written in English. Examples of VCS bodies are: American Society of Testing and Materials (ASTM 100 Barr Harbor Drive, P.O. Box CB700, West Conshohocken, Pennsylvania 19428-B2959, (800) 262-1373, *http://www.astm.org*), American Society of Mechanical Engineers (ASME ASME, Three Park Avenue, New York, NY 10016-5990, (800) 843-2763, *http://www.asme.org*), International Standards Organization (ISO 1, ch. de la Voie-Creuse, Case postale 56, CH-1211

Geneva 20, Switzerland, + 41 22 749 01 11, *http://www.iso.org/iso/home.htm*), Standards Australia (AS Level 10, The Exchange Centre, 20 Bridge Street, Sydney, GPO Box 476, Sydney NSW 2001, + 61 2 9237 6171 *http://www.stadards.org.au*), British Standards Institution (BSI, 389 Chiswick High Road, London, W4 4AL, United Kingdom, + 44 (0)20 8996 9001, *http://www.bsigroup.com*), Canadian Standards Association (CSA 5060 Spectrum Way, Suite 100, Mississauga, Ontario L4W 5N6, Canada, 800-463-6727, *http://www.csa.ca*), European Committee for Standardization (CEN CENELEC Management Centre Avenue Marnix 17 B-1000 Brussels, Belgium + 32 2 550 08 11, *http://www.cen.eu/cen*), and German Engineering Standards (VDI VDI Guidelines Department, P.O. Box 10 11 39 40002, Duesseldorf, Germany, + 49 211 6214-230, *http://www.vdi.eu*). The types of standards that are not considered VCS are standards developed by: The United States, *e.g.,* California (CARB) and Texas (TCEQ); industry groups, such as American Petroleum Institute (API), Gas Processors Association (GPA), and Gas Research Institute (GRI); and other branches of the U.S. government, *e.g.,* Department of Defense (DOD) and Department of Transportation (DOT). This does not preclude EPA from using standards developed by groups that are not VCS bodies within their rule. When this occurs, EPA has done searches and reviews for VCS equivalent to these non-EPA methods.

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

Waste heat process heater means an enclosed device that recovers normally unused energy (i.e., hot exhaust gas) and converts it to usable heat. Waste heat process heaters are also referred to as recuperative process heaters. This definition includes both fired and unfired waste heat process heaters.

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

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

[78 FR 15664, Mar. 21, 2011, as amended at 78 FR 7163, Jan. 31, 2013; 80 FR 72817, Nov. 20, 2015]

Table 1 to Subpart DDDDD of Part 63—Emission Limits for New or Reconstructed Boilers and Process Heaters

As stated in §63.7500, you must comply with the following applicable emission limits:

[Units with heat input capacity of 10 million Btu per hour or greater]

If your boiler or process heater is in this subcategory . . .	For the following pollutants . . .	The emissions must not exceed the following emission limits, except during startup and shutdown . . .	Or the emissions must not exceed the following alternative output-based limits, except during startup and shutdown . . .	Using this specified sampling volume or test run duration . . .
1. Units in all subcategories designed to burn solid fuel.	a. HCl	2.2E-02 lb per MMBtu of heat input	2.5E-02 lb per MMBtu of steam output or 0.28 lb per MWh	For M26A, collect a minimum of 1 dscm per run; for M26 collect a minimum of 120 liters per run.

If your boiler or process heater is in this subcategory . . .	For the following pollutants . . .	The emissions must not exceed the following emission limits, except during startup and shutdown . . .	Or the emissions must not exceed the following alternative output-based limits, except during startup and shutdown . . .	Using this specified sampling volume or test run duration . . .
	b. Mercury	8.0E-07[a] lb per MMBtu of heat input	8.7E-07[a] lb per MMBtu of steam output or 1.1E-05[a] lb per MWh	For M29, collect a minimum of 4 dscm per run; for M30A or M30B, collect a minimum sample as specified in the method; for ASTM D6784[b] collect a minimum of 4 dscm.
2. Units designed to burn coal/solid fossil fuel	a. Filterable PM (or TSM)	1.1E-03 lb per MMBtu of heat input; or (2.3E-05 lb per MMBtu of heat input)	1.1E-03 lb per MMBtu of steam output or 1.4E-02 lb per MWh; or (2.7E-05 lb per MMBtu of steam output or 2.9E-04 lb per MWh)	Collect a minimum of 3 dscm per run.
3. Pulverized coal boilers designed to burn coal/solid fossil fuel	a. Carbon monoxide (CO) (or CEMS)	130 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (320 ppm by volume on a dry basis corrected to 3 percent oxygen,[d] 30-day rolling average)	0.11 lb per MMBtu of steam output or 1.4 lb per MWh; 3-run average	1 hr minimum sampling time.
4. Stokers/others designed to burn coal/solid fossil fuel	a. CO (or CEMS)	130 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (340 ppm by volume on a dry basis corrected to 3 percent oxygen,[d] 30-day rolling average)	0.12 lb per MMBtu of steam output or 1.4 lb per MWh; 3-run average	1 hr minimum sampling time.
5. Fluidized bed units designed to burn coal/solid fossil fuel	a. CO (or CEMS)	130 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (230 ppm by volume on a dry basis corrected to 3 percent oxygen,[d] 30-day rolling average)	0.11 lb per MMBtu of steam output or 1.4 lb per MWh; 3-run average	1 hr minimum sampling time.
6. Fluidized bed units with an integrated heat exchanger designed to burn coal/solid fossil fuel	a. CO (or CEMS)	140 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (150 ppm by volume on a dry basis corrected to 3 percent oxygen,[d] 30-day rolling average)	1.2E-01 lb per MMBtu of steam output or 1.5 lb per MWh; 3-run average	1 hr minimum sampling time.
7. Stokers/sloped grate/others designed to burn wet biomass fuel	a. CO (or CEMS)	620 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (390 ppm by volume on a dry basis corrected to 3 percent oxygen,[d] 30-day rolling average)	5.8E-01 lb per MMBtu of steam output or 6.8 lb per MWh; 3-run average	1 hr minimum sampling time.

If your boiler or process heater is in this subcategory . . .	For the following pollutants . . .	The emissions must not exceed the following emission limits, except during startup and shutdown . . .	Or the emissions must not exceed the following alternative output-based limits, except during startup and shutdown . . .	Using this specified sampling volume or test run duration . . .
	b. Filterable PM (or TSM)	3.0E-02 lb per MMBtu of heat input; or (2.6E-05 lb per MMBtu of heat input)	3.5E-02 lb per MMBtu of steam output or 4.2E-01 lb per MWh; or (2.7E-05 lb per MMBtu of steam output or 3.7E-04 lb per MWh)	Collect a minimum of 2 dscm per run.
8. Stokers/sloped grate/others designed to burn kiln-dried biomass fuel	a. CO	460 ppm by volume on a dry basis corrected to 3 percent oxygen	4.2E-01 lb per MMBtu of steam output or 5.1 lb per MWh	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	3.0E-02 lb per MMBtu of heat input; or (4.0E-03 lb per MMBtu of heat input)	3.5E-02 lb per MMBtu of steam output or 4.2E-01 lb per MWh; or (4.2E-03 lb per MMBtu of steam output or 5.6E-02 lb per MWh)	Collect a minimum of 2 dscm per run.
9. Fluidized bed units designed to burn biomass/bio-based solids	a. CO (or CEMS)	230 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (310 ppm by volume on a dry basis corrected to 3 percent oxygen,[d] 30-day rolling average)	2.2E-01 lb per MMBtu of steam output or 2.6 lb per MWh; 3-run average	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	9.8E-03 lb per MMBtu of heat input; or (8.3E-05[a] lb per MMBtu of heat input)	1.2E-02 lb per MMBtu of steam output or 0.14 lb per MWh; or (1.1E-04[a] lb per MMBtu of steam output or 1.2E-03[a] lb per MWh)	Collect a minimum of 3 dscm per run.
10. Suspension burners designed to burn biomass/bio-based solids	a. CO (or CEMS)	2,400 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (2,000 ppm by volume on a dry basis corrected to 3 percent oxygen,[d] 10-day rolling average)	1.9 lb per MMBtu of steam output or 27 lb per MWh; 3-run average	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	3.0E-02 lb per MMBtu of heat input; or (6.5E-03 lb per MMBtu of heat input)	3.1E-02 lb per MMBtu of steam output or 4.2E-01 lb per MWh; or (6.6E-03 lb per MMBtu of steam output or 9.1E-02 lb per MWh)	Collect a minimum of 2 dscm per run.

If your boiler or process heater is in this subcategory . . .	For the following pollutants . . .	The emissions must not exceed the following emission limits, except during startup and shutdown . . .	Or the emissions must not exceed the following alternative output-based limits, except during startup and shutdown . . .	Using this specified sampling volume or test run duration . . .
11. Dutch Ovens/Pile burners designed to burn biomass/bio-based solids	a. CO (or CEMS)	330 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (520 ppm by volume on a dry basis corrected to 3 percent oxygen,[d] 10-day rolling average)	3.5E-01 lb per MMBtu of steam output or 3.6 lb per MWh; 3-run average	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	3.2E-03 lb per MMBtu of heat input; or (3.9E-05 lb per MMBtu of heat input)	4.3E-03 lb per MMBtu of steam output or 4.5E-02 lb per MWh; or (5.2E-05 lb per MMBtu of steam output or 5.5E-04 lb per MWh)	Collect a minimum of 3 dscm per run.
12. Fuel cell units designed to burn biomass/bio-based solids	a. CO	910 ppm by volume on a dry basis corrected to 3 percent oxygen	1.1 lb per MMBtu of steam output or 1.0E + 01 lb per MWh	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	2.0E-02 lb per MMBtu of heat input; or (2.9E-05[a] lb per MMBtu of heat input)	3.0E-02 lb per MMBtu of steam output or 2.8E-01 lb per MWh; or (5.1E-05 lb per MMBtu of steam output or 4.1E-04 lb per MWh)	Collect a minimum of 2 dscm per run.
13. Hybrid suspension grate boiler designed to burn biomass/bio-based solids	a. CO (or CEMS)	1,100 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (900 ppm by volume on a dry basis corrected to 3 percent oxygen,[d] 30-day rolling average)	1.4 lb per MMBtu of steam output or 12 lb per MWh; 3-run average	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	2.6E-02 lb per MMBtu of heat input; or (4.4E-04 lb per MMBtu of heat input)	3.3E-02 lb per MMBtu of steam output or 3.7E-01 lb per MWh; or (5.5E-04 lb per MMBtu of steam output or 6.2E-03 lb per MWh)	Collect a minimum of 3 dscm per run.
14. Units designed to burn liquid fuel	a. HCl	4.4E-04 lb per MMBtu of heat input	4.8E-04 lb per MMBtu of steam output or 6.1E-03 lb per MWh	For M26A: Collect a minimum of 2 dscm per run; for M26, collect a minimum of 240 liters per run.

If your boiler or process heater is in this subcategory . . .	For the following pollutants . . .	The emissions must not exceed the following emission limits, except during startup and shutdown . . .	Or the emissions must not exceed the following alternative output-based limits, except during startup and shutdown . . .	Using this specified sampling volume or test run duration . . .
	b. Mercury	4.8E-07[a] lb per MMBtu of heat input	5.3E-07[a] lb per MMBtu of steam output or 6.7E-06[a] lb per MWh	For M29, collect a minimum of 4 dscm per run; for M30A or M30B, collect a minimum sample as specified in the method; for ASTM D6784[b] collect a minimum of 4 dscm.
15. Units designed to burn heavy liquid fuel	a. CO	130 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average	0.13 lb per MMBtu of steam output or 1.4 lb per MWh; 3-run average	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	1.3E-02 lb per MMBtu of heat input; or (7.5E-05 lb per MMBtu of heat input)	1.5E-02 lb per MMBtu of steam output or 1.8E-01 lb per MWh; or (8.2E-05 lb per MMBtu of steam output or 1.1E-03 lb per MWh)	Collect a minimum of 3 dscm per run.
16. Units designed to burn light liquid fuel	a. CO	130 ppm by volume on a dry basis corrected to 3 percent oxygen	0.13 lb per MMBtu of steam output or 1.4 lb per MWh	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	1.1E-03[a] lb per MMBtu of heat input; or (2.9E-05 lb per MMBtu of heat input)	1.2E-03[a] lb per MMBtu of steam output or 1.6E-02[a] lb per MWh; or (3.2E-05 lb per MMBtu of steam output or 4.0E-04 lb per MWh)	Collect a minimum of 3 dscm per run.
17. Units designed to burn liquid fuel that are non-continental units	a. CO	130 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average based on stack test	0.13 lb per MMBtu of steam output or 1.4 lb per MWh; 3-run average	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	2.3E-02 lb per MMBtu of heat input; or (8.6E-04 lb per MMBtu of heat input)	2.5E-02 lb per MMBtu of steam output or 3.2E-01 lb per MWh; or (9.4E-04 lb per MMBtu of steam output or 1.2E-02 lb per MWh)	Collect a minimum of 4 dscm per run.
18. Units designed to burn gas 2 (other) gases	a. CO	130 ppm by volume on a dry basis corrected to 3 percent oxygen	0.16 lb per MMBtu of steam output or 1.0 lb per MWh	1 hr minimum sampling time.
	b. HCl	1.7E-03 lb per MMBtu of heat input	2.9E-03 lb per MMBtu of steam output or 1.8E-02 lb per MWh	For M26A, Collect a minimum of 2 dscm per run; for M26, collect a minimum of 240 liters per run.

If your boiler or process heater is in this subcategory . . .	For the following pollutants . . .	The emissions must not exceed the following emission limits, except during startup and shutdown . . .	Or the emissions must not exceed the following alternative output-based limits, except during startup and shutdown . . .	Using this specified sampling volume or test run duration . . .
	c. Mercury	7.9E-06 lb per MMBtu of heat input	1.4E-05 lb per MMBtu of steam output or 8.3E-05 lb per MWh	For M29, collect a minimum of 3 dscm per run; for M30A or M30B, collect a minimum sample as specified in the method; for ASTM D6784[b] collect a minimum of 3 dscm.
	d. Filterable PM (or TSM)	6.7E-03 lb per MMBtu of heat input; or (2.1E-04 lb per MMBtu of heat input)	1.2E-02 lb per MMBtu of steam output or 7.0E-02 lb per MWh; or (3.5E-04 lb per MMBtu of steam output or 2.2E-03 lb per MWh)	Collect a minimum of 3 dscm per run.

[a]If you are conducting stack tests to demonstrate compliance and your performance tests for this pollutant for at least 2 consecutive years show that your emissions are at or below this limit, you can skip testing according to §63.7515 if all of the other provisions of §63.7515 are met. For all other pollutants that do not contain a footnote "a", your performance tests for this pollutant for at least 2 consecutive years must show that your emissions are at or below 75 percent of this limit in order to qualify for skip testing.

[b]Incorporated by reference, see §63.14.

[c]If your affected source is a new or reconstructed affected source that commenced construction or reconstruction after June 4, 2010, and before April 1, 2013, you may comply with the emission limits in Tables 11, 12 or 13 to this subpart until January 31, 2016. On and after January 31, 2016, you must comply with the emission limits in Table 1 to this subpart.

[d]An owner or operator may request an alternative test method under §63.7 of this chapter, in order that compliance with the carbon monoxide emissions limit be determined using carbon dioxide as a diluent correction in place of oxygen at 3%. EPA Method 19 F-factors and EPA Method 19 equations must be used to generate the appropriate CO_2 correction percentage for the fuel type burned in the unit, and must also take into account that the 3% oxygen correction is to be done on a dry basis. The alternative test method request must account for any CO_2 being added to, or removed from, the emissions gas stream as a result of limestone injection, scrubber media, etc.

[78 FR 7193, Jan. 31, 2013, as amended at 80 FR 72819, Nov. 20, 2015]

Table 2 to Subpart DDDDD of Part 63—Emission Limits for Existing Boilers and Process Heaters

As stated in §63.7500, you must comply with the following applicable emission limits:

[Units with heat input capacity of 10 million Btu per hour or greater]

If your boiler or process heater is in this subcategory . . .	For the following pollutants . . .	The emissions must not exceed the following emission limits, except during startup and shutdown . . .	The emissions must not exceed the following alternative output-based limits, except during startup and shutdown . . .	Using this specified sampling volume or test run duration . . .
1. Units in all subcategories designed to burn solid fuel	a. HCl	2.2E-02 lb per MMBtu of heat input	2.5E-02 lb per MMBtu of steam output or 0.27 lb per MWh	For M26A, Collect a minimum of 1 dscm per run; for M26, collect a minimum of 120 liters per run.
	b. Mercury	5.7E-06 lb per MMBtu of heat input	6.4E-06 lb per MMBtu of steam output or 7.3E-05 lb per MWh	For M29, collect a minimum of 3 dscm per run; for M30A or M30B, collect a minimum sample as specified in the method; for ASTM D6784[b] collect a minimum of 3 dscm.
2. Units design to burn coal/solid fossil fuel	a. Filterable PM (or TSM)	4.0E-02 lb per MMBtu of heat input; or (5.3E-05 lb per MMBtu of heat input)	4.2E-02 lb per MMBtu of steam output or 4.9E-01 lb per MWh; or (5.6E-05 lb per MMBtu of steam output or 6.5E-04 lb per MWh)	Collect a minimum of 2 dscm per run.
3. Pulverized coal boilers designed to burn coal/solid fossil fuel	a. CO (or CEMS)	130 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (320 ppm by volume on a dry basis corrected to 3 percent oxygen,[c] 30-day rolling average)	0.11 lb per MMBtu of steam output or 1.4 lb per MWh; 3-run average	1 hr minimum sampling time.
4. Stokers/others designed to burn coal/solid fossil fuel	a. CO (or CEMS)	160 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (340 ppm by volume on a dry basis corrected to 3 percent oxygen,[c] 30-day rolling average)	0.14 lb per MMBtu of steam output or 1.7 lb per MWh; 3-run average	1 hr minimum sampling time.
5. Fluidized bed units designed to burn coal/solid fossil fuel	a. CO (or CEMS)	130 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (230 ppm by volume on a dry basis corrected to 3 percent oxygen,[c] 30-day rolling average)	0.12 lb per MMBtu of steam output or 1.4 lb per MWh; 3-run average	1 hr minimum sampling time.

If your boiler or process heater is in this subcategory . . .	**For the following pollutants . . .**	**The emissions must not exceed the following emission limits, except during startup and shutdown . . .**	**The emissions must not exceed the following alternative output-based limits, except during startup and shutdown . . .**	**Using this specified sampling volume or test run duration . . .**
6. Fluidized bed units with an integrated heat exchanger designed to burn coal/solid fossil fuel	a. CO (or CEMS)	140 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (150 ppm by volume on a dry basis corrected to 3 percent oxygen,[c] 30-day rolling average)	1.3E-01 lb per MMBtu of steam output or 1.5 lb per MWh; 3-run average	1 hr minimum sampling time.
7. Stokers/sloped grate/others designed to burn wet biomass fuel	a. CO (or CEMS)	1,500 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (720 ppm by volume on a dry basis corrected to 3 percent oxygen,[c] 30-day rolling average)	1.4 lb per MMBtu of steam output or 17 lb per MWh; 3-run average	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	3.7E-02 lb per MMBtu of heat input; or (2.4E-04 lb per MMBtu of heat input)	4.3E-02 lb per MMBtu of steam output or 5.2E-01 lb per MWh; or (2.8E-04 lb per MMBtu of steam output or 3.4E-04 lb per MWh)	Collect a minimum of 2 dscm per run.
8. Stokers/sloped grate/others designed to burn kiln-dried biomass fuel	a. CO	460 ppm by volume on a dry basis corrected to 3 percent oxygen	4.2E-01 lb per MMBtu of steam output or 5.1 lb per MWh	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	3.2E-01 lb per MMBtu of heat input; or (4.0E-03 lb per MMBtu of heat input)	3.7E-01 lb per MMBtu of steam output or 4.5 lb per MWh; or (4.6E-03 lb per MMBtu of steam output or 5.6E-02 lb per MWh)	Collect a minimum of 1 dscm per run.
9. Fluidized bed units designed to burn biomass/bio-based solid	a. CO (or CEMS)	470 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (310 ppm by volume on a dry basis corrected to 3 percent oxygen,[c] 30-day rolling average)	4.6E-01 lb per MMBtu of steam output or 5.2 lb per MWh; 3-run average	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	1.1E-01 lb per MMBtu of heat input; or (1.2E-03 lb per MMBtu of heat input)	1.4E-01 lb per MMBtu of steam output or 1.6 lb per MWh; or (1.5E-03 lb per MMBtu of steam output or 1.7E-02 lb per MWh)	Collect a minimum of 1 dscm per run.

If your boiler or process heater is in this subcategory . . .	For the following pollutants . . .	The emissions must not exceed the following emission limits, except during startup and shutdown . . .	The emissions must not exceed the following alternative output-based limits, except during startup and shutdown . . .	Using this specified sampling volume or test run duration . . .
10. Suspension burners designed to burn biomass/bio-based solid	a. CO (or CEMS)	2,400 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (2,000 ppm by volume on a dry basis corrected to 3 percent oxygen,[c] 10-day rolling average)	1.9 lb per MMBtu of steam output or 27 lb per MWh; 3-run average	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	5.1E-02 lb per MMBtu of heat input; or (6.5E-03 lb per MMBtu of heat input)	5.2E-02 lb per MMBtu of steam output or 7.1E-01 lb per MWh; or (6.6E-03 lb per MMBtu of steam output or 9.1E-02 lb per MWh)	Collect a minimum of 2 dscm per run.
11. Dutch Ovens/Pile burners designed to burn biomass/bio-based solid	a. CO (or CEMS)	770 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (520 ppm by volume on a dry basis corrected to 3 percent oxygen,[c] 10-day rolling average)	8.4E-01 lb per MMBtu of steam output or 8.4 lb per MWh; 3-run average	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	2.8E-01 lb per MMBtu of heat input; or (2.0E-03 lb per MMBtu of heat input)	3.9E-01 lb per MMBtu of steam output or 3.9 lb per MWh; or (2.8E-03 lb per MMBtu of steam output or 2.8E-02 lb per MWh)	Collect a minimum of 1 dscm per run.
12. Fuel cell units designed to burn biomass/bio-based solid	a. CO	1,100 ppm by volume on a dry basis corrected to 3 percent oxygen	2.4 lb per MMBtu of steam output or 12 lb per MWh	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	2.0E-02 lb per MMBtu of heat input; or (5.8E-03 lb per MMBtu of heat input)	5.5E-02 lb per MMBtu of steam output or 2.8E-01 lb per MWh; or (1.6E-02 lb per MMBtu of steam output or 8.1E-02 lb per MWh)	Collect a minimum of 2 dscm per run.
13. Hybrid suspension grate units designed to burn biomass/bio-based solid	a. CO (or CEMS)	3,500 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (900 ppm by volume on a dry basis corrected to 3 percent oxygen,[c] 30-day rolling average)	3.5 lb per MMBtu of steam output or 39 lb per MWh; 3-run average	1 hr minimum sampling time.

If your boiler or process heater is in this subcategory . . .	For the following pollutants . . .	The emissions must not exceed the following emission limits, except during startup and shutdown . . .	The emissions must not exceed the following alternative output-based limits, except during startup and shutdown . . .	Using this specified sampling volume or test run duration . . .
	b. Filterable PM (or TSM)	4.4E-01 lb per MMBtu of heat input; or (4.5E-04 lb per MMBtu of heat input)	5.5E-01 lb per MMBtu of steam output or 6.2 lb per MWh; or (5.7E-04 lb per MMBtu of steam output or 6.3E-03 lb per MWh)	Collect a minimum of 1 dscm per run.
14. Units designed to burn liquid fuel	a. HCl	1.1E-03 lb per MMBtu of heat input	1.4E-03 lb per MMBtu of steam output or 1.6E-02 lb per MWh	For M26A, collect a minimum of 2 dscm per run; for M26, collect a minimum of 240 liters per run.
	b. Mercury	2.0E-06[a] lb per MMBtu of heat input	2.5E-06[a] lb per MMBtu of steam output or 2.8E-05 lb per MWh	For M29, collect a minimum of 3 dscm per run; for M30A or M30B collect a minimum sample as specified in the method, for ASTM D6784,[b] collect a minimum of 2 dscm.
15. Units designed to burn heavy liquid fuel	a. CO	130 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average	0.13 lb per MMBtu of steam output or 1.4 lb per MWh; 3-run average	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	6.2E-02 lb per MMBtu of heat input; or (2.0E-04 lb per MMBtu of heat input)	7.5E-02 lb per MMBtu of steam output or 8.6E-01 lb per MWh; or (2.5E-04 lb per MMBtu of steam output or 2.8E-03 lb per MWh)	Collect a minimum of 1 dscm per run.
16. Units designed to burn light liquid fuel	a. CO	130 ppm by volume on a dry basis corrected to 3 percent oxygen	0.13 lb per MMBtu of steam output or 1.4 lb per MWh	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	7.9E-03[a] lb per MMBtu of heat input; or (6.2E-05 lb per MMBtu of heat input)	9.6E-03[a] lb per MMBtu of steam output or 1.1E-01[a] lb per MWh; or (7.5E-05 lb per MMBtu of steam output or 8.6E-04 lb per MWh)	Collect a minimum of 3 dscm per run.
17. Units designed to burn liquid fuel that are non-continental units	a. CO	130 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average based on stack test	0.13 lb per MMBtu of steam output or 1.4 lb per MWh; 3-run average	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	2.7E-01 lb per MMBtu of heat input; or (8.6E-04 lb per MMBtu of heat input)	3.3E-01 lb per MMBtu of steam output or 3.8 lb per MWh; or (1.1E-03 lb per MMBtu of steam output or 1.2E-02 lb per MWh)	Collect a minimum of 2 dscm per run.

If your boiler or process heater is in this subcategory . . .	For the following pollutants . . .	The emissions must not exceed the following emission limits, except during startup and shutdown . . .	The emissions must not exceed the following alternative output-based limits, except during startup and shutdown . . .	Using this specified sampling volume or test run duration . . .
18. Units designed to burn gas 2 (other) gases	a. CO	130 ppm by volume on a dry basis corrected to 3 percent oxygen	0.16 lb per MMBtu of steam output or 1.0 lb per MWh	1 hr minimum sampling time.
	b. HCl	1.7E-03 lb per MMBtu of heat input	2.9E-03 lb per MMBtu of steam output or 1.8E-02 lb per MWh	For M26A, collect a minimum of 2 dscm per run; for M26, collect a minimum of 240 liters per run.
	c. Mercury	7.9E-06 lb per MMBtu of heat input	1.4E-05 lb per MMBtu of steam output or 8.3E-05 lb per MWh	For M29, collect a minimum of 3 dscm per run; for M30A or M30B, collect a minimum sample as specified in the method; for ASTM D6784[b] collect a minimum of 2 dscm.
	d. Filterable PM (or TSM)	6.7E-03 lb per MMBtu of heat input or (2.1E-04 lb per MMBtu of heat input)	1.2E-02 lb per MMBtu of steam output or 7.0E-02 lb per MWh; or (3.5E-04 lb per MMBtu of steam output or 2.2E-03 lb per MWh)	Collect a minimum of 3 dscm per run.

[a]If you are conducting stack tests to demonstrate compliance and your performance tests for this pollutant for at least 2 consecutive years show that your emissions are at or below this limit, you can skip testing according to §63.7515 if all of the other provisions of §63.7515 are met. For all other pollutants that do not contain a footnote a, your performance tests for this pollutant for at least 2 consecutive years must show that your emissions are at or below 75 percent of this limit in order to qualify for skip testing.

[b]Incorporated by reference, see §63.14.

[c]An owner or operator may request an alternative test method under §63.7 of this chapter, in order that compliance with the carbon monoxide emissions limit be determined using carbon dioxide as a diluent correction in place of oxygen at 3%. EPA Method 19 F-factors and EPA Method 19 equations must be used to generate the appropriate CO_2 correction percentage for the fuel type burned in the unit, and must also take into account that the 3% oxygen correction is to be done on a dry basis. The alternative test method request must account for any CO_2 being added to, or removed from, the emissions gas stream as a result of limestone injection, scrubber media, etc.

[78 FR 7195, Jan. 31, 2013, as amended at 80 FR 72821, Nov. 20, 2015]

Table 3 to Subpart DDDDD of Part 63—Work Practice Standards

As stated in §63.7500, you must comply with the following applicable work practice standards:

If your unit is . . .	You must meet the following . . .
1. A new or existing boiler or process heater with a continuous oxygen trim system that maintains an optimum air to fuel ratio, or a heat input capacity of less than or equal to 5 million Btu per hour in any of the following subcategories: unit designed to burn gas 1; unit designed to burn gas 2 (other); or unit designed to burn light liquid, or a limited use boiler or process heater	Conduct a tune-up of the boiler or process heater every 5 years as specified in §63.7540.
2. A new or existing boiler or process heater without a continuous oxygen trim system and with heat input capacity of less than 10 million Btu per hour in the unit designed to burn heavy liquid or unit designed to burn solid fuel subcategories; or a new or existing boiler or process heater with heat input capacity of less than 10 million Btu per hour, but greater than 5 million Btu per hour, in any of the following subcategories: unit designed to burn gas 1; unit designed to burn gas 2 (other); or unit designed to burn light liquid	Conduct a tune-up of the boiler or process heater biennially as specified in §63.7540.
3. A new or existing boiler or process heater without a continuous oxygen trim system and with heat input capacity of 10 million Btu per hour or greater	Conduct a tune-up of the boiler or process heater annually as specified in §63.7540. Units in either the Gas 1 or Metal Process Furnace subcategories will conduct this tune-up as a work practice for all regulated emissions under this subpart. Units in all other subcategories will conduct this tune-up as a work practice for dioxins/furans.
4. An existing boiler or process heater located at a major source facility, not including limited use units	Must have a one-time energy assessment performed by a qualified energy assessor. An energy assessment completed on or after January 1, 2008, that meets or is amended to meet the energy assessment requirements in this table, satisfies the energy assessment requirement. A facility that operated under an energy management program developed according to the ENERGY STAR guidelines for energy management or compatible with ISO 50001 for at least one year between January 1, 2008 and the compliance date specified in §63.7495 that includes the affected units also satisfies the energy assessment requirement. The energy assessment must include the following with extent of the evaluation for items a. to e. appropriate for the on-site technical hours listed in §63.7575:
	a. A visual inspection of the boiler or process heater system.
	b. An evaluation of operating characteristics of the boiler or process heater systems, specifications of energy using systems, operating and maintenance procedures, and unusual operating constraints.
	c. An inventory of major energy use systems consuming energy from affected boilers and process heaters and which are under the control of the boiler/process heater owner/operator.

If your unit is . . .	You must meet the following . . .
	d. A review of available architectural and engineering plans, facility operation and maintenance procedures and logs, and fuel usage.
	e. A review of the facility's energy management program and provide recommendations for improvements consistent with the definition of energy management program, if identified.
	f. A list of cost-effective energy conservation measures that are within the facility's control.
	g. A list of the energy savings potential of the energy conservation measures identified.
	h. A comprehensive report detailing the ways to improve efficiency, the cost of specific improvements, benefits, and the time frame for recouping those investments.
5. An existing or new boiler or process heater subject to emission limits in Table 1 or 2 or 11 through 13 to this subpart during startup	a. You must operate all CMS during startup. b. For startup of a boiler or process heater, you must use one or a combination of the following clean fuels: Natural gas, synthetic natural gas, propane, other Gas 1 fuels, distillate oil, syngas, ultra-low sulfur diesel, fuel oil-soaked rags, kerosene, hydrogen, paper, cardboard, refinery gas, liquefied petroleum gas, clean dry biomass, and any fuels meeting the appropriate HCl, mercury and TSM emission standards by fuel analysis. c. You have the option of complying using either of the following work practice standards. (1) If you choose to comply using definition (1) of “startup” in §63.7575, once you start firing fuels that are not clean fuels, you must vent emissions to the main stack(s) and engage all of the applicable control devices except limestone injection in fluidized bed combustion (FBC) boilers, dry scrubber, fabric filter, and selective catalytic reduction (SCR). You must start your limestone injection in FBC boilers, dry scrubber, fabric filter, and SCR systems as expeditiously as possible. Startup ends when steam or heat is supplied for any purpose, OR (2) If you choose to comply using definition (2) of “startup” in §63.7575, once you start to feed fuels that are not clean fuels, you must vent emissions to the main stack(s) and engage all of the applicable control devices so as to comply with the emission limits within 4 hours of start of supplying useful thermal energy. You must engage and operate PM control within one hour of first feeding fuels that are not clean fuels[a]. You must start all applicable control devices as expeditiously as possible, but, in any case, when necessary to comply with other standards applicable to the source by a permit limit or a rule other than this subpart that require operation of the control devices. You must develop and implement a written startup and shutdown plan, as specified in §63.7505(e). d. You must comply with all applicable emission limits at all times except during startup and shutdown periods at which time you must meet this work practice. You must collect monitoring data during periods of startup, as specified in §63.7535(b). You must keep records during periods of startup. You must provide reports concerning activities and periods of startup, as specified in §63.7555.

If your unit is . . .	You must meet the following . . .
6. An existing or new boiler or process heater subject to emission limits in Tables 1 or 2 or 11 through 13 to this subpart during shutdown	You must operate all CMS during shutdown. While firing fuels that are not clean fuels during shutdown, you must vent emissions to the main stack(s) and operate all applicable control devices, except limestone injection in FBC boilers, dry scrubber, fabric filter, and SCR but, in any case, when necessary to comply with other standards applicable to the source that require operation of the control device. If, in addition to the fuel used prior to initiation of shutdown, another fuel must be used to support the shutdown process, that additional fuel must be one or a combination of the following clean fuels: Natural gas, synthetic natural gas, propane, other Gas 1 fuels, distillate oil, syngas, ultra-low sulfur diesel, refinery gas, and liquefied petroleum gas. You must comply with all applicable emissions limits at all times except for startup or shutdown periods conforming with this work practice. You must collect monitoring data during periods of shutdown, as specified in §63.7535(b). You must keep records during periods of shutdown. You must provide reports concerning activities and periods of shutdown, as specified in §63.7555.

[a]As specified in §63.7555(d)(13), the source may request an alternative timeframe with the PM controls requirement to the permitting authority (state, local, or tribal agency) that has been delegated authority for this subpart by EPA. The source must provide evidence that (1) it is unable to safely engage and operate the PM control(s) to meet the "fuel firing + 1 hour" requirement and (2) the PM control device is appropriately designed and sized to meet the filterable PM emission limit. It is acknowledged that there may be another control device that has been installed other than ESP that provides additional PM control (*e.g.*, scrubber).

[78 FR 7198, Jan. 31, 2013, as amended at 80 FR 72823, Nov. 20, 2015]

Table 4 to Subpart DDDDD of Part 63—Operating Limits for Boilers and Process Heaters

As stated in §63.7500, you must comply with the applicable operating limits:

Table 4 to Subpart DDDDD of Part 63—Operating Limits for Boilers and Process Heaters

When complying with a Table 1, 2, 11, 12, or 13 numerical emission limit using . . .	You must meet these operating limits . . .
1. Wet PM scrubber control on a boiler or process heater not using a PM CPMS	Maintain the 30-day rolling average pressure drop and the 30-day rolling average liquid flow rate at or above the lowest one-hour average pressure drop and the lowest one-hour average liquid flow rate, respectively, measured during the performance test demonstrating compliance with the PM emission limitation according to §63.7530(b) and Table 7 to this subpart.
2. Wet acid gas (HCl) scrubber[a] control on a boiler or process heater not using a HCl CEMS	Maintain the 30-day rolling average effluent pH at or above the lowest one-hour average pH and the 30-day rolling average liquid flow rate at or above the lowest one-hour average liquid flow rate measured during the performance test demonstrating compliance with the HCl emission limitation according to §63.7530(b) and Table 7 to this subpart.
3. Fabric filter control on a boiler or process heater not using a PM CPMS	a. Maintain opacity to less than or equal to 10 percent opacity or the highest hourly average opacity reading measured during the performance test run demonstrating compliance with the PM (or TSM) emission limitation (daily block average); or

When complying with a Table 1, 2, 11, 12, or 13 numerical emission limit using . . .	You must meet these operating limits . . .
	b. Install and operate a bag leak detection system according to §63.7525 and operate the fabric filter such that the bag leak detection system alert is not activated more than 5 percent of the operating time during each 6-month period.
4. Electrostatic precipitator control on a boiler or process heater not using a PM CPMS	a. This option is for boilers and process heaters that operate dry control systems (*i.e.*, an ESP without a wet scrubber). Existing and new boilers and process heaters must maintain opacity to less than or equal to 10 percent opacity or the highest hourly average opacity reading measured during the performance test run demonstrating compliance with the PM (or TSM) emission limitation (daily block average).
	b. This option is only for boilers and process heaters not subject to PM CPMS or continuous compliance with an opacity limit (*i.e.*, dry ESP). Maintain the 30-day rolling average total secondary electric power input of the electrostatic precipitator at or above the operating limits established during the performance test according to §63.7530(b) and Table 7 to this subpart.
5. Dry scrubber or carbon injection control on a boiler or process heater not using a mercury CEMS	Maintain the minimum sorbent or carbon injection rate as defined in §63.7575 of this subpart.
6. Any other add-on air pollution control type on a boiler or process heater not using a PM CPMS	This option is for boilers and process heaters that operate dry control systems. Existing and new boilers and process heaters must maintain opacity to less than or equal to 10 percent opacity or the highest hourly average opacity reading measured during the performance test run demonstrating compliance with the PM (or TSM) emission limitation (daily block average).
7. Performance testing	For boilers and process heaters that demonstrate compliance with a performance test, maintain the 30-day rolling average operating load of each unit such that it does not exceed 110 percent of the highest hourly average operating load recorded during the performance test.
8. Oxygen analyzer system	For boilers and process heaters subject to a CO emission limit that demonstrate compliance with an O_2 analyzer system as specified in §63.7525(a), maintain the 30-day rolling average oxygen content at or above the lowest hourly average oxygen concentration measured during the CO performance test, as specified in Table 8. This requirement does not apply to units that install an oxygen trim system since these units will set the trim system to the level specified in §63.7525(a).
9. SO_2 CEMS	For boilers or process heaters subject to an HCl emission limit that demonstrate compliance with an SO_2 CEMS, maintain the 30-day rolling average SO_2 emission rate at or below the highest hourly average SO_2 concentration measured during the HCl performance test, as specified in Table 8.

[a]A wet acid gas scrubber is a control device that removes acid gases by contacting the combustion gas with an alkaline slurry or solution. Alkaline reagents include, but not limited to, lime, limestone and sodium.

[80 FR 72874, Nov. 20, 2015]

Table 5 to Subpart DDDDD of Part 63—Performance Testing Requirements

As stated in §63.7520, you must comply with the following requirements for performance testing for existing, new or reconstructed affected sources:

To conduct a performance test for the following pollutant . . .	You must. . .	Using, as appropriate . . .
1. Filterable PM	a. Select sampling ports location and the number of traverse points	Method 1 at 40 CFR part 60, appendix A-1 of this chapter.
	b. Determine velocity and volumetric flow-rate of the stack gas	Method 2, 2F, or 2G at 40 CFR part 60, appendix A-1 or A-2 to part 60 of this chapter.
	c. Determine oxygen or carbon dioxide concentration of the stack gas	Method 3A or 3B at 40 CFR part 60, appendix A-2 to part 60 of this chapter, or ANSI/ASME PTC 19.10-1981.[a]
	d. Measure the moisture content of the stack gas	Method 4 at 40 CFR part 60, appendix A-3 of this chapter.
	e. Measure the PM emission concentration	Method 5 or 17 (positive pressure fabric filters must use Method 5D) at 40 CFR part 60, appendix A-3 or A-6 of this chapter.
	f. Convert emissions concentration to lb per MMBtu emission rates	Method 19 F-factor methodology at 40 CFR part 60, appendix A-7 of this chapter.
2. TSM	a. Select sampling ports location and the number of traverse points	Method 1 at 40 CFR part 60, appendix A-1 of this chapter.
	b. Determine velocity and volumetric flow-rate of the stack gas	Method 2, 2F, or 2G at 40 CFR part 60, appendix A-1 or A-2 of this chapter.
	c. Determine oxygen or carbon dioxide concentration of the stack gas	Method 3A or 3B at 40 CFR part 60, appendix A-1 of this chapter, or ANSI/ASME PTC 19.10-1981.[a]
	d. Measure the moisture content of the stack gas	Method 4 at 40 CFR part 60, appendix A-3 of this chapter.
	e. Measure the TSM emission concentration	Method 29 at 40 CFR part 60, appendix A-8 of this chapter
	f. Convert emissions concentration to lb per MMBtu emission rates	Method 19 F-factor methodology at 40 CFR part 60, appendix A-7 of this chapter.
3. Hydrogen chloride	a. Select sampling ports location and the number of traverse points	Method 1 at 40 CFR part 60, appendix A-1 of this chapter.
	b. Determine velocity and volumetric flow-rate of the stack gas	Method 2, 2F, or 2G at 40 CFR part 60, appendix A-2 of this chapter.

To conduct a performance test for the following pollutant . . .	You must. . .	Using, as appropriate . . .
	c. Determine oxygen or carbon dioxide concentration of the stack gas	Method 3A or 3B at 40 CFR part 60, appendix A-2 of this chapter, or ANSI/ASME PTC 19.10-1981.[a]
	d. Measure the moisture content of the stack gas	Method 4 at 40 CFR part 60, appendix A-3 of this chapter.
	e. Measure the hydrogen chloride emission concentration	Method 26 or 26A (M26 or M26A) at 40 CFR part 60, appendix A-8 of this chapter.
	f. Convert emissions concentration to lb per MMBtu emission rates	Method 19 F-factor methodology at 40 CFR part 60, appendix A-7 of this chapter.
4. Mercury	a. Select sampling ports location and the number of traverse points	Method 1 at 40 CFR part 60, appendix A-1 of this chapter.
	b. Determine velocity and volumetric flow-rate of the stack gas	Method 2, 2F, or 2G at 40 CFR part 60, appendix A-1 or A-2 of this chapter.
	c. Determine oxygen or carbon dioxide concentration of the stack gas	Method 3A or 3B at 40 CFR part 60, appendix A-1 of this chapter, or ANSI/ASME PTC 19.10-1981.[a]
	d. Measure the moisture content of the stack gas	Method 4 at 40 CFR part 60, appendix A-3 of this chapter.
	e. Measure the mercury emission concentration	Method 29, 30A, or 30B (M29, M30A, or M30B) at 40 CFR part 60, appendix A-8 of this chapter or Method 101A at 40 CFR part 61, appendix B of this chapter, or ASTM Method D6784.[a]
	f. Convert emissions concentration to lb per MMBtu emission rates	Method 19 F-factor methodology at 40 CFR part 60, appendix A-7 of this chapter.
5. CO	a. Select the sampling ports location and the number of traverse points	Method 1 at 40 CFR part 60, appendix A-1 of this chapter.
	b. Determine oxygen concentration of the stack gas	Method 3A or 3B at 40 CFR part 60, appendix A-3 of this chapter, or ASTM D6522-00 (Reapproved 2005), or ANSI/ASME PTC 19.10-1981.[a]
	c. Measure the moisture content of the stack gas	Method 4 at 40 CFR part 60, appendix A-3 of this chapter.
	d. Measure the CO emission concentration	Method 10 at 40 CFR part 60, appendix A-4 of this chapter. Use a measurement span value of 2 times the concentration of the applicable emission limit.

[a]Incorporated by reference, see §63.14.

[76 FR 15664, Mar. 21, 2011, as amended at 78 FR 7200, Jan. 31, 2013; 80 FR 72825, Nov. 20, 2015]

Table 6 to Subpart DDDDD of Part 63—Fuel Analysis Requirements

As stated in §63.7521, you must comply with the following requirements for fuel analysis testing for existing, new or reconstructed affected sources. However, equivalent methods (as defined in §63.7575) may be used in lieu of the prescribed methods at the discretion of the source owner or operator:

To conduct a fuel analysis for the following pollutant . . .	You must . . .	Using . . .
1. Mercury	a. Collect fuel samples	Procedure in §63.7521(c) or ASTM D5192,[a] or ASTM D7430,[a] or ASTM D6883,[a] or ASTM D2234/D2234M[a] (for coal) or ASTM D6323[a] (for solid), or ASTM D4177[a] (for liquid), or ASTM D4057[a] (for liquid), or equivalent.
	b. Composite fuel samples	Procedure in §63.7521(d) or equivalent.
	c. Prepare composited fuel samples	EPA SW-846-3050B[a] (for solid samples), ASTM D2013/D2013M[a] (for coal), ASTM D5198[a] (for biomass), or EPA 3050[a] (for solid fuel), or EPA 821-R-01-013[a] (for liquid or solid), or equivalent.
	d. Determine heat content of the fuel type	ASTM D5865[a] (for coal) or ASTM E711[a] (for biomass), or ASTM D5864[a] for liquids and other solids, or ASTM D240[a] or equivalent.
	e. Determine moisture content of the fuel type	ASTM D3173,[a] ASTM E871,[a] or ASTM D5864,[a] or ASTM D240, or ASTM D95[a] (for liquid fuels), or ASTM D4006[a] (for liquid fuels), or equivalent.
	f. Measure mercury concentration in fuel sample	ASTM D6722[a] (for coal), EPA SW-846-7471B[a] or EPA 1631 or EPA 1631E (for solid samples), or EPA SW-846-7470A[a] (for liquid samples), or EPA 821-R-01-013 (for liquid or solid), or equivalent.
	g. Convert concentration into units of pounds of mercury per MMBtu of heat content	For fuel mixtures use Equation 8 in §63.7530.
2. HCl	a. Collect fuel samples	Procedure in §63.7521(c) or ASTM D5192,[a] or ASTM D7430,[a] or ASTM D6883,[a] or ASTM D2234/D2234M[a] (for coal) or ASTM D6323[a] (for coal or biomass), ASTM D4177[a] (for liquid fuels) or ASTM D4057[a] (for liquid fuels), or equivalent.
	b. Composite fuel samples	Procedure in §63.7521(d) or equivalent.
	c. Prepare composited fuel samples	EPA SW-846-3050B[a] (for solid samples), ASTM D2013/D2013M[a] (for coal), or ASTM D5198[a] (for biomass), or EPA 3050[a] or equivalent.
	d. Determine heat content of the fuel type	ASTM D5865[a] (for coal) or ASTM E711[a] (for biomass), ASTM D5864, ASTM D240[a] or equivalent.
	e. Determine moisture content of the fuel type	ASTM D3173[a] or ASTM E871,[a] or D5864,[a] or ASTM D240,[a] or ASTM D95[a] (for liquid fuels), or ASTM D4006[a] (for liquid fuels), or equivalent.
	f. Measure chlorine concentration in fuel sample	EPA SW-846-9250,[a] ASTM D6721,[a] ASTM D4208[a] (for coal), or EPA SW-846-5050[a] or ASTM E776[a] (for solid fuel), or EPA SW-846-9056[a] or SW-846-9076[a] (for solids or liquids) or equivalent.

To conduct a fuel analysis for the following pollutant . . .	**You must . . .**	**Using . . .**
	g. Convert concentrations into units of pounds of HCl per MMBtu of heat content	For fuel mixtures use Equation 7 in §63.7530 and convert from chlorine to HCl by multiplying by 1.028.
3. Mercury Fuel Specification for other gas 1 fuels	a. Measure mercury concentration in the fuel sample and convert to units of micrograms per cubic meter, or	Method 30B (M30B) at 40 CFR part 60, appendix A-8 of this chapter or ASTM D5954,[a] ASTM D6350,[a] ISO 6978-1:2003(E),[a] or ISO 6978-2:2003(E),[a] or EPA-1631[a] or equivalent.
	b. Measure mercury concentration in the exhaust gas when firing only the other gas 1 fuel is fired in the boiler or process heater	Method 29, 30A, or 30B (M29, M30A, or M30B) at 40 CFR part 60, appendix A-8 of this chapter or Method 101A or Method 102 at 40 CFR part 61, appendix B of this chapter, or ASTM Method D6784[a] or equivalent.
4. TSM	a. Collect fuel samples	Procedure in §63.7521(c) or ASTM D5192,[a] or ASTM D7430,[a] or ASTM D6883,[a] or ASTM D2234/D2234M[a] (for coal) or ASTM D6323[a] (for coal or biomass), or ASTM D4177,[a] (for liquid fuels) or ASTM D4057[a] (for liquid fuels), or equivalent.
	b. Composite fuel samples	Procedure in §63.7521(d) or equivalent.
	c. Prepare composited fuel samples	EPA SW-846-3050B[a] (for solid samples), ASTM D2013/D2013M[a] (for coal), ASTM D5198[a] or TAPPI T266[a] (for biomass), or EPA 3050[a] or equivalent.
	d. Determine heat content of the fuel type	ASTM D5865[a] (for coal) or ASTM E711[a] (for biomass), or ASTM D5864[a] for liquids and other solids, or ASTM D240[a] or equivalent.
	e. Determine moisture content of the fuel type	ASTM D3173[a] or ASTM E871,[a] or D5864, or ASTM D240,[a] or ASTM D95[a] (for liquid fuels), or ASTM D4006[a] (for liquid fuels), or ASTM D4177[a] (for liquid fuels) or ASTM D4057[a] (for liquid fuels), or equivalent.
	f. Measure TSM concentration in fuel sample	ASTM D3683,[a] or ASTM D4606,[a] or ASTM D6357[a] or EPA 200.8[a] or EPA SW-846-6020,[a] or EPA SW-846-6020A,[a] or EPA SW-846-6010C,[a] EPA 7060[a] or EPA 7060A[a] (for arsenic only), or EPA SW-846-7740[a] (for selenium only).
	g. Convert concentrations into units of pounds of TSM per MMBtu of heat content	For fuel mixtures use Equation 9 in §63.7530.

[a]Incorporated by reference, see §63.14.

[80 FR 72825, Nov. 20, 2015]

Table 7 to Subpart DDDDD of Part 63—Establishing Operating Limitsab

As stated in §63.7520, you must comply with the following requirements for establishing operating limits:

Table 7 to Subpart DDDDD of Part 63—Establishing Operating Limits[ab]

If you have an applicable emission limit for . . .	And your operating limits are based on . . .	You must . . .	Using . . .	According to the following requirements
1. PM, TSM, or mercury	a. Wet scrubber operating parameters	i. Establish a site-specific minimum scrubber pressure drop and minimum flow rate operating limit according to §63.7530(b)	(1) Data from the scrubber pressure drop and liquid flow rate monitors and the PM, TSM, or mercury performance test	(a) You must collect scrubber pressure drop and liquid flow rate data every 15 minutes during the entire period of the performance tests. (b) Determine the lowest hourly average scrubber pressure drop and liquid flow rate by computing the hourly averages using all of the 15-minute readings taken during each performance test.
	b. Electrostatic precipitator operating parameters (option only for units that operate wet scrubbers)	i. Establish a site-specific minimum total secondary electric power input according to §63.7530(b)	(1) Data from the voltage and secondary amperage monitors during the PM or mercury performance test	(a) You must collect secondary voltage and secondary amperage for each ESP cell and calculate total secondary electric power input data every 15 minutes during the entire period of the performance tests. (b) Determine the average total secondary electric power input by computing the hourly averages using all of the 15-minute readings taken during each performance test.
	c. Opacity	i. Establish a site-specific maximum opacity level	(1) Data from the opacity monitoring system during the PM performance test	(a) You must collect opacity readings every 15 minutes during the entire period of the performance tests. (b) Determine the average hourly opacity reading for each performance test run by computing the hourly averages using all of the 15-minute readings taken during each performance test run. (c) Determine the highest hourly average opacity reading measured during the test run demonstrating compliance with the PM (or TSM) emission limitation.

If you have an applicable emission limit for . . .	And your operating limits are based on . . .	You must . . .	Using . . .	According to the following requirements
2. HCl	a. Wet scrubber operating parameters	i. Establish site-specific minimum effluent pH and flow rate operating limits according to §63.7530(b)	(1) Data from the pH and liquid flow-rate monitors and the HCl performance test	(a) You must collect pH and liquid flow-rate data every 15 minutes during the entire period of the performance tests. (b) Determine the hourly average pH and liquid flow rate by computing the hourly averages using all of the 15-minute readings taken during each performance test.
	b. Dry scrubber operating parameters	i. Establish a site-specific minimum sorbent injection rate operating limit according to §63.7530(b). If different acid gas sorbents are used during the HCl performance test, the average value for each sorbent becomes the site-specific operating limit for that sorbent	(1) Data from the sorbent injection rate monitors and HCl or mercury performance test	(a) You must collect sorbent injection rate data every 15 minutes during the entire period of the performance tests. (b) Determine the hourly average sorbent injection rate by computing the hourly averages using all of the 15-minute readings taken during each performance test. (c) Determine the lowest hourly average of the three test run averages established during the performance test as your operating limit. When your unit operates at lower loads, multiply your sorbent injection rate by the load fraction, as defined in §63.7575, to determine the required injection rate.
	c. Alternative Maximum SO_2emission rate	i. Establish a site-specific maximum SO_2emission rate operating limit according to §63.7530(b)	(1) Data from SO_2 CEMS and the HCl performance test	(a) You must collect the SO_2 emissions data according to §63.7525(m) during the most recent HCl performance tests. (b) The maximum SO_2emission rate is equal to the highest hourly average SO_2emission rate measured during the most recent HCl performance tests.

If you have an applicable emission limit for . . .	And your operating limits are based on . . .	You must . . .	Using . . .	According to the following requirements
3. Mercury	a. Activated carbon injection	i. Establish a site-specific minimum activated carbon injection rate operating limit according to §63.7530(b)	(1) Data from the activated carbon rate monitors and mercury performance test	(a) You must collect activated carbon injection rate data every 15 minutes during the entire period of the performance tests. (b) Determine the hourly average activated carbon injection rate by computing the hourly averages using all of the 15-minute readings taken during each performance test. (c) Determine the lowest hourly average established during the performance test as your operating limit. When your unit operates at lower loads, multiply your activated carbon injection rate by the load fraction, as defined in §63.7575, to determine the required injection rate.
4. Carbon monoxide for which compliance is demonstrated by a performance test	a. Oxygen	i. Establish a unit-specific limit for minimum oxygen level according to §63.7530(b)	(1) Data from the oxygen analyzer system specified in §63.7525(a)	(a) You must collect oxygen data every 15 minutes during the entire period of the performance tests. (b) Determine the hourly average oxygen concentration by computing the hourly averages using all of the 15-minute readings taken during each performance test. (c) Determine the lowest hourly average established during the performance test as your minimum operating limit.
5. Any pollutant for which compliance is demonstrated by a performance test	a. Boiler or process heater operating load	i. Establish a unit specific limit for maximum operating load according to §63.7520(c)	(1) Data from the operating load monitors or from steam generation monitors	(a) You must collect operating load or steam generation data every 15 minutes during the entire period of the performance test. (b) Determine the average operating load by computing the hourly averages using all of the 15-minute readings taken during each performance test. (c) Determine the highest hourly average of the three test run averages during the performance test, and multiply this by 1.1 (110 percent) as your operating limit.

[a]Operating limits must be confirmed or reestablished during performance tests.

[b]If you conduct multiple performance tests, you must set the minimum liquid flow rate and pressure drop operating limits at the higher of the minimum values established during the performance tests. For a minimum oxygen level, if you conduct multiple performance tests, you must set the minimum oxygen level at the lower of the minimum values established during the performance tests.

[80 FR 72827, Nov. 20, 2015]

Table 8 to Subpart DDDDD of Part 63—Demonstrating Continuous Compliance

As stated in §63.7540, you must show continuous compliance with the emission limitations for each boiler or process heater according to the following:

If you must meet the following operating limits or work practice standards . . .	You must demonstrate continuous compliance by . . .
1. Opacity	a. Collecting the opacity monitoring system data according to §63.7525(c) and §63.7535; and
	b. Reducing the opacity monitoring data to 6-minute averages; and
	c. Maintaining daily block average opacity to less than or equal to 10 percent or the highest hourly average opacity reading measured during the performance test run demonstrating compliance with the PM (or TSM) emission limitation.
2. PM CPMS	a. Collecting the PM CPMS output data according to §63.7525;
	b. Reducing the data to 30-day rolling averages; and
	c. Maintaining the 30-day rolling average PM CPMS output data to less than the operating limit established during the performance test according to §63.7530(b)(4).
3. Fabric Filter Bag Leak Detection Operation	Installing and operating a bag leak detection system according to §63.7525 and operating the fabric filter such that the requirements in §63.7540(a)(7) are met.
4. Wet Scrubber Pressure Drop and Liquid Flow-rate	a. Collecting the pressure drop and liquid flow rate monitoring system data according to §§63.7525 and 63.7535; and
	b. Reducing the data to 30-day rolling averages; and
	c. Maintaining the 30-day rolling average pressure drop and liquid flow-rate at or above the operating limits established during the performance test according to §63.7530(b).
5. Wet Scrubber pH	a. Collecting the pH monitoring system data according to §§63.7525 and 63.7535; and
	b. Reducing the data to 30-day rolling averages; and
	c. Maintaining the 30-day rolling average pH at or above the operating limit established during the performance test according to §63.7530(b).
6. Dry Scrubber Sorbent or Carbon Injection Rate	a. Collecting the sorbent or carbon injection rate monitoring system data for the dry scrubber according to §§63.7525 and 63.7535; and
	b. Reducing the data to 30-day rolling averages; and
	c. Maintaining the 30-day rolling average sorbent or carbon injection rate at or above the minimum sorbent or carbon injection rate as defined in §63.7575.
7. Electrostatic Precipitator Total Secondary Electric Power Input	a. Collecting the total secondary electric power input monitoring system data for the electrostatic precipitator according to §§63.7525 and 63.7535; and
	b. Reducing the data to 30-day rolling averages; and

If you must meet the following operating limits or work practice standards . . .	You must demonstrate continuous compliance by . . .
	c. Maintaining the 30-day rolling average total secondary electric power input at or above the operating limits established during the performance test according to §63.7530(b).
8. Emission limits using fuel analysis	a. Conduct monthly fuel analysis for HCl or mercury or TSM according to Table 6 to this subpart; and
	b. Reduce the data to 12-month rolling averages; and
	c. Maintain the 12-month rolling average at or below the applicable emission limit for HCl or mercury or TSM in Tables 1 and 2 or 11 through 13 to this subpart.
	d. Calculate the HCl, mercury, and/or TSM emission rate from the boiler or process heater in units of lb/MMBtu using Equation 15 and Equations 17, 18, and/or 19 in §63.7530.
9. Oxygen content	a. Continuously monitor the oxygen content using an oxygen analyzer system according to §63.7525(a). This requirement does not apply to units that install an oxygen trim system since these units will set the trim system to the level specified in §63.7525(a)(7).
	b. Reducing the data to 30-day rolling averages; and
	c. Maintain the 30-day rolling average oxygen content at or above the lowest hourly average oxygen level measured during the CO performance test.
10. Boiler or process heater operating load	a. Collecting operating load data or steam generation data every 15 minutes. b. Reducing the data to 30-day rolling averages; and
	c. Maintaining the 30-day rolling average operating load such that it does not exceed 110 percent of the highest hourly average operating load recorded during the performance test according to §63.7520(c).
11. SO_2 emissions using SO_2 CEMS	a. Collecting the SO_2 CEMS output data according to §63.7525;
	b. Reducing the data to 30-day rolling averages; and
	c. Maintaining the 30-day rolling average SO_2 CEMS emission rate to a level at or below the highest hourly SO_2 rate measured during the HCl performance test according to §63.7530.

[78 FR 7204, Jan. 31, 2013, as amended at 80 FR 72829, Nov. 20, 2015]

Table 9 to Subpart DDDDD of Part 63—Reporting Requirements

As stated in §63.7550, you must comply with the following requirements for reports:

You must submit a(n)	The report must contain . . .	You must submit the report . . .
1. Compliance report	a. Information required in §63.7550(c)(1) through (5); and	Semiannually, annually, biennially, or every 5 years according to the requirements in §63.7550(b).

You must submit a(n)	The report must contain . . .	You must submit the report . . .
	b. If there are no deviations from any emission limitation (emission limit and operating limit) that applies to you and there are no deviations from the requirements for work practice standards for periods of startup and shutdown in Table 3 to this subpart that apply to you, a statement that there were no deviations from the emission limitations and work practice standards during the reporting period. If there were no periods during which the CMSs, including continuous emissions monitoring system, continuous opacity monitoring system, and operating parameter monitoring systems, were out-of-control as specified in §63.8(c)(7), a statement that there were no periods during which the CMSs were out-of-control during the reporting period; and	
	c. If you have a deviation from any emission limitation (emission limit and operating limit) where you are not using a CMS to comply with that emission limit or operating limit, or a deviation from a work practice standard for periods of startup and shutdown, during the reporting period, the report must contain the information in §63.7550(d); and	
	d. If there were periods during which the CMSs, including continuous emissions monitoring system, continuous opacity monitoring system, and operating parameter monitoring systems, were out-of-control as specified in §63.8(c)(7), or otherwise not operating, the report must contain the information in §63.7550(e)	

[76 FR 15664, Mar. 21, 2011, as amended at 78 FR 7205, Jan. 31, 2013; 80 FR 72830, Nov. 20, 2015]

Table 10 to Subpart DDDDD of Part 63—Applicability of General Provisions to Subpart DDDDD

As stated in §63.7565, you must comply with the applicable General Provisions according to the following:

Citation	Subject	Applies to subpart DDDDD
§63.1	Applicability	Yes.
§63.2	Definitions	Yes. Additional terms defined in §63.7575
§63.3	Units and Abbreviations	Yes.
§63.4	Prohibited Activities and Circumvention	Yes.
§63.5	Preconstruction Review and Notification Requirements	Yes.
§63.6(a), (b)(1)-(b)(5), (b)(7), (c)	Compliance with Standards and Maintenance Requirements	Yes.
§63.6(e)(1)(i)	General duty to minimize emissions.	No. See §63.7500(a)(3) for the general duty requirement.
§63.6(e)(1)(ii)	Requirement to correct malfunctions as soon as practicable.	No.
§63.6(e)(3)	Startup, shutdown, and malfunction plan requirements.	No.

Citation	Subject	Applies to subpart DDDDD
§63.6(f)(1)	Startup, shutdown, and malfunction exemptions for compliance with non-opacity emission standards.	No.
§63.6(f)(2) and (3)	Compliance with non-opacity emission standards.	Yes.
§63.6(g)	Use of alternative standards	Yes, except §63.7555(d)(13) specifies the procedure for application and approval of an alternative timeframe with the PM controls requirement in the startup work practice (2).
§63.6(h)(1)	Startup, shutdown, and malfunction exemptions to opacity standards.	No. See §63.7500(a).
§63.6(h)(2) to (h)(9)	Determining compliance with opacity emission standards	No. Subpart DDDDD specifies opacity as an operating limit not an emission standard.
§63.6(i)	Extension of compliance	Yes. Note: Facilities may also request extensions of compliance for the installation of combined heat and power, waste heat recovery, or gas pipeline or fuel feeding infrastructure as a means of complying with this subpart.
§63.6(j)	Presidential exemption.	Yes.
§63.7(a), (b), (c), and (d)	Performance Testing Requirements	Yes.
§63.7(e)(1)	Conditions for conducting performance tests	No. Subpart DDDDD specifies conditions for conducting performance tests at §63.7520(a) to (c).
§63.7(e)(2)-(e)(9), (f), (g), and (h)	Performance Testing Requirements	Yes.
§63.8(a) and (b)	Applicability and Conduct of Monitoring	Yes.
§63.8(c)(1)	Operation and maintenance of CMS	Yes.
§63.8(c)(1)(i)	General duty to minimize emissions and CMS operation	No. See §63.7500(a)(3).
§63.8(c)(1)(ii)	Operation and maintenance of CMS	Yes.
§63.8(c)(1)(iii)	Startup, shutdown, and malfunction plans for CMS	No.
§63.8(c)(2) to (c)(9)	Operation and maintenance of CMS	Yes.
§63.8(d)(1) and (2)	Monitoring Requirements, Quality Control Program	Yes.

Citation	Subject	Applies to subpart DDDDD
§63.8(d)(3)	Written procedures for CMS	Yes, except for the last sentence, which refers to a startup, shutdown, and malfunction plan. Startup, shutdown, and malfunction plans are not required.
§63.8(e)	Performance evaluation of a CMS	Yes.
§63.8(f)	Use of an alternative monitoring method.	Yes.
§63.8(g)	Reduction of monitoring data	Yes.
§63.9	Notification Requirements	Yes.
§63.10(a), (b)(1)	Recordkeeping and Reporting Requirements	Yes.
§63.10(b)(2)(i)	Recordkeeping of occurrence and duration of startups or shutdowns	Yes.
§63.10(b)(2)(ii)	Recordkeeping of malfunctions	No. See §63.7555(d)(7) for recordkeeping of occurrence and duration and §63.7555(d)(8) for actions taken during malfunctions.
§63.10(b)(2)(iii)	Maintenance records	Yes.
§63.10(b)(2)(iv) and (v)	Actions taken to minimize emissions during startup, shutdown, or malfunction	No.
§63.10(b)(2)(vi)	Recordkeeping for CMS malfunctions	Yes.
§63.10(b)(2)(vii) to (xiv)	Other CMS requirements	Yes.
§63.10(b)(3)	Recordkeeping requirements for applicability determinations	No.
§63.10(c)(1) to (9)	Recordkeeping for sources with CMS	Yes.
§63.10(c)(10) and (11)	Recording nature and cause of malfunctions, and corrective actions	No. See §63.7555(d)(7) for recordkeeping of occurrence and duration and §63.7555(d)(8) for actions taken during malfunctions.
§63.10(c)(12) and (13)	Recordkeeping for sources with CMS	Yes.
§63.10(c)(15)	Use of startup, shutdown, and malfunction plan	No.
§63.10(d)(1) and (2)	General reporting requirements	Yes.
§63.10(d)(3)	Reporting opacity or visible emission observation results	No.
§63.10(d)(4)	Progress reports under an extension of compliance	Yes.

Citation	Subject	Applies to subpart DDDDD
§63.10(d)(5)	Startup, shutdown, and malfunction reports	No. See §63.7550(c)(11) for malfunction reporting requirements.
§63.10(e)	Additional reporting requirements for sources with CMS	Yes.
§63.10(f)	Waiver of recordkeeping or reporting requirements	Yes.
§63.11	Control Device Requirements	No.
§63.12	State Authority and Delegation	Yes.
§63.13-63.16	Addresses, Incorporation by Reference, Availability of Information, Performance Track Provisions	Yes.
§63.1(a)(5),(a)(7)-(a)(9), (b)(2), (c)(3)-(4), (d), 63.6(b)(6), (c)(3), (c)(4), (d), (e)(2), (e)(3)(ii), (h)(3), (h)(5)(iv), 63.8(a)(3), 63.9(b)(3), (h)(4), 63.10(c)(2)-(4), (c)(9).	Reserved	No.

[76 FR 15664, Mar. 21, 2011, as amended at 78 FR 7205, Jan. 31, 2013; 80 FR 72830, Nov. 20, 2015]

Table 11 to Subpart DDDDD of Part 63—Alternative Emission Limits for New or Reconstructed Boilers and Process Heaters That Commenced Construction or Reconstruction After June 4, 2010, and Before May 20, 2011

If your boiler or process heater is in this subcategory . . .	For the following pollutants . . .	The emissions must not exceed the following emission limits, except during periods of startup and shutdown . . .	Using this specified sampling volume or test run duration . . .
1. Units in all subcategories designed to burn solid fuel	a. HCl	0.022 lb per MMBtu of heat input	For M26A, collect a minimum of 1 dscm per run; for M26 collect a minimum of 120 liters per run.
2. Units in all subcategories designed to burn solid fuel that combust at least 10 percent biomass/bio-based solids on an annual heat input basis and less than 10 percent coal/solid fossil fuels on an annual heat input basis	a. Mercury	8.0E-07[a] lb per MMBtu of heat input	For M29, collect a minimum of 4 dscm per run; for M30A or M30B, collect a minimum sample as specified in the method; for ASTM D6784[b] collect a minimum of 4 dscm.
3. Units in all subcategories designed to burn solid fuel that combust at least 10 percent coal/solid fossil fuels on an annual heat input basis and less than 10 percent biomass/bio-based solids on an annual heat input basis	a. Mercury	2.0E-06 lb per MMBtu of heat input	For M29, collect a minimum of 4 dscm per run; for M30A or M30B, collect a minimum sample as specified in the method; for ASTM D6784[b] collect a minimum of 4 dscm.

If your boiler or process heater is in this subcategory . . .	For the following pollutants . . .	The emissions must not exceed the following emission limits, except during periods of startup and shutdown . . .	Using this specified sampling volume or test run duration . . .
4. Units design to burn coal/solid fossil fuel	a. Filterable PM (or TSM)	1.1E-03 lb per MMBtu of heat input; or (2.3E-05 lb per MMBtu of heat input)	Collect a minimum of 3 dscm per run.
5. Pulverized coal boilers designed to burn coal/solid fossil fuel	a. Carbon monoxide (CO) (or CEMS)	130 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (320 ppm by volume on a dry basis corrected to 3 percent oxygen,[c] 30-day rolling average)	1 hr minimum sampling time.
6. Stokers designed to burn coal/solid fossil fuel	a. CO (or CEMS)	130 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (340 ppm by volume on a dry basis corrected to 3 percent oxygen,[c] 10-day rolling average)	1 hr minimum sampling time.
7. Fluidized bed units designed to burn coal/solid fossil fuel	a. CO (or CEMS)	130 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (230 ppm by volume on a dry basis corrected to 3 percent oxygen,[c] 30-day rolling average)	1 hr minimum sampling time.
8. Fluidized bed units with an integrated heat exchanger designed to burn coal/solid fossil fuel	a. CO (or CEMS)	140 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (150 ppm by volume on a dry basis corrected to 3 percent oxygen,[c] 30-day rolling average)	1 hr minimum sampling time.
9. Stokers/sloped grate/others designed to burn wet biomass fuel	a. CO (or CEMS)	620 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (390 ppm by volume on a dry basis corrected to 3 percent oxygen,[c] 30-day rolling average)	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	3.0E-02 lb per MMBtu of heat input; or (2.6E-05 lb per MMBtu of heat input)	Collect a minimum of 2 dscm per run.
10. Stokers/sloped grate/others designed to burn kiln-dried biomass fuel	a. CO	560 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	3.0E-02 lb per MMBtu of heat input; or (4.0E-03 lb per MMBtu of heat input)	Collect a minimum of 2 dscm per run.
11. Fluidized bed units designed to burn biomass/bio-based solids	a. CO (or CEMS)	230 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (310 ppm by volume on a dry basis corrected to 3 percent oxygen,[c] 30-day rolling average)	1 hr minimum sampling time.

If your boiler or process heater is in this subcategory . . .	For the following pollutants . . .	The emissions must not exceed the following emission limits, except during periods of startup and shutdown . . .	Using this specified sampling volume or test run duration . . .
	b. Filterable PM (or TSM)	9.8E-03 lb per MMBtu of heat input; or (8.3E-05[a] lb per MMBtu of heat input)	Collect a minimum of 3 dscm per run.
12. Suspension burners designed to burn biomass/bio-based solids	a. CO (or CEMS)	2,400 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (2,000 ppm by volume on a dry basis corrected to 3 percent oxygen,[c] 10-day rolling average)	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	3.0E-02 lb per MMBtu of heat input; or (6.5E-03 lb per MMBtu of heat input)	Collect a minimum of 2 dscm per run.
13. Dutch Ovens/Pile burners designed to burn biomass/bio-based solids	a. CO (or CEMS)	1,010 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (520 ppm by volume on a dry basis corrected to 3 percent oxygen,[c] 10-day rolling average)	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	8.0E-03 lb per MMBtu of heat input; or (3.9E-05 lb per MMBtu of heat input)	Collect a minimum of 3 dscm per run.
14. Fuel cell units designed to burn biomass/bio-based solids	a. CO	910 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	2.0E-02 lb per MMBtu of heat input; or (2.9E-05 lb per MMBtu of heat input)	Collect a minimum of 2 dscm per run.
15. Hybrid suspension grate boiler designed to burn biomass/bio-based solids	a. CO (or CEMS)	1,100 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (900 ppm by volume on a dry basis corrected to 3 percent oxygen,[c] 30-day rolling average)	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	2.6E-02 lb per MMBtu of heat input; or (4.4E-04 lb per MMBtu of heat input)	Collect a minimum of 3 dscm per run.
16. Units designed to burn liquid fuel	a. HCl	4.4E-04 lb per MMBtu of heat input	For M26A: Collect a minimum of 2 dscm per run; for M26, collect a minimum of 240 liters per run.
	b. Mercury	4.8E-07[a] lb per MMBtu of heat input	For M29, collect a minimum of 4 dscm per run; for M30A or M30B, collect a minimum sample as specified in the method; for ASTM D6784[b] collect a minimum of 4 dscm.

If your boiler or process heater is in this subcategory . . .	**For the following pollutants . . .**	**The emissions must not exceed the following emission limits, except during periods of startup and shutdown . . .**	**Using this specified sampling volume or test run duration . . .**
17. Units designed to burn heavy liquid fuel	a. CO	130 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	1.3E-02 lb per MMBtu of heat input; or (7.5E-05 lb per MMBtu of heat input)	Collect a minimum of 3 dscm per run.
18. Units designed to burn light liquid fuel	a. CO	130 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	2.0E-03[a] lb per MMBtu of heat input; or (2.9E-05 lb per MMBtu of heat input)	Collect a minimum of 3 dscm per run.
19. Units designed to burn liquid fuel that are non-continental units	a. CO	130 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average based on stack test	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	2.3E-02 lb per MMBtu of heat input; or (8.6E-04 lb per MMBtu of heat input)	Collect a minimum of 4 dscm per run.
20. Units designed to burn gas 2 (other) gases	a. CO	130 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average	1 hr minimum sampling time.
	b. HCl	1.7E-03 lb per MMBtu of heat input	For M26A, Collect a minimum of 2 dscm per run; for M26, collect a minimum of 240 liters per run.
	c. Mercury	7.9E-06 lb per MMBtu of heat input	For M29, collect a minimum of 3 dscm per run; for M30A or M30B, collect a minimum sample as specified in the method; for ASTM D6784[b] collect a minimum of 3 dscm.
	d. Filterable PM (or TSM)	6.7E-03 lb per MMBtu of heat input; or (2.1E-04 lb per MMBtu of heat input)	Collect a minimum of 3 dscm per run.

[a]If you are conducting stack tests to demonstrate compliance and your performance tests for this pollutant for at least 2 consecutive years show that your emissions are at or below this limit, you can skip testing according to §63.7515 if all of the other provision of §63.7515 are met. For all other pollutants that do not contain a footnote “a”, your performance tests for this pollutant for at least 2 consecutive years must show that your emissions are at or below 75 percent of this limit in order to qualify for skip testing.

[b]Incorporated by reference, see §63.14.

[c]An owner or operator may request an alternative test method under §63.7 of this chapter, in order that compliance with the carbon monoxide emissions limit be determined using carbon dioxide as a diluent correction in place of oxygen at 3%. EPA Method 19 F-factors and EPA Method 19 equations must be used to generate the appropriate CO_2 correction percentage for the fuel type burned in the unit, and must also take into account that the 3% oxygen

correction is to be done on a dry basis. The alternative test method request must account for any CO_2 being added to, or removed from, the emissions gas stream as a result of limestone injection, scrubber media, etc.

[80 FR 72831, Nov. 20, 2015]

Table 12 to Subpart DDDDD of Part 63—Alternative Emission Limits for New or Reconstructed Boilers and Process Heaters That Commenced Construction or Reconstruction After May 20, 2011, and Before December 23, 2011

If your boiler or process heater is in this subcategory . . .	For the following pollutants . . .	The emissions must not exceed the following emission limits, except during periods of startup and shutdown . . .	Using this specified sampling volume or test run duration . . .
1. Units in all subcategories designed to burn solid fuel	a. HCl	0.022 lb per MMBtu of heat input	For M26A, collect a minimum of 1 dscm per run; for M26 collect a minimum of 120 liters per run.
	b. Mercury	3.5E-06[a] lb per MMBtu of heat input	For M29, collect a minimum of 3 dscm per run; for M30A or M30B, collect a minimum sample as specified in the method; for ASTM D6784[b] collect a minimum of 3 dscm.
2. Units design to burn coal/solid fossil fuel	a. Filterable PM (or TSM)	1.1E-03 lb per MMBtu of heat input; or (2.3E-05 lb per MMBtu of heat input)	Collect a minimum of 3 dscm per run.
3. Pulverized coal boilers designed to burn coal/solid fossil fuel	a. Carbon monoxide (CO) (or CEMS)	130 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (320 ppm by volume on a dry basis corrected to 3 percent oxygen,[c] 30-day rolling average)	1 hr minimum sampling time.
4. Stokers designed to burn coal/solid fossil fuel	a. CO (or CEMS)	130 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (340 ppm by volume on a dry basis corrected to 3 percent oxygen,[c] 10-day rolling average)	1 hr minimum sampling time.
5. Fluidized bed units designed to burn coal/solid fossil fuel	a. CO (or CEMS)	130 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (230 ppm by volume on a dry basis corrected to 3 percent oxygen,[c] 30-day rolling average)	1 hr minimum sampling time.
6. Fluidized bed units with an integrated heat exchanger designed to burn coal/solid fossil fuel	a. CO (or CEMS)	140 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (150 ppm by volume on a dry basis corrected to 3 percent oxygen,[c] 30-day rolling average)	1 hr minimum sampling time.
7. Stokers/sloped grate/others designed to burn wet biomass fuel	a. CO (or CEMS)	620 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (390 ppm by volume on a dry basis corrected to 3 percent oxygen,[c] 30-day rolling average)	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	3.0E-02 lb per MMBtu of heat input; or (2.6E-05 lb per MMBtu of heat input)	Collect a minimum of 2 dscm per run.

If your boiler or process heater is in this subcategory . . .	For the following pollutants . . .	The emissions must not exceed the following emission limits, except during periods of startup and shutdown . . .	Using this specified sampling volume or test run duration . . .
8. Stokers/sloped grate/others designed to burn kiln-dried biomass fuel	a. CO b. Filterable PM (or TSM)	460 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average 3.0E-02 lb per MMBtu of heat input; or (4.0E-03 lb per MMBtu of heat input)	1 hr minimum sampling time. Collect a minimum of 2 dscm per run.
9. Fluidized bed units designed to burn biomass/bio-based solids	a. CO (or CEMS)	260 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (310 ppm by volume on a dry basis corrected to 3 percent oxygen,[c] 30-day rolling average)	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	9.8E-03 lb per MMBtu of heat input; or (8.3E-05[a] lb per MMBtu of heat input)	Collect a minimum of 3 dscm per run.
10. Suspension burners designed to burn biomass/bio-based solids	a. CO (or CEMS)	2,400 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (2,000 ppm by volume on a dry basis corrected to 3 percent oxygen,[c] 10-day rolling average)	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	3.0E-02 lb per MMBtu of heat input; or (6.5E-03 lb per MMBtu of heat input)	Collect a minimum of 2 dscm per run.
11. Dutch Ovens/Pile burners designed to burn biomass/bio-based solids	a. CO (or CEMS)	470 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (520 ppm by volume on a dry basis corrected to 3 percent oxygen,[c] 10-day rolling average)	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	3.2E-03 lb per MMBtu of heat input; or (3.9E-05 lb per MMBtu of heat input)	Collect a minimum of 3 dscm per run.
12. Fuel cell units designed to burn biomass/bio-based solids	a. CO b. Filterable PM (or TSM)	910 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average 2.0E-02 lb per MMBtu of heat input; or (2.9E-05 lb per MMBtu of heat input)	1 hr minimum sampling time. Collect a minimum of 2 dscm per run.
13. Hybrid suspension grate boiler designed to burn biomass/bio-based solids	a. CO (or CEMS)	1,500 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (900 ppm by volume on a dry basis corrected to 3 percent oxygen,[c] 30-day rolling average)	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	2.6E-02 lb per MMBtu of heat input; or (4.4E-04 lb per MMBtu of heat input)	Collect a minimum of 3 dscm per run.
14. Units designed to burn liquid fuel	a. HCl	4.4E-04 lb per MMBtu of heat input	For M26A: Collect a minimum of 2 dscm per run; for M26, collect a minimum of 240 liters per run.

If your boiler or process heater is in this subcategory . . .	For the following pollutants . . .	The emissions must not exceed the following emission limits, except during periods of startup and shutdown . . .	Using this specified sampling volume or test run duration . . .
	b. Mercury	4.8E-07[a] lb per MMBtu of heat input	For M29, collect a minimum of 4 dscm per run; for M30A or M30B, collect a minimum sample as specified in the method; for ASTM D6784[b] collect a minimum of 4 dscm.
15. Units designed to burn heavy liquid fuel	a. CO	130 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	1.3E-02 lb per MMBtu of heat input; or (7.5E-05 lb per MMBtu of heat input)	Collect a minimum of 2 dscm per run.
16. Units designed to burn light liquid fuel	a. CO	130 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	1.3E-03[a] lb per MMBtu of heat input; or (2.9E-05 lb per MMBtu of heat input)	Collect a minimum of 3 dscm per run.
17. Units designed to burn liquid fuel that are non-continental units	a. CO	130 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average based on stack test	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	2.3E-02 lb per MMBtu of heat input; or (8.6E-04 lb per MMBtu of heat input)	Collect a minimum of 4 dscm per run.
18. Units designed to burn gas 2 (other) gases	a. CO	130 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average	1 hr minimum sampling time.
	b. HCl	1.7E-03 lb per MMBtu of heat input	For M26A, Collect a minimum of 2 dscm per run; for M26, collect a minimum of 240 liters per run.
	c. Mercury	7.9E-06 lb per MMBtu of heat input	For M29, collect a minimum of 3 dscm per run; for M30A or M30B, collect a minimum sample as specified in the method; for ASTM D6784[b] collect a minimum of 3 dscm.
	d. Filterable PM (or TSM)	6.7E-03 lb per MMBtu of heat input; or (2.1E-04 lb per MMBtu of heat input)	Collect a minimum of 3 dscm per run.

[a]If you are conducting stack tests to demonstrate compliance and your performance tests for this pollutant for at least 2 consecutive years show that your emissions are at or below this limit, you can skip testing according to §63.7515 if all of the other provision of §63.7515 are met. For all other pollutants that do not contain a footnote "a", your performance tests for this pollutant for at least 2 consecutive years must show that your emissions are at or below 75 percent of this limit in order to qualify for skip testing.

[b]Incorporated by reference, see §63.14.

[c]An owner or operator may request an alternative test method under §63.7 of this chapter, in order that compliance with the carbon monoxide emissions limit be determined using carbon dioxide as a diluent correction in place of oxygen at 3%. EPA Method 19 F-factors and EPA Method 19 equations must be used to generate the appropriate CO_2 correction percentage for the fuel type burned in the unit, and must also take into account that the 3% oxygen correction is to be done on a dry basis. The alternative test method request must account for any CO_2 being added to, or removed from, the emissions gas stream as a result of limestone injection, scrubber media, etc.

[80 FR 72834, Nov. 20, 2015]

Table 13 to Subpart DDDDD of Part 63— Alternative Emission Limits for New or Reconstructed Boilers and Process Heaters That Commenced Construction or Reconstruction After December 23, 2011, and Before April 1, 2013

If your boiler or process heater is in this subcategory . . .	For the following pollutants . . .	The emissions must not exceed the following emission limits, except during periods of startup and shutdown . . .	Using this specified sampling volume or test run duration . . .
1. Units in all subcategories designed to burn solid fuel	a. HCl	0.022 lb per MMBtu of heat input	For M26A, collect a minimum of 1 dscm per run; for M26 collect a minimum of 120 liters per run.
	b. Mercury	8.6E-07[a] lb per MMBtu of heat input	For M29, collect a minimum of 4 dscm per run; for M30A or M30B, collect a minimum sample as specified in the method; for ASTM D6784[b] collect a minimum of 4 dscm.
2. Pulverized coal boilers designed to burn coal/solid fossil fuel	a. Carbon monoxide (CO) (or CEMS)	130 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (320 ppm by volume on a dry basis corrected to 3 percent oxygen,[c] 30-day rolling average)	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	1.1E-03 lb per MMBtu of heat input; or (2.8E-05 lb per MMBtu of heat input)	Collect a minimum of 3 dscm per run.
3. Stokers designed to burn coal/solid fossil fuel	a. CO (or CEMS)	130 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (340 ppm by volume on a dry basis corrected to 3 percent oxygen,[c] 10-day rolling average)	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	2.8E-02 lb per MMBtu of heat input; or (2.3E-05 lb per MMBtu of heat input)	Collect a minimum of 2 dscm per run.
4. Fluidized bed units designed to burn coal/solid fossil fuel	a. CO (or CEMS)	130 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (230 ppm by volume on a dry basis corrected to 3 percent oxygen,[c] 30-day rolling average)	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	1.1E-03 lb per MMBtu of heat input; or (2.3E-05 lb per MMBtu of heat input)	Collect a minimum of 3 dscm per run.
5. Fluidized bed units with an integrated heat exchanger designed to burn coal/solid fossil fuel	a. CO (or CEMS)	140 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (150 ppm by volume on a dry basis corrected to 3 percent oxygen,[c] 30-day rolling average)	1 hr minimum sampling time.

If your boiler or process heater is in this subcategory . . .	For the following pollutants . . .	The emissions must not exceed the following emission limits, except during periods of startup and shutdown . . .	Using this specified sampling volume or test run duration . . .
	b. Filterable PM (or TSM)	1.1E-03 lb per MMBtu of heat input; or (2.3E-05 lb per MMBtu of heat input)	Collect a minimum of 3 dscm per run.
6. Stokers/sloped grate/others designed to burn wet biomass fuel	a. CO (or CEMS)	620 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (410 ppm by volume on a dry basis corrected to 3 percent oxygen,[c] 10-day rolling average)	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	3.0E-02 lb per MMBtu of heat input; or (2.6E-05 lb per MMBtu of heat input)	Collect a minimum of 2 dscm per run.
7. Stokers/sloped grate/others designed to burn kiln-dried biomass fuel	a. CO	460 ppm by volume on a dry basis corrected to 3 percent oxygen	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	3.2E-01 lb per MMBtu of heat input; or (4.0E-03 lb per MMBtu of heat input)	Collect a minimum of 2 dscm per run.
8. Fluidized bed units designed to burn biomass/bio-based solids	a. CO (or CEMS)	230 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (310 ppm by volume on a dry basis corrected to 3 percent oxygen,[c] 30-day rolling average)	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	9.8E-03 lb per MMBtu of heat input; or (8.3E-05[a] lb per MMBtu of heat input)	Collect a minimum of 3 dscm per run.*
9. Suspension burners designed to burn biomass/bio-based solids	a. CO (or CEMS)	2,400 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (2,000 ppm by volume on a dry basis corrected to 3 percent oxygen,[c] 10-day rolling average)	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	5.1E-02 lb per MMBtu of heat input; or (6.5E-03 lb per MMBtu of heat input)	Collect a minimum of 2 dscm per run.
10. Dutch Ovens/Pile burners designed to burn biomass/bio-based solids	a. CO (or CEMS)	810 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (520 ppm by volume on a dry basis corrected to 3 percent oxygen,[c] 10-day rolling average)	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	3.6E-02 lb per MMBtu of heat input; or (3.9E-05 lb per MMBtu of heat input)	Collect a minimum of 2 dscm per run.
11. Fuel cell units designed to burn biomass/bio-based solids	a. CO	910 ppm by volume on a dry basis corrected to 3 percent oxygen	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	2.0E-02 lb per MMBtu of heat input; or (2.9E-05 lb per MMBtu of heat input)	Collect a minimum of 2 dscm per run.
12. Hybrid suspension grate boiler designed to burn biomass/bio-based solids	a. CO (or CEMS)	1,500 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (900 ppm by volume on a dry basis corrected to 3 percent oxygen,[c] 30-day rolling average)	1 hr minimum sampling time.

If your boiler or process heater is in this subcategory . . .	For the following pollutants . . .	The emissions must not exceed the following emission limits, except during periods of startup and shutdown . . .	Using this specified sampling volume or test run duration . . .
	b. Filterable PM (or TSM)	2.6E-02 lb per MMBtu of heat input; or (4.4E-04 lb per MMBtu of heat input)	Collect a minimum of 3 dscm per run.
13. Units designed to burn liquid fuel	a. HCl	1.2E-03 lb per MMBtu of heat input	For M26A: Collect a minimum of 2 dscm per run; for M26, collect a minimum of 240 liters per run.
	b. Mercury	4.9E-07[a] lb per MMBtu of heat input	For M29, collect a minimum of 4 dscm per run; for M30A or M30B, collect a minimum sample as specified in the method; for ASTM D6784[b] collect a minimum of 4 dscm.
14. Units designed to burn heavy liquid fuel	a. CO (or CEMS)	130 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (18 ppm by volume on a dry basis corrected to 3 percent oxygen,[c] 10-day rolling average)	1 hr minimum sampling time.
15. Units designed to burn light liquid fuel	a. CO (or CEMS)	130[a] ppm by volume on a dry basis corrected to 3 percent oxygen; or (60 ppm by volume on a dry basis corrected to 3 percent oxygen,[c] 1-day block average)	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	1.1E-03[a] lb per MMBtu of heat input; or (2.9E-05 lb per MMBtu of heat input)	Collect a minimum of 3 dscm per run.
16. Units designed to burn liquid fuel that are non-continental units	a. CO	130 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average based on stack test; or (91 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-hour rolling average)	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	2.3E-02 lb per MMBtu of heat input; or (8.6E-04 lb per MMBtu of heat input)	Collect a minimum of 2 dscm per run.
17. Units designed to burn gas 2 (other) gases	a. CO	130 ppm by volume on a dry basis corrected to 3 percent oxygen	1 hr minimum sampling time.
	b. HCl	1.7E-03 lb per MMBtu of heat input	For M26A, Collect a minimum of 2 dscm per run; for M26, collect a minimum of 240 liters per run.
	c. Mercury	7.9E-06 lb per MMBtu of heat input	For M29, collect a minimum of 3 dscm per run; for M30A or M30B, collect a minimum sample as specified in the method; for ASTM D6784[b] collect a minimum of 3 dscm.
	d. Filterable PM (or TSM)	6.7E-03 lb per MMBtu of heat input; or (2.1E-04 lb per MMBtu of heat input)	Collect a minimum of 3 dscm per run.

[a]If you are conducting stack tests to demonstrate compliance and your performance tests for this pollutant for at least 2 consecutive years show that your emissions are at or below this limit and you are not required to conduct testing for CEMS or CPMS monitor certification, you can skip testing according to §63.7515 if all of the other provision of

§63.7515 are met. For all other pollutants that do not contain a footnote “a”, your performance tests for this pollutant for at least 2 consecutive years must show that your emissions are at or below 75 percent of this limit in order to qualify for skip testing.

[b]Incorporated by reference, see §63.14.

[c]An owner or operator may request an alternative test method under §63.7 of this chapter, in order that compliance with the carbon monoxide emissions limit be determined using carbon dioxide as a diluent correction in place of oxygen at 3%. EPA Method 19 F-factors and EPA Method 19 equations must be used to generate the appropriate CO_2 correction percentage for the fuel type burned in the unit, and must also take into account that the 3% oxygen correction is to be done on a dry basis. The alternative test method request must account for any CO_2 being added to, or removed from, the emissions gas stream as a result of limestone injection, scrubber media, etc.

[78 FR 7210, Jan. 31, 2013, as amended at 80 FR 72836, Nov. 20, 2015]

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:	**Indiana University**
Source Location:	**820 North Walnut Grove Ave., Bloomington, Indiana 47405**
County:	**Monroe**
SIC Code:	**8221 (Colleges, Universities, and Professional Schools)**
Permit Renewal No.:	**T105-41051-00005**
Permit Reviewer:	**Aasim Noveer**

On February 12, 2019, Indiana University (IU) 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 IU relating to the operation of a University campus that includes steam production sources that supply the IU campus with heat from boilers and emergency generators IU was issued its Second Part 70 Operating Permit Renewal (T105-34100-00005) on November 19, 2014.

Existing Approvals

The source was issued Part 70 Operating Permit Renewal No. T105-34100-00005 on November 19, 2014. There have been no subsequent approvals issued.

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) natural gas-fired boiler, (using low-sulfur No. 1 or No. 2 fuel oil as a back-up), identified as EU-07, approved for construction in 2007, including a mud drum heat exchanger, with a maximum design capacity of 217 MMBtu per hour heat input when combusting natural gas and 208 MMBtu per hour heat input when combusting fuel oil, and equipped with low NOx burners and induced flue gas recirculation for NOx control, with continuous emissions monitors (CEM) for monitoring CO and NOx, exhausting to stack 002. The boiler burner pilot light can ignite using propane.

Under [40 CFR 60, Subpart Db] and [40 CFR 63, Subpart DDDDD], this is an affected source.

(b) Two (2) coal, natural gas, No. 1 or No. 2 fuel oil fired boilers, identified as EU-03 and EU-04, both constructed in 1959, with economizers replaced in 2010, with a maximum design capacity of 125 MMBtu per hour heat input each (operating at a maximum capacity of 100 MMBtu per hour heat input each when combusting coal or a combination of fuels), and with a maximum design capacity of 80 MMBtu per hour heat input each when combusting natural gas and/or fuel oil, each equipped with low NOx burners for natural gas and/or fuel oil, and each with a multiclone and a jet pulse baghouse, identified as Boiler 3 Bag and Boiler 4 Bag, for particulate control, permitted in 2008, when combusting coal and/or fuel oil, both exhausting at stack 002. In addition, the stack exhaust from boilers EU-03 and EU-04 can be treated by an activated carbon injection system for mercury control and a lime injection system for hydrogen chloride control.

[Under 40 CFR 63, Subpart DDDDD, this is an affected source]

(c) One (1) natural gas-fired boiler, (using low-sulfur No. 1 or No. 2 fuel oil as a back-up), identified as EU-05, constructed in 1964, and modified in 1989, with a maximum design capacity of 190 MMBtu per hour heat input, equipped with a mud drum heat exchanger installed in 2013 and low NOx burners (two natural gas fired burners at 75 MMBtu per hour heat input each) for natural gas and/or fuel oil, and a multiclone for particulate control when combusting fuel oil, exhausting to stack 002 or 003. The boiler burner pilot light can ignite using propane.

[Under 40 CFR 63, Subpart DDDDD, this is an affected source]

(d) One (1) coal, natural gas, No. 1 or No. 2 fuel oil fired boiler, identified as EU-06, constructed in 1970, with economizers replaced in 2010, with a maximum design capacity of 190 MMBtu per hour heat input when combusting coal and/or fuel oil, and 150 MMBtu per hour heat input (two natural gas fired burners rated at 75 MMBtu per hour heat input each) when combusting natural gas, equipped with a mud drum heat exchanger installed in 2014, equipped with low NOx burners for natural gas and/or fuel oil, a multiclone and a jet pulse baghouse, identified as Boiler 6 Bag, for particulate control when combusting coal and/or fuel oil, permitted in 2008, and a continuous opacity monitor for monitoring opacity, exhausting to stack 003. In addition, the stack exhaust from boiler EU-06 can be treated by an activated carbon injection system for mercury control and a lime injection system for hydrogen chloride control.

[Under 40 CFR 63, Subpart DDDDD, this is an affected source]

(e) One (1) coal storage and handling system, with a maximum design throughput of 200 tons of coal per hour, consisting of the following:

(1) One (1) coal truck receiving system, consisting of an interior wet suppression system to control coal dust emissions during coal receiving, and two (2) truck hoppers. [326 IAC 6-3-2]

(2) Four (4) enclosed belt conveyors, and one (1) enclosed bucket conveyor, with particulate emissions controlled by a fabric filter system, with four (4) dust collectors, identified as DC1 through 4, located internally at various points along the enclosed conveyor system, with all dust collectors exhausting internally. [326 IAC 6-3-2]

(3) One (1) coal storage silo with a storage capacity of 1,000 tons of coal, with particulate emissions controlled by one (1) dust collector, identified as DC6, exhausting externally at vent 6. [326 IAC 6-3-2]

Emission Units and Pollution Control Equipment Removed From the Source

The source has removed the following emission units:

(a) Emergency Generator, identified as CBSB 1, constructed in 2004, with a maximum capacity of 56 hp, using no control, and exhausting to atmosphere.

(b) Emergency Generator, identified as SBSB-1, constructed in 2007, with a maximum capacity of 156 hp, using no control, and exhausting to atmosphere.

(c) Emergency Generator, identified as AHSB-1, constructed in 2008, with a maximum capacity of 400 hp, using no control, and exhausting to atmosphere.

Insignificant Activities

The source also consists of the following specifically regulated insignificant activities:

(a) Natural gas-fired combustion sources with heat input equal to or less than ten (10) million Btu per hour heat input:

(1) Twenty-two (22) boilers constructed before 1972, with a combined total heat input of 29.130 MMBtu per hour. [326 IAC 6-2] [40 CFR 63, Subpart DDDDD]

(2) One (1) boiler constructed in 1977, with a heat input of 0.60 MMBtu per hour. [326 IAC 6-2] [40 CFR 63, Subpart DDDDD]

(3) One (1) boiler constructed in 1981, with a heat input of 0.110 MMBtu per hour. [326 IAC 6-2] [40 CFR 63, Subpart DDDDD]

(4) Sixty-six (66) boilers constructed after 1983, with a combined heat input of 145.25 MMBtu per hour. [326 IAC 6-2-4(a) and (b)] [40 CFR 63, Subpart DDDDD]

(5) Informatics East Building Boiler, constructed in 2008, with a heat input capacity of 1.44 MMBtu/hr. [326 IAC 6-2-4] [40 CFR 63, Subpart DDDDD]

(6) Hutton Honors College Furnace, constructed in 2008, with a heat input capacity of 0.432 MMBtu/hr. [326 IAC 6-2-4] [40 CFR 63, Subpart DDDDD]

(7) Three (3) natural gas-fired boilers, each constructed in 2009 and located at the Innovation Center, each with a heat input capacity of 1.1 MMBtu/hr. [326 IAC 6-2-4] [40 CFR 63, Subpart DDDDD]

(b) Degreasing operations that do not exceed 145 gallons per 12 months, except if subject to [326 IAC 20-6] [326 IAC 8-3-2] [326 IAC 8-3-8].

(c) Oil-fired emergency generators not exceeding 1,600 horsepower:

(1) One (1) emergency generator, identified as MSB 1, permitted in 2007, with a maximum capacity of 1,200 horsepower, located inside of utility structure. [40 CFR Part 60, Subpart IIII] [40 CFR 63, Subpart ZZZZ]

(d) Two (2) pneumatic ash handling legs, identified as Ash Leg #1 and Ash Leg #2, permitted in 2008, with a maximum throughput capacity of 0.71 tons of fly ash per hour, emissions are controlled by water spray. [326 IAC 6-3-2]

(e) One (1) activated carbon injection system, constructed in 2008, consisting of one (1) activated carbon storage silo, with a maximum storage capacity of 52 tons and throughput of 1,200 lbs/hr, identified as Carbon Silo, controlled by a bin vent baghouse, identified as CS Bag, exhausting indoors to stack CS Vent. [326 IAC 6-3-2]

(f) One (1) lime injection system, constructed in 2008, consisting of one (1) lime storage silo, with a maximum storage capacity of 25 tons and throughput of 30 lbs/hr, identified as Lime Silo, controlled by a bin vent baghouse, identified as LS Bag, exhausting indoors to stack LS Vent. [326 IAC 6-3-2]

(g) Twenty Three (23) Diesel Emergency Generators:

(1) One (1) diesel emergency generators, identified as FQHSB-1, manufactured in 2006, with a maximum capacity of 282 hp, located outside the Foster Quad/Harper Buildings.
[Under 40 CFR 60, Subpart IIII, this is an affected source]
[Under 40 CFR 63, Subpart ZZZZ, this is an affected source]

(2) One (1) diesel emergency generators, identified as TTASB-1, manufactured in 2006, with a maximum capacity of 300 hp, located outside the Tulip Tree Apartments.
[Under 40 CFR 60, Subpart IIII, this is an affected source]
[Under 40 CFR 63, Subpart ZZZZ, this is an affected source]

(3) One (1) diesel emergency generator, identified as HAPSB-1, manufactured in 2007, with a maximum capacity of 60 hp, located outside the Henderson/Atwater Parking Area.
[Under 40 CFR 60, Subpart IIII, this is an affected source]
[Under 40 CFR 63, Subpart ZZZZ, this is an affected source]

(4) One (1) diesel emergency generator, identified as IUPD-1, manufactured in 2007, with a maximum capacity of 545 hp, located outside of the IU Police Department Building.
[Under 40 CFR 60, Subpart IIII, this is an affected source]
[Under 40 CFR 63, Subpart ZZZZ, this is an affected source]

(5) One (1) diesel emergency generator, identified as JHSB-1, manufactured in 2007, with a maximum capacity of 225 hp, located outside of Johnston Hall.
[Under 40 CFR 60, Subpart IIII, this is an affected source]
[Under 40 CFR 63, Subpart ZZZZ, this is an affected source]

(6) One (1) diesel emergency generator, identified as TQSB-1, manufactured in 2007, with a maximum capacity of 320 hp, located outside of Teter Quad Building.
[Under 40 CFR 60, Subpart IIII, this is an affected source]
[Under 40 CFR 63, Subpart ZZZZ, this is an affected source]

(7) One (1) diesel emergency generator, identified as MSB-1, manufactured in 2007, with a maximum capacity of 1,200 hp, located inside of the MSB-1 Building.
[Under 40 CFR 60, Subpart IIII, this is an affected source]
[Under 40 CFR 63, Subpart ZZZZ, this is an affected source]

(8) One (1) diesel emergency generator, identified as JDHSB-1, manufactured in 2007, with a maximum capacity of 80 hp, located at Jordan Hall.
[Under 40 CFR 60, Subpart IIII, this is an affected source]
[Under 40 CFR 63, Subpart ZZZZ, this is an affected source]

(9) One (1) diesel emergency generator, identified as WQSB-1, manufactured in 2007, with a maximum capacity of 225.6 hp, located at Wright Quad.
[Under 40 CFR 60, Subpart IIII, this is an affected source]
[Under 40 CFR 63, Subpart ZZZZ, this is an affected source]

(10) One (1) diesel emergency generator, identified as HCSB-1, manufactured in 2007, with a maximum capacity of 1,150 hp, located outside of the Health Center.
[Under 40 CFR 60, Subpart IIII, this is an affected source]
[Under 40 CFR 63, Subpart ZZZZ, this is an affected source]

(11) One (1) diesel emergency generator, identified as MSB-2, manufactured in 2008, with a maximum capacity of 1,490 hp, located at Simon Hall.
[Under 40 CFR 60, Subpart IIII, this is an affected source]
[Under 40 CFR 63, Subpart ZZZZ, this is an affected source]

(12) One (1) diesel emergency generator, identified as MSNSB-1, manufactured in 2008, with a maximum capacity of 258 hp, located at Memorial Stadium North.
[Under 40 CFR 60, Subpart IIII, this is an affected source]
[Under 40 CFR 63, Subpart ZZZZ, this is an affected source]

(13) One (1) diesel emergency generator, identified as BCSB-1, manufactured in 2008, with a maximum capacity of 360 hp, located at Basketball Center Cook Hall.
[Under 40 CFR 60, Subpart IIII, this is an affected source]
[Under 40 CFR 63, Subpart ZZZZ, this is an affected source]

(14) One (1) diesel emergency generator, identified as CHSB-1, manufactured in 2009, with a maximum capacity of 300 hp, located at Cedar Hall.
[Under 40 CFR 60, Subpart IIII, this is an affected source]
[Under 40 CFR 63, Subpart ZZZZ, this is an affected source]

(15) One (1) diesel emergency generator, identified as HPSB-1, manufactured in 2009, with a maximum capacity of 606 hp, located at HPER.
[Under 40 CFR 60, Subpart IIII, this is an affected source]
[Under 40 CFR 63, Subpart ZZZZ, this is an affected source]

(16) One (1) diesel emergency generator, identified as ICSB-1, manufactured in 2009, with a maximum capacity of 186 hp,located at IU Innovation Center.
[Under 40 CFR 60, Subpart IIII, this is an affected source]
[Under 40 CFR 63, Subpart ZZZZ, this is an affected source]

(17) One (1) diesel emergency generator, identified as MHSB-1, manufactured in 2009, with a maximum capacity of 56 hp, located outside of Mason Hall.
[Under 40 CFR 60, Subpart IIII, this is an affected source]
[Under 40 CFR 63, Subpart ZZZZ, this is an affected source]

(18) One (1) diesel emergency generator, identified as DCSB-1, manufactured in 2008, with a maximum capacity of 2,200 hp, located inside of Data Center #1.
[Under 40 CFR 60, Subpart IIII, this is an affected source]
[Under 40 CFR 63, Subpart ZZZZ, this is an affected source]

(19) One (1) diesel emergency generator, identified as DCSB-2, manufactured in 2008, with a maximum capacity of 2,200 hp, located inside of Data Center #2.
[Under 40 CFR 60, Subpart IIII, this is an affected source]
[Under 40 CFR 63, Subpart ZZZZ, this is an affected source]

(20) One (1) diesel emergency generator, identified as BBSB-1, manufactured in 2011, with a maximum capacity of 720 hp, located at Briscoe Building.
[Under 40 CFR 60, Subpart IIII, this is an affected source]
[Under 40 CFR 63, Subpart ZZZZ, this is an affected source]

(21) One (1) diesel emergency generator, identified as MACSB-1, manufactured in 2011, with a maximum capacity of 120 hp, located at the Musical Arts Center.
[Under 40 CFR 60, Subpart IIII, this is an affected source]
[Under 40 CFR 63, Subpart ZZZZ, this is an affected source]

(22) One (1) diesel emergency generator, identified as FQSB-1, manufactured in 2012, with a maximum capacity of 460 hp, located at Forest Quad.
[Under 40 CFR 60, Subpart IIII, this is an affected source]
[Under 40 CFR 63, Subpart ZZZZ, this is an affected source]

(23) One (1) diesel emergency generator, identified as JSMSB-1, manufactured in 2012, with a maximum capacity of 475 hp, located at the Jacobs School of Music.
[Under 40 CFR 60, Subpart IIII, this is an affected source]
[Under 40 CFR 63, Subpart ZZZZ, this is an affected source]

The source also consists of the following other insignificant activities:

(h) Woodworking area for maintenance, installed in 2007, equipped with a baghouse with an exhaust flow rate of 11,700 CFM.

(i) One (1) natural gas-fired make-up air unit (direct heat source), constructed in 2009, located at the Innovation Center, with a heat input capacity of 0.7 MMBtu/hr.

Emission Units and Pollution Control Equipment
Constructed Under the Provisions of 326 IAC 2-1.1-3 (Exemptions)

The following existing unpermitted Diesel Emergency Generators constructed under the provisions of 326 IAC 2-1.1-3 (Exemptions), are being incorporated in the permit as part of this permitting action. Each emission unit is considered as a single project because of construction date and location.

1. One (1) diesel emergency generator, identified as FHSB-1, constructed in 1957 with a maximum capacity of 67.5 hp, located at Field House / 604.
[Under 40 CFR 63, Subpart ZZZZ, this is an affected source]

2. One (1) diesel emergency generator, identified as HASB-1, constructed in 1970 with a maximum capacity of 26.2 hp, located at Hall Admin. / 463.
[Under 40 CFR 63, Subpart ZZZZ, this is an affected source]

3. One (1) diesel emergency generator, identified as FHSB-2, constructed in 1972 with a maximum capacity of 22.5 hp, located at Franklin Hall / 007.
[Under 40 CFR 63, Subpart ZZZZ, this is an affected source]

4. One (1) diesel emergency generator, identified as LBSB-1, constructed in 1981 with a maximum capacity of 150 hp, located at Law Building / 001.
[Under 40 CFR 63, Subpart ZZZZ, this is an affected source]

5. One (1) diesel emergency generator, identified as POPSB-1, constructed in 1985 with a maximum capacity of 255 hp, located at Poplars Bldg. / 008.
[Under 40 CFR 63, Subpart ZZZZ, this is an affected source]

6. One (1) diesel emergency generator, identified as SBSB-4, constructed in 1986 with a maximum capacity of 765 hp, located at Service Bldg / 630.
[Under 40 CFR 63, Subpart ZZZZ, this is an affected source]

7. One (1) diesel emergency generator, identified as MASB-1, constructed in 1989 with a maximum capacity of 91.5 hp, located at Music Addition / 148.
[Under 40 CFR 63, Subpart ZZZZ, this is an affected source]

8. One (1) diesel emergency generator, identified as CASB-1, constructed in 1990 with a maximum capacity of 900 hp, located at Chemistry Addition / 072.
[Under 40 CFR 63, Subpart ZZZZ, this is an affected source]

9. One (1) diesel emergency generator, identified as JHSB-2, constructed in 1990 with a maximum capacity of 600 hp, located at Jordan Hall / 107.
   [Under 40 CFR 63, Subpart ZZZZ, this is an affected source]

10. One (1) diesel emergency generator, identified as SBSB-3, constructed in 1991 with a maximum capacity of 30 hp, located at Student Building / 017.
    [Under 40 CFR 63, Subpart ZZZZ, this is an affected source]

11. One (1) diesel emergency generator, identified as CEESB-1, constructed in 1991 with a maximum capacity of 600 hp, located at W.W. Wright (CEE) / 245.
    [Under 40 CFR 63, Subpart ZZZZ, this is an affected source]

12. One (1) diesel emergency generator, identified as IMUSB-1, constructed in 1993 with a maximum capacity of 750 hp, located at Memorial Union / 053.
    [Under 40 CFR 63, Subpart ZZZZ, this is an affected source]

13. One (1) diesel emergency generator, identified as GSSB-1, constructed in 1994 with a maximum capacity of 30 hp, located at Geological Sciences /417.
    [Under 40 CFR 63, Subpart ZZZZ, this is an affected source]

14. One (1) diesel emergency generator, identified as RSSB-1, constructed in 1994 with a maximum capacity of 187.5 hp, located at Recreational Sports / 475.
    [Under 40 CFR 63, Subpart ZZZZ, this is an affected source]

15. One (1) diesel emergency generator, identified as RTVSB-1, constructed in 1996 with a maximum capacity of 300 hp, located at Radio/TV / 158.
    [Under 40 CFR 63, Subpart ZZZZ, this is an affected source]

16. One (1) diesel emergency generator, identified as AUSB-1, constructed in 1999 with a maximum capacity of 600 hp, located at Auditorium / 171.
    [Under 40 CFR 63, Subpart ZZZZ, this is an affected source]

17. One (1) diesel emergency generator, identified as CHPSB-1, constructed in 1999 with a maximum capacity of 1109 hp, located at Cen. Heat Plant / 445.
    [Under 40 CFR 63, Subpart ZZZZ, this is an affected source]

18. One (1) diesel emergency generator, identified as WQSB-2, constructed in 1999 with a maximum capacity of 600 hp, located at Willkie Quad / 299.
    [Under 40 CFR 63, Subpart ZZZZ, this is an affected source]

19. One (1) diesel emergency generator, identified as ALFSB-1, constructed in 2000 with a maximum capacity of 335 hp, located at ALF.
    [Under 40 CFR 63, Subpart ZZZZ, this is an affected source]

20. One (1) diesel emergency generator, identified as RHSB-1, constructed in 2000 with a maximum capacity of 525 hp, located at Read Hall / 227.
    [Under 40 CFR 63, Subpart ZZZZ, this is an affected source]

21. One (1) diesel emergency generator, identified as CVSB-1, constructed in 2001 with a maximum capacity of 300 hp, located at Campus View / 529.
    [Under 40 CFR 63, Subpart ZZZZ, this is an affected source]

22. One (1) diesel emergency generator, identified as EGSB-1, constructed in 2001 with a maximum capacity of 450 hp, located at Eigenmann / 313.
    [Under 40 CFR 63, Subpart ZZZZ, this is an affected source]

23. One (1) diesel emergency generator, identified as SHSB-1, constructed in 2001 with a maximum capacity of 375 hp, located at Spruce Hall / 298.
[Under 40 CFR 63, Subpart ZZZZ, this is an affected source]

24. One (1) diesel emergency generator, identified as TDSB-1, constructed in 2001 with a maximum capacity of 412.5 hp, located at Lee Norvelle Theatre Drama /172.
[Under 40 CFR 63, Subpart ZZZZ, this is an affected source]

25. One (1) diesel emergency generator, identified as MHSB-2, constructed in 2001 with a maximum capacity of 600 hp, located at McNutt / 439.
[Under 40 CFR 63, Subpart ZZZZ, this is an affected source]

26. One (1) diesel emergency generator, identified as MHSB-3, constructed in 2001 with a maximum capacity of 750 hp, located at Myers Hall / 101.
[Under 40 CFR 63, Subpart ZZZZ, this is an affected source]

27. One (1) diesel emergency generator, identified as ALSB-1, constructed in 2002 with a maximum capacity of 90 hp, located at Animal Lab / 411.
[Under 40 CFR 63, Subpart ZZZZ, this is an affected source]

28. One (1) diesel emergency generator, identified as USASB-1, constructed in 2005 with a maximum capacity of 450 hp, located at Union St Apts / 296.
[Under 40 CFR 63, Subpart ZZZZ, this is an affected source]

29. One (1) diesel emergency generator, identified as CIBSB-1, constructed in 2007 with a maximum capacity of 469 hp, located at CIB / 578.
[Under 40 CFR 60, Subpart IIII, this is an affected source]
[Under 40 CFR 63, Subpart ZZZZ, this is an affected source]

30. One (1) diesel emergency generator, identified as BASB-1, constructed in 2012 with a maximum capacity of 147 hp, located at Baseball/ 593.
[Under 40 CFR 60, Subpart IIII, this is an affected source]
[Under 40 CFR 63, Subpart ZZZZ, this is an affected source]

31. One (1) diesel emergency generator, identified as SBSB-2, constructed in 2012 with a maximum capacity of 99 hp, located at Softball/ 594.
[Under 40 CFR 60, Subpart IIII, this is an affected source]
[Under 40 CFR 63, Subpart ZZZZ, this is an affected source]

32. One (1) diesel emergency generator, identified as OPSB-1, constructed in 2014 with a maximum capacity of 375 hp, located at Optometry / 065
[Under 40 CFR 60, Subpart IIII, this is an affected source]
[Under 40 CFR 63, Subpart ZZZZ, this is an affected source]

33. One (1) diesel emergency generator, identified as WLSB-1, constructed in 2014 with a maximum capacity of 1206 hp, located at Wells Library /GISB 209.
[Under 40 CFR 60, Subpart IIII, this is an affected source]
[Under 40 CFR 63, Subpart ZZZZ, this is an affected source]

34. One (1) diesel emergency generator, identified as AHSB-2, constructed in 2015 with a maximum capacity of 668 hp, located at Assembly Hall / 603.
[Under 40 CFR 60, Subpart IIII, this is an affected source]
[Under 40 CFR 63, Subpart ZZZZ, this is an affected source]

35. One (1) diesel emergency generator, identified as FWSB-1, constructed in 2016 with a maximum capacity of 536 hp, located at Food Warehouse / 615.
[Under 40 CFR 60, Subpart IIII, this is an affected source]
[Under 40 CFR 63, Subpart ZZZZ, this is an affected source]

36. One (1) diesel emergency generator, identified as MESH-1, constructed in 2018 with a maximum capacity of 683.91 hp, located at MESH.
[Under 40 CFR 60, Subpart IIII, this is an affected source]
[Under 40 CFR 63, Subpart ZZZZ, this is an affected source]

37. One (1) diesel emergency generator, identified as 2NDSB-1, constructed in 2018 with a maximum capacity of 131 hp, located at 2427 E 2ND ST.
[Under 40 CFR 60, Subpart IIII, this is an affected source]
[Under 40 CFR 63, Subpart ZZZZ, this is an affected source]

38. One (1) diesel emergency generator, identified as ALFSB-2, constructed in 2018 with a maximum capacity of 201 hp, located at ALF.
[Under 40 CFR 60, Subpart IIII, this is an affected source]
[Under 40 CFR 63, Subpart ZZZZ, this is an affected source]

39. One (1) diesel emergency generator, identified as LHSB-1, constructed in 2018 with a maximum capacity of 324 hp, located at Luddy Hall.
[Under 40 CFR 60, Subpart IIII, this is an affected source]
[Under 40 CFR 63, Subpart ZZZZ, this is an affected source]

40. One (1) diesel emergency generator, identified as MSEZSB-1, constructed in 2018 with a maximum capacity of 450 hp, located at Memorial Stadium South End Zone.
[Under 40 CFR 60, Subpart IIII, this is an affected source]
[Under 40 CFR 63, Subpart ZZZZ, this is an affected source]

41. One (1) diesel emergency generator, identified as SPEASB-1, constructed in 2018 with a maximum capacity of 670 hp, located at SPEA / 452.
[Under 40 CFR 60, Subpart IIII, this is an affected source]
[Under 40 CFR 63, Subpart ZZZZ, this is an affected source]

42. One (1) diesel emergency generator, identified as SWSB-1, constructed in 2018 with a maximum capacity of 754 hp, located at Swain West.
[Under 40 CFR 60, Subpart IIII, this is an affected source]
[Under 40 CFR 63, Subpart ZZZZ, this is an affected source]

The source has following four (4) existing Off Campus Diesel Emergency Generators

43. One (1) diesel emergency generator, identified as Off Campus, constructed in 1996 with a maximum capacity of 52.5 hp, located at Morgan-Monroe Observatory / 690.

44. One (1) diesel emergency generator, identified as Off Campus, constructed in 1999 with a maximum capacity of 30 hp, located at Kent Farm / 700A.

45. One (1) diesel emergency generator, identified as Off Campus, constructed in 2007 with a maximum capacity of 145 hp, located at Sare Rd Transmitter.

46. One (1) diesel emergency generator, identified as Off Campus, constructed in 2012 with a maximum capacity of 315 hp, located at Sare Rd Transmitter /800A.

The source also has the following fifteen (15) existing, portable non-road Diesel Emergency Generators, but the source has opted to permit them as stationary to avoid tracking of their location.

47. One (1) diesel emergency generator, identified as PORT-1, constructed in 2002 with a maximum capacity of 80.46 hp, located at Service Building.
    [Under 40 CFR 63, Subpart ZZZZ, this is an affected source]

48. One (1) diesel emergency generator, identified as PORT-2, constructed in 1999 with a maximum capacity of 22.80 hp, located at Service Building/630.
    [Under 40 CFR 63, Subpart ZZZZ, this is an affected source]

49. Two (2) diesel emergency generators, identified as PORT-3 and PORT-4, each, constructed in 1999 with a maximum capacity of 80.46 hp, located at Union St. Chiller Plant – RPS.
    [Under 40 CFR 63, Subpart ZZZZ, this is an affected source]

50. Four (4) diesel emergency generator, identified as PORT-5, PORT-6, PORT-7 and PORT-8, each, constructed in 1999 with a maximum capacity of 13 hp, located at Service Building.
    [Under 40 CFR 63, Subpart ZZZZ, this is an affected source]

51. One (1) diesel emergency generator, identified as PORT-9, constructed in 2007 with a maximum capacity of 8.05 hp, located at service Building-Carpenter.
    [Under 40 CFR 60, Subpart IIII, this is an affected source]
    [Under 40 CFR 63, Subpart ZZZZ, this is an affected source]

52. Three (3) diesel emergency generator, identified as PORT-10, PORT-11 and PORT-12, each, constructed in 2006 with a maximum capacity of 156 hp, 2.68 hp and 2.68 hp respectively, located at service Building.
    [Under 40 CFR 60, Subpart IIII, this is an affected source]
    [Under 40 CFR 63, Subpart ZZZZ, this is an affected source]

53. Three (3) diesel emergency generator, identified as PORT-13, PORT-14 and PORT-15, constructed in 2015, 2017 and 2008 with a maximum capacity of 23.5 hp, 23.5 hp and 24.5 hp respectively, located at Utilities Building.
    [Under 40 CFR 60, Subpart IIII, this is an affected source]
    [Under 40 CFR 63, Subpart ZZZZ, this is an affected source]

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 Monroe County.

Pollutant	Designation
SO_2	Better than national standards.
CO	Unclassifiable or attainment effective November 15, 1990.
O_3	Unclassifiable or attainment effective July 20, 2012, for the 2008 8-hour ozone standard.[1]
$PM_{2.5}$	Unclassifiable or attainment effective April 15, 2015, for the 2012 annual PM2.5 standard.
$PM_{2.5}$	Unclassifiable or attainment effective December 13, 2009, for the 2006 24-hour PM2.5 standard.
PM_{10}	Unclassifiable effective November 15, 1990.

Pollutant	Designation
NO_2	Unclassifiable or attainment effective January 29, 2012, for the 2010 NO2 standard.
Pb	Unclassifiable or attainment effective December 31, 2011, for the 2008 lead standard.
[1]Unclassifiable or attainment effective October 18, 2000, for the 1-hour ozone standard which was revoked effective June 15, 2005.	

(a) Ozone Standards
Volatile organic compounds (VOC) and Nitrogen Oxides (NO_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. Monroe 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) $PM_{2.5}$
Monroe 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
Monroe 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 this source is classified as a stationary power plant that supplies campus with heat from fossils fuel boilers (or combinations thereof) totaling more than two hundred fifty million (250,000,000) British thermal units per hour heat input., it is considered one (1) of the twenty-eight (28) listed source categories, as specified in 326 IAC 2-2-1(ff)(1)(V), 326 IAC 2-3-2(g)(21), or 326 IAC 2-7-1(22)(B)(xxi). Therefore, fugitive emissions are counted toward the determination of PSD, Emission Offset, and Part 70 Permit applicability.

The fugitive emissions of hazardous air pollutants (HAP) are counted toward the determination of Part 70 Permit applicability and source status under Section 112 of the Clean Air Act (CAA).

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**	**Singl HAP[3]**		**Total HAPs**
Boiler EU-03 (Coal, NG & FO#2)	1204.5	240.90	240.90	2184.5	200.75	1.89	91.25	22.10	Hydrogen Chloride	25.06
Boiler EU-04 (Coal, NG & FO#2)	1204.5	240.90	240.90	2184.5	200.75	1.89	91.25	22.10	Hydrogen Chloride	25.06
Boiler EU-05 (NG & FO#2)	11.89	13.67	9.21	466.63	142.66	4.49	68.53	1.47	Hexane	1.54
Boiler EU-06 (Coal, NG & FO#2)	2288.6	457.71	457.71	4150.6	381.43	3.54	173.4	41.52	Hydrogen Chloride	47.62
Boiler EU-07 (NG & FO#2)	13.01	14.97	10.09	510.83	156.18	5.13	78.27	1.68	Hexane	1.76
Small NG Boilers (Insignificant Activites)	1.46	5.82	5.82	0.46	76.60	4.21	64.35	1.38	Hexane	1.45
Informatics East Building Boiler and Hutton Honors College Furnace	0.015	0.06	0.06	0.00	0.80	0.04	0.68	0.010	Hexane	0.015
Diesel-Fired Emergency Generators (< 600 hp)	6.70	6.70	6.70	6.24	94.41	7.66	20.34	0.025	Formalde hyde	0.083
Diesel-Fired Emergency Generators (> 600 hp)	3.64	2.09	2.09	0.06	124.93	3.67	28.63	0.028	Benzene	0.113
Coal Handling System	8.59	4.05	0.61	-	-	-	-	-	-	-
Fly Ash Silo Vent	1.89	1.89	1.89	-	-	-	-	-	-	-
Fly Ash Conveying Leg #1	9.75	3.41	3.41	-	-	-	-	-	-	-
Fly Ash Conveying Leg #2	9.75	3.41	3.41	-	-	-	-	-	-	-
Lime Silo Baghouse Vent	1.60	1.60	1.60	-	-	-	-	-	-	-
Carbon Silo Baghouse Vent	0.04	0.04	0.04	-	-	-	-	-	-	-
Fugitive Dust - Paved Roads	0.86	0.17	0.17	-	-	-	-			
Total PTE of Entire Source Including Fugitives*	**4766.74**	**997.39**	**984.61**	**9503.88**	**1378.52**	**32.52**	**616.68**	**85.72**	Hydrogen Chloride	**102.70**
Title V Major Source Thresholds	NA	100	100	100	100	100	100	10		25
PSD Major Source Thresholds	100	100	100	100	100	100	100	--		--

[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 unrestricted potential emissions of the source.

(a) The potential to emit (as defined in 326 IAC 2-7-1(30)) of PM10 PM2.5 SO2 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 equal to or greater than ten (10) tons per year and/or the potential to emit (as defined in 326 IAC 2-7-1(30)) of a combination of HAPs is equal to or greater than twenty-five (25) tons per year. The source will be issued a Part 70 Operating Permit Renewal.

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	NO_X	VOC	CO	Single HAP[3]		Total HAPs
Boiler EU-03 (Coal, NG & FO#2)	1204.5	240.90	240.90	2184.5	200.75	1.89	91.25	22.10	Hydrogen Chloride	25.06
Boiler EU-04 (Coal, NG & FO#2)	1204.5	240.90	240.90	2184.5	200.75	1.89	91.25	22.10	Hydrogen Chloride	25.06
Boiler EU-05 (NG & FO#2)	11.89	13.67	9.21	466.63	142.66	4.49	68.53	1.47	Hexane	1.54
Boiler EU-06 (Coal, NG & FO#2)	2288.5	457.71	457.71	4150.6	381.43	3.54	173.38	41.52	Hydrogen Chloride	47.62
Boiler EU-07 (NG & FO#2)	1.77	7.08	7.08	2.58	34.22	5.13	78.27	1.68	Hexane	1.76
Small NG Boilers (Insignificant Activites)	1.46	5.82	5.82	0.46	76.60	4.21	64.35	1.35	Hexane	1.45
Informatics East Building Boiler and Hutton Honors College Furnace	0.02	0.06	0.06	0.005	0.80	0.04	0.68	0.01	Hexane	0.015
Diesel-Fired Emergency Generators (< 600 hp)	6.70	6.70	6.70	6.24	94.41	7.66	20.34	0.025	Formaldehyde	0.083
Diesel-Fired Emergency Generators (> 600 hp)	3.64	2.09	2.09	0.06	124.93	3.67	28.63	0.028	Benzene	0.113
Coal Handling System	8.58	4.05	0.61	-	-	-	-	-	-	-
Fly Ash Silo Vent	1.89	1.89	1.89	-	-	-	-	-	-	-
Fly Ash Conveying Leg #1	9.75	3.41	3.41	-	-	-	-	-	-	-
Fly Ash Conveying Leg #2	9.75	3.41	3.41	-	-	-	-	-	-	-

	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	NO_X	VOC	CO	Single HAP[3]		Total HAPs
Lime Silo Baghouse Vent	1.60	1.60	1.60	-	-	-	-	-	-	-
Carbon Silo Baghouse Vent	0.04	0.04	0.04	-	-	-	-	-	-	-
Fugitive Dust - Paved Roads	0.86	0.17	0.17	-	-	-	-	-	-	-
Total PTE of Entire Source Including Fugitives*	**4755.50**	**989.50**	**981.61**	**8995.63**	**1256.55**	**32.52**	**616.68**	**85.72**	**Hydrogen Chloride**	**102.70**
Title V Major Source Thresholds	NA	100	100	100	100	100	100	XX	10	25
PSD Major Source Thresholds	100	100	100	100	100	100	100	XX	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 a PSD regulated pollutant, PM PM10 PM2.5 SO2 NOx and CO, are emitted at a rate of 100 tons per year or more, and it is one of the twenty-eight (28) listed source categories, as specified in 326 IAC 2-2-1(ff)(1).

(b) This source is a major source of HAP, as defined in 40 CFR 63.2, because HAP emissions are equal to or greater than ten (10) tons per year for a single HAP and equal to or greater than twenty-five (25) tons per year for a combination of HAPs. Therefore, this source is a major source under Section 112 of the Clean Air Act (CAA).

Federal Rule Applicability

Federal rule applicability for this source has been reviewed as follows:

New Source Performance Standards (NSPS):

(a) The Diesel-Fired Emergency Generators are subject to the New Source Performance Standard for Stationary Compression Ignition Internal Combustion Engines, 40 CFR 60, Subpart IIII, and 326 IAC 12, because each of these generators are compression ignition type with displacement of less than 30 liters/cylinder and constructed on or after the July 11, 2005, applicability date.

The Diesel-Fired Emergency Generators subject to this rule include the followings:

(1) One (1) diesel emergency generator, identified as HAPSB-1, manufactured in 2007, with a maximum capacity of 60 hp, located outside the Henderson/Atwater Parking Area.
[Under 40 CFR 60, Subpart IIII, this is an affected source]
[Under 40 CFR 63, Subpart ZZZZ, this is an affected source]

(2) One (1) diesel emergency generator, identified as IUPD-1, manufactured in 2007, with a maximum capacity of 545 hp, located outside of the IU Police Department Building.

[Under 40 CFR 60, Subpart IIII, this is an affected source]
[Under 40 CFR 63, Subpart ZZZZ, this is an affected source]

(3) One (1) diesel emergency generator, identified as JHSB-1, manufactured in 2007, with a maximum capacity of 225 hp, located outside of Johnston Hall.
[Under 40 CFR 60, Subpart IIII, this is an affected source]
[Under 40 CFR 63, Subpart ZZZZ, this is an affected source]

(4) One (1) diesel emergency generator, identified as TQSB-1, manufactured in 2007, with a maximum capacity of 320 hp, located outside of Teter Quad Building.
[Under 40 CFR 60, Subpart IIII, this is an affected source]
[Under 40 CFR 63, Subpart ZZZZ, this is an affected source]

(5) One (1) diesel emergency generator, identified as MSB-1, manufactured in 2007, with a maximum capacity of 1,200 hp, located inside of the MSB-1 Building.
[Under 40 CFR 60, Subpart IIII, this is an affected source]
[Under 40 CFR 63, Subpart ZZZZ, this is an affected source]

(6) One (1) diesel emergency generator, identified as JDHSB-1, manufactured in 2007, with a maximum capacity of 80 hp, located at Jordan Hall.
[Under 40 CFR 60, Subpart IIII, this is an affected source]
[Under 40 CFR 63, Subpart ZZZZ, this is an affected source]

(7) One (1) diesel emergency generator, identified as WQSB-1, manufactured in 2007, with a maximum capacity of 225.6 hp, located at Wright Quad.
[Under 40 CFR 60, Subpart IIII, this is an affected source]
[Under 40 CFR 63, Subpart ZZZZ, this is an affected source]

(8) One (1) diesel emergency generator, identified as HCSB-1, manufactured in 2008, with a maximum capacity of 1,150 hp, located outside of the Health Center.
[Under 40 CFR 60, Subpart IIII, this is an affected source]
[Under 40 CFR 63, Subpart ZZZZ, this is an affected source]

(9) One (1) diesel emergency generator, identified as MSB-2, manufactured in 2008, with a maximum capacity of 1,490 hp, located at Simon Hall.
[Under 40 CFR 60, Subpart IIII, this is an affected source]
[Under 40 CFR 63, Subpart ZZZZ, this is an affected source]

(10) One (1) diesel emergency generator, identified as MSNSB-1, manufactured in 2007, with a maximum capacity of 258 hp, located at Memorial Stadium North.
[Under 40 CFR 60, Subpart IIII, this is an affected source]
[Under 40 CFR 63, Subpart ZZZZ, this is an affected source]

(11) One (1) diesel emergency generator, identified as BCSB-1, manufactured in 2008, with a maximum capacity of 360 hp, located at Basketball Center Cook Hall.
[Under 40 CFR 60, Subpart IIII, this is an affected source]
[Under 40 CFR 63, Subpart ZZZZ, this is an affected source]

(12) One (1) diesel emergency generator, identified as CHSB-1, manufactured in 2009, with a maximum capacity of 300 hp, located at Cedar Hall.
[Under 40 CFR 60, Subpart IIII, this is an affected source]
[Under 40 CFR 63, Subpart ZZZZ, this is an affected source]

(13) One (1) diesel emergency generator, identified as HPSB-1, manufactured in 2009, with a maximum capacity of 606 hp, located at HPER.
[Under 40 CFR 60, Subpart IIII, this is an affected source]

[Under 40 CFR 63, Subpart ZZZZ, this is an affected source]

(14) One (1) diesel emergency generator, identified as ICSB-1, manufactured in 2009, with a maximum capacity of 186 hp,located at IU Innovation Center.
[Under 40 CFR 60, Subpart IIII, this is an affected source]
[Under 40 CFR 63, Subpart ZZZZ, this is an affected source]

(15) One (1) diesel emergency generator, identified as MHSB-1, manufactured in 2009, with a maximum capacity of 56 hp, located outside of Mason Hall.
[Under 40 CFR 60, Subpart IIII, this is an affected source]
[Under 40 CFR 63, Subpart ZZZZ, this is an affected source]

(16) One (1) diesel emergency generator, identified as DCSB-1, manufactured in 2008, with a maximum capacity of 2,200 hp, located inside of Data Center #1.
[Under 40 CFR 60, Subpart IIII, this is an affected source]
[Under 40 CFR 63, Subpart ZZZZ, this is an affected source]

(17) One (1) diesel emergency generator, identified as DCSB-2, manufactured in 2008, with a maximum capacity of 2,200 hp, located inside of Data Center #2.
[Under 40 CFR 60, Subpart IIII, this is an affected source]
[Under 40 CFR 63, Subpart ZZZZ, this is an affected source]

(18) One (1) diesel emergency generator, identified as BBSB-1, manufactured in 2011, with a maximum capacity of 720 hp, located at Briscoe Building.
[Under 40 CFR 60, Subpart IIII, this is an affected source]
[Under 40 CFR 63, Subpart ZZZZ, this is an affected source]

(19) One (1) diesel emergency generator, identified as MACSB-1, manufactured in 2011, with a maximum capacity of 120 hp, located at the Musical Arts Center.
[Under 40 CFR 60, Subpart IIII, this is an affected source]
[Under 40 CFR 63, Subpart ZZZZ, this is an affected source]

(20) One (1) diesel emergency generator, identified as FQSB-1, manufactured in 2012, with a maximum capacity of 460 hp, located at Forest Quad.
[Under 40 CFR 60, Subpart IIII, this is an affected source]
[Under 40 CFR 63, Subpart ZZZZ, this is an affected source]

(21) One (1) diesel emergency generator, identified as JSMSB-1, manufactured in 2012, with a maximum capacity of 475 hp, located at the Jacobs School of Music.
[Under 40 CFR 60, Subpart IIII, this is an affected source]
[Under 40 CFR 63, Subpart ZZZZ, this is an affected source]

These Diesel-Fired Emergency Generators are subject to the following portions of 40 CFR 60, Subpart IIII:

(1) 40 CFR 60.4202(a)(2)
(2) 40 CFR 60.4205(b)
(3) 40 CFR 60.4206
(4) 40 CFR 60.4207(a), (b)
(5) 40 CFR 60.4208(a), (b), (h), (i)
(6) 40 CFR 60.4209(a)
(7) 40 CFR 60.4211(a), (c),(f)(2)(i), (g)
(8) 40 CFR 60.4212
(9) 40 CFR 60.4214(b)
(10) 40 CFR 60.4218
(11) 40 CFR 60.4219

(12) Table 8, Subpart IIII of 60

(b) The Diesel-Fired Emergency Generators are subject to the New Source Performance Standards for Standards of Performance for Stationary Compression Ignition Internal Combustion Engines, 40 CFR 60, Subpart IIII and 326 IAC 12 because each of these generators are compression ignition type with displacement of greater than or equal to 10 liters per cylinder and less than 30 liters per cylinder that are not fire pump engines.and constructed after July 11, 2005. The Diesel-Fired Emergency Generators subject to this rule include the following:

(1) One (1) diesel emergency generators, identified as FQHSB-1, manufactured in 2006, with a maximum capacity of 282 hp, located outside the Foster Quad/Harper Buildings.
[Under 40 CFR 60, Subpart IIII, this is an affected source]
[Under 40 CFR 63, Subpart ZZZZ, this is an affected source]

(2) One (1) diesel emergency generators, identified as TTASB-1, manufactured in 2006, with a maximum capacity of 300 hp, located outside the Tulip Tree Apartments.
[Under 40 CFR 60, Subpart IIII, this is an affected source]
[Under 40 CFR 63, Subpart ZZZZ, this is an affected source]

These Diesel-Fired Emergency Generators are subject to the following portions of 40 CFR 60, Subpart IIII:

(1) 40 CFR 60.4200(a)(2)(i)
(2) 40 CFR 60.4205(a)
(3) 40 CFR 60.4206
(4) 40 CFR 60.4207(b)
(5) 40 CFR 60.4209(a)
(6) 40 CFR 60.4211(f)(2)(i)
(7) 40 CFR 60.4214(b)
(8) 40 CFR 60.4218
(9) 40 CFR 60.4219
(10) Table 8, Subpart IIII of 60

(c) The Diesel-Fired Emergency Generators (unpermitted) are subject to the New Source Performance Standards for Standards of Performance for Stationary Compression Ignition Internal Combustion Engines, 40 CFR 60, Subpart IIII and 326 IAC 12 because each of these generators are compression ignition type with displacement of greater than or equal to 10 liters per cylinder and less than 30 liters per cylinder that are not fire pump engines and constructed after July 11, 2005.

The Diesel-Fired Emergency Generators subject to this rule include the following:

1. One (1) diesel emergency generator, identified as CIBSB-1, constructed in 2007 with a maximum capacity of 469 hp, located at CIB / 578.
[Under 40 CFR 60, Subpart IIII, this is an affected source]
[Under 40 CFR 63, Subpart ZZZZ, this is an affected source]

2. One (1) diesel emergency generator, identified as BASB-1, constructed in 2012 with a maximum capacity of 147 hp, located at Baseball/ 593.
[Under 40 CFR 60, Subpart IIII, this is an affected source]
[Under 40 CFR 63, Subpart ZZZZ, this is an affected source]

3. One (1) diesel emergency generator, identified as SBSB-2, constructed in 2012 with a maximum capacity of 99 hp, located at Softball/ 594.

[Under 40 CFR 60, Subpart IIII, this is an affected source]
[Under 40 CFR 63, Subpart ZZZZ, this is an affected source]

4. One (1) diesel emergency generator, identified as OPSB-1, constructed in 2014 with a maximum capacity of 375 hp, located at Optometry / 065
[Under 40 CFR 60, Subpart IIII, this is an affected source]
[Under 40 CFR 63, Subpart ZZZZ, this is an affected source]

5. One (1) diesel emergency generator, identified as WLSB-1, constructed in 2014 with a maximum capacity of 1206 hp, located at Wells Library /GISB 209.
[Under 40 CFR 60, Subpart IIII, this is an affected source]
[Under 40 CFR 63, Subpart ZZZZ, this is an affected source]

6. One (1) diesel emergency generator, identified as AHSB-2, constructed in 2015 with a maximum capacity of 668 hp, located at Assembly Hall / 603.
[Under 40 CFR 60, Subpart IIII, this is an affected source]
[Under 40 CFR 63, Subpart ZZZZ, this is an affected source]

7. One (1) diesel emergency generator, identified as FWSB-1, constructed in 2016 with a maximum capacity of 536 hp, located at Food Warehouse / 615.
[Under 40 CFR 60, Subpart IIII, this is an affected source]
[Under 40 CFR 63, Subpart ZZZZ, this is an affected source]

8. One (1) diesel emergency generator, identified as MESH-1, constructed in 2018 with a maximum capacity of 683.91 hp, located at MESH.
[Under 40 CFR 60, Subpart IIII, this is an affected source]
[Under 40 CFR 63, Subpart ZZZZ, this is an affected source]

9. One (1) diesel emergency generator, identified as 2NDSB-1, constructed in 2018 with a maximum capacity of 131 hp, located at 2427 E 2ND ST.
[Under 40 CFR 60, Subpart IIII, this is an affected source]
[Under 40 CFR 63, Subpart ZZZZ, this is an affected source]

10. One (1) diesel emergency generator, identified as ALFSB-2, constructed in 2018 with a maximum capacity of 201 hp, located at ALF.
[Under 40 CFR 60, Subpart IIII, this is an affected source]
[Under 40 CFR 63, Subpart ZZZZ, this is an affected source]

11. One (1) diesel emergency generator, identified as LHSB-1, constructed in 2018 with a maximum capacity of 324 hp, located at Luddy Hall.
[Under 40 CFR 60, Subpart IIII, this is an affected source]
[Under 40 CFR 63, Subpart ZZZZ, this is an affected source]

12. One (1) diesel emergency generator, identified as MSEZSB-1, constructed in 2018 with a maximum capacity of 450 hp, located at Memorial Stadium South End Zone.
[Under 40 CFR 60, Subpart IIII, this is an affected source]
[Under 40 CFR 63, Subpart ZZZZ, this is an affected source]

13. One (1) diesel emergency generator, identified as SPEASB-1, constructed in 2018 with a maximum capacity of 670 hp, located at SPEA / 452.
[Under 40 CFR 60, Subpart IIII, this is an affected source]
[Under 40 CFR 63, Subpart ZZZZ, this is an affected source]

14. One (1) diesel emergency generator, identified as SWSB-1, constructed in 2018 with a maximum capacity of 754 hp, located at Swain West.
[Under 40 CFR 60, Subpart IIII, this is an affected source]

[Under 40 CFR 63, Subpart ZZZZ, this is an affected source]

15. One (1) diesel emergency generator, identified as PORT-9, constructed in 2007 with a maximum capacity of 8.05 hp, located at service Building-Carpenter.
[Under 40 CFR 60, Subpart IIII, this is an affected source]
[Under 40 CFR 63, Subpart ZZZZ, this is an affected source]

16. Three (3) diesel emergency generator, identified as PORT-10, PORT-11 and PORT-12, each, constructed in 2006 with a maximum capacity of 156 hp, 2.68 hp and 2.68 hp respectively, located at service Building.
[Under 40 CFR 60, Subpart IIII, this is an affected source]
[Under 40 CFR 63, Subpart ZZZZ, this is an affected source]

17. Three (3) diesel emergency generator, identified as PORT-13, PORT-14 and PORT-15, constructed in 2015, 2017 and 2008 with a maximum capacity of 23.5 hp, 23.5 hp and 24.5 hp respectively, located at Utilities Building.
[Under 40 CFR 60, Subpart IIII, this is an affected source]
[Under 40 CFR 63, Subpart ZZZZ, this is an affected source]

These Diesel-Fired Emergency Generators are subject to the following portions of 40 CFR 60,Subpart IIII:

(1) 40 CFR 60.4200(a)(2)(i)
(2) 40 CFR 60.4202(a)
(3) 40 CFR 60.4205(a), (b)
(4) 40 CFR 60.4206
(5) 40 CFR 60.4207(a), (b)
(6) 40 CFR 60.4208
(7) 40 CFR 60.4209(a)
(8) 40 CFR 60.4211(a), (f)(2)(i), (g)
(9) 40 CFR 60.4214(b)
(10) 40 CFR 60.4218
(11) 40 CFR 60.4219
(12) Table 8, Subpart IIII of 60

The requirements of 40 CFR Part 60, Subpart A – General Provisions, which are incorporated as 326 IAC 12-1, apply to the emergency generators except as otherwise specified in 40 CFR 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 ~~strikethroug~~h 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 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.~~

The requirements of the New Source Performance Standard for Standards of Performance for Industrial-Commercial-Institutional Steam Generating Units, 40 CFR 60, Subpart Db and 326 IAC 12, are not included in the permit for Boiler EU-06, because it was construced in 1970 before the rule applicability date of June 19, 1984.

(d) The requirements of the New Source Performance Standard for Standards of Performance for Industrial-Commercial-Institutional Steam Generating Units, 40 CFR 60, Subpart Db and 326 IAC 12, are not included in the permit for Boilers EU-03, EU-04, and EU-05, because those were construced in 1959, 1959 and 1964 respectively before the rule applicability date of June 19, 1984.

(e) The requirements of the New Source Performance Standard for Standards of Performance for Industrial-Commercial-Institutional Steam Generating Units, 40 CFR 60, Subpart Db and 326 IAC 12, are not included in the permit for Boiler EU-06, because it was construced in 1970 before the rule applicability date of June 19, 1984. Also, the addition of two natural gas fired burners added in 1994 shall not be subject to the requirements of the New Source Performance Standard because the emission rate using the natural gas fired burners will be less than the rate for all pollutants when combusting coal.

(f) The requirements of the New Source Performance Standard for Small Industrial-Commercial-Institutional Steam Generating Units, 40 CFR 60, Subpart Dc and 326 IAC 12, are not included in the permit for the following boilers and process heaters because each of these emission units has a maximum design heat input capacity less than 10 MMBtu/hr (2.9 MW)

Construction Year	Type of Unit	Maximum Heat Input Capacity (MMBtu/hr)
Before 1972	22 Boilers	each < 10 29.13 (Total)
1977	1 Boiler	0.60
1981	1 Boiler	0.11
After 1983	66 Boilers	each < 10 145.25 (Total)
2008	Informatics East Bldg. Boiler	1.44
	Hutton Honors College Furnace	0.432
2009	3 Boilers at Innovation Center	1.1 (each)

(g) The natural gas-fired boiler, (using low sulfur No. 1 or No. 2 fuel oil as a back-up), is subject to the New Source Performance Standards for Industrial-Commercial-Institutional Steam Generating Units, 40 CFR 60, Subpart Db and 326 IAC 12, because it was constructed after the applicability date of June 19, 1984 and it has a heat input capacity greater than 100 MMBtu/hr (29 MW).

The emission units subject to this rule are as follows;

(1) One (1) natural gas-fired boiler, (using low sulfur No. 1 or No. 2 fuel oil as a back-up), identified as EU 07, approved for construction in 2007, with a maximum design capacity of 217 MMBtu per hour heat input.

The Boiler, identified as EU-07 is subject to the following portions of 40 CFR 60,Subpart Db:

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

(h) The requirements of the New Source Performance Standard for Stationary Spark Ignition Internal Combustion Engines 40 CFR 60, Subpart JJJJ and 326 IAC 12, are not included in the permit for diesel-fired emergency generators because each generator is a compression ignition internal combustion engine.

(i) The requirements of the New Source Performance Standard for Coal Preparation and Processing Plants, 40 CFR 60, Subpart Y and 326 IAC 12, are not included in the permit for Coal Storage and Handling System, because the university power plant does not dry, clean, break, or crush the coal before combustion.

(j) There are no other New Source Performance Standards (NSPS) (326 IAC 12 and 40 CFR Part 60) included in the permit for this source.

National Emission Standards for Hazardous Air Pollutants (NESHAP):

(k) The Diesel-Fired Emergency Generators are still subject to the National Emission Standards for Hazardous Air Pollutants for Performance for Stationary Reciprocating Internal Combustion Engines, 40 CFR 63, Subpart ZZZZ, which is incorporated by reference as 326 IAC 20-82, because they are located at a major source for hazardous air pollutant emissions (HAP) and they each have a site rating of more than 500 brake horse power. The Emergency Generators subject to this rule include the following:

(1) One (1) diesel emergency generator, identified as BBSB-1, manufactured in 2011, with a maximum capacity of 720 hp, located at Briscoe Building.
[Under 40 CFR 60, Subpart IIII, this is an affected source]
[Under 40 CFR 63, Subpart ZZZZ, this is an affected source]

(2) One (1) diesel emergency generator, identified as HPSB-1, manufactured in 2009, with a maximum capacity of 606 hp, located at HPER.
[Under 40 CFR 60, Subpart IIII, this is an affected source]

[Under 40 CFR 63, Subpart ZZZZ, this is an affected source]

(3) One (1) diesel emergency generator, identified as MSB-2, manufactured in 2008, with a maximum capacity of 1,490 hp, located at Simon Hall.
[Under 40 CFR 60, Subpart IIII, this is an affected source]
[Under 40 CFR 63, Subpart ZZZZ, this is an affected source]

These emissions units are subject to the following portions of 40 CFR 63, Subpart ZZZZ:

(1) 40 CFR 63.6590(b)(1)(i), (c)
(2) 40 CFR 63.6645(f)

(l) The Diesel-Fired Emergency Generators are still subject to the National Emission Standards for Hazardous Air Pollutants for Performance for Stationary Reciprocating Internal Combustion Engines, 40 CFR 63, Subpart ZZZZ, which is incorporated by reference as 326 IAC 20-82, because they are located at a major source for hazardous air pollutant emissions (HAP) and they each have a site rating of less than 500 brake horse power. The Emergency Generators subject to this rule include the following:

(1) One (1) diesel emergency generator, identified as BCSB-1, manufactured in 2008, with a maximum capacity of 360 hp, located at Basketball Center Cook Hall.
[Under 40 CFR 60, Subpart IIII, this is an affected source]
[Under 40 CFR 63, Subpart ZZZZ, this is an affected source]

(2) One (1) diesel emergency generator, identified as CHSB-1, manufactured in 2009, with a maximum capacity of 300 hp, located at Cedar Hall.
[Under 40 CFR 60, Subpart IIII, this is an affected source]
[Under 40 CFR 63, Subpart ZZZZ, this is an affected source]

(3) One (1) diesel emergency generator, identified as FQSB-1, manufactured in 2012, with a maximum capacity of 460 hp, located at Forest Quad.
[Under 40 CFR 60, Subpart IIII, this is an affected source]
[Under 40 CFR 63, Subpart ZZZZ, this is an affected source]

(4) One (1) diesel emergency generator, identified as JSMSB-1, manufactured in 2012, with a maximum capacity of 475 hp, located at the Jacobs School of Music.
[Under 40 CFR 60, Subpart IIII, this is an affected source]
[Under 40 CFR 63, Subpart ZZZZ, this is an affected source]

(5) One (1) diesel emergency generator, identified as JDHSB-1, manufactured in 2007, with a maximum capacity of 80 hp, located at Jordan Hall.
[Under 40 CFR 60, Subpart IIII, this is an affected source]
[Under 40 CFR 63, Subpart ZZZZ, this is an affected source]

(6) One (1) diesel emergency generator, identified as MACSB-1, manufactured in 2011, with a maximum capacity of 120 hp, located at the Musical Arts Center.
[Under 40 CFR 60, Subpart IIII, this is an affected source]
[Under 40 CFR 63, Subpart ZZZZ, this is an affected source]

(7) One (1) diesel emergency generator, identified as ICSB-1, manufactured in 2009, with a maximum capacity of 186 hp,located at IU Innovation Center.
[Under 40 CFR 60, Subpart IIII, this is an affected source]
[Under 40 CFR 63, Subpart ZZZZ, this is an affected source]

(8) One (1) diesel emergency generator, identified as WQSB-1, manufactured in 2007, with a maximum capacity of 225.6 hp, located at Wright Quad.

[Under 40 CFR 60, Subpart IIII, this is an affected source]
[Under 40 CFR 63, Subpart ZZZZ, this is an affected source]

(9) One (1) diesel emergency generator, identified as MSNSB-1, manufactured in 2008, with a maximum capacity of 258 hp, located at Memorial Stadium North.
[Under 40 CFR 60, Subpart IIII, this is an affected source]
[Under 40 CFR 63, Subpart ZZZZ, this is an affected source]

These emissions units are subject to the following portions of 40 CFR 63, Subpart ZZZZ:

(1) 40 CFR 63.6590(b)(1)(i) & (c)(6)
(2) 40 CFR 63.6645(f)

(m) The Diesel-Fired Emergency Generators are still subject to the National Emission Standards for Hazardous Air Pollutants for Performance for Stationary Reciprocating Internal Combustion Engines, 40 CFR 63, Subpart ZZZZ, which is incorporated by reference as 326 IAC 20-82, because they are located at a major source for hazardous air pollutant emissions (HAP) and they each have a site rating of less than 500 brake horse power and do not operate or are 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). The Emergency Generators subject to this rule include the following:

(1) One (1) diesel emergency generators, identified as FQHSB-1, manufactured in 2006, with a maximum capacity of 282 hp, located outside the Foster Quad/Harper Buildings.
[Under 40 CFR 60, Subpart IIII, this is an affected source]
[Under 40 CFR 63, Subpart ZZZZ, this is an affected source]

(2) One (1) diesel emergency generator, identified as HAPSB-1, manufactured in 2007, with a maximum capacity of 60 hp, located outside the Henderson/Atwater Parking Area.
[Under 40 CFR 60, Subpart IIII, this is an affected source]
[Under 40 CFR 63, Subpart ZZZZ, this is an affected source]

(3) One (1) diesel emergency generators, identified as TTASB-1, manufactured in 2006, with a maximum capacity of 300 hp, located outside the Tulip Tree Apartments.
[Under 40 CFR 60, Subpart IIII, this is an affected source]
[Under 40 CFR 63, Subpart ZZZZ, this is an affected source]

(4) One (1) diesel emergency generator, identified as IUPD-1, manufactured in 2007, with a maximum capacity of 545 hp, located outside of the IU Police Department Building.
[Under 40 CFR 60, Subpart IIII, this is an affected source]
[Under 40 CFR 63, Subpart ZZZZ, this is an affected source]

(5) One (1) diesel emergency generator, identified as JHSB-1, manufactured in 2007, with a maximum capacity of 225 hp, located outside of Johnston Hall.
[Under 40 CFR 60, Subpart IIII, this is an affected source]
[Under 40 CFR 63, Subpart ZZZZ, this is an affected source]

(6) One (1) diesel emergency generator, identified as TQSB-1, manufactured in 2007, with a maximum capacity of 320 hp, located outside of Teter Quad Building.
[Under 40 CFR 60, Subpart IIII, this is an affected source]
[Under 40 CFR 63, Subpart ZZZZ, this is an affected source]

(7) One (1) diesel emergency generator, identified as MHSB-1, manufactured in 2009, with a maximum capacity of 56 hp, located outside of Mason Hall.
[Under 40 CFR 60, Subpart IIII, this is an affected source]
[Under 40 CFR 63, Subpart ZZZZ, this is an affected source]

These emissions units are subject to the following portions of 40 CFR 63, Subpart ZZZZ:

(1) 40 CFR 63.6580
(2) 40 CFR 63.6585
(3) 40 CFR 63.6585(b)
(4) 40 CFR 63.6590(a)
(5) 40 CFR 63.6590(a)(2)(ii)
(6) 40 CFR 63.6590(c)
(7) 40 CFR 63.6605
(8) 40 CFR 63.6675

(n) The Diesel-Fired Emergency Generators are still subject to the National Emission Standards for Hazardous Air Pollutants for Performance for Stationary Reciprocating Internal Combustion Engines, 40 CFR 63, Subpart ZZZZ, which is incorporated by reference as 326 IAC 20-82, because they are located at a major source for hazardous air pollutant emissions (HAP) and they each have a site rating of more than 500 brake horse power and do not operate or are 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). The Emergency Generators subject to this rule include the following:

(1) One (1) diesel emergency generator, identified as HCSB-1, manufactured in 2007, with a maximum capacity of 1,150 hp, located outside of the Health Center.
[Under 40 CFR 60, Subpart IIII, this is an affected source]
[Under 40 CFR 63, Subpart ZZZZ, this is an affected source]

(2) One (1) diesel emergency generator, identified as DCSB-1, manufactured in 2008, with a maximum capacity of 2,200 hp, located inside of Data Center #1.
[Under 40 CFR 60, Subpart IIII, this is an affected source]
[Under 40 CFR 63, Subpart ZZZZ, this is an affected source]

(3) One (1) diesel emergency generator, identified as DCSB-2, manufactured in 2008, with a maximum capacity of 2,200 hp, located inside of Data Center #2.
[Under 40 CFR 60, Subpart IIII, this is an affected source]
[Under 40 CFR 63, Subpart ZZZZ, this is an affected source]

(4) One (1) diesel emergency generator, identified as MSB-1, manufactured in 2007, with a maximum capacity of 1,200 hp, located inside of the MSB-1 Building.
[Under 40 CFR 60, Subpart IIII, this is an affected source]
[Under 40 CFR 63, Subpart ZZZZ, this is an affected source]

These emissions units are subject to the following portions of 40 CFR 63, Subpart ZZZZ:

(1) 40 CFR 63.6590(b)(1)(i)
(2) 40 CFR 63.6645(f)

(o) The Diesel-Fired Emergency Generators (unpermitted) are subject to the National Emission Standards for Hazardous Air Pollutants for Performance for Stationary Reciprocating Internal Combustion Engines, 40 CFR 63, Subpart ZZZZ, which is incorporated by reference as 326 IAC 20-82, because they are located at a major source for hazardous air pollutant emissions (HAP). The Emergency Generators subject to this rule include the following:

1. One (1) diesel emergency generator, identified as FHSB-1, constructed in 1957 with a maximum capacity of 67.5 hp, located at Field House / 604.

[Under 40 CFR 63, Subpart ZZZZ, this is an affected source]

2. One (1) diesel emergency generator, identified as HASB-1, constructed in 1970 with a maximum capacity of 26.2 hp, located at Hall Admin. / 463.
[Under 40 CFR 63, Subpart ZZZZ, this is an affected source]

3. One (1) diesel emergency generator, identified as FHSB-2, constructed in 1972 with a maximum capacity of 22.5 hp, located at Franklin Hall / 007.
[Under 40 CFR 63, Subpart ZZZZ, this is an affected source]

4. One (1) diesel emergency generator, identified as LBSB-1, constructed in 1981 with a maximum capacity of 150 hp, located at Law Building / 001.
[Under 40 CFR 63, Subpart ZZZZ, this is an affected source]

5. One (1) diesel emergency generator, identified as POPSB-1, constructed in 1985 with a maximum capacity of 255 hp, located at Poplars Bldg. / 008.
[Under 40 CFR 63, Subpart ZZZZ, this is an affected source]

6. One (1) diesel emergency generator, identified as SBSB-4, constructed in 1986 with a maximum capacity of 765 hp, located at Service Bldg / 630.
[Under 40 CFR 63, Subpart ZZZZ, this is an affected source]

7. One (1) diesel emergency generator, identified as MASB-1, constructed in 1989 with a maximum capacity of 91.5 hp, located at Music Addition / 148.
[Under 40 CFR 63, Subpart ZZZZ, this is an affected source]

8. One (1) diesel emergency generator, identified as CASB-1, constructed in 1990 with a maximum capacity of 900 hp, located at Chemistry Addition / 072.
[Under 40 CFR 63, Subpart ZZZZ, this is an affected source]

9. One (1) diesel emergency generator, identified as JHSB-2, constructed in 1990 with a maximum capacity of 600 hp, located at Jordan Hall / 107.
[Under 40 CFR 63, Subpart ZZZZ, this is an affected source]

10. One (1) diesel emergency generator, identified as SBSB-3, constructed in 1991 with a maximum capacity of 30 hp, located at Student Building / 017.
[Under 40 CFR 63, Subpart ZZZZ, this is an affected source]

11. One (1) diesel emergency generator, identified as CEESB-1, constructed in 1991 with a maximum capacity of 600 hp, located at W.W. Wright (CEE) / 245.
[Under 40 CFR 63, Subpart ZZZZ, this is an affected source]

12. One (1) diesel emergency generator, identified as IMUSB-1, constructed in 1993 with a maximum capacity of 750 hp, located at Memorial Union / 053.
[Under 40 CFR 63, Subpart ZZZZ, this is an affected source]

13. One (1) diesel emergency generator, identified as GSSB-1, constructed in 1994 with a maximum capacity of 30 hp, located at Geological Sciences /417.
[Under 40 CFR 63, Subpart ZZZZ, this is an affected source]

14. One (1) diesel emergency generator, identified as RSSB-1, constructed in 1994 with a maximum capacity of 187.5 hp, located at Recreational Sports / 475.
[Under 40 CFR 63, Subpart ZZZZ, this is an affected source]

15. One (1) diesel emergency generator, identified as RTVSB-1, constructed in 1996 with a maximum capacity of 300 hp, located at Radio/TV / 158.
[Under 40 CFR 63, Subpart ZZZZ, this is an affected source]

16. One (1) diesel emergency generator, identified as AUSB-1, constructed in 1999 with a maximum capacity of 600 hp, located at Auditorium / 171.
[Under 40 CFR 63, Subpart ZZZZ, this is an affected source]

17. One (1) diesel emergency generator, identified as CHPSB-1, constructed in 1999 with a maximum capacity of 1109 hp, located at Cen. Heat Plant / 445.
[Under 40 CFR 63, Subpart ZZZZ, this is an affected source]

18. One (1) diesel emergency generator, identified as WQSB-2, constructed in 1999 with a maximum capacity of 600 hp, located at Willkie Quad / 299.
[Under 40 CFR 63, Subpart ZZZZ, this is an affected source]

19. One (1) diesel emergency generator, identified as ALFSB-1, constructed in 2000 with a maximum capacity of 335 hp, located at ALF.
[Under 40 CFR 63, Subpart ZZZZ, this is an affected source]

20. One (1) diesel emergency generator, identified as RHSB-1, constructed in 2000 with a maximum capacity of 525 hp, located at Read Hall / 227.
[Under 40 CFR 63, Subpart ZZZZ, this is an affected source]

21. One (1) diesel emergency generator, identified as CVSB-1, constructed in 2001 with a maximum capacity of 300 hp, located at Campus View / 529.
[Under 40 CFR 63, Subpart ZZZZ, this is an affected source]

22. One (1) diesel emergency generator, identified as EGSB-1, constructed in 2001 with a maximum capacity of 450 hp, located at Eigenmann / 313.
[Under 40 CFR 63, Subpart ZZZZ, this is an affected source]

23. One (1) diesel emergency generator, identified as SHSB-1, constructed in 2001 with a maximum capacity of 375 hp, located at Spruce Hall / 298.
[Under 40 CFR 63, Subpart ZZZZ, this is an affected source]

24. One (1) diesel emergency generator, identified as TDSB-1, constructed in 2001 with a maximum capacity of 412.5 hp, located at Lee Norvelle Theatre Drama /172.
[Under 40 CFR 63, Subpart ZZZZ, this is an affected source]

25. One (1) diesel emergency generator, identified as MHSB-2, constructed in 2001 with a maximum capacity of 600 hp, located at McNutt / 439.
[Under 40 CFR 63, Subpart ZZZZ, this is an affected source]

26. One (1) diesel emergency generator, identified as MHSB-3, constructed in 2001 with a maximum capacity of 750 hp, located at Myers Hall / 101.
[Under 40 CFR 63, Subpart ZZZZ, this is an affected source]

27. One (1) diesel emergency generator, identified as ALSB-1, constructed in 2002 with a maximum capacity of 90 hp, located at Animal Lab / 411.
[Under 40 CFR 63, Subpart ZZZZ, this is an affected source]

28. One (1) diesel emergency generator, identified as USASB-1, constructed in 2005 with a maximum capacity of 450 hp, located at Union St Apts / 296.
[Under 40 CFR 63, Subpart ZZZZ, this is an affected source]

29. One (1) diesel emergency generator, identified as CIBSB-1, constructed in 2007 with a maximum capacity of 469 hp, located at CIB / 578.
[Under 40 CFR 60, Subpart IIII, this is an affected source]
[Under 40 CFR 63, Subpart ZZZZ, this is an affected source]

30. One (1) diesel emergency generator, identified as BASB-1, constructed in 2012 with a maximum capacity of 147 hp, located at Baseball/ 593.
[Under 40 CFR 60, Subpart IIII, this is an affected source]
[Under 40 CFR 63, Subpart ZZZZ, this is an affected source]

31. One (1) diesel emergency generator, identified as SBSB-2, constructed in 2012 with a maximum capacity of 99 hp, located at Softball/ 594.
[Under 40 CFR 60, Subpart IIII, this is an affected source]
[Under 40 CFR 63, Subpart ZZZZ, this is an affected source]

32. One (1) diesel emergency generator, identified as OPSB-1, constructed in 2014 with a maximum capacity of 375 hp, located at Optometry / 065
[Under 40 CFR 60, Subpart IIII, this is an affected source]
[Under 40 CFR 63, Subpart ZZZZ, this is an affected source]

33. One (1) diesel emergency generator, identified as WLSB-1, constructed in 2014 with a maximum capacity of 1206 hp, located at Wells Library /GISB 209.
[Under 40 CFR 60, Subpart IIII, this is an affected source]
[Under 40 CFR 63, Subpart ZZZZ, this is an affected source]

34. One (1) diesel emergency generator, identified as AHSB-2, constructed in 2015 with a maximum capacity of 668 hp, located at Assembly Hall / 603.
[Under 40 CFR 60, Subpart IIII, this is an affected source]
[Under 40 CFR 63, Subpart ZZZZ, this is an affected source]

35. One (1) diesel emergency generator, identified as FWSB-1, constructed in 2016 with a maximum capacity of 536 hp, located at Food Warehouse / 615.
[Under 40 CFR 60, Subpart IIII, this is an affected source]
[Under 40 CFR 63, Subpart ZZZZ, this is an affected source]

36. One (1) diesel emergency generator, identified as MESH-1, constructed in 2018 with a maximum capacity of 683.91 hp, located at MESH.
[Under 40 CFR 60, Subpart IIII, this is an affected source]
[Under 40 CFR 63, Subpart ZZZZ, this is an affected source]

37. One (1) diesel emergency generator, identified as 2NDSB-1, constructed in 2018 with a maximum capacity of 131 hp, located at 2427 E 2ND ST.
[Under 40 CFR 60, Subpart IIII, this is an affected source]
[Under 40 CFR 63, Subpart ZZZZ, this is an affected source]

38. One (1) diesel emergency generator, identified as ALFSB-2, constructed in 2018 with a maximum capacity of 201 hp, located at ALF.
[Under 40 CFR 60, Subpart IIII, this is an affected source]
[Under 40 CFR 63, Subpart ZZZZ, this is an affected source]

39. One (1) diesel emergency generator, identified as LHSB-1, constructed in 2018 with a maximum capacity of 324 hp, located at Luddy Hall.
[Under 40 CFR 60, Subpart IIII, this is an affected source]
[Under 40 CFR 63, Subpart ZZZZ, this is an affected source]

40. One (1) diesel emergency generator, identified as MSEZSB-1, constructed in 2018 with a maximum capacity of 450 hp, located at Memorial Stadium South End Zone.
[Under 40 CFR 60, Subpart IIII, this is an affected source]
[Under 40 CFR 63, Subpart ZZZZ, this is an affected source]

41. One (1) diesel emergency generator, identified as SPEASB-1, constructed in 2018 with a maximum capacity of 670 hp, located at SPEA / 452.
[Under 40 CFR 60, Subpart IIII, this is an affected source]

[Under 40 CFR 63, Subpart ZZZZ, this is an affected source]

42. One (1) diesel emergency generator, identified as SWSB-1, constructed in 2018 with a maximum capacity of 754 hp, located at Swain West.
[Under 40 CFR 60, Subpart IIII, this is an affected source]
[Under 40 CFR 63, Subpart ZZZZ, this is an affected source]

43. One (1) diesel emergency generator, identified as MESH-1, constructed in 2018 with a maximum capacity of 683.91 hp, located at MESH.
[Under 40 CFR 60, Subpart IIII, this is an affected source]
[Under 40 CFR 63, Subpart ZZZZ, this is an affected source]

44. One (1) diesel emergency generator, identified as PORT-1, constructed in 2002 with a maximum capacity of 80.46 hp, located at Service Building.
[Under 40 CFR 63, Subpart ZZZZ, this is an affected source]

45. One (1) diesel emergency generator, identified as PORT-2, constructed in 1999 with a maximum capacity of 22.80 hp, located at Service Building/630.
[Under 40 CFR 63, Subpart ZZZZ, this is an affected source]

46. Two (2) diesel emergency generators, identified as PORT-3 and PORT-4, each, constructed in 1999 with a maximum capacity of 80.46 hp, located at Union St. Chiller Plant – RPS.
[Under 40 CFR 63, Subpart ZZZZ, this is an affected source]

47. Four (4) diesel emergency generator, identified as PORT-5, PORT-6, PORT-7 and PORT-8, each, constructed in 1999 with a maximum capacity of 13 hp, located at Service Building.
[Under 40 CFR 63, Subpart ZZZZ, this is an affected source]

48. One (1) diesel emergency generator, identified as PORT-9, constructed in 2007 with a maximum capacity of 8.05 hp, located at service Building-Carpenter.
[Under 40 CFR 60, Subpart IIII, this is an affected source]
[Under 40 CFR 63, Subpart ZZZZ, this is an affected source]

49. Three (3) diesel emergency generator, identified as PORT-10, PORT-11 and PORT-12, each, constructed in 2006 with a maximum capacity of 156 hp, 2.68 hp and 2.68 hp respectively, located at service Building.
[Under 40 CFR 60, Subpart IIII, this is an affected source]
[Under 40 CFR 63, Subpart ZZZZ, this is an affected source]

50. Three (3) diesel emergency generator, identified as PORT-13, PORT-14 and PORT-15, constructed in 2015, 2017 and 2008 with a maximum capacity of 23.5 hp, 23.5 hp and 24.5 hp respectively, located at Utilities Building.
[Under 40 CFR 60, Subpart IIII, this is an affected source]
[Under 40 CFR 63, Subpart ZZZZ, this is an affected source]

These emissions units are subject to the following portions of 40 CFR 63, Subpart ZZZZ:

(1) 40 CFR 63.6580
(2) 40 CFR 63.6585(b)
(3) 40 CFR 63.6590
(4) 40 CFR 63.6595
(5) 40 CFR 63.6605
(6) 40 CFR 63.6645
(7) 40 CFR 63.6655(d),(e),(f)
(8) 40 CFR 63.6670
(9) 40 CFR 63.6675

(10) Table 2c, Subpart ZZZZ of 63
(11) Table 2d, item 1, Subpart ZZZZ of 63
(12) Table 6, item 9, Subpart ZZZZ of 63
(13) Table 8, Subpart ZZZZ of 63

The requirements of 40 CFR Part 63, Subpart A – General Provisions, which are incorporated as 326 IAC 20-1-1, apply to the emergency generators except as otherwise specified in 40 CFR 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.~~

(p) The Boilers are subject to the National Emission Standards for Hazardous Air Pollutants for Major Sources: Industrial, Commercial, and Institutional Boilers and Process Heaters 40 CFR 63, Subpart DDDDD, which is incorporated by reference as 326 IAC 20-95., because they are institutional boilers that combust either coal, natural gas, No. 1 or No. 2 fuel oil, located at a major source of Hazardous Air Pollutants (HAP). The Boilers subject to this rule include the following:

1. Two (2) coal, natural gas, No. 1 or No. 2 fuel oil fired boilers, identified as EU-03 and EU-04, constructed in 1959, each, with a maximum design capacity of 125 MMBtu per hour heat input, each (operating at a maximum capacity of 100 MMBtu per hour heat

input when combusting coal or a combination of fuels), and with a maximum design capacity of 80 MMBtu per hour heat input, when combusting natural gas and/or fuel oil, both exhausting to stack 002.

2. One (1) coal, natural gas, No. 1 or No. 2 fuel oil fired boiler, identified as EU-06, constructed in 1970, with economizers replaced in 2010, with a maximum design capacity of 190 MMBtu per hour heat input when combusting coal and/or fuel oil, and 150 MMBtu per hour heat input (two natural gas fired burners rated at 75 MMBtu per hour heat input each) when combusting natural gas.

These emissions units are subject to the following portions of 40 CFR 63, Subpart DDDDD:

(1) 40 CFR 63.7500(a), (f)
(2) 40 CFR 63.7505
(3) 40 CFR 63.7510(a), (e)
(4) 40 CFR 63.7515
(5) 40 CFR 63.7520
(6) 40 CFR 63.7521(a), (e)
(7) 40 CFR 63.7525
(8) 40 CFR 63.7530
(9) 40 CFR 63.7535
(10) 40 CFR 63.7540(a)
(11) 40 CFR 63.7545
(12) 40 CFR 63.7550
(13) 40 CFR 63.7555
(14) 40 CFR 63.7560
(15) 40 CFR 63.740(a)(10)

(q) The Boilers are subject to the National Emission Standards for Hazardous Air Pollutants for Major Sources: Industrial, Commercial, and Institutional Boilers and Process Heaters 40 CFR 63, Subpart DDDDD, which is incorporated by reference as 326 IAC 20-95, because they are institutional boilers that combust either coal, natural gas, No. 1 or No. 2 fuel oil, located at a major source of Hazardous Air Pollutants (HAP). The boilers subject to this rule include the following:

Construction Year	Type of Unit	Maximum Heat Input Capacity (MMBtu/hr)
1964	EU-05 Boiler	190
1970	EU-07 Boiler	190
Before 1972	22 Boilers	29.13 (Total)
1977	1 Boiler	0.60
1981	1 Boiler	0.11
After 1983	66 Boilers	145.25 (Total)
2008	Informatics East Bldg. Boiler	1.44
	Hutton Honors College Furnace	0.432
2009	3 Boilers at Innovation Center	1.1 (each)

All the Boilers listed in the above table are subject to the following portions of 40 CFR 63, Subpart DDDDD:

(1) 40 CFR 63.7540(a)(10)
(2) 40 CFR 63.7500(a), (e), (f)
(3) 40 CFR 63.7505(a)
(4) 40 CFR 63.7510(e)
(5) 40 CFR 63.7515(d)
(6) 40 CFR 63.7530(a)
(7) 40 CFR 63.7540(a)(2), (10), & (11)
(8) 40 CFR 63.7545(a), (b), (f)

(9) 40 CFR 63.7550(a), (b), (c)(1) & (5), (d)
(10) 40 CFR 63.7559(a), (d), & (h)
(11) 40 CFR 63.7560

The requirements of 40 CFR Part 63, Subpart A – General Provisions, which are incorporated as 326 IAC 20-1-1, apply to the boilers except as otherwise specified in 40 CFR 63, Subpart DDDDD.

(r) Boiler EU-07 is not subject to 40 CFR Part 75 Continuous Emissions Monitoring (CEM) performance specifications because it is not an electricity generating unit which is subject to the Acid Rain Program as is noted in 40 CFR Part 72.6(b)(3).

(s) This source is not subject to the requirements of the Acid Rain Program (40 CFR 72), because the source does not produce electricity for sale.

(t) There are no other National Emission Standards for Hazardous Air Pollutants under 40 CFR 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 Used	Emission Limitation (Y/N)	Uncontrolled PTE (tons/year)	Controlled PTE (tons/year)	Major Source Threshold (tons/year)	CAM Applicable (Y/N)	Large Unit (Y/N)
EU-03	$PM_{2.5}/PM_{10}$	multiclone & Boiler 3 bag	N	> 100	< 100	100	N	-
	PM	multiclone & Boiler 3 bag	Y	> 100	< 100	100	Y*	-
	SO_2	None	Y	> 100	> 100	100	N	-
	NO_X	None	N	> 100	> 100	100	N	-
	Hg	carbon injection system	N	> 10	> 10	10	N	-
	HCl	lime injection system	N	> 10	> 10	10	N	-
	Total HAP	carbon & lime injection systems	N	> 25	> 25	25	N	-
EU-04	$PM_{2.5}/PM_{10}$	multiclone & Boiler 4 bag	N	> 100	< 100	100	N	-
	PM	multiclone & Boiler 4 bag	Y	> 100	< 100	100	Y*	-

Emission Unit / Pollutant		Control Device Used	Emission Limitation (Y/N)	Uncontrolled PTE (tons/year)	Controlled PTE (tons/year)	Major Source Threshold (tons/year)	CAM Applicable (Y/N)	Large Unit (Y/N)
	SO_2	None	Y	> 100	> 100	100	N	-
	Hg	carbon injection system	N	> 10	> 10	10	N	-
	HCl	lime injection system	N	> 10	> 10	10	N	-
	Total HAP	carbon & lime injection systems	N	> 25	> 25	25	N	-
EU-05	PM2.5/PM_{10}	multiclone	N	< 100	< 100	100	N	-
EU-06	PM2.5/PM_{10}	multiclone & Boiler 6 bag	N	> 100	< 100	100	N	-
EU-06	PM	multiclone & Boiler 6 bag	Y	> 100	< 100	100	Y*	-
EU-06	SO_2	None	Y	> 100	> 100	100	N	-
EU-06	Hg	carbon injection system	N	> 10	> 10	10	N	-
EU-06	HCl	lime injection system	N	> 10	> 10	10	N	-
EU-06	Total HAP	carbon & lime injection systems	N	> 25	> 25	25	N	-
EU-07	NOx	FGR	Y	< 100	< 100	100	N	-
EU-07	SO_2	None	Y	> 100	< 100	100	N	-
EU-07	PM	None	Y	< 100	< 100	100	N	-
EU-07	PM2.5/PM_{10}	None	Y	< 100	< 100	100	N	-
Coal Storage and Handling System	PM2.5/PM10	Collector DC1	N	< 100	< 100	100	N	-
Coal Storage and Handling System	PM2.5/PM10	Collector DC2	N	< 100	< 100	100	N	-
Coal Storage and Handling System	PM2.5/PM10	Collector DC3	N	< 100	< 100	100	N	-
Coal Storage and Handling System	PM2.5/PM10	Collector DC4	N	< 100	< 100	100	N	-
Coal Storage and Handling System	PM2.5/PM10	Collector DC6	N	< 100	< 100	100	N	-

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.
Under the Part 70 Permit program (40 CFR 70), PM is not a regulated pollutant.

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.

* Based on this evaluation the Boilers, identified as EU-03, EU-04, and EU-06 are subject to the requirements of 40 CFR Part 64. However, they are regulated under 40 CFR Part 63, Subpart DDDDD, which was promulgated after Nov. 15, 1990. Therefore, they are exempt from the requirements of 40 CFR Part 64.

State Rule Applicability - Entire Source

State rule applicability for this source has been reviewed as follows:

326 IAC 2-2 (Prevention of Significant Deterioration (PSD))
The source initially constructed Boilers EU-03 and EU-04 in1959, which is prior to the promulgation of PSD Rules on August 7, 1977. At that time these boilers were emitting PM, PM10, PM2.5, SO2 and NOx at 100 tons per year or greater, therefore, the source was grandfathered major source from the requirements of 326 IAC 2-2, PSD, and it is one of the twenty-eight (28) listed source categories. All

subsequent source modifications made after August 7, 1977 must have been evaluated against the PSD SER (Significant Emission Rates)

1989 Modification

Construction Permit PC (55) 1731, issued on Feb 15, 1989 allowed for the modification of Boiler No. 5, now identified as EU-05 to burn no. 2 fuel oil as additonal fuel for this natural gas-fired boiler. This modification was limited to the following to limit the NOx and SO2 PTE to less than 40 tons per year each:

In order to render the requirements of 326 IAC 2-2 (Prevention of Significant Deterioration (PSD)) not applicable to the 1989, the Permittee shall comply with the following:

(a) The total input of natural gas to boiler EU-05 shall be less than 870 MMCF per twelve (12) consecutive month period, rolled on a monthly basis.

For purposes of determining compliance, every 3.84 kilo-gallons of No. 1 or No. 2 fuel oil combusted shall be equivalent to 1 MMCF of natural gas based on NOx emissions and 0.08% sulfur content of No. 1 fuel oil and 0.49% sulfur content of No. 2 fuel oil. The amount of natural gas and natural gas equivalents used shall be determined as follows:

Amount of natural gas and natural gas equivalents used = ((EU-05 No. 1 fuel oil usage in kgal/yr)/(3.84 kgal/MMCF)) + ((EU-05 No. 2 fuel oil usage in kgal/yr)/(3.84 kgal/MMCF)) + (EU-05 natural gas usage in MMCF/yr)

(b) The total input of No. 2 fuel oil to boiler EU-05 shall be less than 1,120 kgals per (12) twelve consecutive month period, rolled on a monthly basis. For purposes of determining compliance, every kilo-gallon of No. 1 fuel oil combusted shall be equivalent to 5.89 kgal of No. 2 fuel oil based on SO2 emissions and 0.08% sulfur content of No. 1 fuel oil and 0.49% sulfur content of No. 2 fuel oil, and every MMCF of natural gas burned shall be equivalent to 0.009 kgal of No. 2 fuel oil based on SO2 emissions and 0.49% sulfur content of No. 2 fuel oil.

The amount of No. 2 fuel oil and No. 2 fuel oil equivalents used
shall be determined as follows:
Amount of No. 2 fuel oil and No. 2 fuel oil equivalents used = (EU-05 No. 1 fuel oil usage in kgal/yr * 5.89 kgal of No. 2 fuel oil/kgal of No. 1 fuel oil) + (EU-05 No. 2 fuel oil usage in kgal/yr) + (EU-05 natural gas usage in MMCF/yr * 0.009 kgal No. 2 fuel oil/MMCF natural gas)

Compliance with these limits, combined with the potential to emit PM10, NOx and SO2 from all the other emission units in this modification, shall limit the total potential to emit of PM_{10} emissions to less than fifteen (15) tons per year, SO_2 emission to less than 40 tons/yr and NOx to less than forty (40) tons/year, and shall render the requirements of 326 IAC 2 2 (PSD) not applicable to the 1989 modification.

2007 Modification

In order to render the requirements of 326 IAC 2-2 (Prevention of Significant Deterioration (PSD)) not applicable to the 2007 Modification permitted under SSM No. 105-24626-00005, the Permittee shall comply with the following:

Boiler EU-7

(a) Fuel Oil Usage Limit
The input of No. 1 and No. 2 fuel to the EU-7 boiler shall be limited to less than 329,000 gallons per twelve (12) consecutive month period, with compliance determined at the end of each month.

(b) SO_2
The sulfur content in the No. 1 or No. 2 fuel oil used in Boiler EU-07 shall not exceed 0.1 percent.

(c) The emissions of PM_{10} while burning No. 1 or No. 2 fuel oil shall not exceed 3.3 pounds per 1,000 gallons of No. 1 or No. 2 fuel oil burned.

(d) NOx
The emissions of NOx while burning natural gas shall not exeed 36.72 lb/MMCF (this value equals 0.036 lb/MMBtu using natural gas heating value of 1020 MMBtu/MMCF), with a 30 day averaging period for compliance determination. The emissions of NOx while burning No. 1 or No. 2 fuel oil shall not exceed 12.51 lb/Kgal.

Generator MSB 1

(a) The operating hours for the emergency generator MSB 1 shall not exceed 250 hours per twelve (12) consecutive month period with compliance determined at the end of each month.

(b) The emission of NOx shall not exceed 0.024 lb/hp-hr.

Compliance with these limits, combined with the potential to emit PM10, NOx and SO2 from all the other emission units in this modification, shall limit the total potential to emit of PM_{10} emissions to less than fifteen (15) tons per year, SO_2 emission to less than 40 tons/yr and NOx to less than forty (40) tons/year, and shall render the requirements of 326 IAC 2 2 (PSD) not applicable to the 2007 modification.

326 IAC 2-6 (Emission Reporting)
This source 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 PM10 is greater than 250 tons per year, and the potential to emit of SO2 is greater than 2,500 tons per year. Therefore, pursuant to 326 IAC 2-6-3(a)(1), annual reporting is required. An emission statement shall be submitted in accordance with the compliance schedule in 326 IAC 2-6-3 and every year thereafter. The emission statement shall contain, at a minimum, the information specified in 326 IAC 2-6-4.

326 IAC 2-7-6(5) (Annual Compliance Certification)
The U.S. EPA Federal Register 79 FR 54978 notice does not exempt Title V Permittees from the requirements of 40 CFR 70.6(c)(5)(iv) or 326 IAC 2-7-6(5)(D), but the submittal of the Title V annual compliance certification to IDEM satisfies the requirement to submit the Title V annual compliance certifications to EPA. IDEM does not intend to revise any permits since the requirements of 40 CFR 70.6(c)(5)(iv) or 326 IAC 2-7-6(5)(D) still apply, but Permittees can note on their Title V annual compliance certifications that submission to IDEM has satisfied reporting to EPA per Federal Register 79 FR 54978. This only applies to Title V Permittees and Title V compliance certifications.

326 IAC 5-1 (Opacity Limitations)
This source is subject to the opacity limitations specified in 326 IAC 5-1-2(1) (A) and (B).

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

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)
Pursuant to 326 IAC 6.5-1-1(a), this source (located in Monroe County) is not subject to the requirements of 326 IAC 6.5 because it is not located in one of the following counties: Clark, Dearborn, Dubois, Howard, Marion, St. Joseph, Vanderburgh, Vigo or Wayne.

326 IAC 6.8 (Particulate Matter Limitations for Lake County)
Pursuant to 326 IAC 6.8-1-1(a), this source (located in Monroe County) is not subject to the requirements of 326 IAC 6.8 because it is not located in Lake County.

State Rule Applicability – Individual Facilities

State rule applicability has been reviewed as follows:

326 IAC 6-2-3 (Particulate Emission Limitations for Sources of Indirect Heating)
(a) Pursuant to 326 IAC 6-2-3(b), the PM emission from indirect heating facilities existing and in operation before June 8, 1972, shall be limited by the following equation:

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

where: P_t = PM limit in pounds per MMBtu
C = Maximum ground level concentration (50)
N = Number of stacks (3)(assume extra stack for 22 smaller boilers)
a = Plume rise factor (0.67)
h = Stack height in feet (162.5)
Q = Total source maximum operating capacity rating in million Btu per hour (MMBtu/hr) heat input in the year all boilers, heaters, or furnaces were operating.

The PM emissions from the boilers, identified as EU-03, EU-04, EU-05, and EU-06, and the twenty-two (22) boilers constructed before 1972, shall be limited to the pounds per million British thermal units heat input as indicated below:

Particulate emissions from all facilities used for indirect heating purposes which were existing and in operation on or before June 8, 1972, shall in no case exceed 0.8 lb/mmBtu heat input.
[326 IAC 6-2-3(d)]

Indirect Heating Sources, Existing and in Operation Prior to June 8, 1972 [326 IAC 6-2-3(b)]					
Construction Year	**Type of Unit**	**Maximum Heat Input Capacity (MMBtu/hr)**	**Total Q (MMBtu/hr)**	**Calculated Pt (lb/MMBtu) PM**	**Pt (based on Rule 326 IAC 6-2-3(d)) (lb/MMBtu) PM**
1959	Boiler EU-03	100	200	1.02	0.8
	Boiler EU-04	100			
1964	Boiler EU-05	190	390	0.62	N/A
1970	Boiler EU-06	190	580	0.46	
Before 1972	22 Boilers	29.13 (Total)	609.13	0.44	

(b) Pursuant to 326 IAC 6-2-3(c), the PM emission from indirect heating facilities existing and in operation after June 8, 1972 and before September 21, 1983, shall be limited by the following equation:

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

where: P_t = PM limit in pounds per MMBtu
C = Maximum ground level concentration (50)
N = Number of stacks (2)

a = Plume rise factor (0.67)
h = Stack height in feet (50)(assumed stack height)
Q = Total source maximum operating capacity rating in million Btu per hour (MMBtu/hr) heat input in the year all boilers, heaters, or furnaces were operating.

The PM emissions from the boiler constructed in 1977, and the boiler constructed in 1981, shall be limited to the pounds per million British thermal units heat input as indicated below:

Construction Year	Type of Unit	Maximum Heat Input Capacity (MMBtu/hr)	Total Q (MMBtu/hr)	Calculated Pt (lb/MMBtu) PM
-	-	-	609.13	0.44
1977	1 Boiler	0.60	609.73	0.15
1981	1 Boiler	0.11	609.84	0.15

326 IAC 6-2-4 (Particulate Emission Limitations for Sources of Indirect Heating)
Pursuant to 326 IAC 6-2-4(a), the PM emission from indirect heating facilities existing and in operation after September 21, 1983, shall be limited by the following equation:

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

Where: Pt = Pounds of particulate matter per million Btu (lb/MMBtu) heat input
Q = Total source maximum operating capacity rating in million Btu per hour (MMBtu/hr) heat input in the year all boilers, heaters, or furnaces were operating.

The PM emissions from the Boiler EU-7, and the 66 boilers constructed after 1983, the Informatics East Building Boiler, the Hutton Honors College Furnace (indirect forced air unit), and three (3) boilers at the Innovation Center shall be limited to the pounds per million British thermal units heat input as indicated below:

Construction Year	Type of Unit	Maximum Heat Input Capacity (MMBtu/hr)	Total Q (MMBtu/hr)	Pt (lb/MMBtu) PM
-	-	-	609.84	0.15
After 1983	66 Boilers	145.25 (Total)	755.09	0.19
2007	Boiler EU-07	217	972.09	0.18
2008	Informatics East Bldg. Boiler	1.44	973.96	0.18
	Hutton Honors College Furnace	0.432		
2009	3 Boilers at Innovation Center	1.1 (each)	977.26	0.18

For a total source maximum operating capacity rating, Q, less than 10 MMBtu/hr, particulate emissions, Pt shall not exceed 0.6 pound per MMBtu of heat input. For Q greater than or equal to 10,000 MMBtu/hr, Pt shall not exceed 0.1 pound per MMBtu of heat input.

326 IAC 6-3-2 (Particulate Emission Limitations for Manufacturing Processes)
(a) Pursuant to 326 IAC 6-3-1(a), the requirements of 326 IAC 6-3-2 are applicable to the following units, since it is a manufacturing process not exempted from this rule under 326 IAC 6-3-1(b) and is not subject to a particulate matter limitation that is as stringent as or more stringent than the particulate limitation established in this rule as specified in 326 IAC 6-3-1(c).

(i) Pursuant to 326 IAC 6-3-2, the particulate matter (PM) from the coal storage and handling system shall not exceed 58.5 pounds per hour when operating at a process weight rate of 200 tons per hour. The pound per hour limitation was calculated with the following equation:

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

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

(ii) Pursuant to 326 IAC 6-3-2, the particulate matter (PM) from the two (2) conveying legs of the ash handling system shall not exceed 3.26 pounds per hour when operating at a process weight rate of 0.71 tons per hour. The pound per hour limitation was calculated with the following equation:

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

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

(b) The particulate matter emissions from the Ash Silo, the Activated Carbon Silo and the Lime Silo are each less than 0.551 pound per hour; therefore, they are exempt from 326 IAC 6-3-2.

(c) The activated carbon and lime injection systems consist of a totally enclosed pneumatic receiving system, activated carbon and lime storage silos, each equipped with a bin vent baghouse. The receiving system will not have emissions because it is totally enclosed and empties into the storage silo which is controlled by a baghouse. The only emissions are from the silo vents.

326 IAC 7-1.1 (Sulfur Dioxide Emission Limitations)

(a) Pursuant to 326 IAC 7-1.1-2(a)(1), (b) sulfur dioxide emissions from each boiler, EU-03 and EU-04, shall not exceed 6.0 pounds per million British thermal units (lb/MMBtu) of heat input when combusting coal, and when combusting coal and oil simultaneously, and 0.5 pounds per million British thermal units (lb/MMBtu) of heat input when combusting No. 1 or No. 2 fuel oil.

(b) Pursuant to 326 IAC 7-1.1-2(a)(3), sulfur dioxide emissions shall not exceed 0.5 pounds per million British thermal units (lb/MMBtu) of heat input from boiler EU-05 when combusting No. 1 or No. 2 fuel oil.

(c) Pursuant to 326 IAC 7-1.1-2(a)(1), sulfur dioxide emissions from boiler EU-06 shall not exceed 6.0 pounds per million British thermal units (lb/MMBtu) of heat input when combusting coal.

(d) Pursuant to 326 IAC 7-1.1-2(a)(3), (b), for facilities (EU-06) is combusting No. 1 or No. 2 fuel oil, solely, sulfur dioxide emissions shall not exceed 0.5 pounds per million British thermal units (lb/MMBtu) of heat input and when combusting coal and oil simultaneously, sulfur dioxide emissions shall not exceed six and zero-tenths (6.0) pounds per million British thermal units (lb/MMBtu) of heat input, and when EU-06.

(e) Pursuant to 326 IAC 7-1.1-2(a)(3), sulfur dioxide emissions shall not exceed 0.5 pounds per million British thermal units (lb/MMBtu) of heat input from boiler EU-07 when combusting No. 1 or No. 2 fuel oil.

326 IAC 8-3 (Organic Solvent Degreasing Operations)
Pursuant to 326 IAC 8-3-1(c)(1)(B) the degreasing operations listed as insignificant activities which were constructed after January 1, 1980, are subject to the requirements of 326 IAC 8-3-2 (Cold Cleaner Degreaser Control Equipment and Operating Requirements) and 326 IAC 8-3-8(Material Requirements for Cold Cleaner Degreasers).

All Emergency Generators

(a) **326 IAC 6-2 (Particulate Emission Limitations for Sources of Indirect Heating)**
None of the emergency generators noted in the emission unit summary are sources of indirect heating. Therefore, none of the emergency generators are not subject to the provisions of 326 IAC 6-2.

(b) **326 IAC 6-3-2 (Particulate Emission Limitations for Manufacturing Processes)**
None of the emergency generators noted in the emission unit summary are subject to the requirements of 326 IAC 6-3-2, because they burn only liquid fuel and liquids are not considered in determining this rule. Therefore, 326 IAC 6-3-2 does not apply.

(c) **326 IAC 7-1.1 (Sulfur Dioxide Emission Limitations)**
None of the emergency generators noted in the emission unit summary have a potential to emit twenty-five (25) tons per year or ten (10) pounds per hour of sulfur dioxide. Therefore, none of the emergency generators are subject to the provisions of 326 IAC 7-1.1.

(d) **326 IAC 8-1-6 (VOC Rules: General Reduction Requirements for New Facilities)**
None of the emergency generators noted in the emission unit summary are subject to the requirements of 326 IAC 8-1-6, since the unlimited VOC potential emissions from each emergency generator is less than twenty-five (25) tons per year.

Compliance Determination and Monitoring Requirements

Permits issued under 326 IAC 2-7 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 2-7-5. As a result, Compliance Determination Requirements are included in the permit. The Compliance Determination Requirements in Section D of the permit are those conditions that are found directly within state and federal rules and the violation of which serves as grounds for enforcement action.

If the Compliance Determination Requirements are not sufficient to demonstrate continuous compliance, they will be supplemented with Compliance Monitoring Requirements, also in Section D of the permit. Unlike Compliance Determination Requirements, failure to meet Compliance Monitoring conditions would serve as a trigger for corrective actions and not grounds for enforcement action. However, a violation in relation to a compliance monitoring condition will arise through a source's failure to take the appropriate corrective actions within a specific time period.

(a) The Compliance Determination Requirements applicable to this source are as follows:

Table 1: Summary of Testing Requirements

Emission Unit	Control Device	Pollutant	Frequency of Testing	Limit or Requirement
EU-03 & EU-04	Stack Test	PM	Every 5 years	0.38 lb/MMBtu
EU-06	Stack Test	PM	Every 5 years	0.38 lb/MMBtu

(b) The Compliance Monitoring Requirements applicable to this source are as follows:

<table>
<tr><th colspan="5">Table 1: Summary of Compliance Monitoring Requirements</th></tr>
<tr><th>Control</th><th>Parameter</th><th>Frequency</th><th>Value / Range</th><th>Excursions and Exceedances</th></tr>
<tr><td>EU-03 - baghouse
EU-04 - baghouse</td><td>Visible Emissions</td><td>Daily</td><td>Normal / Abnormal</td><td rowspan="7">Response Steps</td></tr>
<tr><td>EU-05</td><td>Visible Emissions</td><td>Daily</td><td>Normal / Abnormal</td></tr>
<tr><td>EU-06 - Baghouse</td><td>Opacity COM</td><td>Continuous</td><td>< 40% for one 6 minute averaging period</td></tr>
<tr><td>EU-07</td><td>Visible Emissions</td><td>Daily</td><td>Normal / Abnormal</td></tr>
<tr><td>Coal truck receiving system -
wet suppression system</td><td>Visible Emissions</td><td>Weekly</td><td>Normal / Abnormal</td></tr>
<tr><td rowspan="2">Dust Collectors: DC-1, DC-2, DC-3, DC-4 & DC-6</td><td>Visible Emissions</td><td>Weekly</td><td>Normal / Abnormal</td></tr>
<tr><td>Pressure Drop</td><td>Weekly</td><td>1.0 - 8.0 inches water</td></tr>
</table>

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):

SECTION D.1 EMISSIONS UNIT OPERATION CONDITIONS

D.1.1 **Prevention of Significant Deterioration (PSD)** Minor Limits [326 IAC 2-2]

~~In order to render 326 IAC 2-2 not applicable, Boiler EU-07 shall be limited as follows:~~
In order to render the requirements of 326 IAC 2-2 (Prevention of Significant Deterioration (PSD)) not applicable, the Permittee shall comply with the following:
*****
~~Compliance with these limits and Condition D.5.1 will limit SO2 emissions to less than 40 tons per year, PM emissions to less than 25 tons per year, PM10 emissions to less than 15 tons per year, and NOx emissions to less than 40 tons per year from the modification and will render the requirements of 326 IAC 2-2 (PSD) not applicable to the modification, permitted under SSM 105-24626-00005, for EU-07 and MSB 1.~~

Compliance with these limits, combined with the potential to emit PM10, NOx and SO2 from all the other emission units in this modification, shall limit the total potential to emit of PM_{10} emissions to less than fifteen (15) tons per year, SO_2 emission to less thna 40 tons/yr and NOx to less than forty (40) tons/year, and shall render the requirements of 326 IAC 2 2 (PSD) not applicable to the 2007 modification.

D.1.2 **Particulate Emission Limitations for Sources of Indirect Heating** ~~Particulate Matter Limitation (PM)~~ [326 IAC 6-2-4]

Pursuant to 326 IAC 6-2-4(a), the PM emissions from EU-07, shall not exceed 0.18 pounds of particulate matter per million British thermal units heat input. ~~This limitation is based on the following equation:~~

~~$Pt = 1.09 / Q^{0.26}$~~

~~where: P_t = PM limit in pounds per MMBtu~~
~~Q = total source permitted capacity in MMBtu/hr~~
~~= 972.09 MMBtu/hr for EU-07~~

D.1.3 Sulfur Dioxide (SO_2) **Emission Limitations** [326 IAC 7-1.1]

Pursuant to 326 IAC 7-1.1-2 sulfur dioxide emissions shall not exceed 0.5 pounds per million British thermal units (lb/MMBtu) of heat input from boiler EU-07 when combusting No.1 or No.2 fuel oil.

*****

D.1.5 Sulfur Dioxide Emissions and Sulfur Content **[326 IAC 3-7] [326 IAC 7-2] [326 IAC 7-1.1-2 2]**

~~Compliance with Condition D.1.1(c) and D.1.2 shall be determined utilizing one of the following options:~~

To determine the compliance status with the sulfur content limit of the fuel oil in D,1,1(b) and the sulfur dioxide emissions limit in D.1.3, the Permitee shall perform sampling of the sulfur-bearing fuels utilizing one of the following options:

*****

D.1.6 Continuous Emissions Monitoring **System (CEMS)** [326 IAC 3-5] [40 CFR Part 60]

*****

D.1.7 Maintenance of Continuous Emission Monitoring System [326 IAC 2-7-5(3)(A)(iii)]

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

(b) The Permittee shall implement its CO and NOx CEMS operation and maintenance plan (O&M Plan) any time the CO and NOx CEMs are down for four (4) or more hours. The backup system for the CO and NOx CEMS will include a calibrated online process control CO and NOx analyzer on a representative portion of the stack gas flow. The primary CEMS shall be returned to operation as soon as practicable.

(c) 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 or 40 CFR 60.

*****

D.1.~~9~~**.10** Reporting Requirements

A quarterly summary of the information to document the compliance status with Condition D.1.1 (a) shall be submitted **using the reporting forms located at the end of this permit or their equivalent,** not later than thirty (30) days after the end of the quarter being reported. Section C - General Reporting 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).

IDEM has renumbered the conditions in D.1 section.

SECTION D.2 EMISSIONS UNIT OPERATION CONDITIONS

D.2.1 Particulate Emission Limitations for Sources of Indirect Heating ~~Particulate Matter Limitation (PM)~~ [326 IAC 6-2-3]

(a) Pursuant to 326 IAC 6-2-3(d), ~~(Particulate emission limitations for sources of indirect~~

~~heating: emission limitations for facilities specified in 326 IAC 6-2-1(c)),~~ the PM emissions from EU-03 and EU-04, shall not exceed 0.8 pounds of particulate matter per million British thermal unit heat input each.

(b) Pursuant to 326 IAC 6-2-3(b)(Particulate emission limitations for sources of indirect heating: emission limitations for facilities specified in 326 IAC 6-2-1(c)), the PM emissions from EU-05, shall not exceed 0.62 pounds of particulate matter per million British thermal unit heat input. ~~This limitation is based on the following equation:~~

$$\cancel{P_t = \frac{(C * a * h)}{(76.5 * Q^{0.75} * N^{0.25})}}$$

~~where: P_t = PM limit in pounds per MMBtu~~
~~C = Maximum ground level concentration~~
~~a = Plume rise factor~~
~~h = Stack height in feet~~
~~Q = total source permitted capacity in MMBtu/hr~~
~~= 390MMBtu/hr for EU-05~~
~~N = Number of stacks~~

D.2.2 Sulfur Dioxide (SO_2) **Emission Limitations** [326 IAC 7-1.1]

(a) Pursuant to 326 IAC 7-1.1-2 **(Sulfur Dioxide Emission Limitations),** sulfur dioxide emissions from each boiler, EU-03 and EU-04, shall not exceed 6.0 pounds per million British thermal units (lb/MMBtu) of heat input when combusting coal, and when combusting coal and oil simultaneously, and 0.5 pounds per million British thermal unit (lb/MMBtu) of heat input when combusting No.1 or No.2 fuel oil.

(b) Pursuant to 326 IAC 7-1.1-2 **(Sulfur Dioxide Emission Limitations),** sulfur dioxide emissions shall not exceed 0.5 pounds per million British thermal unit (lb/MMBtu) of heat input from boiler EU-05 when combusting No.1 or No.2 fuel oil.

*****

D.2.4 **Prevention of Significant Deterioration (PSD)** Minor Limit [326 IAC 2-2]

In order to render 326 IAC 2-2 (Prevention of Significant Deteriration) not applicable, the Permittee shall comply with the following;

*****

~~Compliance with the above limits shall limit NOx and SO_2 emissions to less than 40 tons per year and renders the requirements of 326 IAC 2-2 (PSD) not applicable to the 1989 modification.~~

Compliance with these limits, combined with the potential to emit PM10, NOx and SO2 from all the other emission units in this modification, shall limit the total potential to emit of PM_{10} emissions to less than fifteen (15) tons per year, SO_2 emission to less than 40 tons/yr and NOx to less than forty (40) tons/year, and shall render the requirements of 326 IAC 2 2 (PSD) not applicable to the 1989 modification.

D.2.6 Testing Requirements [326 IAC 2-7-6(1),(6)] [326 IAC 2-1.1-11]

In order to ~~determine~~ **demonstrate** compliance with condition D.2.1, the Permittee shall perform PM testing for the coal-fired boilers, identified as EU-03 and EU-04, utilizing methods as approved by the Commissioner **at least once every five (5) calendar years from the date of the most recent valid compliance demonstration .**

~~These tests shall be repeated at least once every five (5) calendar years following this valid compliance demonstration.~~ Testing shall be conducted in accordance with ~~Section C - Performance Testing.~~ **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. PM10 and PM2.5 includes filterable and condensable PM.**

*****

D.2.10 Sulfur Dioxide Emissions and Sulfur Content [326 IAC 3-7] [326 IAC 7-2] [326 IAC 7-1.1-2]

To determine the compliance status with the sulfur dioxide emissions limit in D.2.2(a), the Permittee shall perform sampling of the sulfur-bearing fuels utilizing one of the following options:

*****

D.2.11 Sulfur Dioxide Emissions and Sulfur Content [326 IAC 3-7] [326 IAC 7-2] [326 IAC 7-1.1-2]

To determine the compliance status with the sulfur dioxide emissions limit in D.2.2(b), the Permittee shall perform sampling of the sulfur-bearing fuels utilizing one of the following options, ~~W~~ **w**hen EU-03, EU-04, and EU-05 are combusting fuel oil, or fuel oil in combination with natural gas, ~~compliance shall be determined utilizing one of the following options~~:

*****

*****

D.2.14 Record Keeping Requirements

(a) To document the compliance status with Conditions D.2.2, ~~D.2.9~~ and D.2.10, the Permittee shall maintain records in accordance with (1) through (4) below. Records maintained for (1) through (4) shall be taken monthly and shall be complete and sufficient to establish compliance with the SO_2 emission limits established in Condition D.2.2. Records necessary to demonstrate compliance shall be available within 30 days of the end of each compliance period.

*****

(b) To document the compliance status with Section C - Opacity and Conditions D.2.1, ~~D.2.7, D.2.8, and D.2.10~~, the Permittee shall maintain records in accordance with (1) through (3) below. Records shall be complete and sufficient to establish compliance with the limits established in Section C - Opacity, and in Condition D.2.1. Records necessary to demonstrate compliance shall be available within 30 days of the end of each compliance period.

*****

*****

(e) To document the compliance status with Condition ~~D.2.10~~**D.2.12**, the Permittee shall maintain records of daily visible emission notations of the boiler stack exhausts ~~during~~ **when operating** ~~operating conditions described in D.2.12~~. The Permittee shall include in its daily record when a visible emission notation is not taken and the reason for the lack of a visible emission notation (e.g. the process did not operate that day).

*****

*****

D.2.15 Reporting Requirements

(a) A quarterly summary of the information to document the compliance status with Condition D.2.2 shall be submitted **using the reporting forms located at the end of this permit or their equivalent,** not later than thirty (30) days after the end of the quarter being reported. Section C - General Reporting contains the Permittee's obligation with regard to the reporting required by this condition.

(b) A quarterly summary of the information to document the compliance status with Condition D.2.4 shall be submitted **using the reporting forms located at the end of this permit or their equivalent,** not later than thirty (30) days after the end of the quarter being reported. Section C - General Reporting contains the Permittee's obligation with regard to the reporting required by this condition.

*****

SECTION D.3 EMISSIONS UNIT OPERATION CONDITIONS

D.3.1 **Particulate Emission Limitations for Sources of Indirect Heating** ~~Matter Limitation (PM)~~ [326 IAC 6-2-3]

Pursuant to 326 IAC 6-2-3(b) (Particulate Emission Limitations for Sources of Indirect Heating) ~~emission limitations for facilities specified in 326 IAC 6-2-1(c)),~~ the PM emissions from EU-06 shall not exceed 0.46 pounds of particulate matter per million British thermal units heat input~~. This limitation is based on the following equation:~~

~~$P_t = \frac{(C * a * h)}{(76.5 * Q^{0.75} * N^{0.25})}$~~

~~where: P_t = PM limit in pounds per MMBtu~~
~~C = Maximum ground level concentration~~
~~a = Plume rise factor~~
~~h = Stack height in feet~~
~~Q = total source permitted capacity in MMBtu/hr = 580 MMBtu/hr for EU-06~~
~~N = Number of stacks~~

D.3.2 Sulfur Dioxide (SO_2) **Emission Limitations** [326 IAC 7-1.1]

(a) Pursuant to 326 IAC 7-1.1-2 **(Sulfur Dioxide Emission Limitations)**, sulfur dioxide emissions from boiler EU-06 shall not exceed 6.0 pounds per million British thermal units (lb/MMBtu) of heat input when combusting coal.

(b) Pursuant to 326 IAC 7-1.1-2 **(Sulfur Dioxide Emission Limitations)**, for facilities (EU-06) combusting coal and oil simultaneously, sulfur dioxide emissions shall not exceed six and zero-tenths (6.0) pounds per million British thermal units (lb/MMBtu) of heat input, and when EU-06 is combusting No. 1 or No. 2 fuel oil, solely, sulfur dioxide emissions shall not exceed 0.5 pounds per million British thermal units (lb/MMBtu) of heat input.

*****

D.3.4 Testing Requirements [326 IAC 2-7-6(1),(6)] [326 IAC 2-1.1-11]

In order to ~~determine~~ **demonstrate** compliance with the PM limitation, the Permittee shall perform PM testing for the coal-fired boiler, identified as EU-06, utilizing methods as approved by the Commissioner **at least once every five (5) calendar years from the date of the most recent valid compliance demonstration**. ~~This test shall be repeated at least once every five (5) calendar years from the date of the most recent valid compliance demonstration. Section C - Performance Testing contains the Permittee's obligation with regard to the performance testing required by this condition.~~

Testing shall be conducted in accordance with 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. PM10 and PM2.5 includes filterable and condensable PM.

*****

D.3.6 Sulfur Dioxide Emissions and Sulfur Content [326 IAC 3-7] [326 IAC 7-2] [326 IAC 7-1.1-2]

To determine the compliance status with the sulfur dioxide emissions limit in D.3.2(a), the Permittee shall perform sampling of the sulfur-bearing fuels utilizing one of the following options:

*****

D.3.7 Sulfur Dioxide Emissions and Sulfur Content [326 IAC 3-7] [326 IAC 7-2] [326 IAC 7-1.1-2]

~~When EU-06 is combusting fuel oil, but not simultaneously with coal, compliance shall be determined utilizing one of the following options.~~

To determine the compliance status with the sulfur dioxide emissions limit in D.3.2(b), the Permittee shall perform sampling of the sulfur-bearing fuels utilizing one of the following options when EU-06 is combusting fuel oil, or fuel oil in combination with natural gas:

*****

*****

D.3.10 Reporting Requirements

(a) A quarterly summary of the information to document the compliance status with Conditions D.3.2, D.3.6 and D.3.7 shall be submitted **using the reporting forms located at the end of this permit or their equivalent,** not later than thirty (30) days after the end of the quarter being reported. Section C - General Reporting contains the Permittee's obligation with regard to the reporting required by this condition.

(b) Quarterly report of opacity exceedances shall be submitted **using the reporting forms located at the end of this permit or their equivalent,** not later than thirty (30) days after the end of the quarter being reported. Section C - General Reporting contains the Permittee's obligation with regard to the reporting required by this condition.
*****

SECTION D.4 EMISSIONS UNIT OPERATION CONDITIONS

D.4.1 ~~Particulate Matter (PM) [326 IAC 6-3]~~ **Particulate Emission Limitations for Manufacturing Processes [326 IAC 6-3-2]**

Pursuant to 326 IAC 6-3-2 ~~(Process Operations)~~, the ~~allowable~~ PM emission ~~rate~~ from the coal storage and handling system shall not exceed 58.5 pounds per hour when operating at a maximum process weight rate of **200 tons per hour** ~~400,000 pounds per hour as established in the following formula:~~
*****

*****

4.3 Particulate Matter (PM) ~~[40 CFR 64]~~

(a) The coal truck receiving interior wet suppression system shall be in operation and control the PM emissions from the associated equipment at all times that the coal receiving system is in operation.

*****

SECTION D.5 EMISSIONS UNIT OPERATION CONDITIONS

D.5.1 **Prevention of Significant Deterioration (PSD)** Minor Limits [326 IAC 2-2]

In order to render the requirements of 326 IAC 2-2 (Prevention of Significant Deteriration) not applicable, the Permittee shall comply with the following;

(a) The operating hours for the emergency generator MSB 1 shall not exceed 250 hours per twelve (12) consecutive month period with compliance determined at the end of each month.

(b) The emission of NOx shall not exceed 0.024 lb/hp-hr.

Compliance with these limits, combined with the potential to emit PM10, NOx and SO2 from all the other emission units in this modification, shall limit the total potential to emit of PM_{10} emissions to less than fifteen (15) tons per year, SO_2 emission to less than 40 tons/yr and NOx to less than forty (40) tons/year, and shall render the requirements of 326 IAC 2 2 (PSD) not applicable to the 2007 modification.

D.5.2 Particulate Emission Limitations for Sources of Indirect Heating [326 IAC 6-2]

(a) Pursuant to 326 IAC 6-2-3(b) (Particulate Emission Limitations for Sources of Indirect Heating: Emission limitations for facilities specified in 326 IAC 6-2-1(c)), the emission limitations for those indirect heating facilities which were existing and in operation on or before June 8, 1972, ~~shall not exceed the pound per million Btu heat input (lb/MMBtu).~~

$$\cancel{Pt = \frac{(C) * (a) * (h)}{76.5 * (Q^{0.75}) * (N^{0.25})}}$$

~~Where C = 50 µg/m³~~
~~Q = total source permitted capacity in MMBtu/hr = 609.13 MMBtu/hr for the twenty-two (22) boilers constructed prior to 1972~~
~~N = number of stacks~~
~~a = 0.67~~
~~h = average stack height (feet)~~

~~The PM emissions~~ from the twenty-two (22) boilers constructed prior to 1972 shall not exceed 0.44 pounds of particulate matter per million British thermal units heat input.

(b) Pursuant to 326 IAC 6-2-3(c), the emission limitations for those indirect heating facilities which began operation after June 8, 1972, and before September 21, 1983, ~~shall not exceed the pound per million Btu heat input (lb/MMBtu).~~

$$\cancel{Pt = \frac{(C) * (a) * (h)}{76.5 * (Q^{0.75}) * (N^{0.25})}}$$

~~Where C = 50 μg/m³~~
~~Q = total source permitted capacity in MMBtu/hr = 609.73 MMBtu/hr for the one (1) boiler constructed in 1977~~
~~N = number of stacks = 2~~
~~a = 0.67~~
~~h = average stack height (feet); assume 50~~

~~The PM emissions~~ from the boiler constructed in 1977, and the boiler constructed in 1981, shall not exceed 0.15 pounds of particulate matter per million British thermal units heat input.

(c) Pursuant to 326 IAC 6-2-4 (Particulate Emission Limitations for Sources of Indirect Heating: Emission limitations for facilities specified in 326 IAC 6-2-1(d)), the PM emissions from indirect heating facilities constructed after September 21, 1983, ~~shall not exceed the pound per million Btu heat input (lb/MMBtu) calculated using the following equation:~~

$$\cancel{Pt = 1.09 / Q^{0.26}}$$

~~Where: Pt = Pounds of particulate matter per million Btu (lb/MMBtu) heat input~~
~~Q = Total source maximum operating capacity rating in million Btu per hour (MMBtu/hr) heat input in the year all boilers, heaters, or furnaces were operating.~~

~~The PM emissions~~ from the Boiler EU-7, and the 66 boilers constructed after 1983, the Informatics East Building Boiler, the Hutton Honors College Furnace (indirect forced air unit), and the three (3) natural gas-fired boilers located at the Innovation Center, shall be limited to the pounds per million British thermal units heat input as indicated below:
*****

*****

D.5.6 Preventive Maintenance Plan [326 IAC 2-7-5(12)]

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

D.5.~~6~~**7** Record Keeping Requirements

(a) To document the compliance status with Condition D.5.1, the Permittee shall maintain monthly records of the operating hours for the emergency generator MSB-1.

*****

~~D.5.7 Record Keeping Requirements~~

~~(a) To document the compliance status with Condition D.5.1, the Permittee shall maintain monthly records of the operating hours for the emergency generator MSB-1.~~

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

D.5.8 Reporting Requirements

A quarterly summary of the information to document the compliance status with Condition D.5.1 shall be submitted **using the reporting forms located at the end of this permit or their equivalent,** not later than thirty (30) days after the end of the quarter being reported. Section C - General Reporting 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 E.1 ~~EMISSIONS UNIT OPERATION CONDITIONS~~ **NSPS**

*****

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

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

~~The provisions of 40 CFR 60, Subpart A - General Provisions, which are incorporated by reference in 326 IAC 12-1, apply to EU-07 except when otherwise specified in 40 CFR 60, Subpart Db.~~

(a) ~~The provisions of 40 CFR 60, Subpart A - General Provisions, which are incorporated by reference in 326 IAC 12-1, apply to the Emergency Generators except when otherwise specified in 40 CFR 60, Subpart IIII.~~**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 units 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 ~~New Source Performance Standards (NSPS)~~ **Standards of Performance for Industrial-Commercial-Institutional Steam Generating Units** [326 IAC 12] [40 CFR 60, Subpart Db]

~~Pursuant to 40 CFR 60 Subpart Db, the~~ **The** Permittee shall comply with the provisions of 40 CFR 60 Subpart Db **(included as Attachment A to the operating permit)**, which are incorporated as 326 IAC 12-1 for **Boiler** EU-07., ~~as specified as follows:~~
*****

SECTION E.2 ~~EMISSIONS UNIT OPERATION CONDITIONS~~ **NSPS**

Emissions Unit Description:

(c) *****

~~(g) Twenty-six (26) Diesel Emergency Generators:~~

~~(1) CBSB-1, 56 hp, manufactured in 2004, located outside the Cyclotron~~
~~(2) FQHSB-1, 282 hp, manufactured in 2006, located outside the Foster Quad/Harper Buildings~~
~~(3) TTASB-1, 300 hp, manufactured in 2006, located outside the Tulip Tree Apartments~~
~~(4) HAPSB-1, 60 hp, manufactured in 2007, located outside the Henderson/Atwater Parking Area~~
~~(5) IUPD-1, 545 hp, manufactured in 2007, located outside of the IU Police Department Building~~
~~(6) JHSB-1, 225 hp, manufactured in 2007, located outside of Johnson Hall~~
~~(7) SBSB-1, 156 hp, manufactured in 2007, located outside of the Service Building~~
~~(8) TQSB-1, 320 hp, manufactured in 2007, located outside of Teter Quad Building~~
~~(9) MSB-1, 1,200 hp, manufactured in 2007, located inside of the MSB-1 Building~~
~~(10) JDHSB-1, 80 hp, manufactured in 2007, located at Jordan Hall~~

~~(11) WQSB-1, 225.6 hp, manufactured in 2007, located at Wright Quad~~
~~(12) AHSB-1, 400 hp, manufactured in 2008, located inside of Assembly Hall~~
~~(13) HCSB-1, 1,150 hp, manufactured in 2008, located outside of the Health Center~~
~~(14) MSB-2, 1,490 hp, manufactured in 2008, located at Simon Hall~~
~~(15) MSNSB-1, 258 hp, manufactured in 2008, located at Memorial Stadium North~~
~~(16) BCSB-1, 360 hp, manufactured in 2008, located at Basketball Center Cook Hall~~
~~(17) CHSB-1, 300 hp, manufactured in 2009, located at Cedar Hall~~
~~(18) HPSB-1, 606 hp, manufactured in 2009, located at HPER (Old Gym)~~
~~(19) ICSB-1, 186 hp, manufactured in 2009, located at IU Innovation Center~~
~~(20) MHSB-1, 56 hp, manufactured in 2009, located outside of Mason Hall~~
~~(21) DCSB-1, 2,200 hp, manufactured in 2009, located inside of Data Center #1~~
~~(22) DCSB-2, 2,200 hp, manufactured in 2009, located inside of Data Center #2~~
~~(23) BBSB-1, 720 hp, manufactured in 2011, located at Briscoe Building~~
~~(24) MACSB-1, 120 hp, manufactured in 2011, located at the Musical Arts Center~~
~~(25) FQSB-1, 460 hp, manufactured in 2012, located at Forest Quad~~
~~(26) JSMSB-1, 475 hp, manufactured in 2012, located at the Jacob School of Music~~

(g) **Twenty three (23) Diesel Emergency Generators:**

(1) One (1) diesel emergency generators, identified as FQHSB-1, manufactured in 2006, with a maximum capacity of 282 hp, located outside the Foster Quad/Harper Buildings.
[Under 40 CFR 60, Subpart IIII, this is an affected source]
[Under 40 CFR 63, Subpart ZZZZ, this is an affected source]

(2) One (1) diesel emergency generators, identified as TTASB-1, manufactured in 2006, with a maximum capacity of 300 hp, located outside the Tulip Tree Apartments.
[Under 40 CFR 60, Subpart IIII, this is an affected source]
[Under 40 CFR 63, Subpart ZZZZ, this is an affected source]

(3) One (1) diesel emergency generator, identified as HAPSB-1, manufactured in 2007, with a maximum capacity of 60 hp, located outside the Henderson/Atwater Parking Area.
[Under 40 CFR 60, Subpart IIII, this is an affected source]
[Under 40 CFR 63, Subpart ZZZZ, this is an affected source]

(4) One (1) diesel emergency generator, identified as IUPD-1, manufactured in 2007, with a maximum capacity of 545 hp, located outside of the IU Police Department Building.
[Under 40 CFR 60, Subpart IIII, this is an affected source]
[Under 40 CFR 63, Subpart ZZZZ, this is an affected source]

(5) One (1) diesel emergency generator, identified as JHSB-1, manufactured in 2007, with a maximum capacity of 225 hp, located outside of Johnston Hall.
[Under 40 CFR 60, Subpart IIII, this is an affected source]
[Under 40 CFR 63, Subpart ZZZZ, this is an affected source]

(6) One (1) diesel emergency generator, identified as TQSB-1, manufactured in 2007, located outside of Teter Quad Building.
[Under 40 CFR 60, Subpart IIII, this is an affected source]
[Under 40 CFR 63, Subpart ZZZZ, this is an affected source]

(7) One (1) diesel emergency generator, identified as MSB-1, with a maximum capacity of 1,200 hp, manufactured in 2007, with a maximum capacity of 320 hp, located inside of the MSB-1 Building.
[Under 40 CFR 60, Subpart IIII, this is an affected source]

[Under 40 CFR 63, Subpart ZZZZ, this is an affected source]

**(8) One (1) diesel emergency generator, identified as JDHSB-1, manufactured in 2007, with a maximum capacity of 80 hp, located at Jordan Hall.
[Under 40 CFR 60, Subpart IIII, this is an affected source]
[Under 40 CFR 63, Subpart ZZZZ, this is an affected source]**

**(9) One (1) diesel emergency generator, identified as WQSB-1, manufactured in 2007, with a maximum capacity of 225.6 hp, located at Wright Quad.
[Under 40 CFR 60, Subpart IIII, this is an affected source]
[Under 40 CFR 63, Subpart ZZZZ, this is an affected source]**

**(10) One (1) diesel emergency generator, identified as HCSB-1, manufactured in 2008, with a maximum capacity of 1,150 hp, located outside of the Health Center.
[Under 40 CFR 60, Subpart IIII, this is an affected source]
[Under 40 CFR 63, Subpart ZZZZ, this is an affected source]**

**(11) One (1) diesel emergency generator, identified as MSB-2, manufactured in 2008, with a maximum capacity of 1,490 hp, located at Simon Hall.
[Under 40 CFR 60, Subpart IIII, this is an affected source]
[Under 40 CFR 63, Subpart ZZZZ, this is an affected source]**

**(12) One (1) diesel emergency generator, identified as MSNSB-1, manufactured in 2008, with a maximum capacity of 258 hp, located at Memorial Stadium North.
[Under 40 CFR 60, Subpart IIII, this is an affected source]
[Under 40 CFR 63, Subpart ZZZZ, this is an affected source]**

**(13) One (1) diesel emergency generator, identified as BCSB-1, manufactured in 2008, with a maximum capacity of 360 hp, located at Basketball Center Cook Hall.
[Under 40 CFR 60, Subpart IIII, this is an affected source]
[Under 40 CFR 63, Subpart ZZZZ, this is an affected source]**

**(14) One (1) diesel emergency generator, identified as CHSB-1, manufactured in 2009, with a maximum capacity of 300 hp, located at Cedar Hall.
[Under 40 CFR 60, Subpart IIII, this is an affected source]
[Under 40 CFR 63, Subpart ZZZZ, this is an affected source]**

**(15) One (1) diesel emergency generator, identified as HPSB-1, manufactured in 2009, with a maximum capacity of 606 hp, located at HPER.
[Under 40 CFR 60, Subpart IIII, this is an affected source]
[Under 40 CFR 63, Subpart ZZZZ, this is an affected source]**

**(16) One (1) diesel emergency generator, identified as ICSB-1, manufactured in 2009, with a maximum capacity of 186 hp,located at IU Innovation Center.
[Under 40 CFR 60, Subpart IIII, this is an affected source]
[Under 40 CFR 63, Subpart ZZZZ, this is an affected source]**

**(17) One (1) diesel emergency generator, identified as MHSB-1, manufactured in 2009, with a maximum capacity of 56 hp, located outside of Mason Hall.
[Under 40 CFR 60, Subpart IIII, this is an affected source]
[Under 40 CFR 63, Subpart ZZZZ, this is an affected source]**

**(18) One (1) diesel emergency generator, identified as DCSB-1, manufactured in 2008, with a maximum capacity of 2,200 hp, located inside of Data Center #1.
[Under 40 CFR 60, Subpart IIII, this is an affected source]
[Under 40 CFR 63, Subpart ZZZZ, this is an affected source]**

(19) One (1) diesel emergency generator, identified as DCSB-2, manufactured in 2008, with a maximum capacity of 2,200 hp, located inside of Data Center #2.
[Under 40 CFR 60, Subpart IIII, this is an affected source]
[Under 40 CFR 63, Subpart ZZZZ, this is an affected source]

(20) One (1) diesel emergency generator, identified as BBSB-1, manufactured in 2011, with a maximum capacity of 720 hp, located at Briscoe Building.
[Under 40 CFR 60, Subpart IIII, this is an affected source]
[Under 40 CFR 63, Subpart ZZZZ, this is an affected source]

(21) One (1) diesel emergency generator, identified as MACSB-1, manufactured in 2011, with a maximum capacity of 120 hp, located at the Musical Arts Center.
[Under 40 CFR 60, Subpart IIII, this is an affected source]
[Under 40 CFR 63, Subpart ZZZZ, this is an affected source]

(22) One (1) diesel emergency generator, identified as FQSB-1, manufactured in 2012, with a maximum capacity of 460 hp, located at Forest Quad.
[Under 40 CFR 60, Subpart IIII, this is an affected source]
[Under 40 CFR 63, Subpart ZZZZ, this is an affected source]

(23) One (1) diesel emergency generator, identified as JSMSB-1, manufactured in 2012, with a maximum capacity of 475 hp, located at the Jacobs School of Music.
[Under 40 CFR 60, Subpart IIII, this is an affected source]
[Under 40 CFR 63, Subpart ZZZZ, this is an affected source]

(h) Fourteen (14) Diesel Emergency Generators:

52. One (1) diesel emergency generator, identified as CIBSB-1, constructed in 2007 with a maximum capacity of 469 hp, located at CIB / 578.
[Under 40 CFR 60, Subpart IIII, this is an affected source]
[Under 40 CFR 63, Subpart ZZZZ, this is an affected source]

53. One (1) diesel emergency generator, identified as BASB-1, constructed in 2012 with a maximum capacity of 147 hp, located at Baseball/ 593.
[Under 40 CFR 60, Subpart IIII, this is an affected source]
[Under 40 CFR 63, Subpart ZZZZ, this is an affected source]

54. One (1) diesel emergency generator, identified as SBSB-2, constructed in 2012 with a maximum capacity of 99 hp, located at Softball/ 594.
[Under 40 CFR 60, Subpart IIII, this is an affected source]
[Under 40 CFR 63, Subpart ZZZZ, this is an affected source]

55. One (1) diesel emergency generator, identified as OPSB-1, constructed in 2014 with a maximum capacity of 375 hp, located at Optometry / 065
[Under 40 CFR 60, Subpart IIII, this is an affected source]
[Under 40 CFR 63, Subpart ZZZZ, this is an affected source]

56. One (1) diesel emergency generator, identified as WLSB-1, constructed in 2014 with a maximum capacity of 1206 hp, located at Wells Library /GISB 209.
[Under 40 CFR 60, Subpart IIII, this is an affected source]
[Under 40 CFR 63, Subpart ZZZZ, this is an affected source]

57. One (1) diesel emergency generator, identified as AHSB-2, constructed in 2015 with a maximum capacity of 668 hp, located at Assembly Hall / 603.
[Under 40 CFR 60, Subpart IIII, this is an affected source]

[Under 40 CFR 63, Subpart ZZZZ, this is an affected source]

58. One (1) diesel emergency generator, identified as FWSB-1, constructed in 2016 with a maximum capacity of 536 hp, located at Food Warehouse / 615.
[Under 40 CFR 60, Subpart IIII, this is an affected source]
[Under 40 CFR 63, Subpart ZZZZ, this is an affected source]

59. One (1) diesel emergency generator, identified as MESH-1, constructed in 2018 with a maximum capacity of 683.91 hp, located at MESH.
[Under 40 CFR 60, Subpart IIII, this is an affected source]
[Under 40 CFR 63, Subpart ZZZZ, this is an affected source]

60. One (1) diesel emergency generator, identified as 2NDSB-1, constructed in 2018 with a maximum capacity of 131 hp, located at 2427 E 2ND ST.
[Under 40 CFR 60, Subpart IIII, this is an affected source]
[Under 40 CFR 63, Subpart ZZZZ, this is an affected source]

61. One (1) diesel emergency generator, identified as ALFSB-2, constructed in 2018 with a maximum capacity of 201 hp, located at ALF.
[Under 40 CFR 60, Subpart IIII, this is an affected source]
[Under 40 CFR 63, Subpart ZZZZ, this is an affected source]

62. One (1) diesel emergency generator, identified as LHSB-1, constructed in 2018 with a maximum capacity of 324 hp, located at Luddy Hall.
[Under 40 CFR 60, Subpart IIII, this is an affected source]
[Under 40 CFR 63, Subpart ZZZZ, this is an affected source]

63. One (1) diesel emergency generator, identified as MSEZSB-1, constructed in 2018 with a maximum capacity of 450 hp, located at Memorial Stadium South End Zone.
[Under 40 CFR 60, Subpart IIII, this is an affected source]
[Under 40 CFR 63, Subpart ZZZZ, this is an affected source]

64. One (1) diesel emergency generator, identified as SPEASB-1, constructed in 2018 with a maximum capacity of 670 hp, located at SPEA / 452.
[Under 40 CFR 60, Subpart IIII, this is an affected source]
[Under 40 CFR 63, Subpart ZZZZ, this is an affected source]

65. One (1) diesel emergency generator, identified as SWSB-1, constructed in 2018 with a maximum capacity of 754 hp, located at Swain West.
[Under 40 CFR 60, Subpart IIII, this is an affected source]
[Under 40 CFR 63, Subpart ZZZZ, this is an affected source]

(j) Seven (7) portable non-road Diesel Emergency Generators.

(74) One (1) diesel emergency generator, identified as PORT-9, constructed in 2007 with a maximum capacity of 8.05 hp, located at service Building-Carpenter.
[Under 40 CFR 60, Subpart IIII, this is an affected source]
[Under 40 CFR 63, Subpart ZZZZ, this is an affected source]

(75) Three (3) diesel emergency generator, identified as PORT-10, PORT-11 and PORT-12, each, constructed in 2006 with a maximum capacity of 156 hp, 2.68 hp and 2.68 hp respectively, located at service Building.
[Under 40 CFR 60, Subpart IIII, this is an affected source]
[Under 40 CFR 63, Subpart ZZZZ, this is an affected source]

(76) Three (3) diesel emergency generator, identified as PORT-13, PORT-14 and PORT-15, constructed in 2015, 2017 and 2008 with a maximum capacity of 23.5 hp, 23.5 hp and 24.5 hp respectively, located at Utilities Building.
[Under 40 CFR 60, Subpart IIII, this is an affected source]
[Under 40 CFR 63, Subpart ZZZZ, this is an affected source]

(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 ~~(NSPS)~~ [326 IAC 12 1] [40 CFR 60, Subpart A] [326 IAC 12]

(a) ~~The provisions of 40 CFR 60, Subpart A – General Provisions, which are incorporated by reference in 326 IAC 12 1, apply to the Emergency Generators except when otherwise specified in 40 CFR 60, Subpart IIII.~~**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 units 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 ~~New Source Performance Standards (NSPS)~~ **Standards of Performance for Stationary Compression Ignition Internal Combustion Engines** [326 IAC 12] [40 CFR 60, Subpart IIII] ~~[326 IAC 12]~~

~~(a)~~ ~~Pursuant to 40 CFR 60 Subpart IIII, the~~**The** Permittee shall comply with the provisions of 40 CFR 60 Subpart IIII **(included as Attachment B to the operating permit)**, which are incorporated as 326 IAC 12-1 ~~for the following~~.

(a) Emergency Generators **identified as**:
HAPSB-1, IUPD-1, JHSB-1, TQSB-1, MSB-1, MSB 1, JDHSB-1, WQSB-1, ~~AHSB-1,~~ HCSB-1, MSB-2, MSNSB-1, BCSB-1, MHSB-1, DCSB-1, DCSB-2, CHSB-1, HPSB-1, ICSB-1, BBSB-1, MACSB-1,FQSB-1, and JSMSB-1.

*****
(7) 40 CFR 60.4211(a), (c),(f)**(2)(i)**, (g)
*****
(12) Table 8, **Subpart IIII of 60**

(b) ~~Pursuant to 40 CFR 60 Subpart IIII, the Permittee shall comply with the provisions of 40 CFR 60 Subpart IIII, which are incorporated as 326 IAC 12-1 for the following~~ Emergency Generators **identified as**:
FQHSB-1 and TTASB-1.

*****
(6) 40 CFR 60.4211**(f)(2)**(i)
*****
(10) Table 8, **Subpart IIII of 60**

(c) Emergency Generators identified as:

CIBSB-1, BASB-1, SBSB-2, OPSB-1, WLSB-1, AHSB-2, FWSB-1, MESH-1, 2NDSB-1, ALFSB-2, LHSB-1, MSEZSB-1, SPEASB-1, SWSB-1 and PORT-9 through PORT-15.

(1) 40 CFR 60.4200(a)(2)(i)
(2) 40 CFR 60.4202(a)
(3) 40 CFR 60.4205(a)(b)
(4) 40 CFR 60.4206
(5) 40 CFR 60.4207(a)(b)
(6) 40 CFR 60.4208
(7) 40 CFR 60.4209(a)
(8) 40 CFR 60.4211(a)(f)(2)(i), (g)
(9) 40 CFR 60.4214(b)
(10) 40 CFR 60.4218
(11) 40 CFR 60.4219
(12) Table 8, Subpart IIII of 60

SECTION E.3 ~~EMISSIONS UNIT OPERATION CONDITIONS~~ **NESHAP**

Emissions Unit Description:
Emissions Unit Description:

A.3 Specifically Regulated Insignificant Activities
(c)
*****
(g) ~~Twenty Three (26) Diesel Emergency Generators:~~

~~FQHSB-1, 282 hp, manufactured in 2006, located outside the Foster Quad/Harper Buildings~~
~~(2) TTASB-1, 300 hp, manufactured in 2006, located outside the Tulip Tree Apartments~~
~~(3) HAPSB-1, 60 hp, manufactured in 2007, located outside the Henderson/Atwater Parking Area~~
~~(4) IUPD-1, 545 hp, manufactured in 2007, located outside of the IU Police Department Building~~
~~(5) JHSB-1, 225 hp, manufactured in 2007, located outside of Johnson Hall~~
~~(6) TQSB-1, 320 hp, manufactured in 2007, located outside of Teter Quad Building~~
~~(7) MSB-1, 1,200 hp, manufactured in 2007, located inside of the MSB-1 Building~~
~~(8) JDHSB-1, 80 hp, manufactured in 2007, located at Jordan Hall~~
~~(9) WQSB-1, 225.6 hp, manufactured in 2007, located at Wright Quad~~
~~(10)HCSB-1, 1,150 hp, manufactured in 2008, located outside of the Health Center~~
~~(11)MSB-2, 1,490 hp, manufactured in 2008, located at Simon Hall~~
~~(12)MSNSB-1, 258 hp, manufactured in 2008, located at Memorial Stadium North~~
~~(13)BCSB-1, 360 hp, manufactured in 2008, located at Basketball Center Cook Hall~~
~~(14)CHSB-1, 300 hp, manufactured in 2009, located at Cedar Hall~~
~~(15)HPSB-1, 606 hp, manufactured in 2009, located at HPER (Old Gym)~~
~~(16)ICSB-1, 186 hp, manufactured in 2009, located at IU Innovation Center~~
~~(17)MHSB-1, 56 hp, manufactured in 2009, located outside of Mason Hall~~
~~(18)DCSB-1, 2,200 hp, manufactured in 2009, located inside of Data Center #1~~
~~(19)DCSB-2, 2,200 hp, manufactured in 2009, located inside of Data Center #2~~
~~(20)BBSB-1, 720 hp, manufactured in 2011, located at Briscoe Building~~
~~(21)MACSB-1, 120 hp, manufactured in 2011, located at the Musical Arts Center~~
~~(22)FQSB-1, 460 hp, manufactured in 2012, located at Forest Quad~~
~~(23)JSMSB-1, 475 hp, manufactured in 2012, located at the Jacob School of Music~~

(g) Twenty three (23) Diesel Emergency Generators:

(1) One (1) diesel emergency generators, identified as FQHSB-1, manufactured in 2006, with a maximum capacity of 282 hp, located outside the Foster Quad/Harper Buildings.
[Under 40 CFR 60, Subpart IIII, this is an affected source]

[Under 40 CFR 63, Subpart ZZZZ, this is an affected source]

(2) One (1) diesel emergency generators, identified as TTASB-1, manufactured in 2006, with a maximum capacity of 300 hp, located outside the Tulip Tree Apartments.
[Under 40 CFR 60, Subpart IIII, this is an affected source]
[Under 40 CFR 63, Subpart ZZZZ, this is an affected source]

(3) One (1) diesel emergency generator, identified as HAPSB-1, manufactured in 2007, with a maximum capacity of 60 hp, located outside the Henderson/Atwater Parking Area.
[Under 40 CFR 60, Subpart IIII, this is an affected source]
[Under 40 CFR 63, Subpart ZZZZ, this is an affected source]

(4) One (1) diesel emergency generator, identified as IUPD-1, manufactured in 2007, with a maximum capacity of 545 hp, located outside of the IU Police Department Building.
[Under 40 CFR 60, Subpart IIII, this is an affected source]
[Under 40 CFR 63, Subpart ZZZZ, this is an affected source]

(5) One (1) diesel emergency generator, identified as JHSB-1, manufactured in 2007, with a maximum capacity of 225 hp, located outside of Johnston Hall.
[Under 40 CFR 60, Subpart IIII, this is an affected source]
[Under 40 CFR 63, Subpart ZZZZ, this is an affected source]

(6) One (1) diesel emergency generator, identified as TQSB-1, manufactured in 2007, located outside of Teter Quad Building.
[Under 40 CFR 60, Subpart IIII, this is an affected source]
[Under 40 CFR 63, Subpart ZZZZ, this is an affected source]

(7) One (1) diesel emergency generator, identified as MSB-1, with a maximum capacity of 1,200 hp, manufactured in 2007, with a maximum capacity of 320 hp, located inside of the MSB-1 Building.
[Under 40 CFR 60, Subpart IIII, this is an affected source]
[Under 40 CFR 63, Subpart ZZZZ, this is an affected source]

(8) One (1) diesel emergency generator, identified as JDHSB-1, manufactured in 2007, with a maximum capacity of 80 hp, located at Jordan Hall.
[Under 40 CFR 60, Subpart IIII, this is an affected source]
[Under 40 CFR 63, Subpart ZZZZ, this is an affected source]

(9) One (1) diesel emergency generator, identified as WQSB-1, manufactured in 2007, with a maximum capacity of 225.6 hp, located at Wright Quad.
[Under 40 CFR 60, Subpart IIII, this is an affected source]
[Under 40 CFR 63, Subpart ZZZZ, this is an affected source]

(10) One (1) diesel emergency generator, identified as HCSB-1, manufactured in 2008, with a maximum capacity of 1,150 hp, located outside of the Health Center.
[Under 40 CFR 60, Subpart IIII, this is an affected source]
[Under 40 CFR 63, Subpart ZZZZ, this is an affected source]

(11) One (1) diesel emergency generator, identified as MSB-2, manufactured in 2008, with a maximum capacity of 1,490 hp, located at Simon Hall.
[Under 40 CFR 60, Subpart IIII, this is an affected source]
[Under 40 CFR 63, Subpart ZZZZ, this is an affected source]

(12) One (1) diesel emergency generator, identified as MSNSB-1, manufactured in 2008, with a maximum capacity of 258 hp, located at Memorial Stadium North.
[Under 40 CFR 60, Subpart IIII, this is an affected source]
[Under 40 CFR 63, Subpart ZZZZ, this is an affected source]

(13) One (1) diesel emergency generator, identified as BCSB-1, manufactured in 2008, with a maximum capacity of 360 hp, located at Basketball Center Cook Hall.
[Under 40 CFR 60, Subpart IIII, this is an affected source]
[Under 40 CFR 63, Subpart ZZZZ, this is an affected source]

(14) One (1) diesel emergency generator, identified as CHSB-1, manufactured in 2009, with a maximum capacity of 300 hp, located at Cedar Hall.
[Under 40 CFR 60, Subpart IIII, this is an affected source]
[Under 40 CFR 63, Subpart ZZZZ, this is an affected source]

(15) One (1) diesel emergency generator, identified as HPSB-1, manufactured in 2009, with a maximum capacity of 606 hp, located at HPER.
[Under 40 CFR 60, Subpart IIII, this is an affected source]
[Under 40 CFR 63, Subpart ZZZZ, this is an affected source]

(16) One (1) diesel emergency generator, identified as ICSB-1, manufactured in 2009, with a maximum capacity of 186 hp,located at IU Innovation Center.
[Under 40 CFR 60, Subpart IIII, this is an affected source]
[Under 40 CFR 63, Subpart ZZZZ, this is an affected source]

(17) One (1) diesel emergency generator, identified as MHSB-1, manufactured in 2009, with a maximum capacity of 56 hp, located outside of Mason Hall.
[Under 40 CFR 60, Subpart IIII, this is an affected source]
[Under 40 CFR 63, Subpart ZZZZ, this is an affected source]

(18) One (1) diesel emergency generator, identified as DCSB-1, manufactured in 2008, with a maximum capacity of 2,200 hp, located inside of Data Center #1.
[Under 40 CFR 60, Subpart IIII, this is an affected source]
[Under 40 CFR 63, Subpart ZZZZ, this is an affected source]

(19) One (1) diesel emergency generator, identified as DCSB-2, manufactured in 2008, with a maximum capacity of 2,200 hp, located inside of Data Center #2.
[Under 40 CFR 60, Subpart IIII, this is an affected source]
[Under 40 CFR 63, Subpart ZZZZ, this is an affected source]

(20) One (1) diesel emergency generator, identified as BBSB-1, manufactured in 2011, with a maximum capacity of 720 hp, located at Briscoe Building.
[Under 40 CFR 60, Subpart IIII, this is an affected source]
[Under 40 CFR 63, Subpart ZZZZ, this is an affected source]

(21) One (1) diesel emergency generator, identified as MACSB-1, manufactured in 2011, with a maximum capacity of 120 hp, located at the Musical Arts Center.
[Under 40 CFR 60, Subpart IIII, this is an affected source]
[Under 40 CFR 63, Subpart ZZZZ, this is an affected source]

(22) One (1) diesel emergency generator, identified as FQSB-1, manufactured in 2012, with a maximum capacity of 460 hp, located at Forest Quad.
[Under 40 CFR 60, Subpart IIII, this is an affected source]
[Under 40 CFR 63, Subpart ZZZZ, this is an affected source]

**(23) One (1) diesel emergency generator, identified as JSMSB-1, manufactured in 2012, with a maximum capacity of 475 hp, located at the Jacobs School of Music.
[Under 40 CFR 60, Subpart IIII, this is an affected source]
[Under 40 CFR 63, Subpart ZZZZ, this is an affected source]**

(h) Forty Two (42) Diesel Emergency Generators:

**(24) One (1) diesel emergency generator, identified as FHSB-1, constructed in 1957 with a maximum capacity of 67.5 hp, located at Field House / 604.
[Under 40 CFR 63, Subpart ZZZZ, this is an affected source]**

**(25) One (1) diesel emergency generator, identified as HASB-1, constructed in 1970 with a maximum capacity of 26.2 hp, located at Hall Admin. / 463.
[Under 40 CFR 63, Subpart ZZZZ, this is an affected source]**

**(26) One (1) diesel emergency generator, identified as FHSB-2, constructed in 1972 with a maximum capacity of 22.5 hp, located at Franklin Hall / 007.
[Under 40 CFR 63, Subpart ZZZZ, this is an affected source]**

**(27) One (1) diesel emergency generator, identified as LBSB-1, constructed in 1981 with a maximum capacity of 150 hp, located at Law Building / 001.
[Under 40 CFR 63, Subpart ZZZZ, this is an affected source]**

**(28) One (1) diesel emergency generator, identified as POPSB-1, constructed in 1985 with a maximum capacity of 255 hp, located at Poplars Bldg. / 008.
[Under 40 CFR 63, Subpart ZZZZ, this is an affected source]**

**(29) One (1) diesel emergency generator, identified as SBSB-4, constructed in 1986 with a maximum capacity of 765 hp, located at Service Bldg / 630.
[Under 40 CFR 63, Subpart ZZZZ, this is an affected source]**

**(30) One (1) diesel emergency generator, identified as MASB-1, constructed in 1989 with a maximum capacity of 91.5 hp, located at Music Addition / 148.
[Under 40 CFR 63, Subpart ZZZZ, this is an affected source]**

**(31) One (1) diesel emergency generator, identified as CASB-1, constructed in 1990 with a maximum capacity of 900 hp, located at Chemistry Addition / 072.
[Under 40 CFR 63, Subpart ZZZZ, this is an affected source]**

**(32) One (1) diesel emergency generator, identified as JHSB-2, constructed in 1990 with a maximum capacity of 600 hp, located at Jordan Hall / 107.
[Under 40 CFR 63, Subpart ZZZZ, this is an affected source]**

**(33) One (1) diesel emergency generator, identified as SBSB-3, constructed in 1991 with a maximum capacity of 30 hp, located at Student Building / 017.
[Under 40 CFR 63, Subpart ZZZZ, this is an affected source]**

**(34) One (1) diesel emergency generator, identified as CEESB-1, constructed in 1991 with a maximum capacity of 600 hp, located at W.W. Wright (CEE) / 245.
[Under 40 CFR 63, Subpart ZZZZ, this is an affected source]**

**(35) One (1) diesel emergency generator, identified as IMUSB-1, constructed in 1993 with a maximum capacity of 750 hp, located at Memorial Union / 053.
[Under 40 CFR 63, Subpart ZZZZ, this is an affected source]**

**(36) One (1) diesel emergency generator, identified as GSSB-1, constructed in 1994 with a maximum capacity of 30 hp, located at Geological Sciences /417.
[Under 40 CFR 63, Subpart ZZZZ, this is an affected source]**

**(37) One (1) diesel emergency generator, identified as RSSB-1, constructed in 1994 with a maximum capacity of 187.5 hp, located at Recreational Sports / 475.
[Under 40 CFR 63, Subpart ZZZZ, this is an affected source]**

**(38) One (1) diesel emergency generator, identified as RTVSB-1, constructed in 1996 with a maximum capacity of 300 hp, located at Radio/TV / 158.
[Under 40 CFR 63, Subpart ZZZZ, this is an affected source]**

**(39) One (1) diesel emergency generator, identified as AUSB-1, constructed in 1999 with a maximum capacity of 600 hp, located at Auditorium / 171.
[Under 40 CFR 63, Subpart ZZZZ, this is an affected source]**

**(40) One (1) diesel emergency generator, identified as CHPSB-1, constructed in 1999 with a maximum capacity of 1109 hp, located at Cen. Heat Plant / 445.
[Under 40 CFR 63, Subpart ZZZZ, this is an affected source]**

**(41) One (1) diesel emergency generator, identified as WQSB-2, constructed in 1999 with a maximum capacity of 600 hp, located at Willkie Quad / 299.
[Under 40 CFR 63, Subpart ZZZZ, this is an affected source]**

**(42) One (1) diesel emergency generator, identified as ALFSB-1, constructed in 2000 with a maximum capacity of 335 hp, located at ALF.
[Under 40 CFR 63, Subpart ZZZZ, this is an affected source]**

**(43) One (1) diesel emergency generator, identified as RHSB-1, constructed in 2000 with a maximum capacity of 525 hp, located at Read Hall / 227.
[Under 40 CFR 63, Subpart ZZZZ, this is an affected source]**

**(44) One (1) diesel emergency generator, identified as CVSB-1, constructed in 2001 with a maximum capacity of 300 hp, located at Campus View / 529.
[Under 40 CFR 63, Subpart ZZZZ, this is an affected source]**

**(45) One (1) diesel emergency generator, identified as EGSB-1, constructed in 2001 with a maximum capacity of 450 hp, located at Eigenmann / 313.
[Under 40 CFR 63, Subpart ZZZZ, this is an affected source]**

**(46) One (1) diesel emergency generator, identified as SHSB-1, constructed in 2001 with a maximum capacity of 375 hp, located at Spruce Hall / 298.
[Under 40 CFR 63, Subpart ZZZZ, this is an affected source]**

**(47) One (1) diesel emergency generator, identified as TDSB-1, constructed in 2001 with a maximum capacity of 412.5 hp, located at Lee Norvelle Theatre Drama /172.
[Under 40 CFR 63, Subpart ZZZZ, this is an affected source]**

**(48) One (1) diesel emergency generator, identified as MHSB-2, constructed in 2001 with a maximum capacity of 600 hp, located at McNutt / 439.
[Under 40 CFR 63, Subpart ZZZZ, this is an affected source]**

**(49) One (1) diesel emergency generator, identified as MHSB-3, constructed in 2001 with a maximum capacity of 750 hp, located at Myers Hall / 101.
[Under 40 CFR 63, Subpart ZZZZ, this is an affected source]**

(50) One (1) diesel emergency generator, identified as ALSB-1, constructed in 2002 with a maximum capacity of 90 hp, located at Animal Lab / 411.
[Under 40 CFR 63, Subpart ZZZZ, this is an affected source]

(51) One (1) diesel emergency generator, identified as USASB-1, constructed in 2005 with a maximum capacity of 450 hp, located at Union St Apts / 296.
[Under 40 CFR 63, Subpart ZZZZ, this is an affected source]

(52) One (1) diesel emergency generator, identified as CIBSB-1, constructed in 2007 with a maximum capacity of 469 hp, located at CIB / 578.
[Under 40 CFR 60, Subpart IIII, this is an affected source]
[Under 40 CFR 63, Subpart ZZZZ, this is an affected source]

(53) One (1) diesel emergency generator, identified as BASB-1, constructed in 2012 with a maximum capacity of 147 hp, located at Baseball/ 593.
[Under 40 CFR 60, Subpart IIII, this is an affected source]
[Under 40 CFR 63, Subpart ZZZZ, this is an affected source]

(54) One (1) diesel emergency generator, identified as SBSB-2, constructed in 2012 with a maximum capacity of 99 hp, located at Softball/ 594.
[Under 40 CFR 60, Subpart IIII, this is an affected source]
[Under 40 CFR 63, Subpart ZZZZ, this is an affected source]

(55) One (1) diesel emergency generator, identified as OPSB-1, constructed in 2014 with a maximum capacity of 375 hp, located at Optometry / 065
[Under 40 CFR 60, Subpart IIII, this is an affected source]
[Under 40 CFR 63, Subpart ZZZZ, this is an affected source]

(56) One (1) diesel emergency generator, identified as WLSB-1, constructed in 2014 with a maximum capacity of 1206 hp, located at Wells Library /GISB 209.
[Under 40 CFR 60, Subpart IIII, this is an affected source]
[Under 40 CFR 63, Subpart ZZZZ, this is an affected source]

(57) One (1) diesel emergency generator, identified as AHSB-2, constructed in 2015 with a maximum capacity of 668 hp, located at Assembly Hall / 603.
[Under 40 CFR 60, Subpart IIII, this is an affected source]
[Under 40 CFR 63, Subpart ZZZZ, this is an affected source]

(58) One (1) diesel emergency generator, identified as FWSB-1, constructed in 2016 with a maximum capacity of 536 hp, located at Food Warehouse / 615.
[Under 40 CFR 60, Subpart IIII, this is an affected source]
[Under 40 CFR 63, Subpart ZZZZ, this is an affected source]

(59) One (1) diesel emergency generator, identified as MESH-1, constructed in 2018 with a maximum capacity of 683.91 hp, located at MESH.
[Under 40 CFR 60, Subpart IIII, this is an affected source]
[Under 40 CFR 63, Subpart ZZZZ, this is an affected source]

(60) One (1) diesel emergency generator, identified as 2NDSB-1, constructed in 2018 with a maximum capacity of 131 hp, located at 2427 E 2ND ST.
[Under 40 CFR 60, Subpart IIII, this is an affected source]
[Under 40 CFR 63, Subpart ZZZZ, this is an affected source]

(61) One (1) diesel emergency generator, identified as ALFSB-2, constructed in 2018 with a maximum capacity of 201 hp, located at ALF.

[Under 40 CFR 60, Subpart IIII, this is an affected source]
[Under 40 CFR 63, Subpart ZZZZ, this is an affected source]

(62) **One (1) diesel emergency generator, identified as LHSB-1, constructed in 2018 with a maximum capacity of 324 hp, located at Luddy Hall.**
[Under 40 CFR 60, Subpart IIII, this is an affected source]
[Under 40 CFR 63, Subpart ZZZZ, this is an affected source]

(63) **One (1) diesel emergency generator, identified as MSEZSB-1, constructed in 2018 with a maximum capacity of 450 hp, located at Memorial Stadium South End Zone.**
[Under 40 CFR 60, Subpart IIII, this is an affected source]
[Under 40 CFR 63, Subpart ZZZZ, this is an affected source]

(64) **One (1) diesel emergency generator, identified as SPEASB-1, constructed in 2018 with a maximum capacity of 670 hp, located at SPEA / 452.**
[Under 40 CFR 60, Subpart IIII, this is an affected source]
[Under 40 CFR 63, Subpart ZZZZ, this is an affected source]

(65) **One (1) diesel emergency generator, identified as SWSB-1, constructed in 2018 with a maximum capacity of 754 hp, located at Swain West.**
[Under 40 CFR 60, Subpart IIII, this is an affected source]
[Under 40 CFR 63, Subpart ZZZZ, this is an affected source]

(j) **Fifteen (15) portable non-road Diesel Emergency Generators.**

(70) **One (1) diesel emergency generator, identified as PORT-1, constructed in 2002 with a maximum capacity of 80.46 hp, located at Service Building.**
[Under 40 CFR 63, Subpart ZZZZ, this is an affected source]

(71) **One (1) diesel emergency generator, identified as PORT-2, constructed in 1999 with a maximum capacity of 22.80 hp, located at Service Building/630.**
[Under 40 CFR 63, Subpart ZZZZ, this is an affected source]

(72) **Two (2) diesel emergency generators, identified as PORT-3 and PORT-4, each, constructed in 1999 with a maximum capacity of 80.46 hp, located at Union St. Chiller Plant – RPS.**
[Under 40 CFR 63, Subpart ZZZZ, this is an affected source]

(73) **Four (4) diesel emergency generator, identified as PORT-5, PORT-6, PORT-7 and PORT-8, each, constructed in 1999 with a maximum capacity of 13 hp, located at Service Building.**
[Under 40 CFR 63, Subpart ZZZZ, this is an affected source]

(74) **One (1) diesel emergency generator, identified as PORT-9, constructed in 2007 with a maximum capacity of 8.05 hp, located at service Building-Carpenter.**
[Under 40 CFR 60, Subpart IIII, this is an affected source]
[Under 40 CFR 63, Subpart ZZZZ, this is an affected source]

(75) **Three (3) diesel emergency generator, identified as PORT-10, PORT-11 and PORT-12, each, constructed in 2006 with a maximum capacity of 156 hp, 2.68 hp and 2.68 hp respectively, located at service Building.**
[Under 40 CFR 60, Subpart IIII, this is an affected source]
[Under 40 CFR 63, Subpart ZZZZ, this is an affected source]

(76) Three (3) diesel emergency generator, identified as PORT-13, PORT-14 and PORT-15, constructed in 2015, 2017 and 2008 with a maximum capacity of 23.5 hp, 23.5 hp and 24.5 hp respectively, located at Utilities Building.
[Under 40 CFR 60, Subpart IIII, this is an affected source]
[Under 40 CFR 63, Subpart ZZZZ, this is an affected source]

(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 (NESHAP) [326 IAC 20-82 [40 CFR 63, Subpart A]

~~The provisions of 40 CFR 63, Subpart A - General Provisions, which are incorporated by reference in 326 IAC 20-82, apply to the Emergency Generators except when otherwise specified in 40 CFR 63, Subpart ZZZZ.~~

(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 20-82, for the emission units 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** ~~Stationary Emergency Generators, NESHAP~~ [326 IAC 20-82] [40 CFR 63, Subpart ZZZZ]

(a) ~~Pursuant to 40 CFR 63 Subpart ZZZZ, the~~ **The** Permittee shall comply with the provisions of 40 CFR 63 Subpart ZZZZ **(included as Attachment C to the operating permit)**, which are incorporated as 326 IAC 20-82 for **the emission units listed below.**

Emergency Generators **identified as:**
BBSB-1, HPSB-1, and MSB-2. ~~as specified as follows:~~
*****

(b) ~~Pursuant to 40 CFR 63 Subpart ZZZZ, the Permittee shall comply with the provisions of 40 CFR 63 Subpart ZZZZ, which are incorporated as 326 IAC 20-82 for~~
Emergency Generators **identified as:**
BCSB-1, CHSB-1, FQSB-1, JSMSB-1, JDHSB-1, MACSB-1, ICSB-1, WQSB-1, and MSNSB-1.~~, as specified as follows:~~
*****

(c) ~~Pursuant to 40 CFR 63 Subpart ZZZZ, the Permittee shall comply with the provisions of 40 CFR 63 Subpart ZZZZ, which are incorporated as 326 IAC 20-82 for~~
Emergency Generators **identified as:**
~~AHSB-1~~, FQHSB-1, HAPSB-1, IUPD-1, JHSB-1, MHSB-1, ~~SBSB-1~~, TQSB-1, and TTASB-1.~~, as specified as follows:~~
*****

(d) ~~Pursuant to 40 CFR 63 Subpart ZZZZ, the Permittee shall comply with the provisions of~~

~~40 CFR 63 Subpart ZZZZ, which are incorporated as 326 IAC 20-82 for~~
Emergency Generators **identified as:**
HCSB-1, DCSB-1, DCSB-2, ~~MSB-1,~~ and MSB-1.~~, as specified as follows:~~
*****

(e) **Emergency Generators identified as:**
FHSB-1, HASB-1, FHSB-2, LBSB-1, POPSB-1, SBSB-4, MASB-1, CASB-1, JHSB-2, SBSB-3, CEESB-1, IMUSB-1, GSSB-1, RSSB-1, RTVSB-1, AUSB-1, CHPSB-1, WQSB-2, ALFSB-1, RHSB-1, CVSB-1, EGSB-1, SHSB-1, TDSB-1, MHSB-2, MHSB-3, ALSB-1, USASB-1, CIBSB-1, BASB-1, SBSB-2, OPSB-1, WLSB-1, AHSB-2, FWSB-1, MESH-1, 2NDSB-1, ALFSB-2, LHSB-1, MSEZSB-1, SPEASB-1, SWSB-1, and PORT-1 through PORT-15. ~~, as specified as follows:~~

(1) 40 CFR 63.6580
(2) 40 CFR 63.6585(b)
(3) 40 CFR 63.6590
(4) 40 CFR 63.6595
(5) 40 CFR 63.6605
(6) 40 CFR 63.6645
(7) 40 CFR 63.6655(d),(e),(f)
(8) 40 CFR 63.6670
(9) 40 CFR 63.6675
(10) Table 2c, Subpart ZZZZ of 63
(11) Table 2d, item 1, Subpart ZZZZ of 63
(12) Table 6, item 9, Subpart ZZZZ of 63
(13) Table 8, Subpart ZZZZ of 63

~~(e) Pursuant to 40 CFR 63 Subpart ZZZZ, the Permittee shall comply with the provisions of 40 CFR 63 Subpart ZZZZ, which are incorporated as 326 IAC 20-82 for Emergency Generator CBSB-1, as specified as follows:~~

~~(1) 40 CFR 63.6580~~
~~(2) 40 CFR 63.6585~~
~~(3) 40 CFR 63.6585(b)~~
~~(4) 40 CFR 63.6590(a)~~
~~(5) 40 CFR 63.6602 - Table 2c and 2c.1~~
~~(6) 40 CFR 63.6605(a), (b)~~
~~(7) 40 CFR 63.6625(e)(2), (f), (h), (i)~~
~~(8) 40 CFR 63.6640(a) - Table 6 - 9.a.i - ii~~
~~(9) 40 CFR 63.6640(b), (e), (f)(1)~~
~~(10) 40 CFR 63.6650(f)~~
~~(11) 40 CFR 63.6655(a), (a)(1)-(2), (a)(4)-(5), (d)-(f)~~
~~(12) 40 CFR 63.6660(a)-(c)~~

SECTION E.4 ~~EMISSIONS UNIT OPERATION CONDITIONS~~ **NESHAP**

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

~~The provisions of 40 CFR 63, Subpart A - General Provisions, which are incorporated by reference in 326 IAC 20-1-1, apply to the boilers EU-03, EU-04, EU-05, EU-06, EU-07, and the Various Insignificant Boilers and indirect-heat furnace, except when otherwise specified in 40 CFR 63, Subpart DDDDD.~~

(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 20-1-1, for the emission units listed above, except as otherwise specified in 40 CFR Part 63, Subpart DDDDD.**

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

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

E.4.2 **National Emissions Standards for Hazardous Air Pollutants for** Major Source: Industrial, Commercial, and Institutional Boilers and Process Heaters ~~NESHAP~~ [326 IAC 20-1-1] [40 CFR 63, Subpart DDDDD]

~~Pursuant to 40 CFR 63 Subpart DDDDD, the~~ **The** Permittee shall comply with the provisions of 40 CFR 63 Subpart DDDDD **(included as Attachment D to the operating permit)**, which are incorporated as 326 IAC 20-1-1.

(a) Boilers **identified as:**
EU-03, EU-04, and EU-06~~, as specified as follows:~~
*****

~~E.4.3 National Emissions Standards for Hazardous Air Pollutants for Major Source: Industrial, Commercial, and Institutional Boilers and Process Heaters [326 IAC 20-1-1] [40 CFR 63, Subpart DDDDD]~~

~~The Permittee shall comply with the provisions of 40 CFR 63 Subpart DDDDD (included as Attachment D to the operating permit), which are incorporated as 326 IAC 20-1-1 for the emission units listed below~~

(b) Boilers identified as:
EU-05, EU-07, Various Insignificant Boilers, the three boilers located at the Innovation Center, and the indirect-heat furnace **located at Hutton Honors College**.
*****

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 February 15, 2019. Additional information was received on May 9, 2019.

The operation of this stationary source power plant that supplies campus with process heat from boilers shall be subject to the conditions of the attached proposed Part 70 Operating Permit Renewal No. 105-41051-00005.

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 Aasim Noveer, 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) 234-1243 or (800) 451-6027, and ask for Aasim Noveer or (317) 234-1243.

(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: Entire Source Emission Summary - Limited PTE

Company Name: Indiana University
Source Address: 820 North Walnut Grove, Bloomington, Indiana 47405
Permit Number: 105-41051-00005
Reviewer: Aasim Noveer

Limited Emissions (tons/year)

Emission Units	PM	PM_{10}	$PM_{2.5}$	SO_2	NOx	VOC	CO	Total HAPs	Worst Case HAPs	
Boiler EU-03 (Coal, NG & FO#2)	1204.50	240.90	240.90	2184.53	200.75	1.89	91.25	25.06	22.10	Hydrogen Chloride
Boiler EU-04 (Coal, NG & FO#2)	1204.50	240.90	240.90	2184.53	200.75	1.89	91.25	25.06	22.10	Hydrogen Chloride
Boiler EU-05 (NG & FO#2)	11.89	13.67	9.21	466.63	142.66	4.49	68.53	1.54	1.47	Hexane
Boiler EU-06 (Coal, NG & FO#2)	2288.55	457.71	457.71	4150.60	381.43	3.54	173.38	47.62	41.52	Hydrogen Chloride
Boiler EU-07 (NG & FO#2)	1.77	7.08	7.08	2.58	34.22	5.13	78.27	1.76	1.68	Hexane
Small NG Boilers (Insignificant Activites)	1.46	5.82	5.82	0.46	76.60	4.21	64.35	1.45	1.35	Hexane
Informatics East Building Boiler and Hutton Honors College Furnace	0.02	0.06	0.06	0.005	0.80	0.04	0.68	0.015	0.01	Hexane
Diesel-Fired Emergency Generators (< 600 hp)	6.70	6.70	6.70	6.24	94.41	7.66	20.34	0.083	0.025	Formaldehyde
Diesel-Fired Emergency Generators (> 600 hp)	3.64	2.09	2.09	0.06	124.93	3.67	28.63	0.11	0.028	Benzene
Coal Handling System	8.58	4.05	0.61	-	-	-	-	-	-	-
Fly Ash Silo Vent	1.89	1.89	1.89	-	-	-	-	-	-	-
Fly Ash Conveying Leg #1	9.75	3.41	3.41	-	-	-	-	-	-	-
Fly Ash Conveying Leg #2	9.75	3.41	3.41	-	-	-	-	-	-	-
Lime Silo Baghouse Vent	1.60	1.60	1.60	-	-	-	-	-	-	-
Carbon Silo Baghouse Vent	0.04	0.04	0.04	-	-	-	-	-	-	-
Fugitive Dust - Paved Roads	0.86	0.17	0.17	-	-	-	-	-	-	-
Total	**4755.50**	**989.50**	**981.61**	**8995.63**	**1256.55**	**32.52**	**616.68**	**102.70**	**85.72**	**Hydrogen Chloride**

NOTE:

The limited potential to emit from the ash silo vent, the lime silo vent, and the activated carbon silo vent is before control because these units are considered exempt units and no rules apply.

The limited potential to emit from the ash conveying system is before control. These systems can comply with the 326 IAC 6-3-2 limit without control.

Appendix A: Entire Source Emission Summary - Limited PTE

Company Name: Indiana University
Source Address: 820 North Walnut Grove, Bloomington, Indiana 47405
Permit Number: 105-41051-00005
Reviewer: Aasim Noveer

Uncontrolled Emissions (tons/year)

Emission Units	PM	PM_{10}	$PM_{2.5}$	SO_2	NOx	VOC	CO	Total HAPs	Worst Case HAPs	
Boiler EU-03 (Coal, NG & FO#2)	1204.50	240.90	240.90	2184.53	200.75	1.89	91.25	25.06	22.10	Hydrogen Chloride
Boiler EU-04 (Coal, NG & FO#2)	1204.50	240.90	240.90	2184.53	200.75	1.89	91.25	25.06	22.10	Hydrogen Chloride
Boiler EU-05 (NG & FO#2)	11.89	13.67	9.21	466.63	142.66	4.49	68.53	1.54	1.47	Hexane
Boiler EU-06 (Coal, NG & FO#2)	2288.55	457.71	457.71	4150.60	381.43	3.54	173.38	47.62	41.52	Hydrogen Chloride
Boiler EU-07 (NG & FO#2)	13.01	14.97	10.09	510.83	156.18	5.13	78.27	1.76	1.68	Hexane
Small NG Boilers (Insignificant Activites)	1.46	5.82	5.82	0.46	76.60	4.21	64.35	1.45	1.38	Hexane
Informatics East Building Boiler and Hutton Honors College Furnace	0.02	0.06	0.06	0.00	0.80	0.04	0.68	0.015	0.010	Hexane
Diesel-Fired Emergency Generators (< 600 hp)	6.70	6.70	6.70	6.24	94.41	7.66	20.34	0.083	0.025	Formaldehyde
Diesel-Fired Emergency Generators (> 600 hp)	3.64	2.09	2.09	0.06	124.93	3.67	28.63	0.113	0.028	Benzene
Coal Handling System	8.58	4.05	0.61	-	-	-	-	-	-	-
Fly Ash Silo Vent	1.89	1.89	1.89	-	-	-	-	-	-	-
Fly Ash Conveying Leg #1	9.75	3.41	3.41	-	-	-	-	-	-	-
Fly Ash Conveying Leg #2	9.75	3.41	3.41	-	-	-	-	-	-	-
Lime Silo Baghouse Vent	1.60	1.60	1.60	-	-	-	-	-	-	-
Carbon Silo Baghouse Vent	0.04	0.04	0.04	-	-	-	-	-	-	-
Fugitive Dust - Paved Roads	0.86	0.17	0.17	-	-	-	-	-	-	-
Total	**4766.74**	**997.39**	**984.61**	**9503.88**	**1378.52**	**32.52**	**616.68**	**102.70**	**85.72**	**Hydrogen Chloride**

NOTE:
The limited potential to emit from the ash silo vent, the lime silo vent, and the activated carbon silo vent is before control because these units are considered exempt units and no rules apply.

The limited potential to emit from the ash conveying system is before control. These systems can comply with the 326 IAC 6-3-2 limit without control.

Appendix A: Entire Source Emission Summary - Controlled Emissions

Company Name: Indiana University
Source Address: 820 North Walnut Grove, Bloomington, Indiana 47405
Permit Number: 105-41051-00005
Reviewer: Aasim Noveer

Controlled Emissions (tons/year)

Emission Units	PM	PM_{10}	$PM_{2.5}$	SO_2	NOx	VOC	CO	Total HAPs	Worst Case HAPs	
Boiler EU-03	240.90	48.18	48.18	2184.53	200.75	0.91	91.25	25.06	22.10	Hydrogen Chloride
Boiler EU-04	240.90	48.18	48.18	2184.53	200.75	0.91	91.25	25.06	22.10	Hydrogen Chloride
Boiler EU-05	11.89	13.67	9.21	466.63	142.66	4.49	68.53	1.54	1.47	Hexane
Boiler EU-06	205.47	41.09	41.09	4150.60	381.43	1.73	173.38	47.62	41.52	Hydrogen Chloride
Boiler EU-07	13.01	14.97	10.09	510.83	156.18	5.13	78.27	1.76	1.68	Hexane
Small NG Boilers (Insignificant Activites)	1.46	5.82	5.82	0.46	76.60	4.21	64.35	1.446	1.350	Hexane
Informatics East Building Boiler and Hutton Honors College Furnace	0.02	0.06	0.06	0.00	0.80	0.04	0.68	0.015	0.010	Hexane
Diesel-Fired Emergency Generators (< 600 hp)	6.70	6.70	6.70	6.24	94.41	7.66	20.34	0.083	0.025	Formaldehyde
Diesel-Fired Emergency Generators (> 600 hp)	3.64	2.09	2.09	0.06	124.93	3.67	28.63	0.113	0.028	Benzene
Coal Handling System	8.58	4.05	0.61	0.00	0.00	0.00	0.00	0.00	-	-
Fly Ash Silo Vent	1.89	1.89	1.89	0.00	0.00	0.00	0.00	0.00	-	-
Fly Ash Conveying Leg #1	9.75	3.41	3.41	0.00	0.00	0.00	0.00	0.00	-	-
Fly Ash Conveying Leg #2	9.75	3.41	3.41	0.00	0.00	0.00	0.00	0.00	-	-
Lime Silo Baghouse Vent	1.60	1.60	1.60	0.00	0.00	0.00	0.00	0.00	-	-
Carbon Silo Baghouse Vent	0.04	0.04	0.04	0.00	0.00	0.00	0.00	0.00	-	-
Fugitive Dust - Paved Roads	0.86	0.17	0.17	0.00	0.00	0.00	0.00	0.00	-	-
Total	**756.46**	**195.33**	**182.56**	**9503.88**	**1378.52**	**28.76**	**616.68**	**102.70**	**85.72**	**Hydrogen Chloride**

Appendix A: Boiler PTE - Worst Case Combustion Summary

Company Name: Indiana University
Source Address: 820 North Walnut Grove, Bloomington, Indiana 47405
Permit Number: 105-41051-00005
Reviewer: Aasim Noveer

Coal Combustion Only - Uncontrolled PTE for Boilers (tons/year)

Emission Units	PM	PM_{10}	$PM_{2.5}$	SO_2	NOx	VOC	CO	Total HAPs	Worst Case HAPs	
Boiler EU-03	1204.50	240.90	240.90	2184.53	200.75	0.91	91.25	25.06	21.90	Hydrogen Chloride
Boiler EU-04	1204.50	240.90	240.90	2184.53	200.75	0.91	91.25	25.06	21.90	Hydrogen Chloride
Boiler EU-06	2288.55	457.71	457.71	4150.60	381.43	1.73	173.38	47.62	41.61	Hydrogen Chloride
Total	**4697.6**	**939.5**	**939.5**	**8519.6**	**782.9**	**3.56**	**355.9**	**97.74**	**85.41**	**Hydrogen Chloride**

NG Combustion Only - Uncontrolled PTE for Boilers (tons/year)

Emission Units	PM	PM_{10}	$PM_{2.5}$	SO_2	NOx	VOC	CO	Total HAPs	Worst Case HAPs	
Boiler EU-03	0.65	2.61	2.61	0.21	48.09	1.89	28.86	#REF!	0.61	Hexane
Boiler EU-04	0.65	2.61	2.61	0.21	48.09	1.89	28.86	0.65	0.61	Hexane
Boiler EU-05	1.55	6.20	6.20	0.49	114.22	4.49	68.53	1.54	1.47	Hexane
Boiler EU-06	1.22	4.90	4.90	0.39	90.18	3.54	54.11	1.22	1.16	Hexane
Boiler EU-07	1.77	7.08	7.08	0.56	93.18	5.13	78.27	1.76	1.68	Hexane
Total	**5.85**	**23.4**	**23.4**	**1.85**	**393.8**	**16.9**	**258.6**	**#REF!**	**5.53**	**Hexane**

FO #2 Combustion Only - Uncontrolled PTE for Boilers (tons/year)

Emission Units	PM	PM_{10}	$PM_{2.5}$	SO_2	NOx	VOC	CO	Total HAPs	Worst Case HAPs	
Boiler EU-03	5.01	5.96	5.33	177.70	50.06	0.85	12.51	0.02	0.005	Selenium
Boiler EU-04	5.01	5.96	5.33	177.70	50.06	0.85	12.51	0.02	0.005	Selenium
Boiler EU-05	11.89	13.67	9.21	466.63	142.66	1.19	29.72	0.04	0.012	Selenium
Boiler EU-06	11.89	13.67	9.21	466.63	142.66	1.19	29.72	0.04	0.012	Selenium
Boiler EU-07	13.01	14.97	10.09	510.83	156.18	1.30	32.54	0.04	0.013	Selenium
Total	**46.80**	**54.2**	**39.2**	**1799.49**	**541.6**	**5.4**	**117.0**	**0.16**	**0.05**	**Selenium**

Worst Case Combustion When Using Either Coal, NG, or FO - Uncontrolled PTE for Boilers (tons/year)

Emission Units	PM	PM_{10}	$PM_{2.5}$	SO_2	NOx	VOC	CO	Total HAPs	Worst Case HAPs	
Boiler EU-03	1,204.50	240.90	240.90	2,184.53	200.75	1.89	91.25	#REF!	21.90	Hydrogen Chloride
Boiler EU-04	1,204.50	240.90	240.90	2,184.53	200.75	1.89	91.25	25.06	21.90	Hydrogen Chloride
Boiler EU-05	11.89	13.67	9.21	466.63	142.66	4.49	68.53	1.54	1.47	Hexane
Boiler EU-06	2,288.55	457.71	457.71	4,150.60	381.43	3.54	173.38	47.62	41.61	Hydrogen Chloride
Boiler EU-07	13.01	14.97	10.09	510.83	156.18	5.13	78.27	1.76	1.68	Hexane
Total	**4722.45**	**968.1**	**958.8**	**9497.11**	**1081.8**	**16.9**	**502.7**	**#REF!**	**128.78**	**Hydrogen Chloride**

Appendix A: Boiler PTE - Controlled PTE for Boilers EU-03, EU-04, and EU-06

Company Name: Indiana University
Source Address: 820 North Walnut Grove, Bloomington, Indiana 47405
Permit Number: 105-41051-00005
Reviewer: Aasim Noveer

Controlled PTE for Boilers EU-3, EU-04, and EU-6 (tons/year)

Emission Units	PM	PM_{10}	$PM_{2.5}$	SO_2	NOx	VOC	CO
Boiler EU-03 (with Multiclone)	240.90	48.18	48.18	2184.53	200.75	0.91	91.25
Boiler EU-04 (with Multiclone)	240.90	48.18	48.18	2184.53	200.75	0.91	91.25
Boiler EU-06 (with Multiclone and ESP)	205.47	41.09	41.09	4150.60	381.43	1.73	173.38
Total	**687.3**	**137.5**	**137.5**	**8519.6**	**782.9**	**3.56**	**355.9**

Appendix A: Emissions Calculations
Coal Combustion: Spreader Stokers
Coal Burning - Uncontrolled PTE for Boiler EU-03 (Rated at Maximum of 100 MMBtu/hr When Combusting Coal (each)) ***

Company Name:	**Indiana University**
Address City IN Zip:	**820 North Walnut Grove, Bloomington, Indiana 47405**
Permit No.:	**105-41051-00005**
Reviewer:	**Aasim Noveer**

Heat Input Capacity MMBtu/hr	Heat Content of Coal Btu/lb of Coal **	Potential Throughput tons/year		Weight % Sulfur in Fuel		Weight %
100	12,000	36,500	S =	3.15	A = Ash =	9.7

	Pollutant					
	PM*	PM10*/PM2.5	SO2	NOx	VOC	CO
Emission Factor in lb/ton	66.0 ****	13.2	119.7 *(38S)*	11.0	0.05 *****	5.00
Potential Emission in tons/yr With particulate control 0.00% efficiency	1205 1205	241 241	2185	201	0.9	91.3
Potential Emission in lbs/MMBtu With particulate control 0.00% efficiency	2.75 **2.75**		**4.99**			

Methodology

* The PM emission factor is filterable PM only. The PM10/PM2.5 emission factor is filterable.
** Per the TV application for this source; 1 lb bituminous coal has a BTU rating of 12,000.
*** EU-03 and EU-04 have maximum design capacities of 125 MMBtu/per hour each, but are limited to 100 MMBtu per hour of heat input each when using coal or coal with a combination of fuels.
****See AP-42, Table 1.1-4 (footnote e), (Ash content taken into account with PM emission factor).
*****See AP-42, Table 1.1-19 (footnote c); (Average E.F. for spreader stokers included).
VOC emission factor is from Table 1.1-19 (Total non-methane organic carbon).
Potential Throughput (tons/year) = Heat Input Capacity (MMBtu/hr) x 10^6 Btu/MMBtu / Heat Content of Coal (Btu/lb) / 2000 lb/ton x 8,760 hrs/yr
Emission Factors from AP-42, Chapter 1.1 for spreader stoker SCC 1-01-002-04/24 (Supplement E, 9/98)
HAPs emission factors are available in AP-42, Chapter 1.1.
Emission (tons/yr) = Throughput tons per year x Emission Factor (lb/ton) / 2,000 lb/ton
Emissions (lbs/MMBtu) = 10^6 Btu/MMBtu / Heat Content of Coal (Btu/lb) / 2000 lb/ton x Emission Factor (lb/ton)

Appendix A: Emissions Calculations
Coal Combustion: Spreader Stokers
Coal Burning - Controlled PM PTE for Boiler EU-03 (Rated at Maximum of 100 MMBtu/hr When Combusting Coal and/or Fuel Oil) *

Company Name: **Indiana University**
Address City IN Zip: **820 North Walnut Grove, Bloomington, Indiana 47405**
Permit No. **105-41051-00005**
Reviewer: **Aasim Noveer**

Heat Input Capacity MMBtu/hr	Heat Content of Coal Btu/lb of Coal**	Potential Throughput tons/year	Weight % Sulfur in Fuel	Weight %
100	12,000	36,500	S = 3.15 %	A = Ash = 9.7

	Pollutant					
	PM*	PM10*/PM2.5	SO2	NOx	VOC	CO
Emission Factor in lb/ton	66.0 ****	13.2	119.7 *(38S)*	11.0	0.05 *****	5.00
Potential Emission in tons/yr	1204.5	240.9	2184.5	200.8	0.9	91.3
With PM control: 80.00% efficiency	240.9	48.2				
Potential Emission in lbs/MMBtu	2.750		**4.988**			
With PM control: 80.00% efficiency	**0.550**					

Methodology

* The PM emission factor is filterable PM only. The PM10/PM2.5 emission factor is filterable.

** Per the TV application for this source; 1 lb bituminous coal has a BTU rating of 12,000.

*** EU-03 and EU-04 have maximum design capacities of 125 MMBtu/per hour each, but are limited to 100 MMBtu per hour of heat input each when using coal or coal with a combination of fuels.

****See AP-42, Table 1.1-4 (footnote e), (Ash content taken into account with PM emission factor).

*****See AP-42, Table 1.1-19 (footnote c); (Average E.F. for spreader stokers included).

VOC emission factor is from Table 1.1-19 (Total non-methane organic carbon).

Potential Throughput (tons/year) = Heat Input Capacity (MMBtu/hr) x 10^6 Btu/MMBtu / Heat Content of Coal (Btu/lb) / 2000 lb/ton x 8,760 hrs/yr

Emission Factors from AP-42, Chapter 1.1 for spreader stoker SCC 1-01-002-04/24 (Supplement E, 9/98)

HAPs emission factors are available in AP-42, Chapter 1.1.

Emission (tons/yr) = Throughput tons per year x Emission Factor (lb/ton) / 2,000 lb/ton

Emissions (lbs/MMBtu) = ((10^6 Btu/MMBtu / Heat Content of Coal (Btu/lb)) / (1 ton/2000 lb)) x Emission Factor (lb/ton)

After control emissions for PM/PM10/PM2.5 = Potentila emissions (tons/year) * (1-multi-clone control efficiency); and for EU-06, use the after control emissions from equation above and multiply by (1-ESP Control Efficiency). See Page 1 of 9, TSD App. A, of Permit T105-6642-00005.

OTE: Multiclone Control Efficiency for EU-03 and EU-04 = 80%; Multiclone Control Efficiency for EU-06 = 86.6%. See Page 1 of 9, TSD App. A, of Permit T105-6642-0000

Appendix A: Emissions Calculations
Coal Combustion: Spreader Stokers
Coal Burning - Uncontrolled PTE for Boiler EU-04 (Rated at Maximum of 100 MMBtu/hr When Combusting Coal (each)) *

Company Name:	**Indiana University**
Address City IN Zip:	**820 North Walnut Grove, Bloomington, Indiana 47405-2206**
Permit No.:	**105-41051-00005**
Reviewer:	**Aasim Noveer**

Heat Input Capacity MMBtu/hr	Heat Content of Coal Btu/lb of Coal **	Potential Throughput tons/year	Weight % Sulfur in Fuel	Weight %
100	12,000	36,500	S = 3.15	A = Ash = 9.7

	Pollutant					
	PM*	PM10*/PM2.5	SO2	NOx	VOC	CO
Emission Factor in lb/ton	66.0 ****	13.2	119.7 *(38S)*	11.0	0.05 *****	5.00
Potential Emission in tons/yr	1205	241	2185	201	0.9	91.3
With particulate control: 0.00% efficiency	1205	241				
Potential Emission in lbs/MMBtu	2.75		**4.99**			
With particulate control: 0.00% efficiency	**2.75**					

Methodology

* The PM emission factor is filterable PM only. The PM10/PM2.5 emission factor is filterable.

** Per the TV application for this source; 1 lb bituminous coal has a BTU rating of 12,000.

*** EU-03 and EU-04 have maximum design capacities of 125 MMBtu/per hour each, but are limited to 100 MMBtu per hour of heat input each when using coal or coal with a combination of fuels.

****See AP-42, Table 1.1-4 (footnote e), (Ash content taken into account with PM emission factor).

*****See AP-42, Table 1.1-19 (footnote c); (Average E.F. for spreader stokers included).

VOC emission factor is from Table 1.1-19 (Total non-methane organic carbon).

Potential Throughput (tons/year) = Heat Input Capacity (MMBtu/hr) x 10^6 Btu/MMBtu / Heat Content of Coal (Btu/lb) / 2000 lb/ton x 8,760 hrs/yr

Emission Factors from AP-42, Chapter 1.1 for spreader stoker SCC 1-01-002-04/24 (Supplement E, 9/98)

HAPs emission factors are available in AP-42, Chapter 1.1.

Emission (tons/yr) = Throughput tons per year x Emission Factor (lb/ton) / 2,000 lb/ton

Emissions (lbs/MMBtu) = 10^6 Btu/MMBtu / Heat Content of Coal (Btu/lb) / 2000 lb/ton x Emission Factor (lb/ton)

Appendix A: Emissions Calculations
Coal Combustion: Spreader Stokers

Coal Burning - Controlled PM PTE for Boiler EU-04 (Rated at Maximum of 100 MMBtu/hr When Combusting Coal and/or Fuel Oil) ***

Company Name: **Indiana University**
Address City IN Zip: **820 North Walnut Grove, Bloomington, Indiana 47405-2206**
Permit No. **105-41051-00005**
Reviewer: **Aasim Noveer**

Heat Input Capacity MMBtu/hr	Heat Content of Coal Btu/lb of Coal**	Potential Throughput tons/year		Weight % Sulfur in Fuel		Weight %
100	12,000	36,500	S =	3.15 %	A = Ash =	9.7

	Pollutant					
	PM*	PM10*/PM2.5	SO2	NOx	VOC	CO
Emission Factor in lb/ton	66.0 ****	13.2	119.7 *(38S)*	11.0	0.05 *****	5.00
Potential Emission in tons/yr With PM control: 80.00% efficiency	1204.5 240.9	240.9 48.2	2184.5	200.8	0.9	91.3
Potential Emission in lbs/MMBtu With PM control: 80.00% efficiency	2.750 **0.550**		**4.988**			

Methodology

* The PM emission factor is filterable PM only. The PM10/PM2.5 emission factor is filterable.

** Per the TV application for this source; 1 lb bituminous coal has a BTU rating of 12,000.

*** EU-03 and EU-04 have maximum design capacities of 125 MMBtu/per hour each, but are limited to 100 MMBtu per hour of heat input each when using coal or coal with a combination of fuels.

****See AP-42, Table 1.1-4 (footnote e), (Ash content taken into account with PM emission factor).

*****See AP-42, Table 1.1-19 (footnote c); (Average E.F. for spreader stokers included).

VOC emission factor is from Table 1.1-19 (Total non-methane organic carbon).

Potential Throughput (tons/year) = Heat Input Capacity (MMBtu/hr) x 10^6 Btu/MMBtu / Heat Content of Coal (Btu/lb) / 2000 lb/ton x 8,760 hrs/yr

Emission Factors from AP-42, Chapter 1.1 for spreader stoker SCC 1-01-002-04/24 (Supplement E, 9/98)

HAPs emission factors are available in AP-42, Chapter 1.1.

Emission (tons/yr) = Throughput tons per year x Emission Factor (lb/ton) / 2,000 lb/ton

Emissions (lbs/MMBtu) = 10^6 Btu/MMBtu / Heat Content of Coal (Btu/lb) / 2000 lb/ton x Emission Factor (lb/ton)

After control emissions for PM/PM10/PM2.5 = Potentila emissions (tons/year) * (1-multi-clone control efficiency); and for EU-06, use the after control emissions from equation above and multiply by (1-ESP Control Efficiency). See Page 1 of 9, TSD App. A, of Permit T105-6642-00005.

NOTE: Multiclone Control Efficiency for EU-03 and EU-04 = 80%; Multiclone Control Efficiency for EU-06 = 86.6%. See Page 1 of 9, TSD App. A, of Permit T105-6642-00005.

Appendix A: Emissions Calculations
Coal Combustion: Spreader Stokers
Coal Burning - Uncontrolled PTE for Boiler EU-06 (Rated at Maximum of 190 MMBtu/hr When Combusting Coal and/or Fuel Oil) ***

Company Name:	**Indiana University**
Address City IN Zip:	**820 North Walnut Grove, Bloomington, Indiana 47405-2206**
Permit No.:	**105-41051-00005**
Reviewer:	**Aasim Noveer**

Heat Input Capacity MMBtu/hr	Heat Content of Coal Btu/lb of Coal **	Potential Throughput tons/year	Weight % Sulfur in Fuel	Weight %
190	12,000	69,350	S = 3.15	A = Ash = 9.7

	Pollutant					
	PM*	PM10*/PM2.5	SO2	NOx	VOC	CO
Emission Factor in lb/ton	66.0 ****	13.2	119.7 *(38S)*	11.0	0.05 *****	5.00
Potential Emission in tons/yr	2289	458	4151	381	1.7	173.4
With particulate control 0.00% efficiency	2289	458				
Potential Emission in lbs/MMBtu	2.75		**4.99**			
With particulate control 0.00% efficiency	**2.75**					

Methodology

* The PM emission factor is filterable PM only. The PM10/PM2.5 emission factor is filterable.
** Per the TV application for this source; 1 lb bituminous coal has a BTU rating of 12,000.
*** EU-03 and EU-04 have maximum design capacities of 125 MMBtu/per hour each, but are limited to 100 MMBtu per hour of heat input each when using coal or coal with a combination of fuels.
****See AP-42, Table 1.1-4 (footnote e), (Ash content taken into account with PM emission factor).
*****See AP-42, Table 1.1-19 (footnote c); (Average E.F. for spreader stokers included).
VOC emission factor is from Table 1.1-19 (Total non-methane organic carbon).
Potential Throughput (tons/year) = Heat Input Capacity (MMBtu/hr) x 10^6 Btu/MMBtu / Heat Content of Coal (Btu/lb) / 2000 lb/ton x 8,760 hrs/yr
Emission Factors from AP-42, Chapter 1.1 for spreader stoker SCC 1-01-002-04/24 (Supplement E, 9/98)
HAPs emission factors are available in AP-42, Chapter 1.1.
Emission (tons/yr) = Throughput tons per year x Emission Factor (lb/ton) / 2,000 lb/ton
Emissions (lbs/MMBtu) = 10^6 Btu/MMBtu / Heat Content of Coal (Btu/lb) / 2000 lb/ton x Emission Factor (lb/ton)

Appendix A: Emissions Calculations
Coal Combustion: Spreader Stokers

Coal Burning - Controlled PTE for Boiler EU-06 (Rated at Maximum of 190 MMBtu/hr When Combusting Coal and/or Fuel Oil) ***

Company Name: **Indiana University**
Address City IN Zip: **820 North Walnut Grove, Bloomington, Indiana 47405-2206**
Permit No. **105-41051-00005**
Reviewer: **Aasim Noveer**

Heat Input Capacity MMBtu/hr	Heat Content of Coal Btu/lb of Coal**	Potential Throughput tons/year	Weight % Sulfur in Fuel	Weight %
190	12,000	69,350	S = 3.15 %	A = Ash = 9.7

	Pollutant					
	PM*	PM10*/PM2.5	SO2	NOx	VOC	CO
Emission Factor in lb/ton	66.0 ****	13.2	119.7 *(38S)*	11.0	0.05 *****	5.00
Potential Emission in tons/yr With PM control: 86.60% efficiency	2288.6 205.5	457.7 41.1	4150.6	381.4	1.7	173.4
Potential Emission in lbs/MMBtu With PM control: 86.60% efficiency	2.750 **0.247**		**4.988**			

Methodology

* The PM emission factor is filterable PM only. The PM10/PM2.5 emission factor is filterable.

** Per the TV application for this source; 1 lb bituminous coal has a BTU rating of 12,000.

*** EU-03 and EU-04 have maximum design capacities of 125 MMBtu/per hour each, but are limited to 100 MMBtu per hour of heat input each when using coal or coal with a combination of fuels.

****See AP-42, Table 1.1-4 (footnote e), (Ash content taken into account with PM emission factor).

*****See AP-42, Table 1.1-19 (footnote c); (Average E.F. for spreader stokers included).

VOC emission factor is from Table 1.1-19 (Total non-methane organic carbon).

Potential Throughput (tons/year) = Heat Input Capacity (MMBtu/hr) x 10^6 Btu/MMBtu / Heat Content of Coal (Btu/lb) / 2000 lb/ton x 8,760 hrs/yr

Emission Factors from AP-42, Chapter 1.1 for spreader stoker SCC 1-01-002-04/24 (Supplement E, 9/98)

HAPs emission factors are available in AP-42, Chapter 1.1.

Emission (tons/yr) = Throughput tons per year x Emission Factor (lb/ton) / 2,000 lb/ton

Emissions (lbs/MMBtu) = 10^6 Btu/MMBtu / Heat Content of Coal (Btu/lb) / 2000 lb/ton x Emission Factor (lb/ton)

After control emissions for PM/PM10/PM2.5 = Potentila emissions (tons/year) * (1 - multi-clone control efficiency); and for EU-06, use the after control emissions from equation above and multiply by (1 - ESP Control Efficiency). See Page 1 of 9, TSD App. A, of Permit T105-6642-00005.

NOTE: Multiclone Control Efficiency for EU-03 and EU-04 = 80%; Multiclone Control Efficiency for EU-06 = 86.6%. See Page 1 of 9, TSD App. A, of Permit T105-6642-00005.

Appendix A: Emissions Calculations
Coal Burning - HAP PTE for Boiler EU-03 (Rated at Maximum of 100 MMBtu/hr When Combusting Coal)*

Company Name: Indiana University
Address, City IN Zip: 820 North Walnut Grove, Bloomington, Indiana 47405-2206
Permit Number: 105-41051-00005
Reviewer: Aasim Noveer

Boiler Emission Unit:	**EU-03**
Total Maximum Heat Input Capacity (MMBtu/hr)	**100.0**
Total Maximum Coal Input Capacity (tons/hr)	**4.2**

Pollutant	Emission Factor (lbs/ton of Coal)	PTE of HAP (tons/year)
Antimony	1.8E-05	0.000
Arsenic	4.1E-04	0.007
Beryllium	2.1E-05	0.000
Cadmium	5.1E-05	0.001
Chromium	2.6E-04	0.005
Chromium (VI)	7.09E-05	0.001
Cobalt	1.00E-04	0.002
Lead	4.2E-04	0.008
Magnesium	1.1E-02	0.201
Manganese	4.9E-04	0.009
Mercury	8.3E-05	0.002
Nickel	2.8E-04	0.005
Selenium	1.3E-03	0.024
Hydrogen Fluoride	1.50E-01	2.738
Hydrogen Chloride	1.20E+00	21.900
Acetaldehyde	5.70E-04	0.010
Acetophenone	1.50E-05	0.000
Acrolein	2.90E-04	0.005
Benzene	1.30E-03	0.024
Benzyl Chloride	7.00E-04	0.013
DEHP	7.30E-05	0.001
Bromoform	3.90E-05	0.001
Carbon Disulfide	1.30E-04	0.002
2-Chloroacetophenone	7.00E-06	0.000
Chlorobenzene	2.20E-05	0.000
Chloroform	5.90E-05	0.001
Cumene	5.30E-06	0.000
Cyanide	2.50E-03	0.046
2,4-Dinitrotoluene	2.80E-07	0.000
Dimethyl Sulfate	4.80E-05	0.001
Ethyl Benzene	9.40E-05	0.002
Ethyl Chloride	4.20E-05	0.001
Ethylene Dichloride	4.00E-05	0.001
Ethylene Dibromide	1.20E-06	0.000
Formaldehyde	2.40E-04	0.004
Hexane	6.70E-05	0.001
Isophorone	5.80E-04	0.011
Methyl Bromide	1.60E-04	0.003
Methyl Chloride	5.30E-04	0.010
Methyl Hydrazine	1.70E-04	0.003
Methyl Methacrylate	2.00E-05	0.000
Methyl Tert Butyl Ether	3.50E-05	0.001
Methylene Chloride	2.90E-04	0.005
Phenol	1.60E-05	0.000
Propionaldehyde	3.80E-04	0.007
Tetrachloroethylene	4.30E-05	0.001
Toluene	2.40E-04	0.004
1,1,1-Trichloroethane	2.00E-05	0.000
Styrene	2.50E-05	0.000
Xylenes	3.70E-05	0.001
Vinyl Acetate	7.60E-06	0.000
Total		**25.063**

Note: Emission factors from, AP-42, Tables 1.1-14, 1.1-15, 1.1-16, and 1.1-18 for Coal Combustion (09/98).
*** EU-03 and EU-04 have maximum design capacities of 125 MMBtu/per hour each, but are limited to 100 MMBtu per hour of heat input each when using coal or coal with a combination of fuels.

Methodology

PTE of HAP (tons/year) = Total Maximum Heat Input (MMBtu/hr) / ((12,000 Btu/lb)*(2000lb/ton)*(1 MMBtu/1000000Btu)) * Emission Factor (lb/ton) * 8,760 hrs/yr * 1 ton/2,000 lb

Maximum Coal Input Capacity (tons/hr) = Potential throughput (tons/yr) * (1 year / 8760 hr) = (73,000 tons/yr) * (1 year / 8760 hrs)

Appendix A: Emissions Calculations

Coal Burning - HAP PTE for Boiler EU-04 (Rated at Maximum of 100 MMBtu/hr When Combusting Coal)***

Company Name:	**Indiana University**
Address, City IN Zip:	**820 North Walnut Grove, Bloomington, Indiana 47405-2206**
Permit Number:	**105-41051-00005**
Reviewer:	**Aasim Noveer**

Boiler Emission Unit:	**EU-04**
Total Maximum Heat Input Capacity (MMBtu/hr)	**100.0**
Maximum Coal Input Capacity (tons/hr)	**4.2**

Pollutant	Emission Factor (lbs/ton of Coal)	PTE of HAP (tons/year)
Antimony	1.8E-05	0.000
Arsenic	4.1E-04	0.007
Beryllium	2.1E-05	0.000
Cadmium	5.1E-05	0.001
Chromium	2.6E-04	0.005
Chromium (VI)	7.09E-05	0.001
Cobalt	1.00E-04	0.002
Lead	4.2E-04	0.008
Magnesium	1.1E-02	0.201
Manganese	4.9E-04	0.009
Mercury	8.3E-05	0.002
Nickel	2.8E-04	0.005
Selenium	1.3E-03	0.024
Hydrogen Fluoride	1.50E-01	2.738
Hydrogen Chloride	1.20E+00	21.900
Acetaldehyde	5.70E-04	0.010
Acetophenone	1.50E-05	0.000
Acrolein	2.90E-04	0.005
Benzene	1.30E-03	0.024
Benzyl Chloride	7.00E-04	0.013
DEHP	7.30E-05	0.001
Bromoform	3.90E-05	0.001
Carbon Disulfide	1.30E-04	0.002
2-Chloroacetophenone	7.00E-06	0.000
Chlorobenzene	2.20E-05	0.000
Chloroform	5.90E-05	0.001
Cumene	5.30E-06	0.000
Cyanide	2.50E-03	0.046
2,4-Dinitrotoluene	2.80E-07	0.000
Dimethyl Sulfate	4.80E-05	0.001
Ethyl Benzene	9.40E-05	0.002
Ethyl Chloride	4.20E-05	0.001
Ethylene Dichloride	4.00E-05	0.001
Ethylene Dibromide	1.20E-06	0.000
Formaldehyde	2.40E-04	0.004
Hexane	6.70E-05	0.001
Isophorone	5.80E-04	0.011
Methyl Bromide	1.60E-04	0.003
Methyl Chloride	5.30E-04	0.010
Methyl Hydrazine	1.70E-04	0.003
Methyl Methacrylate	2.00E-05	0.000
Methyl Tert Butyl Ether	3.50E-05	0.001
Methylene Chloride	2.90E-04	0.005
Phenol	1.60E-05	0.000
Propionaldehyde	3.80E-04	0.007
Tetrachloroethylene	4.30E-05	0.001
Toluene	2.40E-04	0.004
1,1,1-Trichloroethane	2.00E-05	0.000
Styrene	2.50E-05	0.000
Xylenes	3.70E-05	0.001
Vinyl Acetate	7.60E-06	0.000
Total		**25.063**

Note: Emission factors from, AP-42, Tables 1.1-14, 1.1-15, 1.1-16, and 1.1-18 for Coal Combustion (09/98).
*** EU-03 and EU-04 have maximum design capacities of 125 MMBtu/per hour each, but are limited to 100 MMBtu per hour of heat input each when using coal or coal with a combination of fuels.

Methodology

PTE of HAP (tons/year) = Total Maximum Heat Input (MMBtu/hr) / ((12,000 Btu/lb)*(2000lb/ton)*(1 MMBtu/1000000Btu)) * Emission Factor (lb/ton) * 8,760 hrs/yr * 1 ton/2,000 lb

Maximum Coal Input Capacity (tons/hr) = Potential throughput (tons/yr) * (1 year / 8760 hr) = (73,000 tons/yr) * (1 year / 8760 hrs)

Appendix A: Emissions Calculations
Coal Burning - HAP Emissions for Boiler EU-06 (Rated at Maximum of 190 MMBtu/hr When Combusting Coal and/or Fuel Oil)*

Company Name: Indiana University
Address, City IN Zip: 820 North Walnut Grove, Bloomington, Indiana 47405-2206
Permit Number: 105-41051-00005
Reviewer: Aasim Noveer

Boiler Emission Unit:	**EU-06**
Total Maximum Heat Input Capacity (MMBtu/hr)	**190.0**
Total Maximum Coal Input Capacity (tons/hr)	**7.9**

Pollutant	Emission Factor (lbs/ton of Coal)	PTE of HAP (tons/year)
Antimony	1.8E-05	0.001
Arsenic	4.1E-04	0.014
Beryllium	2.1E-05	0.001
Cadmium	5.1E-05	0.002
Chromium	2.6E-04	0.009
Chromium (VI)	7.09E-05	0.002
Cobalt	1.00E-04	0.003
Lead	4.2E-04	0.015
Magnesium	1.1E-02	0.381
Manganese	4.9E-04	0.017
Mercury	8.3E-05	0.003
Nickel	2.8E-04	0.010
Selenium	1.3E-03	0.045
Hydrogen Fluoride	1.50E-01	5.201
Hydrogen Chloride	1.20E+00	41.610
Acetaldehyde	5.70E-04	0.020
Acetophenone	1.50E-05	0.001
Acrolein	2.90E-04	0.010
Benzene	1.30E-03	0.045
Benzyl Chloride	7.00E-04	0.024
DEHP	7.30E-05	0.003
Bromoform	3.90E-05	0.001
Carbon Disulfide	1.30E-04	0.005
2-Chloroacetophenone	7.00E-06	0.000
Chlorobenzene	2.20E-05	0.001
Chloroform	5.90E-05	0.002
Cumene	5.30E-06	0.000
Cyanide	2.50E-03	0.087
2,4-Dinitrotoluene	2.80E-07	0.000
Dimethyl Sulfate	4.80E-05	0.002
Ethyl Benzene	9.40E-05	0.003
Ethyl Chloride	4.20E-05	0.001
Ethylene Dichloride	4.00E-05	0.001
Ethylene Dibromide	1.20E-06	0.000
Formaldehyde	2.40E-04	0.008
Hexane	6.70E-05	0.002
Isophorone	5.80E-04	0.020
Methyl Bromide	1.60E-04	0.006
Methyl Chloride	5.30E-04	0.018
Methyl Hydrazine	1.70E-04	0.006
Methyl Methacrylate	2.00E-05	0.001
Methyl Tert Butyl Ether	3.50E-05	0.001
Methylene Chloride	2.90E-04	0.010
Phenol	1.60E-05	0.001
Propionaldehyde	3.80E-04	0.013
Tetrachloroethylene	4.30E-05	0.001
Toluene	2.40E-04	0.008
1,1,1-Trichloroethane	2.00E-05	0.001
Styrene	2.50E-05	0.001
Xylenes	3.70E-05	0.001
Vinyl Acetate	7.60E-06	0.000
Total		**47.619**

Note: Emission factors from, AP-42, Tables 1.1-14, 1.1-15, 1.1-16, and 1.1-18 for Coal Combustion (09/98).
* EU-06 has maximum design heat input capacity of 190 MMBtu/per hour when using coal and/or fuel oil.

Methodology

PTE of HAP (tons/year) = Total Maximum Heat Input (MMBtu/hr) / ((12,000 Btu/lb)*(2000lb/ton)*(1 MMBtu/1000000Btu)) * Emission Factor (lb/ton) * 8,760 hrs/yr * 1 ton/2,000 lb

Maximum Coal Input Capacity (tons/hr) = Potential throughput (tons/yr) * (1 year / 8760 hr) = (69,350 tons/yr) * (1 year / 8760 hrs)

Appendix A: Emissions Calculations
Commercial/Institutional/Residential Combustors (< 100 mmBtu/hr)

FO Combustion - Uncontrolled PTE for Boiler EU-03 (Rated at Maximum of 80 MMBtu/hr When Combusting FO #1 or #2)

Company Name: **Indiana University**
Address, City IN Zip: **820 North Walnut Grove, Bloomington, Indiana 47405-2206**
Permit Number: **105-41051-00005**
Reviewer: **Aasim Noveer**

Heat Input Capacity MMBtu/hr	Potential Throughput kgals/year	S = Weight % Sulfur
		0.5
80	5,006	

	Pollutant						
	PM*	PM10	direct PM2.5	SO2	NOx	VOC	CO
Emission Factor in lb/kgal	2.0	2.4	2.1	71 *(142.0S)*	20.0	0.34	5.0
Potential Emission in tons/yr	5.0	6.0	5.3	177.7	50.1	0.9	12.5

Methodology
1 gallon of No. 2 Fuel Oil has a heating value of 140,000 Btu

Potential Throughput (kgals/year) = Heat Input Capacity (MMBtu/hr) x 8,760 hrs/yr x 1kgal per 1000 gallon x 1 gal per 0.140 MM Btu

Emission Factors are from AP 42, Tables 1.3-1, 1.3-2, and 1.3-3 (SCC 1-03-005-01/02/03) Supplement E 9/98 (see erata file)

*PM emission factor is filterable PM only. Condensable PM emission factor is 1.3 lb/kgal.
Emission (tons/yr) = Throughput (kgals/ yr) x Emission Factor (lb/kgal)/2,000 lb/ton

HAPs Emissions

	HAPs - Metals					
	Arsenic	Beryllium	Cadmium	Chromium	Lead	
Emission Factor in lb/mmBtu	4.0E-06	3.0E-06	3.0E-06	3.0E-06	9.0E-06	
Potential Emission in tons/yr	1.40E-03	1.05E-03	1.05E-03	1.05E-03	3.15E-03	7.71E-03

	HAPs - Metals (continued)				
	Mercury	Manganese	Nickel	Selenium	
Emission Factor in lb/mmBtu	3.0E-06	6.0E-06	3.0E-06	1.5E-05	
Potential Emission in tons/yr	1.05E-03	2.10E-03	1.05E-03	5.26E-03	9.46E-03

TOTAL **1.72E-02**

Methodology
No data was available in AP-42 for organic HAPs.
Potential Emissions (tons/year) = Throughput (mmBtu/hr)*Emission Factor (lb/mmBtu)*8,760 hrs/yr / 2,000 lb/ton

Appendix A: Emissions Calculations
Commercial/Institutional/Residential Combustors (< 100 mmBtu/hr)

FO Combustion - Uncontrolled PTE for Boiler EU-04 (Rated at Maximum of 80 MMBtu/hr When Combusting FO #1 or #2)

Company Name: **Indiana University**
Address, City IN Zip: **820 North Walnut Grove, Bloomington, Indiana 47405-2206**
Permit Number: **105-41051-00005**
Reviewer: **Aasim Noveer**

Heat Input Capacity MMBtu/hr	Potential Throughput kgals/year	S = Weight % Sulfur
		0.5
80	5,006	

	Pollutant						
	PM*	PM10	direct PM2.5	SO2	NOx	VOC	CO
Emission Factor in lb/kgal	2.0	2.4	2.1	71 *(142.0S)*	20.0	0.34	5.0
Potential Emission in tons/yr	5.0	6.0	5.3	177.7	50.1	0.9	12.5

Methodology
1 gallon of No. 2 Fuel Oil has a heating value of 140,000 Btu
Potential Throughput (kgals/year) = Heat Input Capacity (MMBtu/hr) x 8,760 hrs/yr x 1kgal per 1000 gallon x 1 gal per 0.140 MM Btu

Emission Factors are from AP 42, Tables 1.3-1, 1.3-2, and 1.3-3 (SCC 1-03-005-01/02/03) Supplement E 9/98 (see erata file)

*PM emission factor is filterable PM only. Condensable PM emission factor is 1.3 lb/kgal.
Emission (tons/yr) = Throughput (kgals/ yr) x Emission Factor (lb/kgal)/2,000 lb/ton

HAPs Emissions

	HAPs - Metals					
	Arsenic	Beryllium	Cadmium	Chromium	Lead	
Emission Factor in lb/mmBtu	4.0E-06	3.0E-06	3.0E-06	3.0E-06	9.0E-06	
Potential Emission in tons/yr	1.40E-03	1.05E-03	1.05E-03	1.05E-03	3.15E-03	7.71E-03

	HAPs - Metals (continued)				
	Mercury	Manganese	Nickel	Selenium	
Emission Factor in lb/mmBtu	3.0E-06	6.0E-06	3.0E-06	1.5E-05	
Potential Emission in tons/yr	1.05E-03	2.10E-03	1.05E-03	5.26E-03	9.46E-03

TOTAL **1.72E-02**

Methodology
No data was available in AP-42 for organic HAPs.
Potential Emissions (tons/year) = Throughput (mmBtu/hr)*Emission Factor (lb/mmBtu)*8,760 hrs/yr / 2,000 lb/ton

Appendix A: Emissions Calculations
Industrial Boilers (> 100 mmBtu/hr)
FO Combustion - Uncontrolled PTE for Boiler EU-05 (Rated at Maximum of 190 MMBtu/hr When Combusting FO #1 or #2)

Company Name: **Indiana University**
Address, City IN Zip: **820 North Walnut Grove, Bloomington, Indiana 47405-2206**
Permit Number: **105-41051-00005**
Reviewer: **Aasim Noveer**

Heat Input Capacity MMBtu/hr	Potential Throughput kgals/year	S = Weight % Sulfur
		0.5
190	11,889	

	Pollutant						
	PM*	PM10	direct PM2.5	SO2	NOx	VOC	CO
Emission Factor in lb/kgal	2.0	2.3	1.6	78.5 *(157S)*	24.0	0.20	5.0
Potential Emission in tons/yr	11.9	13.7	9.2	466.6	142.7	1.2	29.7

Methodology
1 gallon of No. 2 Fuel Oil has a heating value of 140,000 Btu
Potential Throughput (kgals/year) = Heat Input Capacity (MMBtu/hr) x 8,760 hrs/yr x 1kgal per 1000 gallon x 1 gal per 0.140 MM Btu
Emission Factors are from AP 42, Tables 1.3-1, 1.3-2, 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.
Emission (tons/yr) = Throughput (kgals/ yr) x Emission Factor (lb/kgal)/2,000 lb/ton

HAPs Emissions

	HAPs - Metals					
	Arsenic	Beryllium	Cadmium	Chromium	Lead	
Emission Factor in lb/mmBtu	4.0E-06	3.0E-06	3.0E-06	3.0E-06	9.0E-06	
Potential Emission in tons/yr	3.33E-03	2.50E-03	2.50E-03	2.50E-03	7.49E-03	1.83E-02

	HAPs - Metals (continued)				
	Mercury	Manganese	Nickel	Selenium	
Emission Factor in lb/mmBtu	3.0E-06	6.0E-06	3.0E-06	1.5E-05	
Potential Emission in tons/yr	2.50E-03	4.99E-03	2.50E-03	1.25E-02	2.25E-02

TOTAL **4.08E-02**

Methodology
No data was available in AP-42 for organic HAPs.
Potential Emissions (tons/year) = Throughput (mmBtu/hr)*Emission Factor (lb/mmBtu)*8,760 hrs/yr / 2,000 lb/ton

Appendix A: Emissions Calculations
Industrial Boilers (> 100 mmBtu/hr)
FO Combustion - Uncontrolled PTE for Boiler EU-06 (Rated at Maximum of 190 MMBtu/hr When Combusting FO #1 or #2)

Company Name: **Indiana University**
Address, City IN Zip: **820 North Walnut Grove, Bloomington, Indiana 47405-2206**
Permit Number: **105-41051-00005**
Reviewer: **Aasim Noveer**

Heat Input Capacity MMBtu/hr	Potential Throughput kgals/year	S = Weight % Sulfur
		0.5
190	11888.57143	

	Pollutant						
	PM*	PM10	direct PM2.5	SO2	NOx	VOC	CO
Emission Factor in lb/kgal	2.0	2.3	1.6	78.5 *(157S)*	24.0	0.20	5.0
Potential Emission in tons/yr	11.9	13.7	9.2	466.6	142.7	1.2	29.7

Methodology

1 gallon of No. 2 Fuel Oil has a heating value of 140,000 Btu
Potential Throughput (kgals/year) = Heat Input Capacity (MMBtu/hr) x 8,760 hrs/yr x 1kgal per 1000 gallon x 1 gal per 0.140 MM Btu
Emission Factors are from AP 42, Tables 1.3-1, 1.3-2, 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.
Emission (tons/yr) = Throughput (kgals/ yr) x Emission Factor (lb/kgal)/2,000 lb/ton

HAPs Emissions

	HAPs - Metals					
	Arsenic	Beryllium	Cadmium	Chromium	Lead	
Emission Factor in lb/mmBtu	4.0E-06	3.0E-06	3.0E-06	3.0E-06	9.0E-06	
Potential Emission in tons/yr	3.33E-03	2.50E-03	2.50E-03	2.50E-03	7.49E-03	1.83E-02

	HAPs - Metals (continued)				
	Mercury	Manganese	Nickel	Selenium	
Emission Factor in lb/mmBtu	3.0E-06	6.0E-06	3.0E-06	1.5E-05	
Potential Emission in tons/yr	2.50E-03	4.99E-03	2.50E-03	1.25E-02	2.25E-02

TOTAL **4.08E-02**

Methodology
No data was available in AP-42 for organic HAPs.
Potential Emissions (tons/year) = Throughput (mmBtu/hr)*Emission Factor (lb/mmBtu)*8,760 hrs/yr / 2,000 lb/ton

Appendix A: Emission Calculations
NG Combustion - PTE from Boiler EU-03 Rated at 80 MMBtu/hr Combusting NG
Natural Gas Combustion Only
MMBTU/HR >100

Company Name: **Indiana University**
Address City IN Zip: **820 North Walnut Grove, Bloomington, Indiana 47405-2206**
Permit Number: **105-41051-00005**
Reviewer: **Aasim Noveer**

Heat Input Capacity MMBtu/hr	HHV mmBtu/mmscf	Potential Throughput MMCF/yr
80.0	1020	687.1

	Pollutant						
	PM*	PM10*	direct PM2.5*	SO2	NOx	VOC	CO
Emission Factor in lb/MMCF	1.9	7.6	7.6	0.6	140.0 **see below	5.5	84.0
Potential Emission in tons/yr	0.7	2.6	2.6	0.2	48.1	1.9	28.9

*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)

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 Factors from AP 42, Chapter 1.4, Tables 1.4-1, 1.4-2, and 1.4-3, SCC #1-01-006-01, 1-01-006-04
(AP-42 Supplement D 3/98)
Emission (tons/yr) = Throughput (MMCF/yr) x Emission Factor (lb/MMCF)/2,000 lb/ton

HAPs Emissions

	HAPs - Organics					
	Benzene	Dichlorobenzene	Formaldehyde	Hexane	Toluene	
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	7.21E-04	4.12E-04	2.58E-02	6.18E-01	1.17E-03	6.46E-01

	HAPs - Metals					
	Lead	Cadmium	Chromium	Manganese	Nickel	
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	1.72E-04	3.78E-04	4.81E-04	1.31E-04	7.21E-04	1.88E-03
					TOTAL	**6.48E-01**

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
NG Combustion - PTE from Boiler EU-04 Rated at 80 MMBtu/hr Combusting NG
Natural Gas Combustion Only
MMBTU/HR >100

Company Name: **Indiana University**
Address City IN Zip: **820 North Walnut Grove, Bloomington, Indiana 47405-2206**
Permit Number: **105-41051-00005**
Reviewer: **Aasim Noveer**

Heat Input Capacity MMBtu/hr	HHV mmBtu/mmscf	Potential Throughput MMCF/yr
80.0	1020	687.1

	Pollutant						
	PM*	PM10*	direct PM2.5*	SO2	NOx	VOC	CO
Emission Factor in lb/MMCF	1.9	7.6	7.6	0.6	140.0 **see below	5.5	84.0
Potential Emission in tons/yr	0.7	2.6	2.6	0.2	48.1	1.9	28.9

*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)

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 Factors from AP 42, Chapter 1.4, Tables 1.4-1, 1.4-2, and 1.4-3, SCC #1-01-006-01, 1-01-006-04
(AP-42 Supplement D 3/98)
Emission (tons/yr) = Throughput (MMCF/yr) x Emission Factor (lb/MMCF)/2,000 lb/ton

HAPs Emissions

	HAPs - Organics					
	Benzene	Dichlorobenzene	Formaldehyde	Hexane	Toluene	
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	7.21E-04	4.12E-04	2.58E-02	6.18E-01	1.17E-03	6.46E-01

	HAPs - Metals					
	Lead	Cadmium	Chromium	Manganese	Nickel	
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	1.72E-04	3.78E-04	4.81E-04	1.31E-04	7.21E-04	1.88E-03

TOTAL **6.48E-01**

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
NG Combustion - PTE from Boiler EU-05 Rated at 190 MMBtu/hr Combusting NG
Natural Gas Combustion Only
MMBTU/HR >100

Company Name: **Indiana University**
Address City IN Zip: **820 North Walnut Grove, Bloomington, Indiana 47405-2206**
Permit Number: **105-41051-00005**
Reviewer: **Aasim Noveer**

Heat Input Capacity MMBtu/hr	HHV mmBtu/mmscf	Potential Throughput MMCF/yr
190.0	1020	1631.8

	Pollutant						
	PM*	PM10*	direct PM2.5*	SO2	NOx	VOC	CO
Emission Factor in lb/MMCF	1.9	7.6	7.6	0.6	140.0 **see below	5.5	84.0
Potential Emission in tons/yr	1.6	6.2	6.2	0.5	114.2	4.5	68.5

*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)

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 Factors from AP 42, Chapter 1.4, Tables 1.4-1, 1.4-2, and 1.4-3, SCC #1-01-006-01, 1-01-006-04
(AP-42 Supplement D 3/98)
Emission (tons/yr) = Throughput (MMCF/yr) x Emission Factor (lb/MMCF)/2,000 lb/ton

HAPs Emissions

	HAPs - Organics					
	Benzene	Dichlorobenzene	Formaldehyde	Hexane	Toluene	
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	1.71E-03	9.79E-04	6.12E-02	1.47E+00	2.77E-03	1.54E+00

	HAPs - Metals					
	Lead	Cadmium	Chromium	Manganese	Nickel	
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	4.08E-04	8.97E-04	1.14E-03	3.10E-04	1.71E-03	4.47E-03

TOTAL **1.54E+00**

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
NG Combustion - PTE from Boiler EU-06 Rated at 150 MMBtu/hr Combusting NG
Natural Gas Combustion Only
MMBTU/HR >100

Company Name: **Indiana University**
Address City IN Zip: **820 North Walnut Grove, Bloomington, Indiana 47405-2206**
Permit Number: **105-41051-00005**
Reviewer: **Aasim Noveer**

Heat Input Capacity MMBtu/hr	HHV mmBtu/mmscf	Potential Throughput MMCF/yr
150.0	1020	1288.2

	Pollutant						
	PM*	PM10*	direct PM2.5*	SO2	NOx	VOC	CO
Emission Factor in lb/MMCF	1.9	7.6	7.6	0.6	140.0 **see below	5.5	84.0
Potential Emission in tons/yr	1.2	4.9	4.9	0.4	90.2	3.5	54.1

*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.
**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)

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 Factors from AP 42, Chapter 1.4, Tables 1.4-1, 1.4-2, and 1.4-3, SCC #1-01-006-01, 1-01-006-04
(AP-42 Supplement D 3/98)
Emission (tons/yr) = Throughput (MMCF/yr) x Emission Factor (lb/MMCF)/2,000 lb/ton

HAPs Emissions

	HAPs - Organics					
	Benzene	Dichlorobenzene	Formaldehyde	Hexane	Toluene	
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	1.35E-03	7.73E-04	4.83E-02	1.16E+00	2.19E-03	1.21E+00

	HAPs - Metals					
	Lead	Cadmium	Chromium	Manganese	Nickel	
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	3.22E-04	7.09E-04	9.02E-04	2.45E-04	1.35E-03	3.53E-03

TOTAL **1.22E+00**

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
Industrial Boilers (> 100 mmBtu/hr)
FO Combustion - Uncontrolled PTE for Boiler EU-07 (Rated at Maximum of 208 MMBtu/hr When Combusting FO #1 or #2)

Company Name: **Indiana University**
Address, City IN Zip: **820 North Walnut Grove, Bloomington, Indiana 47405-2206**
Permit Number: **105-41051-00005**
Reviewer: **Aasim Noveer**

Heat Input Capacity MMBtu/hr	Potential Throughput kgals/year	S = Weight % Sulfur
		0.5
208	13014.85714	

	Pollutant						
	PM*	PM10	direct PM2.5	SO2	NOx	VOC	CO
Emission Factor in lb/kgal	2.0	2.3	1.6	78.5 *(157S)*	24.0	0.20	5.0
Potential Emission in tons/yr	13.0	15.0	10.1	510.8	156.2	1.3	32.5

Methodology

1 gallon of No. 2 Fuel Oil has a heating value of 140,000 Btu

Potential Throughput (kgals/year) = Heat Input Capacity (MMBtu/hr) x 8,760 hrs/yr x 1kgal per 1000 gallon x 1 gal per 0.140 MM Btu

Emission Factors are from AP 42, Tables 1.3-1, 1.3-2, 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.

Emission (tons/yr) = Throughput (kgals/ yr) x Emission Factor (lb/kgal)/2,000 lb/ton

HAPs Emissions

	HAPs - Metals					
	Arsenic	Beryllium	Cadmium	Chromium	Lead	
Emission Factor in lb/mmBtu	4.0E-06	3.0E-06	3.0E-06	3.0E-06	9.0E-06	
Potential Emission in tons/yr	3.64E-03	2.73E-03	2.73E-03	2.73E-03	8.20E-03	2.00E-02

	HAPs - Metals (continued)				
	Mercury	Manganese	Nickel	Selenium	
Emission Factor in lb/mmBtu	3.0E-06	6.0E-06	3.0E-06	1.5E-05	
Potential Emission in tons/yr	2.73E-03	5.47E-03	2.73E-03	1.37E-02	2.46E-02

Methodology

TOTAL **4.46E-02**

No data was available in AP-42 for organic HAPs.

Potential Emissions (tons/year) = Throughput (mmBtu/hr)*Emission Factor (lb/mmBtu)*8,760 hrs/yr / 2,000 lb/ton

Appendix A: Emissions Calculations
Industrial Boilers (> 100 MMBtu/hr)
FO Combustion - PTE for Boiler EU-07 (Rated at Maximum of 208 MMBtu/hr When Combusting FO #1 or #2) - Limited **

Company Name: **Indiana University**
Address, City IN Zip: **820 North Walnut Grove, Bloomington, Indiana 47405-2206**
Permit Number: **105-41051-00005**
Reviewer: **Aasim Noveer**

Heat Input Capacity MMBtu/hr	Potential Throughput (kgals/year)	S = Weight % Sulfur	Limited Throughput **(kgals/year)
208	13014.86	0.1 ***	329

	Pollutant						
	PM*	PM10	direct PM2.5	SO2	NOx	VOC	CO
Emission Factor in lb/kgal	2.0	2.3	1.6	15.7 *(157S)*	12.51	0.20	5.0
Potential Emission in tons/yr	0.3	0.4	0.3	2.6	2.1	0.03	0.8

Methodology
1 gallon of No. 2 Fuel Oil has a heating value of 140,000 Btu
*PM emission factor is filterable PM only. Condensable PM emission factor is 1.3 lb/kgal.
Potential Throughput (kgals/year) = Heat Input Capacity (MMBtu/hr) x 8,760 hrs/yr x 1kgal per 1000 gallon x 1 gal per 0.140 MM Btu
** Limited Throughput = 329 kgal/year; based on source comments and Addendum to TSD for SSM T105-24626-00005, limit accepted by IDEM - OAQ.
*** Sulfur Content in No. 2 Fuel Oil used in Boiler EU-07 shall not exceed 0.1%; based on source comments and Addendum to TSD for SSM T105-24626-00005, sulfur content accepted by IDEM - OAQ.
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
Emission (tons/yr) = Throughput (kgals/ yr) x Emission Factor (lb/kgal)/2,000 lb/ton

HAPs Emissions

	HAPs - Metals					
	Arsenic	Beryllium	Cadmium	Chromium	Lead	
Emission Factor in lb/mmBtu	4.0E-06	3.0E-06	3.0E-06	3.0E-06	9.0E-06	
Potential Emission in tons/yr	3.64E-03	2.73E-03	2.73E-03	2.73E-03	8.20E-03	2.00E-02

	HAPs - Metals (continued)				
	Mercury	Manganese	Nickel	Selenium	
Emission Factor in lb/mmBtu	3.0E-06	6.0E-06	3.0E-06	1.5E-05	
Potential Emission in tons/yr	2.73E-03	5.47E-03	2.73E-03	1.37E-02	2.46E-02

TOTAL **4.46E-02**

Methodology
No data was available in AP-42 for organic HAPs.
Potential Emissions (tons/year) = Throughput (mmBtu/hr)*Emission Factor (lb/mmBtu)*8,760 hrs/yr / 2,000 lb/ton

Appendix A: Emission Calculations
NG Combustion - PTE from Boiler EU-07 with Induced Flue Gas Recirculation For NOx Control
(Rated Maximum Heat Input Capacity of 217 MMBtu/hr During NG Combustion)
Natural Gas Combustion Only
MMBTU/HR >100

Company Name: Indiana University
Address City IN Zip: 820 North Walnut Grove, Bloomington, Indiana 47405-2206
Permit Number: 105-41051-00005
Reviewer: Aasim Noveer

Heat Input Capacity MMBtu/hr	HHV mmBtu/mmscf	Potential Throughput MMCF/yr
217.0	1020	1863.6

	Pollutant						
	PM*	PM10*	direct PM2.5*	SO2	NOx	VOC	CO
Emission Factor in lb/MMCF	1.9	7.6	7.6	0.6	100.0 **see below	5.5	84.0
Potential Emission in tons/yr	1.8	7.1	7.1	0.6	93.2	5.1	78.3

*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)

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 Factors from AP 42, Chapter 1.4, Tables 1.4-1, 1.4-2, and 1.4-3, SCC #1-01-006-01, 1-01-006-04
(AP-42 Supplement D 3/98)
Emission (tons/yr) = Throughput (MMCF/yr) x Emission Factor (lb/MMCF)/2,000 lb/ton

HAPs Emissions

	HAPs - Organics					
	Benzene	Dichlorobenzene	Formaldehyde	Hexane	Toluene	
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	1.96E-03	1.12E-03	6.99E-02	1.68E+00	3.17E-03	1.75E+00

	HAPs - Metals					
	Lead	Cadmium	Chromium	Manganese	Nickel	
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	4.66E-04	1.03E-03	1.30E-03	3.54E-04	1.96E-03	5.11E-03

TOTAL **1.76E+00**

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
NG Combustion - PTE from Boiler EU-07 with Induced Flue Gas Recirculation For NOx Control - Limited **
(Rated Maximum Heat Input Capacity of 217 MMBtu/hr During NG Combustion)
Natural Gas Combustion Only
MMBTU/HR >100

Company Name:	**Indiana University**
Address City IN Zip:	**820 North Walnut Grove, Bloomington, Indiana 47405-2206**
Permit Number:	**105-41051-00005**
Reviewer:	**Aasim Noveer**

Heat Input Capacity MMBtu/hr	HHV mmBtu/mmscf	Potential Throughput MMCF/yr
217.0	1020	1863.6

	Pollutant						
	PM*	PM10*	direct PM2.5*	SO2	NOx **	VOC	CO
Emission Factor in lb/MMCF	1.9	7.6	7.6	0.6	36.72 **see below	5.5	84.0
Potential Emission in tons/yr	1.8	7.1	7.1	0.6	34.2	5.1	78.3

*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 Factor for NOx: Limited NOx E.F. shall not exceed 36.72 lb/MMcf as indicated by SSM T105-24626-00005.

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 Factors from AP 42, Chapter 1.4, Tables 1.4-1, 1.4-2, and 1.4-3, SCC #1-01-006-01, 1-01-006-04
(AP-42 Supplement D 3/98)
Emission (tons/yr) = Throughput (MMCF/yr) x Emission Factor (lb/MMCF)/2,000 lb/ton

	HAPs - Organics					
	Benzene	Dichlorobenzene	Formaldehyde	Hexane	Toluene	
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	1.96E-03	1.12E-03	6.99E-02	1.68E+00	3.17E-03	1.75E+00

	HAPs - Metals					
	Lead	Cadmium	Chromium	Manganese	Nickel	
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	4.66E-04	1.03E-03	1.30E-03	3.54E-04	1.96E-03	5.11E-03

TOTAL **1.76E+00**

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
PTE - Small NG Boilers with Heat Input Capacity Equal to or Less than 10 MMBtu/hr
Natural Gas Combustion Only
MM BTU/HR <100

Company Name: **Indiana University**
Address City IN Zip: **820 North Walnut Grove, Bloomington, Indiana 47405-2206**
Permit Number: **105-41051-00005**
Reviewer: **Aasim Noveer**

Constructon Year	Quantity	Total MMBtu/hr
Before 1972	22	29.13
1977	1	0.60
1981	1	0.11
After 1983	66	145.25
2009- Innovation Center	3	3.30
	Total	**178.39**

Heat Input Capacity MMBtu/hr	HHV mmBtu/mmscf	Potential Throughput MMCF/yr
178.39	1020	1,532.06

	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	1.5	5.8	5.8	0.5	76.6	4.2	64.3

*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

HAPS Calculations

	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	1.609E-03	9.192E-04	5.745E-02	1.379E+00	2.604E-03	**1.441E+00**

	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	3.830E-04	8.426E-04	1.072E-03	2.911E-04	1.609E-03	**4.198E-03**
					Total HAPs	**1.446E+00**
					Worst HAP	**1.379E+00**

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
Informatics East Building Boiler & Hutton Honors College Furnace - PTE
Natural Gas Combustion Only
MM BTU/HR <100

Company Name: Indiana University
Address City IN Zip: 820 North Walnut Grove, Bloomington, Indiana 47405-2206
Permit Number: 105-41051-00005
Reviewer: Aasim Noveer

Unit ID	Heat Input Cap. (MMBtu/hr)	Total MMBtu/hr
Informatics East Building Boiler	1.44	1.44
Hutton Honors College Furnace	0.432	0.432
	TOTAL	1.872

Heat Input Capacity	HHV	Potential Throughput
MMBtu/hr	mmBtu / mmscf	MMCF/yr
1.872	1020	16.1

	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	0.0	0.1	0.1	0.0	0.8	0.0	0.7

*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

HAPS Calculations

	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	1.688E-05	9.646E-06	6.029E-04	1.447E-02	2.733E-05	**1.513E-02**

	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	4.019E-06	8.842E-06	1.125E-05	3.055E-06	1.688E-05	**4.405E-05**
					Total HAPs	**1.517E-02**
					Worst HAP	**1.447E-02**

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 Summary Sheet
Ash Silo Vent Potential to Emit

Company Name: Indiana University
Address City IN Zip: 820 North Walnut Grove, Bloomington, Indiana 47405-2206
Permit Number: 105-41051-00005
Reviewer: Aasim Noveer

1. PM / PM10 / PM2.5 Emissions

Process Step	Throughput (ton/yr)	PM Emission Factor (lb/ton)	PTE of PM (ton/yr)	PM10/PM2.5 Emission Factor (lb/ton)	PTE of PM10/PM2.5 (ton/yr)	Overall Control Efficiency (%)	PM after Control (ton/yr)	PM10/PM2.5 after Control (ton/yr)	Uncontrolled PM10/PM2.5 (lb/hr)	326 IAC 6-3-2 Limit (lb/hr)	Comply with 326 IAC 6-3-2 without control
Ash Silo Vent	6,208.50	0.61	1.89	0.61	1.89	95%	0.09	0.09	0.43	Exempt	
Conveyor to Ash Trough (Leg #1)	6,208.50	3.14	9.75	1.10	3.41	40%	5.85	2.05	0.78	3.47	YES
Conveyor from Ash Trough to Truck (Leg #2)	6,208.50	3.14	9.75	1.10	3.41	40%	5.85	2.05	0.78	3.47	YES
Total			21.39		8.71		11.79	4.19			

Methodology
1) The ash silo is existing and is controlled by a baghouse with a 100% capture efficiency and 95% control efficiency.
2) Ash storage and conveyance emissions are based on 6,208.5 tons/year of fly ash processed.
3) Assume PTE for PM10 = PM2.5.
5) All particulate matter is assumed to be PM10/PM2.5.
6) PTE of PM/PM10, ton/yr = (Throughput, ton/yr) x (Emission Factor, lb/ton) x (1 ton/200lb)
7) PM/PM10 after control, ton/yr = (PTE of PM/PM10, ton/yr) x (1 - control efficiency)
8) Uncontrolled PM/PM10, lb/hr = (PTE of PM/PM10, ton/yr) x (2000 lb/ton) ÷ (8760 hr/yr)
9) 326 IAC 6-3-2 limit, lb/hr = 4.10 x (throughput, ton/hr) ^0.67 - (Ash Silo Vent has uncontrolled PM/PM10 emissions less than 0.551 lb/hr and is exempt.)
10) Throughput, ton/hr = (throughput, ton/yr) ÷ 8760 hr/yr
11) Emission factors are based on U.S. EPA, AP-42, Table 11.12-2, SCC 3-05-016-26 for the ash silo vent and SCC 3-06-011-17 for conveying, dated June 2006

Appendix A: Emissions Summary Sheet
Lime Silo Vent and Carbon Silo Vent Potential to Emit

Company Name: Indiana University
Address City IN Zip: 820 North Walnut Grove, Bloomington, Indiana 47405-2206
Permit Number: 105-41051-00005
Reviewer: Aasim Noveer

1. PM / PM10 / PM2.5 Emissions

Process Step	Throughput (lb/hr)	Throughput (ton/yr)	Emission Factor (lb/ton)	PTE of PM/PM10/PM2.5 (ton/yr)	Overall Control Efficiency (%)	PM/PM10/PM2.5 after Control (ton/yr)	Uncontrolled PM/PM10/PM2.5 (lb/hr)	326 IAC 6-3-2 Limit (lb/hr)
Lime Silo Vent	1200.00	5,256.000	0.61	1.60	99.0%	0.02	0.37	Exempt
Carbon Silo Vent	30.00	131.400	0.61	0.04	99.0%	0.00	0.01	Exempt
Total				1.64		0.02		

Methodology
1) The ash silo is existing and is controlled by a baghouse with a 100% capture efficiency and 95% control efficiency.
2) Ash storage and conveyance emissions are based on 6,208.5 tons/year of fly ash processed.
3) All particulate matter is assumed to be PM10.
4) Throughput, ton/yr = (Throughput, lb/hr) x (1 ton/2000 lb) x (8,760 hr/yr)
5) PTE of PM/PM10/PM2.5, ton/yr = (Throughput, ton/yr) x (Emission Factor, lb/ton) x (1ton/2000lb)
8) PM/PM10/PM2.5 after Control, ton/yr = (PTE of PM/PM10, ton/yr) x (1 - Control Efficiency)
9) PM/PM10/PM2.5 after Control for the carbon silo is shown as zero due to significant figures.
10) Uncontrolled PM/PM10/PM2.5, lb/hr = (PTE of PM/PM10, ton/yr) x (2000 lb/ton) ÷ (8760 hr/yr)
11) 326 IAC 6-3-2 does not apply to the lime silo or carbon silo vents..
12) Emission factors are based on U.S. EPA AP-42, Table 11.17-4, SCC 3-05-016-26, dated February 1998.
13) Assume PTE of PM10 = PM2.5.

Appendix A: Emissions Summary Sheet
Potential to Emit from Paved Roads

Company Name: **Indiana University**
Address City IN Zip: **820 North Walnut Grove, Bloomington, Indiana 47405-2206**
Permit Number: **105-41051-00005**
Reviewer: **Aasim Noveer**

1. Emission Factors: AP-42

According to AP-42, Chapter 13.2.1 - Paved Roads (12/03), the PM/PM10 emission factors for paved roads can be estimated from the following equation:

$E = (k \times (sL/2)^a \times (w/3)^b - C) \times (1 - p/(4 \times 365))$

where:

E =	emission factor (lb/vehicle mile traveled)		
sL (non-Winter) =	road surface silt loading (g/m^2) =	0.6	(g/m^2) (AP-42, Table 13.2.1-3)
sL (Winter) =	sL (non-Winter) x 4 (g/m^2) =	2.4	(g/m^2) (AP-42, Table 13.2.1-3)
w =	mean vehicle weight (tons) =	30.0	tons
k =	empirical constant =	0.082 for PM and 0.016 for PM10	
a =	empirical constant =	0.65	
b =	empirical constant =	1.5	
C =	emission factor for exhaust, brake and tire wear	0.00047	for PM and PM10
p =	number of days per year with 0.01 inches precipitation	115	

Non-Winter Emission Factor

PM Emission Factor (non-Winter) =	$(0.082 \times (sL/2)^a \times (w/3)^b - C) \times (1 - p/1460)$ =	**1.09**	lbs/mile
PM10 Emission Factor (non-Winter) =	$(0.016 \times (sL/2)^a \times (w/3)^b - C) \times (1 - p/1460)$ =	**0.21**	lbs/mile

Winter Emission Factor

PM Emission Factor (Winter) =	$(0.082 \times (sL/2)^a \times (w/3)^b - C) \times (1 - p/1460)$ =	**2.69**	lbs/mile
PM10 Emission Factor (Winter) =	$(0.016 \times (sL/2)^a \times (w/3)^b - C) \times (1 - p/1460)$ =	**0.52**	lbs/mile

Average Annual Emission Factor

PM Emission Factor (Average Annual) = ((PM Emission Factor (non-Winter) x 9) + (PM Emission Factor (Winter) x 3))/12
PM Emission Factor (Average Annual) = **1.49** lbs/mile
PM10 Emission Factor (Average Annual) = ((PM10 Emission Factor (non-Winter) x 9) + (PM10 Emission Factor (Winter) x 3))/12
PM10 Emission Factor (Average Annual) = **0.29** lbs/mile

2. Potential to Emit (PTE) of PM/PM10 from Paved Roads:

Vehicle Type	Ave Weight of Vehicles* (tons)	Estimated Trips* (trips/yr)	Round Trip Distance* (feet/trip)	Vehicle Mile Traveled (VMT) (miles/yr)	PM Emission Factor (lb/mile)	PTE of PM (tons/yr)	PM10/PM2.5 Emission Factor (lb/mile)	PTE of PM10/PM2.5 (tons/yr)
Lime Receiving	30.00	263	10,560	526.00	1.49	0.39	0.29	0.08
Carbon Receiving	30.00	7	10,560	14.00	1.49	0.01	0.29	0.00
Fly Ash Hauling	30.00	310	10,560	620.00	1.49	0.46	0.29	0.09
Total Emissions						0.86		0.17

* This information is provided by the source.

Methodology
1) Vehicle Mile Traveled (mile/yr) = Estimated Trips (trips/yr) x Round Trip Distance (feet/trip) x mile / 5,280 ft
2) PTE of PM/PM10 (tons/yr) =VMT (miles/yr) x PM/PM10 Emission Factors (Average Annual) x 1 ton/2000 lbs
3) The estimated round trips for lime receiving is based on the lime needed to achieve 90% HCL removal from the boiler effluent.
4) The estimated round trips for carbon is based on the carbon needed to achieve 50 mercury removal from the boiler effluent.
5) The amount of fly ash generated is based on all of the lime and carbon is converted into fly ash.
6) The estimated round trips for fly ash is based on the increase in fly ash resulting from the addition of lime and carbon and the increased capture efficiency of the pollution control devices.
7) Assume PTE of PM10 = PM2.5.

Appendix A: Emissions Calculations
Uncontolled Coal Handling: Coal Load-In and Load-Out

Company Name: Indiana University
Address, City, IN, Zip: 820 North Walnut Grove, Bloomington, Indiana 47405-2206
Permit No.: 105-41051-00005
Reviewer: Aasim Noveer

		Coal Unloading	Coal Conveyance
Throughput (TPY)		1,752,000	1,752,000
k	PM	0.740	0.740
	PM10	0.350	0.350
	PM2.5	0.053	0.053
U - Conveyor Speed/Wind speed (MPH)		8	8
M - Moisture %		4.50	4.50
PM Emission Factor (lb/ton)		0.00140	0.00140
PM10 Emission Factor (lb/ton)		0.00066	0.00066
PM2.5 Emission Factor (lb/ton)		0.00010	0.00010
Transfer Points		2.0	5.0

Uncontrolled PTE (TPY)			Totals
PM PTE (ton/yr)	2.45	6.13	**8.58**
PM10 PTE (ton/yr)	1.16	2.89	**4.05**
PM2.5 PTE (ton/yr)	0.18	0.44	**0.61**

NOTE:
Maximum Design Throughput for Coal Storage and Handling System is 200 tons/hr = 1,752,000 tons/year.

Methodology:
Emission Factor = (k)(0.0032)[(U/5)^1.3 / (M/2)^1.4] , AP-42, Chapter 13.2.4, 11/06
PTE = Emission Factor (lb/ton) x Throughput (ton/yr) x Transfer Points x (1 ton / 2,000 lb)
Mean Values are taken for Conveyor/wind speed and moisture content from AP 42 table 13.2.4-1

Appendix A: PTE Summary for Unpermitted Emergency Generators

Company Name: Indiana University
Source Address: 820 North Walnut Grove, Bloomington, Indiana 47405-2206
Permit Number: 105-41051-00005
Reviewer: Aasim Noveer

PTE Summary for New Emergency Generators (tons/year)

Building Name	Emission Units	HP	Manu/Const Date	PM	PM_{10}	$PM_{2.5}$	SO_2	NOx	VOC	CO	Total HAPs	Single HAPs	
Field House / 604	FHSB-1	67.50	1957	0.04	0.04	0.04	0.03	0.52	0.04	0.11	4.58E-04	1.39E-04	Formaldehyde
Sub Total for year 1957				**0.04**	**0.04**	**0.04**	**0.03**	**0.52**	**0.04**	**0.11**	**4.58E-04**		
Hall Admin. / 463	HASB-1	26.20	1970	0.01	0.01	0.01	0.01	0.20	0.02	0.04	1.78E-04	5.41E-05	Formaldehyde
Sub Total for year 1970				**0.01**	**0.01**	**0.01**	**0.01**	**0.20**	**0.02**	**0.04**	**1.78E-04**		
Franklin Hall / 007	FHSB-2	22.50	1972	0.01	0.01	0.01	0.01	0.17	0.01	0.04	1.53E-04	4.65E-05	Formaldehyde
Sub Total for year 1972				**0.01**	**0.01**	**0.01**	**0.01**	**0.17**	**0.01**	**0.04**	**1.53E-04**		
Law Building / 001	LBSB-1	150.00	1981	0.08	0.08	0.08	0.08	1.16	0.09	0.25	1.02E-03	3.10E-04	Formaldehyde
Sub Total for year 1981				**0.08**	**0.08**	**0.08**	**0.08**	**1.16**	**0.09**	**0.25**	**1.02E-03**		
Poplars Bldg. / 008	POPSB-1	255.00	1985	0.14	0.14	0.14	0.13	1.98	0.16	0.43	1.73E-03	5.27E-04	Formaldehyde
Sub Total for year 1985				**0.14**	**0.14**	**0.14**	**0.13**	**1.98**	**0.16**	**0.43**	**1.73E-03**		
Service Bldg / 630	SBSB-4	765.00	1986	0.13	0.08	0.08	0.00	4.59	0.13	1.05	2.11E-03	1.04E-03	Benzene
Sub Total for year 1986				**0.13**	**0.08**	**0.08**	**0.00**	**4.59**	**0.13**	**1.05**	**2.11E-03**		
Music Addition / 148	MASB-1	91.50	1989	0.05	0.05	0.05	0.05	0.71	0.06	0.15	6.20E-04	1.89E-04	Formaldehyde
Sub Total for year 1989				**0.05**	**0.05**	**0.05**	**0.05**	**0.71**	**0.06**	**0.15**	**6.20E-04**		
Chemistry Addition / 072	CASB-1	900.00	1990	0.16	0.09	0.09	0.00	5.40	0.16	1.24	2.48E-03	1.22E-03	Benzene
Jordan Hall / 107	JHSB-2	600.00	1990	0.11	0.06	0.06	0.00	3.60	0.11	0.83	1.65E-03	8.15E-04	Benzene
Sub Total for year 1990				**0.26**	**0.15**	**0.15**	**0.00**	**9.00**	**0.26**	**2.06**	**4.13E-03**		
Student Building / 017	SBSB-3	30.00	1991	0.02	0.02	0.02	0.02	0.23	0.02	0.05	2.03E-04	6.20E-05	Formaldehyde
W.W. Wright (CEE) / 245	CEESB-1	600.00	1991	0.11	0.06	0.06	0.00	3.60	0.11	0.83	1.65E-03	8.15E-04	Benzene
Sub Total for year 1991				**0.12**	**0.08**	**0.08**	**0.02**	**3.83**	**0.12**	**0.88**	**1.86E-03**		
Memorial Union / 053	IMUSB-1	750.00	1993	0.13	0.08	0.08	0.00	4.50	0.13	1.03	2.07E-03	1.02E-03	Benzene
Sub Total for year 1993				**0.13**	**0.08**	**0.08**	**0.00**	**4.50**	**0.13**	**1.03**	**2.07E-03**		
Geological Sciences / 417	GSSB-1	30.00	1994	0.02	0.02	0.02	0.02	0.23	0.02	0.05	2.03E-04	6.20E-05	Formaldehyde
Recreational Sports / 475	RSSB-1	187.50	1994	0.10	0.10	0.10	0.10	1.45	0.12	0.31	1.27E-03	3.87E-04	Formaldehyde
Sub Total for year 1994				**0.12**	**0.12**	**0.12**	**0.11**	**1.69**	**0.14**	**0.36**	**1.47E-03**		
Morgan-Monroe Observatory / 690	Off Campus	52.50	1996	0.03	0.03	0.03	0.03	0.41	0.03	0.09	3.56E-04	1.08E-04	Formaldehyde
Radio/TV / 158	RTVSB-1	300.00	1996	0.17	0.17	0.17	0.15	2.33	0.19	0.50	2.03E-03	6.20E-04	Formaldehyde
Sub Total for year 1996				**0.19**	**0.19**	**0.19**	**0.18**	**2.73**	**0.22**	**0.59**	**2.39E-03**		
Kent Farm / 700A	Off Campus	30.00	1999	0.02	0.02	0.02	0.02	0.23	0.02	0.05	2.03E-04	6.20E-05	Formaldehyde
Auditorium / 171	AUSB-1	600.00	1999	0.11	0.06	0.06	0.00	3.60	0.11	0.83	1.65E-03	8.15E-04	Benzene
Cen. Heat Plant / 445	CHPSB-1	1109.00	1999	0.19	0.11	0.11	0.00	6.65	0.20	1.52	3.05E-03	1.51E-03	Benzene
Willkie Quad / 299	WQSB-2	600.00	1999	0.11	0.06	0.06	0.00	3.60	0.11	0.83	1.65E-03	8.15E-04	Benzene
Service Bldg / 630	PORT-2	22.80	1999	0.01	0.01	0.01	0.01	0.18	0.01	0.04	5.45E-04	4.71E-05	Formaldehyde
Union St Chiller Plant - RPS	PORT-3	80.46	1999	0.04	0.04	0.04	0.04	0.62	0.05	0.13	1.55E-04	1.66E-04	Formaldehyde
Union St Chiller Plant - RPS	PORT-4	80.46	1999	0.04	0.04	0.04	0.04	0.62	0.05	0.13	5.45E-04	1.66E-04	Formaldehyde
Service Bldg	PORT-5	13.00	1999	0.01	0.01	0.01	0.01	0.10	0.01	0.02	5.45E-04	2.68E-05	Formaldehyde
Service Bldg	PORT-6	13.00	1999	0.01	0.01	0.01	0.01	0.10	0.01	0.02	8.81E-05	2.68E-05	Formaldehyde
Service Bldg	PORT-7	13.00	1999	0.01	0.01	0.01	0.01	0.10	0.01	0.02	8.81E-05	2.68E-05	Formaldehyde
Service Bldg	PORT-8	13.00	1999	0.01	0.01	0.01	0.01	0.10	0.01	0.02	8.81E-05	2.68E-05	Formaldehyde
Sub Total for year 1999				**0.55**	**0.38**	**0.38**	**0.14**	**15.91**	**0.57**	**3.62**	**6.56E-03**		
ALF	ALFSB-1	335.00	2000	0.18	0.18	0.18	0.17	2.60	0.21	0.56	2.27E-03	6.92E-04	Formaldehyde
Read Hall / 227	RHSB-1	525.00	2000	0.29	0.29	0.29	0.27	4.07	0.33	0.88	3.56E-03	1.08E-03	Formaldehyde
Sub Total for year 2000				**0.47**	**0.47**	**0.47**	**0.44**	**6.67**	**0.54**	**1.44**	**5.83E-03**		
Campus View / 529	CVSB-1	300.00	2001	0.17	0.17	0.17	0.15	2.33	0.19	0.50	2.03E-03	6.20E-04	Formaldehyde
Eigenmann / 313	EGSB-1	450.00	2001	0.25	0.25	0.25	0.23	3.49	0.28	0.75	3.05E-03	9.29E-04	Formaldehyde
Spruce Hall / 298	SHSB-1	375.00	2001	0.21	0.21	0.21	0.19	2.91	0.24	0.63	2.54E-03	7.74E-04	Formaldehyde
Lee Norvelle Theatre Drama /172	TDSB-1	412.50	2001	0.23	0.23	0.23	0.21	3.20	0.26	0.69	2.80E-03	8.52E-04	Formaldehyde
McNutt / 439	MHSB-2	600.00	2001	0.11	0.06	0.06	0.00	3.60	0.11	0.83	1.65E-03	8.15E-04	Benzene
Myers Hall / 101	MHSB-3	750.00	2001	0.13	0.08	0.08	0.00	4.50	0.13	1.03	2.07E-03	1.02E-03	Benzene
Sub Total for year 2001				**1.08**	**0.98**	**0.98**	**0.79**	**20.02**	**1.20**	**4.42**	**1.41E-02**		
Animal Lab / 411	ALSB-1	90.00	2002	0.05	0.05	0.05	0.05	0.70	0.06	0.15	6.10E-04	1.86E-04	Formaldehyde
Service Bldg	PORT-1	80.46	2002	0.04	0.04	0.04	0.04	0.62	0.05	0.13	5.45E-04	1.66E-04	Formaldehyde
Sub Total for year 2002				**0.09**	**0.09**	**0.09**	**0.09**	**1.32**	**0.11**	**0.28**	**1.16E-03**		
Union St Apts / 296	USASB-1	450.00	2005	0.25	0.25	0.25	0.23	3.49	0.28	0.75	3.05E-03	9.29E-04	Formaldehyde
Sub Total for year 2005				**0.25**	**0.25**	**0.25**	**0.23**	**3.49**	**0.28**	**0.75**	**3.05E-03**		
Service Bldg / 630	PORT-10	156.00	2006	0.09	0.09	0.09	0.08	1.21	0.10	0.26	1.06E-03	3.22E-04	Formaldehyde
Service Bldg - Sheetmetal	PORT-11	2.68	2006	1.47E-03	1.47E-03	1.47E-03	1.37E-03	0.02	1.68E-03	4.48E-03	1.82E-05	5.53E-06	Formaldehyde
Service Bldg - Electric shop	PORT-12	2.68	2006	1.47E-03	1.47E-03	1.47E-03	1.37E-03	0.02	1.68E-03	4.48E-03	1.82E-05	5.53E-06	Formaldehyde
Sub Total for year 2006		**161.36**	**6018.00**	**0.09**	**0.09**	**0.09**	**0.08**	**1.25**	**0.10**	**0.27**	**1.09E-03**		
Service Bldg - Carpenter shop	PORT-9	8.05	2007	4.43E-03	4.43E-03	4.43E-03	4.13E-03	6.24E-02	5.06E-03	1.34E-02	5.46E-05	1.66E-05	Formaldehyde
CIB / 578	CIBSB-1	469.00	2007	0.26	0.26	0.26	0.24	3.63	0.29	0.78	3.18E-03	9.68E-04	Formaldehyde
Sub Total for year2007				**0.26**	**0.26**	**0.26**	**0.24**	**3.63**	**0.29**	**0.78**	**3.18E-03**		
Utilities Lights - Gen	PORT-15	24.50	2008	0.01	0.01	0.01	0.01	0.19	0.02	0.04	1.66E-04	5.06E-05	Formaldehyde
Sare Rd Transmitter	Off Campus	145.00	2008	0.08	0.08	0.08	0.07	1.12	0.09	0.24	9.83E-04	2.99E-04	Formaldehyde
Sub Total for year 2008				**0.09**	**0.09**	**0.09**	**0.09**	**1.31**	**0.11**	**0.28**	**1.15E-03**		
Baseball/ 593	BASB-1	147.00	2012	0.08	0.08	0.08	0.08	1.14	0.09	0.25	9.96E-04	3.04E-04	Formaldehyde
Sare Rd Transmitter / 800A	Off Campus	315.00	2012	0.17	0.17	0.17	0.16	2.44	0.20	0.53	2.14E-03	6.50E-04	Formaldehyde
Softball/ 594	SBSB-2	99.00	2012	0.05	0.05	0.05	0.05	0.77	0.06	0.17	6.71E-04	2.04E-04	Formaldehyde
Sub Total for year2012				**0.31**	**0.31**	**0.31**	**0.29**	**4.35**	**0.35**	**0.94**	**3.80E-03**		
Optometry / 065	OPSB-1	375.00	2014	0.21	0.21	0.21	0.19	2.91	0.24	0.63	2.54E-03	7.74E-04	Formaldehyde
Wells Library /GISB 209	WLSB-1	1206.00	2014	0.21	0.12	0.12	0.00	7.24	0.21	1.66	3.32E-03	1.64E-03	Benzene
Sub Total for year 2014				**0.42**	**0.33**	**0.33**	**0.20**	**10.14**	**0.45**	**2.28**	**5.86E-03**		
Utilities	PORT-13	23.50	2015	0.01	0.01	0.01	0.01	0.18	0.01	0.04	1.59E-04	4.85E-05	Formaldehyde
Assembly Hall / 603	AHSB-2	668.00	2015	0.12	0.07	0.07	0.00	4.01	0.12	0.92	1.84E-03	9.07E-04	Benzene
Sub Total for year 2015				**0.13**	**0.08**	**0.08**	**0.01**	**4.19**	**0.13**	**0.96**	**2.00E-03**		
Food Warehouse / 615	FWSB-1	536.00	2016	0.29	0.29	0.29	0.27	4.15	0.34	0.90	3.63E-03	1.11E-03	Formaldehyde
Sub Total for year 2016				**0.29**	**0.29**	**0.29**	**0.27**	**4.15**	**0.34**	**0.90**	**3.63E-03**		
Utilities	PORT-14	23.50	2017	0.01	0.01	0.01	0.01	0.18	0.01	0.04	1.59E-04	4.85E-05	Formaldehyde
Sub Total for year 2017		**23.50**	**2017.00**	**0.01**	**0.01**	**0.01**	**0.01**	**0.18**	**0.01**	**0.04**	**1.59E-04**		
2427 E 2ND ST	2NDSB-1	131.00	2018	0.07	0.07	0.07	0.07	1.02	0.08	0.22	8.88E-04	2.71E-04	Formaldehyde
ALF	ALFSB-2	201.15	2018	0.11	0.11	0.11	0.10	1.56	0.13	0.34	1.36E-03	4.15E-04	Formaldehyde
Luddy Hall	LHSB-1	324.00	2018	0.18	0.18	0.18	0.17	2.51	0.20	0.54	2.20E-03	6.69E-04	Formaldehyde
Memorial Stadium South End Zone	MSEZSB-1	450.00	2018	0.25	0.25	0.25	0.23	3.49	0.28	0.75	3.05E-03	9.29E-04	Formaldehyde
SPEA / 452	SPEASB-1	670.00	2018	0.12	0.07	0.07	0.00	4.02	0.12	0.92	1.85E-03	9.10E-04	Benzene
Swain West	SWSB-1	754.00	2018	0.13	0.08	0.08	0.00	4.52	0.13	1.04	2.08E-03	1.02E-03	Benzene
Sub Total for year 2018				**0.86**	**0.75**	**0.75**	**0.57**	**17.12**	**0.95**	**3.81**	**1.14E-02**		
Total		**18686.30**		**6.21**	**5.42**	**5.42**	**4.09**	**124.82**	**6.84**	**27.77**	**8.12E-02**		

Appendix A: PTE Summary for all Emergency Generators

Company Name: Indiana University
Source Address: 820 North Walnut Grove, Bloomington, Indiana 47405-2206
Permit Number: 105-41051-00005
Reviewer: Aasim Noveer

PTE Summary for Emergency Generators < 600 hp (tons/year)

Emission Units		PM	PM_{10}	$PM_{2.5}$	SO_2	NOx	VOC	CO	Total HAPs	Worst Case HAPs		
	2NDSB-1	0.07	0.07	0.07	0.07	1.02	0.08	0.22	0.001	2.71E-04	Formaldehyde	1
	ALFSB-1	0.18	0.18	0.18	0.17	2.60	0.21	0.56	0.002	6.92E-04	Formaldehyde	2
	ALFSB-2	0.11	0.11	0.11	0.10	1.56	0.13	0.34	0.001	4.15E-04	Formaldehyde	3
	ALSB-1	0.05	0.05	0.05	0.05	0.70	0.06	0.15	0.001	1.86E-04	Formaldehyde	4
	BASB-1	0.08	0.08	0.08	0.08	1.14	0.09	0.25	0.001	3.04E-04	Formaldehyde	5
	BCSB-1	0.20	0.20	0.20	0.18	2.79	0.23	0.60	0.002	7.43E-04	Formaldehyde	6
	CHSB-1	0.17	0.17	0.17	0.15	2.33	0.19	0.50	0.002	6.20E-04	Formaldehyde	7
	CIBSB-1	0.26	0.26	0.26	0.24	3.63	0.29	0.78	0.003	9.68E-04	Formaldehyde	8
	CVSB-1	0.17	0.17	0.17	0.15	2.33	0.19	0.50	0.002	6.20E-04	Formaldehyde	9
	EGSB-1	0.25	0.25	0.25	0.23	3.49	0.28	0.75	0.003	9.29E-04	Formaldehyde	10
	FHSB-1	0.04	0.04	0.04	0.03	0.52	0.04	0.11	0.000	1.39E-04	Formaldehyde	11
	FHSB-2	0.01	0.01	0.01	0.01	0.17	0.01	0.04	0.000	4.65E-05	Formaldehyde	12
	FQHSB-1	0.16	0.16	0.16	0.14	2.19	0.18	0.47	0.002	5.82E-04	Formaldehyde	13
	FQSB-1	0.25	0.25	0.25	0.24	3.57	0.29	0.77	0.003	9.50E-04	Formaldehyde	14
	FWSB-1	0.29	0.29	0.29	0.27	4.15	0.34	0.90	0.004	1.11E-03	Formaldehyde	15
	GSSB-1	0.02	0.02	0.02	0.02	0.23	0.02	0.05	0.000	6.20E-05	Formaldehyde	16
	HAPSB-1	0.03	0.03	0.03	0.03	0.47	0.04	0.10	0.000	1.24E-04	Formaldehyde	17
	HASB-1	0.01	0.01	0.01	0.01	0.20	0.02	0.04	0.000	5.41E-05	Formaldehyde	18
	ICSB-1	0.10	0.10	0.10	0.10	1.44	0.12	0.31	0.001	3.84E-04	Formaldehyde	19
	IUPD-1	0.30	0.30	0.30	0.28	4.22	0.34	0.91	0.004	1.13E-03	Formaldehyde	20
	JDHSB-1	0.04	0.04	0.04	0.04	0.62	0.05	0.13	0.001	1.65E-04	Formaldehyde	21
	JHSB-1	0.12	0.12	0.12	0.12	1.74	0.14	0.38	0.002	4.65E-04	Formaldehyde	22
	JSMSB-1	0.26	0.26	0.26	0.24	3.68	0.30	0.79	0.003	9.81E-04	Formaldehyde	23
	LBSB-1	0.08	0.08	0.08	0.08	1.16	0.09	0.25	0.001	3.10E-04	Formaldehyde	24
	LHSB-1	0.18	0.18	0.18	0.17	2.51	0.20	0.54	0.002	6.69E-04	Formaldehyde	25
	MACSB-1	0.07	0.07	0.07	0.06	0.93	0.08	0.20	0.001	2.48E-04	Formaldehyde	26
	MASB-1	0.05	0.05	0.05	0.05	0.71	0.06	0.15	0.001	1.89E-04	Formaldehyde	27
	MHSB-1	0.03	0.03	0.03	0.03	0.43	0.04	0.09	0.000	1.16E-04	Formaldehyde	28
	MSEZSB-1	0.25	0.25	0.25	0.23	3.49	0.28	0.75	0.003	9.29E-04	Formaldehyde	29
	MSNSB-1	0.14	0.14	0.14	0.13	2.00	0.16	0.43	0.002	5.33E-04	Formaldehyde	30
Diesel-Fired	Off Campus	0.08	0.08	0.08	0.07	1.12	0.09	0.24	0.001	2.99E-04	Formaldehyde	31
EGs < 600 hp	Off Campus	0.03	0.03	0.03	0.03	0.41	0.03	0.09	0.000	1.08E-04	Formaldehyde	32
	Off Campus	0.17	0.17	0.17	0.16	2.44	0.20	0.53	0.002	6.50E-04	Formaldehyde	33
	Off Campus	0.02	0.02	0.02	0.02	0.23	0.02	0.05	0.000	6.20E-05	Formaldehyde	34
	OPSB-1	0.21	0.21	0.21	0.19	2.91	0.24	0.63	0.003	7.74E-04	Formaldehyde	35
	POPSB-1	0.14	0.14	0.14	0.13	1.98	0.16	0.43	0.002	5.27E-04	Formaldehyde	36
	RHSB-1	0.29	0.29	0.29	0.27	4.07	0.33	0.88	0.004	1.08E-03	Formaldehyde	37
	RSSB-1	0.10	0.10	0.10	0.10	1.45	0.12	0.31	0.001	3.87E-04	Formaldehyde	38
	RTVSB-1	0.17	0.17	0.17	0.15	2.33	0.19	0.50	0.002	6.20E-04	Formaldehyde	39
	SBSB-2	0.05	0.05	0.05	0.05	0.77	0.06	0.17	0.001	2.04E-04	Formaldehyde	40
	SBSB-3	0.02	0.02	0.02	0.02	0.23	0.02	0.05	0.000	6.20E-05	Formaldehyde	41
	SHSB-1	0.21	0.21	0.21	0.19	2.91	0.24	0.63	0.003	7.74E-04	Formaldehyde	42
	TDSB-1	0.23	0.23	0.23	0.21	3.20	0.26	0.69	0.003	8.52E-04	Formaldehyde	43
	TQSB-1	0.18	0.18	0.18	0.16	2.48	0.20	0.53	0.002	6.61E-04	Formaldehyde	44
	TTASB-1	0.17	0.17	0.17	0.15	2.33	0.19	0.50	0.002	6.20E-04	Formaldehyde	45
	USASB-1	0.25	0.25	0.25	0.23	3.49	0.28	0.75	0.003	9.29E-04	Formaldehyde	46
	WQSB-1	0.12	0.12	0.12	0.12	1.75	0.14	0.38	0.002	4.66E-04	Formaldehyde	47
	PORT-1	0.04	0.04	0.04	0.04	0.62	0.05	0.134	5.45E-04	1.66E-04	Formaldehyde	48
	PORT-2	0.01	0.01	0.01	0.01	0.18	0.01	0.038	1.55E-04	4.71E-05	Formaldehyde	49
	PORT-3	0.04	0.04	0.04	0.04	0.62	0.05	0.134	5.45E-04	1.66E-04	Formaldehyde	50
	PORT-4	0.04	0.04	0.04	0.04	0.62	0.05	0.134	5.45E-04	1.66E-04	Formaldehyde	51
	PORT-5	0.01	0.01	0.01	0.01	0.10	0.01	0.022	8.81E-05	2.68E-05	Formaldehyde	52
	PORT-6	0.01	0.01	0.01	0.01	0.10	0.01	0.022	8.81E-05	2.68E-05	Formaldehyde	53
	PORT-7	0.01	0.01	0.01	0.01	0.10	0.01	0.022	8.81E-05	2.68E-05	Formaldehyde	54
	PORT-8	0.01	0.01	0.01	0.01	0.10	0.01	0.022	8.81E-05	2.68E-05	Formaldehyde	55
	PORT-9	4.43E-03	4.43E-03	4.43E-03	4.13E-03	0.06	0.01	0.013	5.46E-05	1.66E-05	Formaldehyde	56
	PORT-10	0.09	0.09	0.09	0.08	1.21	0.10	0.261	1.06E-03	3.22E-04	Formaldehyde	57
	PORT-11	1.47E-03	1.47E-03	1.47E-03	1.37E-03	0.02	1.68E-03	0.004	1.82E-05	5.53E-06	Formaldehyde	58
	PORT-12	1.47E-03	1.47E-03	1.47E-03	1.37E-03	0.02	1.68E-03	0.004	1.82E-05	5.53E-06	Formaldehyde	59
	PORT-13	0.01	0.01	0.01	0.01	0.18	0.01	0.039	1.59E-04	4.85E-05	Formaldehyde	60
	PORT-14	0.01	0.01	0.01	0.01	0.18	0.01	0.039	1.59E-04	4.85E-05	Formaldehyde	61
	PORT-15	0.01	0.01	0.01	0.01	0.19	0.02	0.041	1.66E-04	5.06E-05	Formaldehyde	62
		6.70	**6.70**	**6.70**	**6.24**	**94.41**	**7.66**	**20.34**	**0.083**	**0.025**	Formaldehyde	

PTE Summary for Emergency Generators > 600 hp (tons/year)

Emission Units		PM	PM_{10}	$PM_{2.5}$	SO_2	NOx	VOC	CO	Total HAPs	Worst Case HAPs		
	AHSB-2	0.12	0.07	0.07	0.00	4.01	0.12	0.92	1.84E-03	0.001	Benzene	1
	AUSB-1	0.11	0.06	0.06	0.00	3.60	0.11	0.83	1.65E-03	0.001	Benzene	2
	BBSB-1	0.13	0.07	0.07	0.00	4.32	0.13	0.99	1.98E-03	0.001	Benzene	3
	CASB-1	0.16	0.09	0.09	0.00	5.40	0.16	1.24	2.48E-03	0.001	Benzene	4
	CEESB-1	0.11	0.06	0.06	0.00	3.60	0.11	0.83	1.65E-03	0.001	Benzene	5
	CHPSB-1	0.19	0.11	0.11	0.00	6.65	0.20	1.52	3.05E-03	0.002	Benzene	6
	DCSB-1	0.39	0.22	0.22	0.01	13.20	0.39	3.03	6.06E-03	0.003	Benzene	7
	DCSB-2	0.39	0.22	0.22	0.01	13.20	0.39	3.03	6.06E-03	0.003	Benzene	8
	HCSB-1	0.20	0.12	0.12	0.00	6.90	0.20	1.58	3.17E-03	0.002	Benzene	9
Diesel-Fired	HPSB-1	0.11	0.06	0.06	0.00	3.64	0.11	0.83	1.67E-03	0.001	Benzene	10
EGs > 600 hp	IMUSB-1	0.13	0.08	0.08	0.00	4.50	0.13	1.03	2.07E-03	0.001	Benzene	11
	JHSB-2	0.11	0.06	0.06	0.00	3.60	0.11	0.83	1.65E-03	0.001	Benzene	12
	MHSB-2	0.11	0.06	0.06	0.00	3.60	0.11	0.83	1.65E-03	0.001	Benzene	13
	MHSB-3	0.13	0.08	0.08	0.00	4.50	0.13	1.03	2.07E-03	0.001	Benzene	14
	MSB-1	0.21	0.12	0.12	0.00	7.20	0.21	1.65	3.31E-03	0.002	Benzene	15
	MSB-2	0.26	0.15	0.15	0.00	8.94	0.26	2.05	4.10E-03	0.002	Benzene	16
	SBSB-4	0.13	0.08	0.08	0.00	4.59	0.13	1.05	2.11E-03	0.001	Benzene	17
	SPEASB-1	0.12	0.07	0.07	0.00	4.02	0.12	0.92	1.85E-03	0.001	Benzene	18
	SWSB-1	0.13	0.08	0.08	0.00	4.52	0.13	1.04	2.08E-03	0.001	Benzene	19
	WLSB-1	0.21	0.12	0.12	0.00	7.24	0.21	1.66	3.32E-03	0.002	Benzene	20
	WQSB-2	0.11	0.06	0.06	0.00	3.60	0.11	0.83	1.65E-03	0.001	Benzene	21
	MESH-1	0.12	0.07	0.07	0.00	4.10	0.12	0.94	5.74E-02	0.028	Benzene	
		3.64	**2.09**	**2.09**	**0.06**	**124.93**	**3.67**	**28.63**	**0.11**	**0.027**	**Benzene**	

Appendix A: Emission Calculations
Reciprocating Internal Combustion Engines - Diesel Fuel
PTE - Diesel Emergency Generators
Output Rating (<600 HP)
Maximum Input Rate (<4.2 MMBtu/hr)

Company Name: Indiana University
Address City IN Zip: 820 North Walnut Grove, Bloomington, Indiana 47405-2206
Permit Number: 105-41051-00005
Reviewer: Aasim Noveer

Maximum Hours Operated per Year: 500

Emissions calculated based on output rating (hp)

	Pollutant						
	PM*	PM10*	direct PM2.5*	SO2	NOx	VOC	CO
Emission Factor in lb/hp-hr	0.0022	0.0022	0.0022	0.00205	0.0310	0.0025	0.00668
					**see below		

*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 condensable.

			tons per year							
Building Name	**IDEM Name**	**HP**	**PM**	**PM10**	**direct PM2.5**	**SO2**	**NOx**	**VOC**	**CO**	Status
2427 E 2ND ST	2NDSB-1	131.0	0.07	0.07	0.07	0.0671	1.02	0.08	0.22	New
ALF	ALFSB-1	335.0	0.18	0.18	0.18	0.1717	2.60	0.21	0.56	New
ALF	ALFSB-2	201.2	0.11	0.11	0.11	0.1031	1.56	0.13	0.34	New
Animal Lab / 411	ALSB-1	90.0	0.05	0.05	0.05	0.0461	0.70	0.06	0.15	New
Baseball/ 593	BASB-1	147.0	0.08	0.08	0.08	0.0753	1.14	0.09	0.25	New
B-Ball Ctr.Cook Hall /607	BCSB-1	360.0	0.20	0.20	0.20	0.1845	2.79	0.23	0.60	Permitted
Cedar Hall / 276C	CHSB-1	300.0	0.17	0.17	0.17	0.1538	2.33	0.19	0.50	Permitted
CIB / 578	CIBSB-1	469.0	0.26	0.26	0.26	0.2404	3.63	0.29	0.78	New
Campus View / 529	CVSB-1	300.0	0.17	0.17	0.17	0.1538	2.33	0.19	0.50	New
Eigenmann / 313	EGSB-1	450.0	0.25	0.25	0.25	0.2306	3.49	0.28	0.75	New
Field House / 604	FHSB-1	67.5	0.04	0.04	0.04	0.0346	0.52	0.04	0.11	New
Franklin Hall / 007	FHSB-2	22.5	0.01	0.01	0.01	0.0115	0.17	0.01	0.04	New
FosterQuad/Harper / 453	FQHSB-1	282.0	0.16	0.16	0.16	0.1445	2.19	0.18	0.47	Permitted
Forest Quad / 257	FQSB-1	460.0	0.25	0.25	0.25	0.2358	3.57	0.29	0.77	Permitted
Food Warehouse / 615	FWSB-1	536.0	0.29	0.29	0.29	0.2747	4.15	0.34	0.90	New
Geological Sciences /417	GSSB-1	30.0	0.02	0.02	0.02	0.0154	0.23	0.02	0.05	New
Henderson/Atwtr parking/ 063	HAPSB-1	60.0	0.03	0.03	0.03	0.0308	0.47	0.04	0.10	Permitted
Hall Admin. / 463	HASB-1	26.2	0.01	0.01	0.01	0.0134	0.20	0.02	0.04	New
IU Innovation Ctr / 563	ICSB-1	186.0	0.10	0.10	0.10	0.0953	1.44	0.12	0.31	Permitted
IUPD / 990Y	IUPD-1	545.0	0.30	0.30	0.30	0.2793	4.22	0.34	0.91	Permitted
Jordan Hall / 107	JDHSB-1	80.0	0.04	0.04	0.04	0.0410	0.62	0.05	0.13	Permitted
Johnston Hall / 275	JHSB-1	225.0	0.12	0.12	0.12	0.1153	1.74	0.14	0.38	Permitted
Music Studio East (Jacobs School)/150	JSMSB-1	475.0	0.26	0.26	0.26	0.2434	3.68	0.30	0.79	Permitted
Law Building / 001	LBSB-1	150.0	0.08	0.08	0.08	0.0769	1.16	0.09	0.25	New
Luddy Hall	LHSB-1	324.0	0.18	0.18	0.18	0.1661	2.51	0.20	0.54	New
Musical Arts Cen. / 177	MACSB-1	120.0	0.07	0.07	0.07	0.0615	0.93	0.08	0.20	Permitted
Music Addition / 148	MASB-1	91.5	0.05	0.05	0.05	0.0469	0.71	0.06	0.15	New
Mason Hall / 304	MHSB-1	56.0	0.03	0.03	0.03	0.0287	0.43	0.04	0.09	Permitted
Memorial Stadium South End Zone	MSEZSB-1	450.0	0.25	0.25	0.25	0.2306	3.49	0.28	0.75	New
Memorial Stadium North /601	MSNSB-1	258.0	0.14	0.14	0.14	0.1322	2.00	0.16	0.43	Permitted
Sare Rd Transmitter	Off Campus	145.0	0.08	0.08	0.08	0.0743	1.12	0.09	0.24	New
Morgan-MonroeObservatory / 690	Off Campus	52.5	0.03	0.03	0.03	0.0269	0.41	0.03	0.09	New
Sare Rd Transmitter /800A	Off Campus	315.0	0.17	0.17	0.17	0.1614	2.44	0.20	0.53	New
Kent Farm / 700A	Off Campus	30.0	0.02	0.02	0.02	0.0154	0.23	0.02	0.05	New
Optometry / 065	OPSB-1	375.0	0.21	0.21	0.21	0.1922	2.91	0.24	0.63	New
Poplars Bldg. / 008	POPSB-1	255.0	0.14	0.14	0.14	0.1307	1.98	0.16	0.43	New
Read Hall / 227	RHSB-1	525.0	0.29	0.29	0.29	0.2691	4.07	0.33	0.88	New
Recreational Sports / 475	RSSB-1	187.5	0.10	0.10	0.10	0.0961	1.45	0.12	0.31	New
Radio/TV / 158	RTVSB-1	300.0	0.17	0.17	0.17	0.1538	2.33	0.19	0.50	New
Softball/ 594	SBSB-2	99.0	0.05	0.05	0.05	0.0507	0.77	0.06	0.17	New
Student Building / 017	SBSB-3	30.0	0.02	0.02	0.02	0.0154	0.23	0.02	0.05	New
Spruce Hall / 298	SHSB-1	375.0	0.21	0.21	0.21	0.1922	2.91	0.24	0.63	New
Lee Norvelle TheatreDrama /172	TDSB-1	412.5	0.23	0.23	0.23	0.2114	3.20	0.26	0.69	New
Teter Quad / 243	TQSB-1	320.0	0.18	0.18	0.18	0.1640	2.48	0.20	0.53	Permitted
Tulip Tree / 555	TTASB-1	300.0	0.17	0.17	0.17	0.1538	2.33	0.19	0.50	Permitted
Union St Apts / 296	USASB-1	450.0	0.25	0.25	0.25	0.2306	3.49	0.28	0.75	New
Wright Quad / 237	WQSB-1	225.6	0.12	0.12	0.12	0.1156	1.75	0.14	0.38	Permitted
Service Bldg	PORT-1	80.46	0.04	0.04	0.04	0.0412	0.62	0.05	0.134	New
Service Bldg / 630	PORT-2	22.80	0.01	0.01	0.01	0.0117	0.18	0.01	0.04	New
Union St Chiller Plant - RPS	PORT-3	80.46	0.04	0.04	0.04	0.0412	0.62	0.05	0.13	New
Union St Chiller Plant - RPS	PORT-4	80.46	0.04	0.04	0.04	0.0412	0.62	0.05	0.13	New
Service Bldg	PORT-5	13.00	0.01	0.01	0.01	0.0067	0.10	0.01	0.02	New
Service Bldg	PORT-6	13.00	0.01	0.01	0.01	0.0067	0.10	0.01	0.02	New
Service Bldg	PORT-7	13.00	0.01	0.01	0.01	0.0067	0.10	0.01	0.02	New
Service Bldg	PORT-8	13.00	0.01	0.01	0.01	0.0067	0.10	0.01	0.02	New
Service Bldg - Carpenter shop	PORT-9	8.05	4.43E-03	4.43E-03	4.43E-03	0.0041	0.06	0.01	0.01	New
Service Bldg / 630	PORT-10	156.00	0.09	0.09	0.09	0.0800	1.21	0.10	0.26	New
Service Bldg - Sheetmetal	PORT-11	2.68	1.47E-03	1.47E-03	1.47E-03	0.0014	0.02	1.68E-03	4.48E-03	New
Service Bldg - Electric shop	PORT-12	2.68	1.47E-03	1.47E-03	1.47E-03	0.0014	0.02	1.68E-03	4.48E-03	New
Utilities	PORT-13	23.50	0.01	0.01	0.01	0.0120	0.18	0.01	0.04	New
Utilities	PORT-14	23.50	0.01	0.01	0.01	0.0120	0.18	0.01	0.04	New
Utilities Lights - Gen	PORT-15	24.50	0.01	0.01	0.01	0.0126	0.19	0.02	0.04	New
	Total	**12,182.0**	**6.7**	**6.7**	**6.7**	**6.2**	**94.4**	**7.7**	**20.3**	

Hazardous Air Pollutants (HAPs)

	Pollutant							
	Benzene	Toluene	Xylene	1,3-Butadiene	Formaldehyde	Acetaldehyde	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

***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).

			tons per year								
Building Name	**IDEM Name**	**HP**	**Benzene**	**Toluene**	**Xylene**	**1,3-Butadiene**	**Formaldehyde**	**Acetaldehyde**	**Acrolein**	**Total PAH HAPs*** **	**Total HAPs**
2427 E 2ND ST	2NDSB-1	131.0	2.14E-04	9.38E-05	6.53E-05	8.96E-06	2.71E-04	1.76E-04	2.12E-05	3.85E-05	8.88E-04
ALF	ALFSB-1	335.0	5.47E-04	2.40E-04	1.67E-04	2.29E-05	6.92E-04	4.50E-04	5.42E-05	9.85E-05	2.27E-03
ALF	ALFSB-2	201.2	3.28E-04	1.44E-04	1.00E-04	1.38E-05	4.15E-04	2.70E-04	3.26E-05	5.91E-05	1.36E-03
Animal Lab / 411	ALSB-1	90.0	1.47E-04	6.44E-05	4.49E-05	6.16E-06	1.86E-04	1.21E-04	1.46E-05	2.65E-05	6.10E-04
Baseball/ 593	BASB-1	147.0	2.40E-04	1.05E-04	7.33E-05	1.01E-05	3.04E-04	1.97E-04	2.38E-05	4.32E-05	9.96E-04
B-Ball Ctr.Cook Hall /607	BCSB-1	360.0	5.88E-04	2.58E-04	1.80E-04	2.46E-05	7.43E-04	4.83E-04	5.83E-05	1.06E-04	2.44E-03
Cedar Hall / 276C	CHSB-1	300.0	4.90E-04	2.15E-04	1.50E-04	2.05E-05	6.20E-04	4.03E-04	4.86E-05	8.82E-05	2.03E-03
CIB / 578	CIBSB-1	469.0	7.66E-04	3.36E-04	2.34E-04	3.21E-05	9.68E-04	6.30E-04	7.59E-05	1.38E-04	3.18E-03
Campus View / 529	CVSB-1	300.0	4.90E-04	2.15E-04	1.50E-04	2.05E-05	6.20E-04	4.03E-04	4.86E-05	8.82E-05	2.03E-03
Eigenmann / 313	EGSB-1	450.0	7.35E-04	3.22E-04	2.24E-04	3.08E-05	9.29E-04	6.04E-04	7.28E-05	1.32E-04	3.05E-03
Field House / 604	FHSB-1	67.5	1.10E-04	4.83E-05	3.37E-05	4.62E-06	1.39E-04	9.06E-05	1.09E-05	1.98E-05	4.58E-04
Franklin Hall / 007	FHSB-2	22.5	3.67E-05	1.61E-05	1.12E-05	1.54E-06	4.65E-05	3.02E-05	3.64E-06	6.62E-06	1.53E-04
FosterQuad/Harper / 453	FQHSB-1	282.0	4.60E-04	2.02E-04	1.41E-04	1.93E-05	5.82E-04	3.79E-04	4.56E-05	8.29E-05	1.91E-03
Forest Quad / 257	FQSB-1	460.0	7.51E-04	3.29E-04	2.29E-04	3.15E-05	9.50E-04	6.17E-04	7.45E-05	1.35E-04	3.12E-03
Food Warehouse / 615	FWSB-1	536.0	8.75E-04	3.84E-04	2.67E-04	3.67E-05	1.11E-03	7.19E-04	8.68E-05	1.58E-04	3.63E-03
Geological Sciences /417	GSSB-1	30.0	4.90E-05	2.15E-05	1.50E-05	2.05E-06	6.20E-05	4.03E-05	4.86E-06	8.82E-06	2.03E-04
Henderson/Atwtr parking/ 063	HAPSB-1	60.0	9.80E-05	4.29E-05	2.99E-05	4.11E-06	1.24E-04	8.05E-05	9.71E-06	1.76E-05	4.07E-04
Hall Admin. / 463	HASB-1	26.2	4.28E-05	1.88E-05	1.31E-05	1.79E-06	5.41E-05	3.52E-05	4.24E-06	7.70E-06	1.78E-04
IU Innovation Ctr / 563	ICSB-1	186.0	3.04E-04	1.33E-04	9.28E-05	1.27E-05	3.84E-04	2.50E-04	3.01E-05	5.47E-05	1.26E-03
IUPD / 990Y	IUPD-1	545.0	8.90E-04	3.90E-04	2.72E-04	3.73E-05	1.13E-03	7.32E-04	8.82E-05	1.60E-04	3.69E-03
Jordan Hall / 107	JDHSB-1	80.0	1.31E-04	5.73E-05	3.99E-05	5.47E-06	1.65E-04	1.07E-04	1.30E-05	2.35E-05	5.42E-04
Johnston Hall / 275	JHSB-1	225.0	3.67E-04	1.61E-04	1.12E-04	1.54E-05	4.65E-04	3.02E-04	3.64E-05	6.62E-05	1.53E-03
Music Studio East (Jacobs School)/150	JSMSB-1	475.0	7.76E-04	3.40E-04	2.37E-04	3.25E-05	9.81E-04	6.38E-04	7.69E-05	1.40E-04	3.22E-03
Law Building / 001	LBSB-1	150.0	2.45E-04	1.07E-04	7.48E-05	1.03E-05	3.10E-04	2.01E-04	2.43E-05	4.41E-05	1.02E-03
Luddy Hall	LHSB-1	324.0	5.29E-04	2.32E-04	1.62E-04	2.22E-05	6.69E-04	4.35E-04	5.24E-05	9.53E-05	2.20E-03
Musical Arts Cen. / 177	MACSB-1	120.0	1.96E-04	8.59E-05	5.99E-05	8.21E-06	2.48E-04	1.61E-04	1.94E-05	3.53E-05	8.13E-04
Music Addition / 148	MASB-1	91.5	1.49E-04	6.55E-05	4.56E-05	6.26E-06	1.89E-04	1.23E-04	1.48E-05	2.69E-05	6.20E-04
Mason Hall / 304	MHSB-1	56.0	9.14E-05	4.01E-05	2.79E-05	3.83E-06	1.16E-04	7.52E-05	9.07E-06	1.65E-05	3.80E-04
Memorial Stadium South End Zone	MSEZSB-1	450.0	7.35E-04	3.22E-04	2.24E-04	3.08E-05	9.29E-04	6.04E-04	7.28E-05	1.32E-04	3.05E-03
Memorial Stadium North /601	MSNSB-1	258.0	4.21E-04	1.85E-04	1.29E-04	1.77E-05	5.33E-04	3.46E-04	4.18E-05	7.59E-05	1.75E-03
Sare Rd Transmitter	Off Campus	145.0	2.37E-04	1.04E-04	7.23E-05	9.92E-06	2.99E-04	1.95E-04	2.35E-05	4.26E-05	9.83E-04
Morgan-MonroeObservatory / 690	Off Campus	52.5	8.57E-05	3.76E-05	2.62E-05	3.59E-06	1.08E-04	7.05E-05	8.50E-06	1.54E-05	3.56E-04
Sare Rd Transmitter /800A	Off Campus	315.0	5.14E-04	2.25E-04	1.57E-04	2.16E-05	6.50E-04	4.23E-04	5.10E-05	9.26E-05	2.14E-03
Kent Farm / 700A	Off Campus	30.0	4.90E-05	2.15E-05	1.50E-05	2.05E-06	6.20E-05	4.03E-05	4.86E-06	8.82E-06	2.03E-04
Optometry / 065	OPSB-1	375.0	6.12E-04	2.68E-04	1.87E-04	2.57E-05	7.74E-04	5.03E-04	6.07E-05	1.10E-04	2.54E-03
Poplars Bldg. / 008	POPSB-1	255.0	4.16E-04	1.83E-04	1.27E-04	1.74E-05	5.27E-04	3.42E-04	4.13E-05	7.50E-05	1.73E-03
Read Hall / 227	RHSB-1	525.0	8.57E-04	3.76E-04	2.62E-04	3.59E-05	1.08E-03	7.05E-04	8.50E-05	1.54E-04	3.56E-03
Recreational Sports / 475	RSSB-1	187.5	3.06E-04	1.34E-04	9.35E-05	1.28E-05	3.87E-04	2.52E-04	3.04E-05	5.51E-05	1.27E-03
Radio/TV / 158	RTVSB-1	300.0	4.90E-04	2.15E-04	1.50E-04	2.05E-05	6.20E-04	4.03E-04	4.86E-05	8.82E-05	2.03E-03
Softball/ 594	SBSB-2	99.0	1.62E-04	7.09E-05	4.94E-05	6.77E-06	2.04E-04	1.33E-04	1.60E-05	2.91E-05	6.71E-04
Student Building / 017	SBSB-3	30.0	4.90E-05	2.15E-05	1.50E-05	2.05E-06	6.20E-05	4.03E-05	4.86E-06	8.82E-06	2.03E-04
Spruce Hall / 298	SHSB-1	375.0	6.12E-04	2.68E-04	1.87E-04	2.57E-05	7.74E-04	5.03E-04	6.07E-05	1.10E-04	2.54E-03
Lee Norvelle TheatreDrama /172	TDSB-1	412.5	6.74E-04	2.95E-04	2.06E-04	2.82E-05	8.52E-04	5.54E-04	6.68E-05	1.21E-04	2.80E-03
Teter Quad / 243	TQSB-1	320.0	5.22E-04	2.29E-04	1.60E-04	2.19E-05	6.61E-04	4.30E-04	5.18E-05	9.41E-05	2.17E-03
Tulip Tree / 555	TTASB-1	300.0	4.90E-04	2.15E-04	1.50E-04	2.05E-05	6.20E-04	4.03E-04	4.86E-05	8.82E-05	2.03E-03
Union St Apts / 296	USASB-1	450.0	7.35E-04	3.22E-04	2.24E-04	3.08E-05	9.29E-04	6.04E-04	7.28E-05	1.32E-04	3.05E-03
Wright Quad / 237	WQSB-1	225.6	3.68E-04	1.61E-04	1.13E-04	1.54E-05	4.66E-04	3.03E-04	3.65E-05	6.63E-05	1.53E-03
Service Bldg	PORT-1	80.46	1.31E-04	5.76E-05	4.01E-05	5.51E-06	1.66E-04	1.08E-04	1.30E-05	2.37E-05	5.45E-04
Service Bldg / 630	PORT-2	22.80	3.72E-05	1.63E-05	1.14E-05	1.56E-06	4.71E-05	3.06E-05	3.69E-06	6.70E-06	1.55E-04
Union St Chiller Plant - RPS	PORT-3	80.46	1.31E-04	5.76E-05	4.01E-05	5.51E-06	1.66E-04	1.08E-04	1.30E-05	2.37E-05	5.45E-04
Union St Chiller Plant - RPS	PORT-4	80.46	1.31E-04	5.76E-05	4.01E-05	5.51E-06	1.66E-04	1.08E-04	1.30E-05	2.37E-05	5.45E-04
Service Bldg	PORT-5	13.00	2.12E-05	9.30E-06	6.48E-06	8.90E-07	2.68E-05	1.74E-05	2.10E-06	3.82E-06	8.81E-05
Service Bldg	PORT-6	13.00	2.12E-05	9.30E-06	6.48E-06	8.90E-07	2.68E-05	1.74E-05	2.10E-06	3.82E-06	8.81E-05
Service Bldg	PORT-7	13.00	2.12E-05	9.30E-06	6.48E-06	8.90E-07	2.68E-05	1.74E-05	2.10E-06	3.82E-06	8.81E-05
Service Bldg	PORT-8	13.00	2.12E-05	9.30E-06	6.48E-06	8.90E-07	2.68E-05	1.74E-05	2.10E-06	3.82E-06	8.81E-05
Service Bldg - Carpenter shop	PORT-9	8.05	1.31E-05	5.76E-06	4.01E-06	5.51E-07	1.66E-05	1.08E-05	1.30E-06	2.37E-06	5.46E-05
Service Bldg / 630	PORT-10	156.00	2.55E-04	1.12E-04	7.78E-05	1.07E-05	3.22E-04	2.09E-04	2.53E-05	4.59E-05	1.06E-03
Service Bldg - Sheetmetal	PORT-11	2.68	4.38E-06	1.92E-06	1.34E-06	1.83E-07	5.53E-06	3.60E-06	4.34E-07	7.88E-07	1.82E-05
Service Bldg - Electric shop	PORT-12	2.68	4.38E-06	1.92E-06	1.34E-06	1.83E-07	5.53E-06	3.60E-06	4.34E-07	7.88E-07	1.82E-05
Utilities	PORT-13	23.50	3.84E-05	1.68E-05	1.17E-05	1.61E-06	4.85E-05	3.15E-05	3.80E-06	6.91E-06	1.59E-04
Utilities	PORT-14	23.50	3.84E-05	1.68E-05	1.17E-05	1.61E-06	4.85E-05	3.15E-05	3.80E-06	6.91E-06	1.59E-04
Utilities Lights - Gen	PORT-15	24.50	4.00E-05	1.75E-05	1.22E-05	1.68E-06	5.06E-05	3.29E-05	3.97E-06	7.20E-06	1.66E-04
	Total	**12,182.0**	**1.99E-02**	**8.72E-03**	**6.08E-03**	**8.34E-04**	**2.52E-02**	**1.64E-02**	**1.97E-03**	**3.58E-03**	**8.26E-02**
			Benzene	**Toluene**	**Xylene**	**1,3-Butadiene**	**Formaldehyde**	**Acetaldehyde**	**Acrolein**	**Total PAH**	**Total HAPs**
					Potential Emission of Total HAPs (tons/yr)			**8.26E-02**			

Methodology
Emission Factors are from AP 42 (Supplement B 10/96) Tables 3.3-1 and 3.3-2.
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
PTE - Diesel Emergency Generators
Output Rating (>=600 HP)
Maximum Input Rate (>4.2 MMBtu/hr)

Company Name: Indiana University
Address City IN Zip: 820 North Walnut Grove, Bloomington, Indiana 47405-2206
Permit Number: 105-41051-00005
Reviewer: Aasim Noveer

Maximum Hours Operated per Year	500
Sulfur Content (S) of Fuel (% by weight)	0.0015

Emissions calculated based on output rating (hp)

	Pollutant						
	PM*	PM10*	direct PM2.5*	SO2	NOx	VOC	CO
Emission Factor in lb/hp-hr	7.00E-04	4.01E-04	4.01E-04	1.21E-05 *(.00809S)*	2.40E-02 **see below	7.05E-04	5.50E-03

*PM10 emission factor in lb/hp-hr was calculated using the emission factor in lb/MMBtu and a brake specific fuel consumption of 7,000 Btu / hp-hr (AP-42 Table 3.3-1).
**NOx emission factor: uncontrolled = 0.024 lb/hp-hr, controlled by ignition timing retard = 0.013 lb/hp-hr

			tons per year							
Building Name	**IDEM Name**	**HP**	**PM**	**PM10**	**direct PM2.5**	**SO2**	**NOx**	**VOC**	**CO**	Status
Assembly Hall / 603	AHSB-2	668	0.12	0.07	0.07	0.002	4.01	0.12	0.92	New
Auditorium / 171	AUSB-1	600.0	0.11	0.06	0.06	0.002	3.60	0.11	0.83	New
Briscoe / 433	BBSB-1	720.0	0.13	0.07	0.07	0.002	4.32	0.13	0.99	Permitted
Chemistry Addition / 072	CASB-1	900.0	0.16	0.09	0.09	0.003	5.40	0.16	1.24	New
W.W. Wright (CEE) / 245	CEESB-1	600.0	0.11	0.06	0.06	0.002	3.60	0.11	0.83	New
Cen. Heat Plant / 445	CHPSB-1	1109.0	0.19	0.11	0.11	0.003	6.65	0.20	1.52	New
Data Center #1 / 579	DCSB-1	2200.0	0.39	0.22	0.22	0.007	13.20	0.39	3.03	Permitted
Data Center #2 / 579	DCSB-2	2200.0	0.39	0.22	0.22	0.007	13.20	0.39	3.03	Permitted
Health Center / 467	HCSB-1	1150.0	0.20	0.12	0.12	0.003	6.90	0.20	1.58	Permitted
HPER / 119	HPSB-1	606.0	0.11	0.06	0.06	0.002	3.64	0.11	0.83	Permitted
Memorial Union / 053	IMUSB-1	750.0	0.13	0.08	0.08	0.002	4.50	0.13	1.03	New
Jordan Hall / 107	JHSB-2	600.0	0.11	0.06	0.06	0.002	3.60	0.11	0.83	New
McNutt / 439	MHSB-2	600.0	0.11	0.06	0.06	0.002	3.60	0.11	0.83	New
Myers Hall / 101	MHSB-3	750.0	0.13	0.08	0.08	0.002	4.50	0.13	1.03	New
MSB-1 / 070	MSB-1	1200.0	0.21	0.12	0.12	0.004	7.20	0.21	1.65	Permitted
MSB-2 / 423	MSB-2	1490.0	0.26	0.15	0.15	0.005	8.94	0.26	2.05	Permitted
Service Bldg / 630	SBSB-4	765.0	0.13	0.08	0.08	0.002	4.59	0.13	1.05	New
SPEA / 452	SPEASB-1	670.0	0.12	0.07	0.07	0.002	4.02	0.12	0.92	New
Swain West	SWSB-1	754.0	0.13	0.08	0.08	0.002	4.52	0.13	1.04	New
Wells Library /GISB 209	WLSB-1	1206.0	0.21	0.12	0.12	0.004	7.24	0.21	1.66	New
Willkie Quad / 299	WQSB-2	600.0	0.11	0.06	0.06	0.002	3.60	0.11	0.83	New
MESH	MESH-1	683.9	0.12	0.07	0.07	0.002	4.10	0.12	0.94	New
	Total	**20,821.9**	**3.64**	**2.09**	**2.09**	**0.06**	**124.93**	**3.67**	**28.63**	

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

***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).

			tons per year							
Building Name	**IDEM Name**	**HP**	**Benzene**	**Toluene**	**Xylene**	**Formaldehyde**	**Acetaldehyde**	**Acrolein**	**Total PAH HAPs*** **	**Total HAPs**
Assembly Hall / 603	AHSB-2	668	9.07E-04	3.28E-04	2.26E-04	9.22E-05	2.95E-05	9.21E-06	2.48E-04	1.84E-03
Auditorium / 171	AUSB-1	600	8.15E-04	2.95E-04	2.03E-04	8.28E-05	2.65E-05	8.27E-06	2.23E-04	1.65E-03
Briscoe / 433	BBSB-1	720	9.78E-04	3.54E-04	2.43E-04	9.94E-05	3.18E-05	9.93E-06	2.67E-04	1.98E-03
Chemistry Addition / 072	CASB-1	900	1.22E-03	4.43E-04	3.04E-04	1.24E-04	3.97E-05	1.24E-05	3.34E-04	2.48E-03
W.W. Wright (CEE) / 245	CEESB-1	600	8.15E-04	2.95E-04	2.03E-04	8.28E-05	2.65E-05	8.27E-06	2.23E-04	1.65E-03
Cen. Heat Plant / 445	CHPSB-1	1109	1.51E-03	5.45E-04	3.75E-04	1.53E-04	4.89E-05	1.53E-05	4.11E-04	3.05E-03
Data Center #1 / 579	DCSB-1	2200	2.99E-03	1.08E-03	7.43E-04	3.04E-04	9.70E-05	3.03E-05	8.16E-04	6.06E-03
Data Center #2 / 579	DCSB-2	2200	2.99E-03	1.08E-03	7.43E-04	3.04E-04	9.70E-05	3.03E-05	8.16E-04	6.06E-03
Health Center / 467	HCSB-1	1150	1.56E-03	5.66E-04	3.88E-04	1.59E-04	5.07E-05	1.59E-05	4.27E-04	3.17E-03
HPER / 119	HPSB-1	606	8.23E-04	2.98E-04	2.05E-04	8.37E-05	2.67E-05	8.36E-06	2.25E-04	1.67E-03
Memorial Union / 053	IMUSB-1	750	1.02E-03	3.69E-04	2.53E-04	1.04E-04	3.31E-05	1.03E-05	2.78E-04	2.07E-03
Jordan Hall / 107	JHSB-2	600	8.15E-04	2.95E-04	2.03E-04	8.28E-05	2.65E-05	8.27E-06	2.23E-04	1.65E-03
McNutt / 439	MHSB-2	600	8.15E-04	2.95E-04	2.03E-04	8.28E-05	2.65E-05	8.27E-06	2.23E-04	1.65E-03
Myers Hall / 101	MHSB-3	750	1.02E-03	3.69E-04	2.53E-04	1.04E-04	3.31E-05	1.03E-05	2.78E-04	2.07E-03
MSB-1 / 070	MSB-1	1200	1.63E-03	5.90E-04	4.05E-04	1.66E-04	5.29E-05	1.65E-05	4.45E-04	3.31E-03
MSB-2 / 423	MSB-2	1490	2.02E-03	7.33E-04	5.03E-04	2.06E-04	6.57E-05	2.05E-05	5.53E-04	4.10E-03
Service Bldg / 630	SBSB-4	765	1.04E-03	3.76E-04	2.58E-04	1.06E-04	3.37E-05	1.05E-05	2.84E-04	2.11E-03
SPEA / 452	SPEASB-1	670	9.10E-04	3.29E-04	2.26E-04	9.25E-05	2.95E-05	9.24E-06	2.49E-04	1.85E-03
Swain West	SWSB-1	754	1.02E-03	3.71E-04	2.55E-04	1.04E-04	3.33E-05	1.04E-05	2.80E-04	2.08E-03
Wells Library /GISB 209	WLSB-1	1206	1.64E-03	5.93E-04	4.07E-04	1.67E-04	5.32E-05	1.66E-05	4.47E-04	3.32E-03
Willkie Quad / 299	WQSB-2	600	8.15E-04	2.95E-04	2.03E-04	8.28E-05	2.65E-05	8.27E-06	2.23E-04	1.65E-03
MESH	MESH-1	683.9	9.29E-04	3.36E-04	2.31E-04	9.44E-05	3.02E-05	9.43E-06	2.54E-04	1.88E-03
	Total	**20,821.9**	**2.83E-02**	**1.02E-02**	**7.03E-03**	**2.87E-03**	**9.18E-04**	**2.87E-04**	**7.72E-03**	**5.74E-02**

Potential Emission of Total HAPs (tons/yr)	**5.74E-02**

	MMBtu/hr		
	coal	FO	NG
Boiler EU-03	100	80	80
Boiler EU-04	100	80	80
Boiler EU-05		190	190
Boiler EU-06	190	190	150
Boiler EU-07		208	217

	Coal		FO		NG	
HHV	12000	lb/Btu	140	MMBtu/Mgal	1020	MMBtu/MMcf
Sulfur	3.15	Wt %	0.5	Wt %		
Ash	9.7	Wt %				